A Common Framework for Analysis of Well Test and Surveillance Pressure and Rate Data

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Abstract

This paper presents a unified approach for analysis of well test and surveillance-type pressure and rate data. Well test data are normally obtained in exploration and appraisal well tests performed during reservoir discovery and appraisal while surveillance data (pressure and rate history) are acquired during well production operations. Well test data are normally analyzed by Pressure Transient Analysis (PTA) while surveillance pressure and rate data are usually analyzed by the methods of Production Data Analysis (PDA). However, these two analysis methodologies are based on the same underlying physical principles and there is no fundamental reason for using different methods for analysis of these two types of data.

In this paper we present an analysis technique based on pressure-rate deconvolution that is applicable for both well test and surveillance data. This approach does not rely on any automatic pressure-rate deconvolution algorithms which are often too restrictive and not robust enough for surveillance data acquired in the course of routine production operations. In this approach a characteristic constant-rate drawdown response function is reconstructed manually using specialized graphical software. In the course of this reconstruction, the well response function is derived by matching the observed well pressure history to the result of convolution of the well rate data and the reconstructed response function. The shape of the response function is adjusted manually until an acceptable match to the well pressure history is achieved.

In the paper, we demonstrate this approach on a number of synthetic and real well examples that include both oil and gas cases, as well as surveillance data from conventional and unconventional wells. In this reconstruction the drawdown response function is derived in the form of the Bourdet derivative plot with reservoir and well parameters (permeability, skin, fracture length, distance to a boundary, reservoir pore volume, and so on) estimated directly from that analysis plot using standard PTA methods. The derived drawdown response function, which is a reflection of observed well behavior, can then be used to forecast future well rate performance for different scenarios of pressure constraints imposed on the well. This approach is not restricted to single wells and can also be used on multi-well reservoirs.

Integration of PTA and PDA techniques into one common analysis framework as presented in this paper brings the two approaches to a common foundation, simplifies the analysis workflow, eliminates the need for different software tools, and elevates the analysis of surveillance data to the same level as that of pressure transient analysis.

Introduction

Well testing is one of the techniques used for reservoir evaluation/appraisal. A well test is a special experiment performed on a well to study dynamic reservoir behavior in response to changing flow conditions in the well. This technique is used for evaluation of formation permeability, large-scale reservoir heterogeneities and boundaries, reservoir connectivity, reservoir pore volume, and for diagnosing possible well productivity problems. During a well test special efforts are made to acquire high quality pressure and rate data that are analyzed by the methods of Pressure Transient Analysis (PTA). Well pressure during a well test is normally measured downhole in close proximity to the producing reservoir interval. Well tests are relatively short and may last from several days to several weeks.

Surveillance pressure and rate data on the other hand are acquired during well production and normally cover much longer time periods from several months to several years beginning from the time the well is first brought on production. Quality of surveillance pressure and rate data is usually not as good and depends on specific practices of operating companies. In deep water offshore environments where reservoirs are developed with a small number of very expensive wells, the wells are normally equipped with downhole pressure gauges and surveillance pressure data are of reasonably good quality. Wells in onshore fields are less expensive and do not normally have downhole gauges installed. In this case well pressure is measured at surface and is often corrupted by wellbore effects. Surveillance pressure and rate data are often analyzed by the methods of Rate Transient/Production Data Analysis. Production data analysis techniques are geared towards longer time span of pressure and rate data. However, they are based on the same fundamental principles and there are no valid technical reasons for using different techniques/methods for analysis of well test and surveillance data.

When a well is first opened to flow, dynamic pressure behavior at the well is controlled by reservoir properties and by the geometry of flow that develops in close proximity to the well. As the radius of investigation increases with time the reservoir properties further away from the well begin to influence the well pressure behavior. The fluid flow in the reservoir towards the well during this early period evolves with time and it is in transient flow regime. At some point the reservoir boundaries start to influence the pressure at the well. Eventually, the well pressure behavior will be completely controlled by reservoir boundaries and the flow in the reservoir during this period is called boundary dominated flow. It is only with the onset of boundary dominated flow the average reservoir pressure begins to decline as a result of production. Therefore while analysis of transient pressure behavior allows evaluation of formation permeability, reservoir heterogeneities, shape of reservoir compartment drained by the well, and quality of the well completion, analysis of the pressure behavior during boundary dominated flow provides an estimate of reservoir pore volume drained by the well.

It is very unlikely that boundary dominated flow could develop during a relatively short well test unless it is the case of very high permeability and small size reservoir compartment. On the other hand, unless it is an extremely low permeability reservoir, it is likely that surveillance data acquired over a long period of time will show boundary dominated flow and could be used for evaluation of reservoir pore volume drained by the well. For this reason the main focus of production data analysis is evaluation of reservoir pore volume.

In this paper we present an analysis approach that is suitable for both well test and surveillance type data. It reconstructs the characteristic constant-rate drawdown pressure response from the variable rate pressure and rate data. In a way it is a form of pressure-rate deconvolution. However, it is not based on a deconvolution algorithm. In fact, it performs only direct convolution computations of the well rate and the unknown drawdown response function that is reconstructed in the process. The shape of this response function is interactively adjusted by an engineer using a specialized software tool until the result of convolution matches the pressure data. The software has built-in functionality that allows the user to easily experiment with the response function by changing its shape and immediately seeing if this change improves data match or not. Our experience using this approach shows that such interactive reconstruction of constant-rate drawdown response is very intuitive, simple, and is under complete control of the user who limits the search to physically meaningful response function shapes.

The Problem of Single Phase Fluid Flow in Reservoirs

The problem of single-phase fluid-flow in a porous medium is the foundation of Pressure Transient Analysis. It also heavily relies on the principle of superposition that requires the flow problem formulation to be linear. The single-phase flow problem in a reservoir is governed by the following equation:

$$\phi_i \, c_t \rho \frac{\partial p}{\partial t} = \nabla \bullet \left(k \frac{\rho}{\mu} \nabla p \right) \tag{1}$$

Here, ρ is the fluid density, μ is the fluid viscosity, ϕ and k are the rock porosity and permeability. The pressure p in **Eq. 1** is a function of time t and of spatial location in the reservoir. The total compressibility c_t in **Eq. 1** accounts for the combined effect of the compressibility values of rock, c_r, reservoir fluid, c and water, c_w, as follows:

$$c_t = c_r + s_{wi} \, c_w + s_{gi} \, c_g \tag{2}$$

In the case of single phase oil or gas flow in a reservoir, water is assumed to be immobile and s_{wi} is the connate water saturation.

In oil reservoirs, the fluid properties are generally constant and do not depend strongly on pressure. As a result, **Eq. 1** is linear and the superposition principle is valid in this case and is defined by the following equation

$$p(t) = p_i - \int_0^t q(\tau) \frac{dp_u(t-\tau)}{dt} \, d\tau \tag{3}$$

Here, $q(t)$ is the well rate, $p(t)$ is the pressure, p_i is the initial reservoir pressure, and $p_u(t)$ is the unit-rate drawdown pressure response function.

Flow Problem Linearization for Gas Reservoirs

In gas reservoirs, the gas properties ρ_g, μ_g, c_g, depend on pressure. **Eq. 1** in this case is non-linear and superposition is not applicable. It is possible to formulate the same gas flow problem in the reservoir not in terms of pressure, *"p"*, but in terms of a "pseudo-pressure" variable, *m(p)*. The pseudo-pressure, $m(p)$, is a function of pressure defined as follows:

$$m(p) = \frac{\mu_{gi}}{\rho_{gi}} \int_{p_{ref}}^{p} \frac{\rho_g(p')}{\mu_g(p')} dp' \tag{4}$$

Note that the pseudo-pressure defined by **Eq. 4** is normalized in order to give pseudo-pressure the same units as pressure. When presented in terms of pseudo-pressure, **Eq. 1** becomes

$$\phi_i \, c_t(p) \, \mu_g(p) \, \frac{\partial m}{\partial t} = \nabla \bullet \left(k \;\nabla m\right) \tag{5}$$

Eq. 5 is somewhat similar to **Eq. 1**. The main difference is that the non-linear coefficient $\rho_g(p)/\mu_g(p)$ in the right side of **Eq. 1** is not present in **Eq. 5**. However, the coefficient $\phi_i c_t \mu_g$ in the left side of **Eq. 5** is still a function of pressure which means this equation is still non-linear.

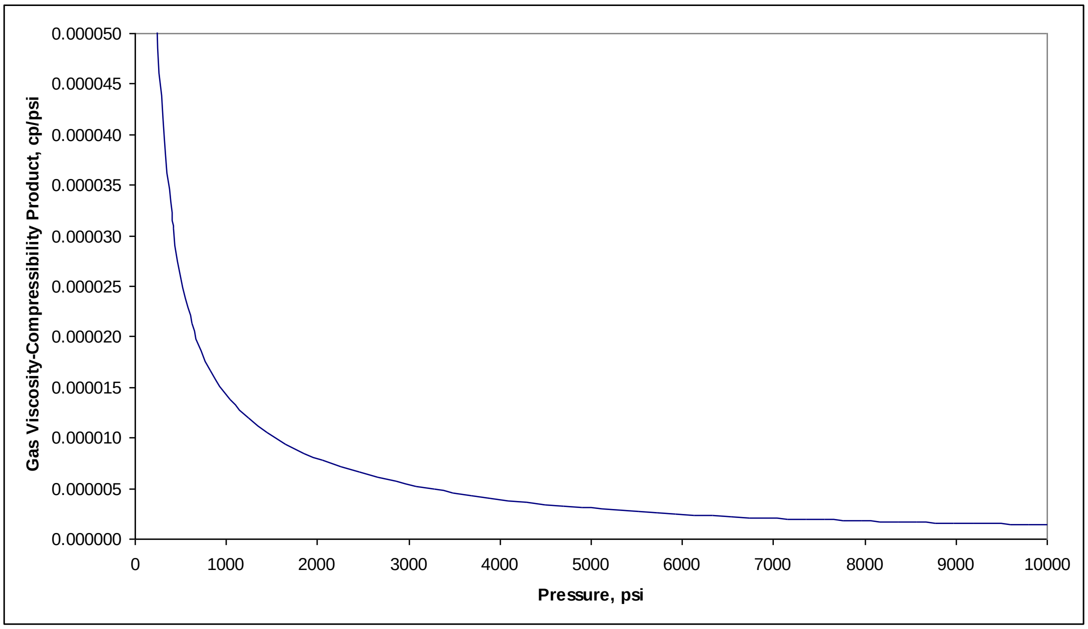


Fig. 1.-Typical behavior of the gas viscosity and compressibility product, $c_g\ \mu_g$, as a function of pressure

Fig. 1 (Levitan, Wilson, 2012) presents a typical plot of the "$c_g\ \mu_g$" product as a function of pressure which shows a monotonically decreasing curve. At high pressure this gas property changes very little. At the pressures above 3000 psi, $c_g\ \mu_g$ can be approximated as constant. According to **Eq. 2**, gas compressibility is a dominant component of the total compressibility c_t. Therefore, at high pressure, the approximation that $c_t\ \mu_g$ is constant makes **Eq. 5** linear. The problem in this case is consistent with the superposition principle which defines the bottom-hole pseudo-pressure during a variable rate flow as:

$$m(t) = m_i - \int_0^t q(\tau) \frac{dm_u(t-\tau)}{dt} d\tau \tag{6}$$

Here, $q(t)$ is the well rate, $m(t)$ is the well pseudo-pressure, $m_i = m(p_i)$ is the pseudo-pressure value at the initial reservoir pressure, and $m_u(t)$ is the unit-rate drawdown pseudo-pressure response function.
Hence, if the pressure in a gas reservoir is sufficiently high, the flow problem is consistent with the principle of superposition. Variation of the coefficient $c_t \mu_g$ cannot be neglected if the pressure in a gas reservoir declines to the point when this coefficient changes significantly. In order to account for this compressibility-viscosity coefficient change with pressure in the governing flow equation and linearize the flow problem one more variable transformation has to be applied to the data. It is generally assumed that the gas flow problem in such case can be linearized by the use of pseudo-time transform (**Agarwal 1979**) in addition to pseudo-pressure transform. In this approach, time in **Eq. 5** is replaced by another variable called pseudo-time, t_a, which is defined as:

$$t_a = c_{ti}\, \mu_{gi} \int_{t_i}^{t} \frac{d\tau}{c_t(p) \mu_g(p)} \tag{7}$$

The pseudo-time shown in **Eq. 7** is normalized so that it still has the units of time, *t*. Note that the variable *p* in **Eq. 7** is the solution of the original gas flow problem in the reservoir. Hence, this time transform is not explicit. The transform is used to linearize the flow problem in order to solve it. However, the transform itself requires the solution to be known. Also note that the pressure *p* is a function of time and of spatial location, $p(\tau, \mathbf{r})$. Hence, the pseudo-time, t_a, defined by **Eq. 7** is a function of spatial location $\mathbf{r}$, $t_a(t, \mathbf{r})$. It has been shown (Lee and Holditch, 1982) that the transform defined by **Eq. 7** linearizes the fluid flow problem provided the derivative of t_a with respect to $\mathbf{r}$ is small. Only if this condition on pseudo-time is true, the fluid flow equation, **Eq. 5**, becomes linear and reduces to:

$$\phi_i \, c_{ti} \, \mu_{gi} \, \frac{\partial m}{\partial t_a} = \nabla \bullet \left(k \;\; \nabla m \right) \qquad (8)$$

A practical approach for using pseudo-time transform is to replace the *p* in **Eq. 7** by the average pressure in the reservoir $\bar{p}$. The average pressure $\bar{p}$ is obtained from a material balance equation. The pseudo-time defined this way is called material balance pseudo-time and was first introduced by Fraim and Wattenbarger, 1987. It was later validated by Palacio and Blasingame (1993) and by Agarwal et al (1999). They verified that for the case when a producing well is located at the center of circular reservoir material balance pseudo-time transform produces results that closely match numerical simulation. This approximation accounts for the variation of the coefficient $c_t\mu_g$ in the left hand side of **Eq. 5** as the average reservoir pressure declines in the course of production from a closed gas reservoir. This is an approximation and the result obtained using this approach is not an exact solution of the original flow problem. However, it is a better approximation than completely ignoring the variation of the $c_t \, \mu_g$ product with pressure.

Note that in the case if material-balance pseudo-time transform is used to linearize the flow problem formulation, the time t in the convolution expression, **Eq. 6**, is replaced by the pseudo-time t_a . The pseudo-pressure response function is a function of pseudo-time, $m_u(t_a)$, the time in the pseudo-pressure and rate functions is mapped to t_a and the integration is with respect to pseudo-time t_a.

Characteristic Well Property

The main objective of well test (or surveillance) data analysis is evaluation of reservoir properties and of the quality of well completion. This is possible because evolution of well pressure behavior with time depends on these reservoir and well characteristics. The problem, however, is that evolution of well pressure also depends on well rate and its variation with time. The pressure behavior caused by rate variation obscures the effects of reservoir properties and well completion. Hence, evaluation of reservoir and well characteristics from well pressure data requires that the effects of rate variation present in the well pressure be identified and removed from the pressure record. This is possible if the well pressure data are consistent with the principle of superposition. The superposition principle is defined by **Eq. 3** in oil case and by **Eq. 6** in gas case. The problem of identification and removal of the effects of rate variation from the pressure record is known as the pressure-rate deconvolution problem. The end-result of this operation is the function that represents the pressure behavior of the same well if it had been produced at constant unit rate throughout its entire production history. This function is called the well unit-rate response function or simply response.

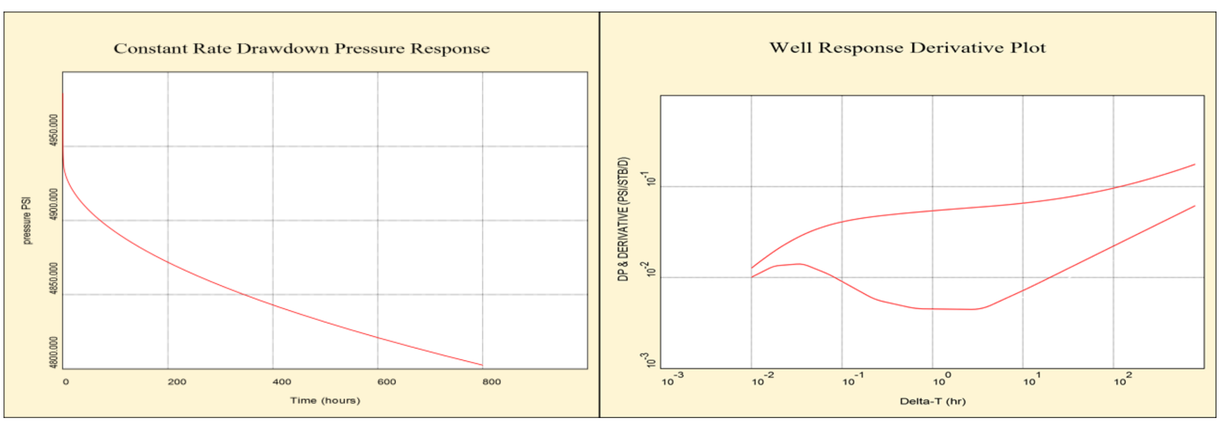


Fig. 2.-Typical behavior of the well constant-rate response on Cartesian plot (left) and on derivative plot (right).

A constant rate response is a monotonically decreasing function of time shown schematically in the left plot in **Fig. 2**. When the same function is presented on standard derivative plot, the plot on the right in **Fig. 2**, it reveals the details of the response function behavior that are difficult to see on the Cartesian plot to the left.

The same information associated with the well response function shown in **Fig 2** plots can also be presented in several other ways. For example, the plots in **Fig. 3** present constant-rate drawdown response in the form of Cartesian plot of rate-normalized $\Delta p = (p_i - p)/q$ function (left) and the reciprocal of this function – the transient productivity index plot (right). Note that the transient productivity index presented in **Fig. 3** is the PI of the well for the case when the well is produced at constant rate.

Constant rate drawdown pressure response reflects the reservoir properties (formation permeability-thickness, reservoir heterogeneities, and boundaries) and the properties of well completion (vertical, horizontal, fractured, multi-frac completion, damage/stimulation) and in this sense it is a characteristic property of the well. In a way, it is a “fingerprint” of the well. Comparing the well fingerprints of the wells from the same reservoir provides a way to identify how differences in well completions and well locations within the reservoir area manifest itself in the well characteristic pressure response.

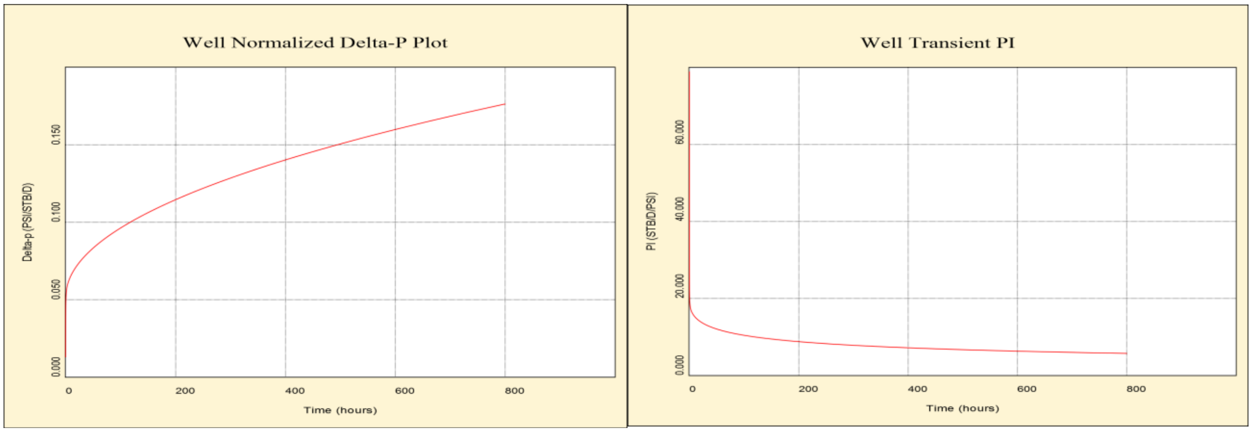


Fig. 3.-Presentation of well response function in the form of normalized Δp plot (left) and transient productivity index plot (right).

Reconstruction of Constant-Rate Drawdown Response

Reconstruction of constant rate drawdown response function is the subject of pressure-rate deconvolution problem. Given the pressure and rate functions, $p(t)$ and $q(t)$ that are obtained in the course of well production (or well testing), pressure-rate deconvolution aims to solve **Eq. 3** for $p_u(t)$. It is assumed that at the start of production the reservoir is in equilibrium and the pressure throughout the reservoir is equal to the initial reservoir pressure p_i. This is a so called “inverse problem” which is very sensitive to the quality of the pressure and rate data and whether these data are consistent with superposition. Success of a deconvolution algorithm in reconstructing a physically meaningful response function depends on whether the pressure and rate data passed to it are consistent with superposition. There are several deconvolution algorithms that have been implemented in commercial well test analysis software and used for well test analysis (von Schroeter et al, 2001; Levitan, 2003). These algorithms rely on an appropriately selected subset of pressure data in the data stream that are more likely to be consistent with superposition. Specifically, these algorithms rely mostly on the pressure data during some of the pressure buildup periods (PBUs) present in the data stream. Even in this case they only use a subset of pressure points from the PBUs selected for deconvolution. All this is done only to make the deconvolution algorithm behave in a stable manner and produce a physically meaningful response function. This approach is too restrictive and not sufficiently robust to handle surveillance type pressure and rate data that may not even have PBUs that could be used by such an algorithm for deconvolution. This is often the case with surveillance type pressure and rate data from unconventional wells.

In this paper we present another approach for reconstruction of the unit-rate response function $p_u(t)$ from well test or surveillance type data. This approach does not rely on automatic deconvolution algorithm. In fact, it is a manual process of fitting observed pressure data to the result of convolution of the observed well rate with the unknown response function $p_u(t)$. On each step of this iterative process the shape of the response derivative on the response derivative plot is adjusted/modified by the user, the resulting response function $p_u(t)$ is convolved with the well rate, and the result of convolution is then compared with the well pressure data. This process of $p_u(t)$ adjustment to match the well pressure is then repeated again until the well pressure data is matched sufficiently well. To facilitate this process we developed a specialized software tool that allows to do all this process of response reconstruction interactively in a graphic fashion on a computer screen/monitor. The software tool is implemented for general multi-well case and can be used for single well and for multi-well problems. In the multi-well case we deal with reconstruction of self-responses (pressure response of a well to its own production) as well as interference responses between different wells.

Since it is the user who controls the process of response reconstruction, he/she should have some basic understanding of which kind of response function shape is physically meaningful and which is not. As was mentioned earlier, a constant rate drawdown pressure response is a smooth monotonically decreasing function of time. It is a solution of diffusivity equation and in general a diffusive process evolves slowly in time. It is difficult to define a precise quantitative measure of response smoothness except a general statement that a transition from one trend to another when the response is displayed on derivative plot takes place over a period of at least one log cycle or more along the time axis. If analyzed pressure data indicate closed reservoir behavior, the constant rate drawdown pressure response will develop a unit-slope late-time asymptotic trend of the derivative if the response function is displayed on a derivative plot. The position of this unit-slope trend on the plot area directly reflects the pore volume of the reservoir compartment drained by the well.

If analyzed pressure and rate data include one or more pressure buildup periods the derivative plot of a representative PBU among them can be used as a blueprint for the shape of reconstructed drawdown response at early time. Transient pressure behavior at early time during drawdown is similar to the pressure behavior during a PBU flow period. The features that may be present in the PBU data on derivative plot that are shorter than ½ log cycle along time axis are not reservoir related and should not be reproduced/included in the reconstructed response function. Having pressure buildup periods in the data stream with the sampling frequency of pressure measurements sufficient for resolving transient behavior is very beneficial but not mandatory for successful reconstruction of constant rate drawdown response function. A data stream that does not include PBU periods has an information gap regarding early time transient pressure behavior. Response reconstruction from such a data stream is still possible; however, the resulting response may have some degree of uncertainty regarding its exact shape at early time.

In the case of a gas reservoir, the well pressure data are always transformed by using pseudo-pressure transform to account for the effects of gas density and viscosity variation with pressure. Hence, in this case the unit-rate drawdown response function is defined in terms of pseudo-pressure, $m_u(t)$. Pseudo-pressure transform of pressure data can also be used in oil reservoir case if oil density and viscosity vary significantly within the range of pressure variation of well pressure data. In addition, if in the course of production the well pressure demonstrates reservoir pressure depletion characteristic of closed reservoir behavior it is necessary to use material-balance pseudo-time transform in order to account for $c_t\mu_g$ variation with pressure. This transform requires an estimate of reservoir pore volume. The reservoir pore volume itself is reflected in the well surveillance data and should be recovered/derived in the same process of response reconstruction. We achieve this iteratively in the following sequence of steps:

1. Apply pseudo-pressure transform to the well pressure data.
2. Adjust the shape of response function $m_u(t)$ to reproduce as close as possible the pressure data and the declining pressure trend over the production history of the well. In order to honor this declining pressure trend the response derivative should develop a unit-slope trend at late time.
3. Select a match point on the unit-slope late time derivative trend and translate its coordinates into the corresponding estimate of reservoir pore volume.
4. Using the value of pore volume obtained in Step 3, apply material balance pseudo-time transform to the surveillance pressure and rate data.
5. Go back to Step 2 and repeat this iterative loop until the pore volume estimates and the response functions are sufficiently close on two successive iterations. Normally it takes less than 5 iterations for this process to converge.

Often, well surveillance pressure and rate data are in general consistent with pressure-rate superposition and only some small portions of the pressure record are out of the convolved pressure trend. These portions of pressure data are likely affected by some short-lived non-linear effects or caused by pressure gauge malfunction. So, these specific parts of the pressure record are not consistent with superposition and should be ignored in the process of response reconstruction. Response reconstruction discussed here is an interactive process and it is relatively easy to identify such portions of pressure data in the course of response reconstruction. It is also possible to conclude if the well pressure and rate data as a whole are consistent with superposition. Another very important and useful feature of this reconstruction process is the ability to assess what parts of the response function are very well defined by the well pressure and rate data and what parts of the response function are associated with significant level of uncertainty.

Our experience in using this approach of unit-rate response reconstruction for both oil and gas reservoirs indicates that it is very efficient, intuitive, and is under complete control of the user. In the course of this response reconstruction the user can keep the shape of response function within what is “physically meaningful” function shape.

We present below several examples of drawdown response reconstruction that demonstrate that it is indeed possible to reconstruct unit-rate drawdown response and match observed pressure data using this approach.

Example 1 – Oil Case

The first example demonstrates response reconstruction for an oil case using synthetic data that emulate a well test type sequence that includes several PBU periods. The data are obtained using a type-curve model of vertical well located between two parallel no-flow boundaries. The blue curve in the top left plot in **Fig. 4** presents the well pressure. The lower part of the plot presents the corresponding well rate. The top right plot in **Fig 4** is the response derivative plot. This plot is used to define and manipulate the shape of the response function. The red curves in this plot represent the initial shape of the response function which is the start point of response reconstruction. The blue curves in the top right plot present the derivative plot of the pressure during the last PBU period of the test sequence in the top left plot. The red curve in the top left plot presents the result of convolution according to Eq. 3 of the well rate and the response function from the top right plot. The red curve, the convolution result, does not match the blue curve because the shape of response function is wrong. In order to match the well pressure data the shape of the response function has to be appropriately adjusted.

The final shape of the response that reproduces the well pressure is shown in the lower right plot in **Fig. 4** and the corresponding match is demonstrated in the lower left plot. The reconstructed response function follows the PBU derivative during early part of the response. At later time it deviates from the PBU derivative and this deviation is necessary in order to reproduce the pressure behavior over entire span of pressure data

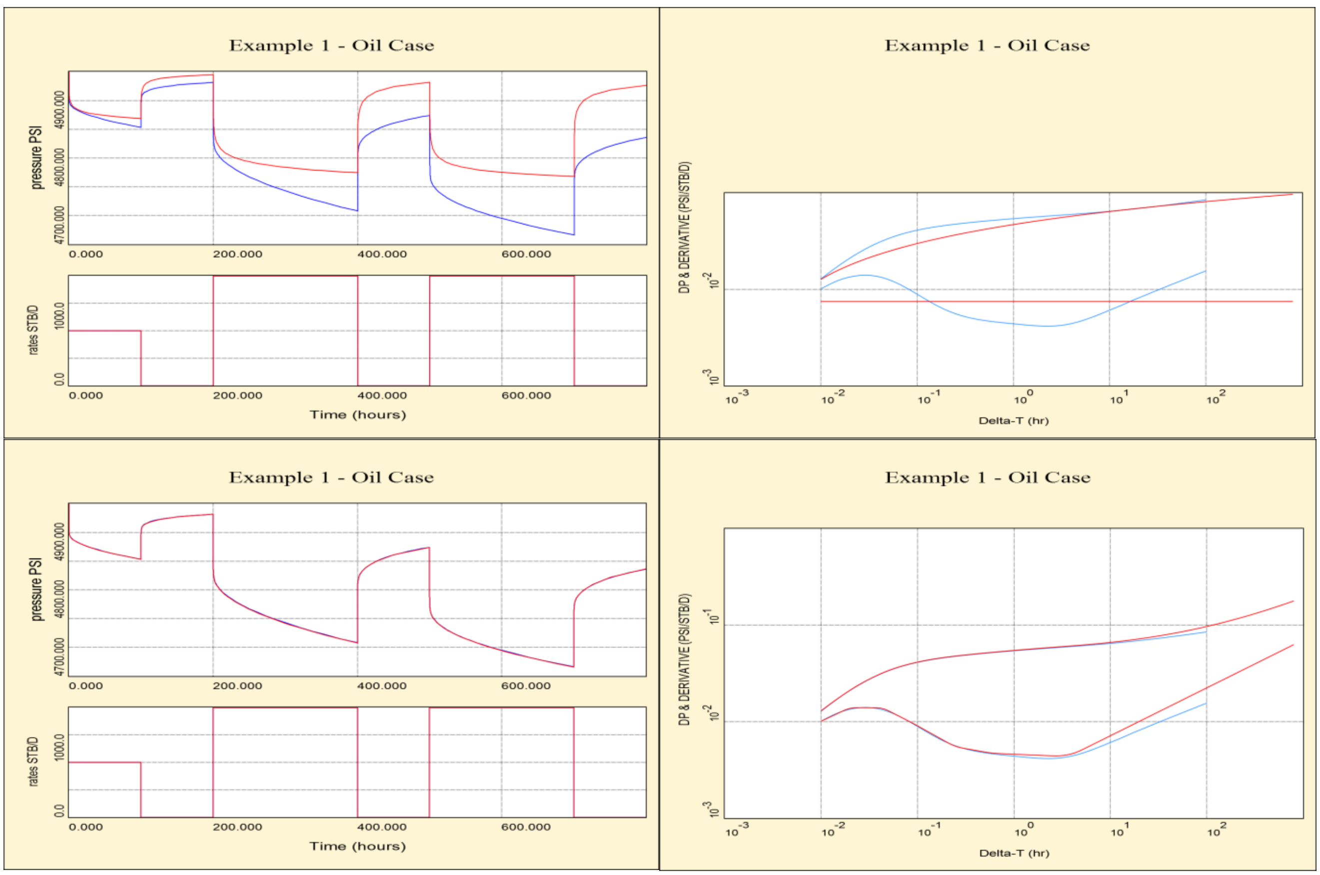


Fig. 4. - Example 1 – Oil Case. Reconstruction of constant rate drawdown response. Top Left plot: blue - well pressure data, red – result of convolution of the well rate data (at the lower part of the plot) with the initial response in top right plot. Top Right plot: red – initial response function, blue – derivative plot of the last PBU well pressure data from top left plot. Bottom Left plot: final match of well test pressure data with the result of convolution of the well rate and the final response function from bottom right plot. Bottom Right plot: red - final response function, blue – derivative plot of the last PBU well pressure data from bottom left plot

Example 2 – Gas Field Example

The second example represents a field surveillance data from high productivity dry gas well (Levitan, Wilson, 2012). This is a single well in the reservoir compartment. The well is instrumented with a permanent downhole pressure gauge. The data in **Fig. 5** represent five years of the well production history. During this period the reservoir pressure declined from 6300 psi to around 1500 psi. The test sequence includes significant number of shut-in periods with some of them yielding good quality pressure transient data. So, in this case we do have PBU data to guide us on the shape of response function at early time.

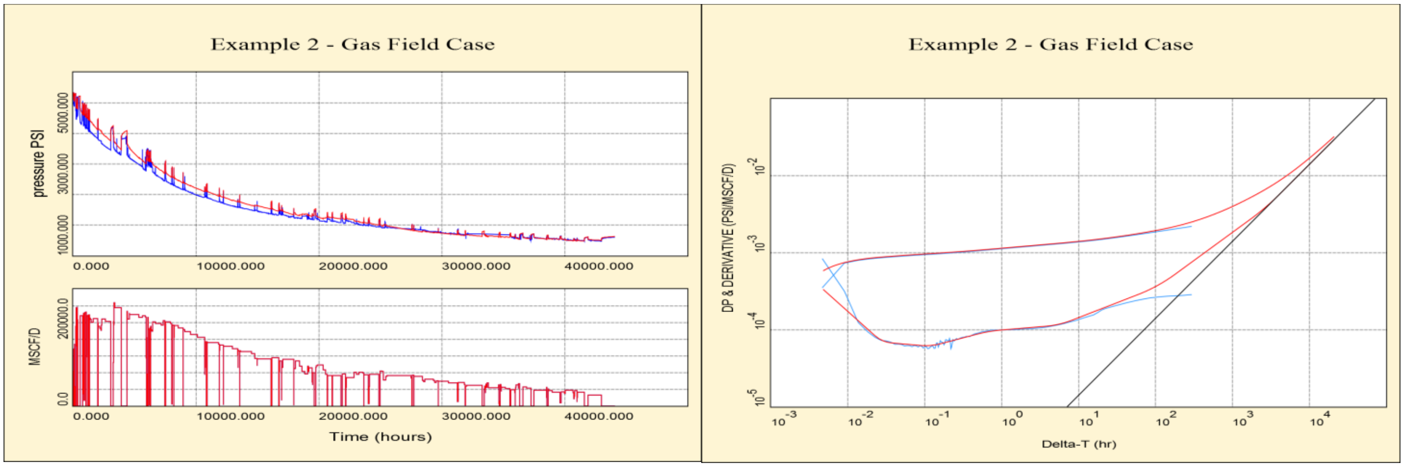


Fig. 5. - Example 2 – Gas Field Case. Reconstruction of constant rate drawdown response. Left plot: blue - well pressure data, red – result of convolution of the well rate data (at the lower part of the plot) with the response in the right plot. Right plot: red – final response function, blue – derivative plot of the last PBU well pressure data from left plot.

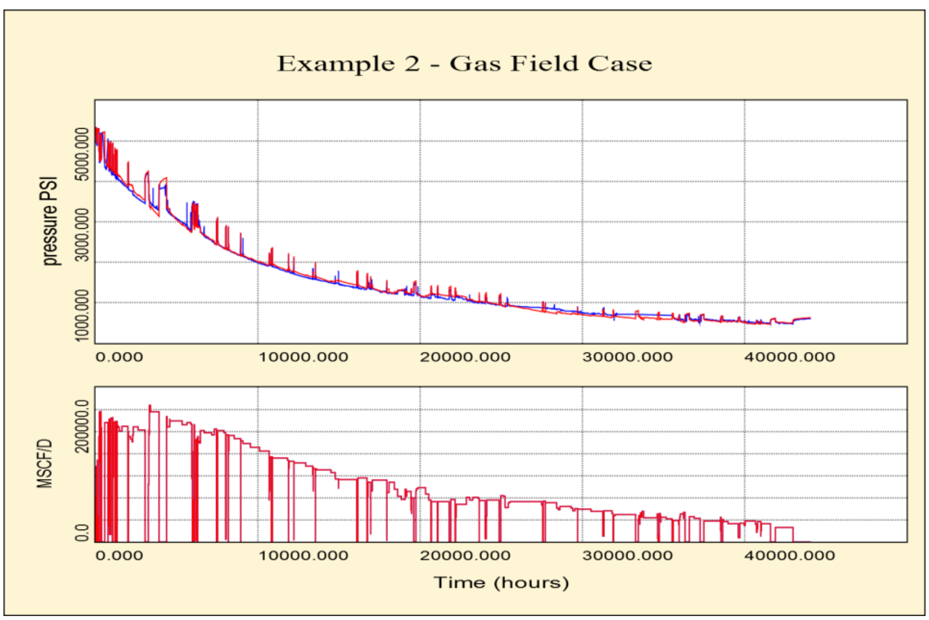


Fig. 6. - Example 2 – Gas Field Case. Match of surveillance pressure with the result of convolution of the well rate and the response function from Fig. 5 that accounts for the rate dependent skin factor.

Since this is a gas reservoir, we account for variation of gas density and viscosity with pressure by applying pseudo-pressure transform, Eq. 4, to the well pressure data. As a result, the unit rate drawdown response function in this case is defined in terms of pseudo-pressure $m_u(t)$ and the principle of superposition is given by the convolution expression, Eq. 6. As in the previous Example we start response reconstruction with the response function defined by constant derivative. We quickly discover that in order to honor the overall declining pressure trend of the well pressure the response function derivative should develop an increasing unit-slope asymptotic trend at late time. However, we also discover that it is not possible to reproduce accurately the long-term pressure behavior by just manipulating the shape of the response function. With the reservoir pressure decline experienced during the period of production the well pressure is affected by significant variation of $c_t\mu_g$ with pressure. As a result, we use the described above iterative procedure for evaluation of reservoir pore volume and unit-rate response reconstruction. The final match of surveillance pressure data and the resulting response function are shown in **Fig. 5**.

Note that the declining reservoir pressure trend in **Fig. 5** is defined by the sequence of PBUs during production history of the well. The convolved pressure (red curve) in **Fig. 5** matches this pressure trend defined by the sequence of PBUs. The discrepancy between the convolved pressure and the surveillance pressure during flow periods of the first half of production history in **Fig. 5** is caused by rate-dependent skin factor of this well. Recall that this is a high rate gas well and its pressure is affected by this phenomenon. It is possible to account for the rate dependent skin effect in the convolved pressure. The resulting match of the well surveillance pressure data is shown in **Fig. 6**.

Example 3 – Oil Case

The third example demonstrates response reconstruction of synthetic data that emulate surveillance data of a well producing at constant pressure constraint. This example does not include any PBU periods to provide information on the early time transient pressure behavior of reconstructed response. It was designed to verify if it is possible to figure out the shape of the response function when the pressure data do not provide any hint of what the response function might look like. The experiment was conducted as a blind test when one of the co-authors of this paper created synthetic pressure and rate data using an analytical type-curve solution and then passed the data to another co-author for response reconstruction. The result of reconstruction was then passed back to the author of the data to check how closely the reconstructed response resembled the original type-curve function.

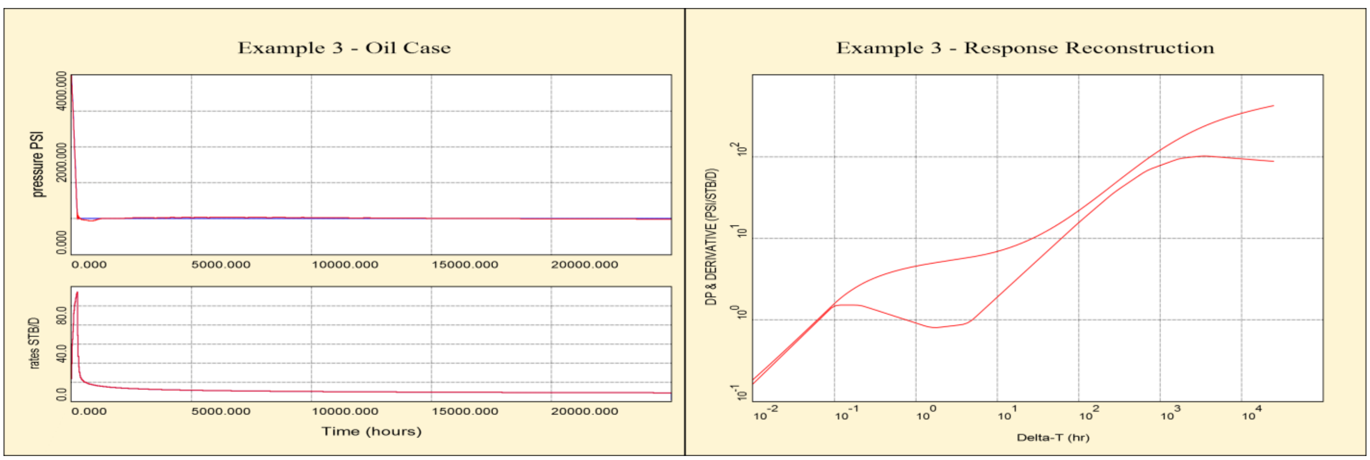


Fig. 7. - Example 3 – Oil Case. Blind reconstruction of response function. Left plot: blue- synthetic pressure and rate data, red – convolution result of well rate with the response function from the plot on the right plot. Right plot: reconstructed response function.

The simulated pressure and rate data are shown in the left plot of **Fig. 7** as blue curve. The red curve in the plot presents the result of convolution of the well rate and the response function from the **Fig. 7** right plot. **Fig. 7** demonstrates that it is indeed possible to reproduce sufficiently well the well pressure data with an appropriately defined response function. The problem is that the response function reconstructed in this process is not unique and it is possible to achieve a similar quality match of the well pressure data with a different response function. The left plot in **Fig 8** presents a different response that matches the well pressure equally well. The right plot in **Fig 8** compares the two reconstructed responses with the true type curve solution used for generating Example 3 pressure data. This plot demonstrates that the reconstructed responses deviate from each other and from the true type-curve function mostly at early time.

This problem of non-uniqueness in recovering response function from production data is not specific to the above data set or to a specific technique used for response reconstruction. It is a problem with production data - production data in general have an information gap regarding the character of transient pressure behavior at early time. This information gap is a fundamental problem recognized and documented in the literature (Wei-Chun Chu et al, 2000; Araya, Ozkan, 2002). While this non-uniqueness in response reconstruction is intrinsic to production data and cannot be fixed through a "smarter" deconvolution algorithm, the uncertainty is confined to a relatively short time period – the first hundred hours in the case of well data in the above example. Beyond this early time period, the data define the shape of response function reasonably well with the level of uncertainty decreasing as time increases. The only practical way to overcome this problem is to include PBU periods in the well production history and to make sure that the pressure sampling frequency during these periods is sufficient for accurate resolution of the pressure behavior during these periods.

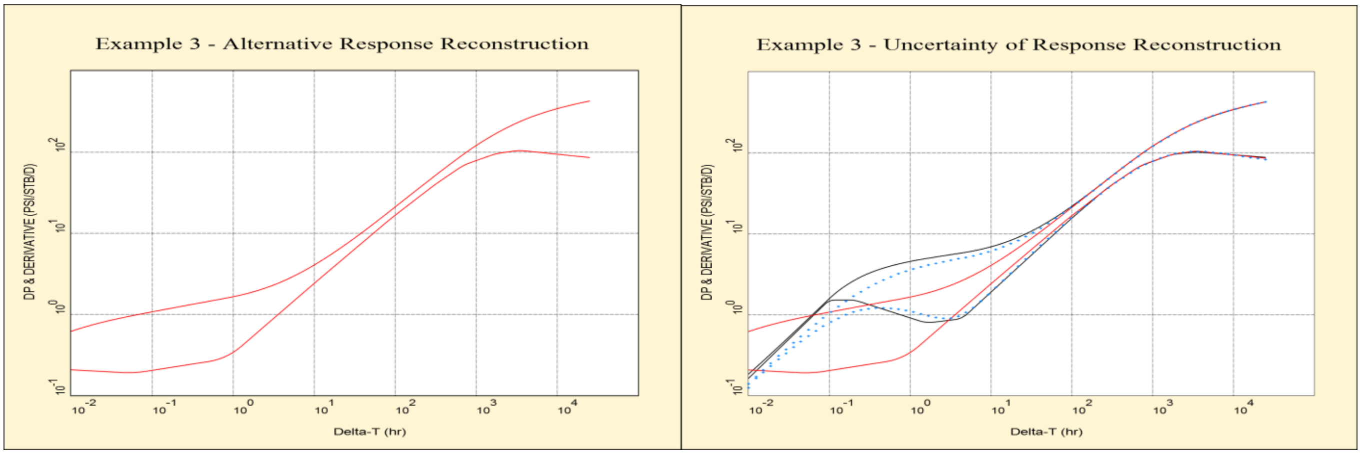


Fig. 8. - Example 3 – Oil Case. Uncertainty of response reconstruction. Left plot: an alternative response reconstruction result. Right plot: reconstructed responses (solid lines) vs. true type curve (markers) used for generation of Example 3 pressure data

Response Is Reconstructed - What Is Next?

The main objective of this paper is to present a reliable and robust technique for reconstruction of the well constant rate drawdown pressure response from the well surveillance or well test pressure and rate data. After this well characteristic is reconstructed it can then be analyzed by standard methods of Pressure Transient Analysis. Note that the response function is defined on the time interval equal to the total time span of the data. For this reason the response function reflects the properties of significantly larger reservoir volume than any volume investigated by a PBU test. In other words, the information content of response function is much richer than that of any PBU test.

The response function is reconstructed originally in the form of derivative plot, however, it can then be presented on any type of analysis plots used in pressure transient analysis. Some basic reservoir and well parameters (permeability, skin, fracture length, distance to a boundary, reservoir pore volume, and so on) can be estimated directly from such analysis plots. Recall that as discussed earlier in Example 2, the reservoir pore volume and turbulence coefficient are estimated in the course of response reconstruction. The next step in the analysis workflow is to build an appropriate reservoir-well model based on the understanding of reservoir description and well completion, guided by the character of the well response function. The model is then calibrated by matching simulated well pressure with the reconstructed response function. If a calibrated model reproduces accurately the well response function, the same model will also reproduce the well pressure and rate data. This model then can be used for simulation of future well production under different types of constraints imposed on the well.

In some situations developing a model that correctly represents the actual reservoir and well configuration downhole is difficult. This is especially the case for unconventional wells because of the uncertainty associated with the fracture system created in the course of well completion. In such situations it is still possible to forecast future well production under different well constraints by using the constant rate response function reconstructed from well surveillance pressure and rate data and without resort to model development and simulation.

Forecasting Future Well Production

A unit rate drawdown response of a well derived from the pressure and rate data observed during the well production history reflects the true ability of the well to produce reservoir fluid. Having obtained this well characteristic, it is possible to predict the future well rate for a specific pressure constraint imposed on the well. This well rate prediction relies on the same convolution expression given by Eq. 3 in case of oil or Eq. 6 in case of gas. During the rate forecast time period, the pressure in the left-hand-side of Eq. 3 is set to the well constraint pressure and the equation is solved for $q(t)$ with the unit rate response function $p_u(t)$ in the right-hand-side obtained in the earlier response reconstruction.

The response function $p_u(t)$, however, is recovered on the time interval equal to the total duration of the observed well production history. For rate prediction it has to be defined on a longer time interval that includes the period of rate forecasting. Hence, well rate forecasting requires extrapolation of the response function $p_u(t)$ to longer time interval. Predicted well rate, therefore, depends on how $p_u(t)$ is extrapolated into the future. A normal approach is to assume that $p_u(t)$ will continue the trend established at the end of the observed well production history. In view of the fact that in a process governed by diffusivity equation a transition to a new trend evolves over a period of at least one log cycle along the time axis of the response function derivative plot, this assumption should work for a "short term" well rate forecast. An extra log cycle after the end of observed production history is actually a long time that may exceed the entire observed production history. The longer is the observed well production history the less sensitive is the predicted rate to the response extrapolation. As an example of well rate forecasting, **Fig. 9** presents prediction of the well rate for the gas well field case discussed in Example 2.

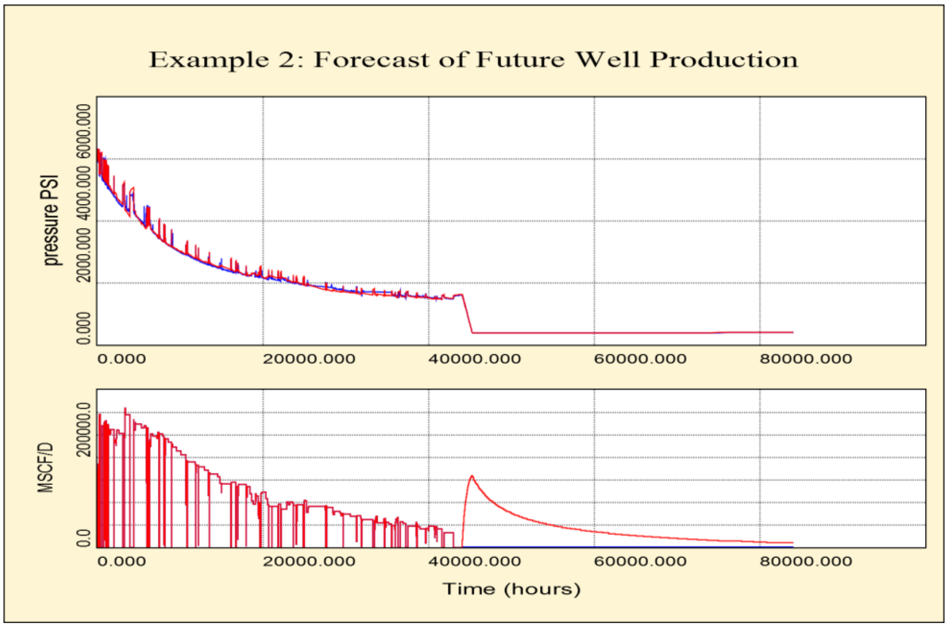


Fig. 9. – Forecast of well production rate for a gas well in Example 2 above.

Unconventional Wells

An explosion in the last decade of gas and oil production from extremely low permeability shale formations is the result of advancements in hydraulic fracturing and well completion technology. These reservoirs are exploited by drilling long horizontal wells with multiple transverse fractures. Because of extremely low formation permeability, evolution of the pressure field during unconventional production is very slow. The reservoir volume investigated during a typical well test is confined to the immediate vicinity of the well (as little as a few feet from the well). For this reason well testing does not allow reliable assessment of long-term well productivity and is not a practical and proper approach for unconventional well evaluation. On the other hand, surveillance pressure and rate data acquired over months and years of well production do contain information on long-term production ability of the well. Production data, however, have an information gap at early time. This gap could be filled by appropriate PBU tests incorporated occasionally in the well production data stream. Such PBU data are not analyzable on its own; however, the PBU data can supplement production data in the analysis and fill the gap in transient pressure behavior at early time. The analysis approach discussed in this paper provides a venue for straightforward incorporation of PBU and production data in the analysis workflow.

Unconventional horizontal wells completed with multiple transverse fractures exhibit transient linear flow towards fractures that may last for years. Analysis of this linear flow reflected in the well surveillance pressure and rate data yields an estimate of the product of square root of rock/shale permeability k and of total/combined fracture length x_f , the combination $\sqrt{k}x_f$. Note that from linear flow pressure behavior it is not possible to determine the formation permeability and the fracture length separately since unconventional wells do not normally show late time derivative stabilization necessary for permeability estimation.

Compared to conventional gas wells, unconventional wells bring some complications into analysis. Unconventional gas wells are often produced at large pressure drawdown with most of this drawdown taking place across a region adjacent to fracture. Thepressure at the outer edge of this region is close to the initial reservoir pressure while near the fracture the pressure is close to the bottomhole well flowing pressure. The parameter combination $c_t\mu_g$ is an input into $\sqrt{k}x_f$ estimation. This parameter combination is mostly controlled by gas properties and it varies across this near-fracture region. Correct estimation of $\sqrt{k}x_f$ requires that variation of $c_t\mu_g$ with pressure in the near-fracture region be accounted correctly. This problem has been studied extensively by a number of researchers. Ibrahim and Wattenbarger (2005, 2006) developed an empirical correction factor while others followed an approach based on the ideas of material balance pseudo-time transform used to account for $c_t\mu_g$ variation with pressure during boundary dominated flow. The problem, however, is that during linear flow regime the reservoir behaves as an open system. Anderson and Mattar (2005) proposed to use the so-called corrected pseudo-time in which gas viscosity and total compressibility are evaluated at the average pressure in the "region of influence". Nobakht and Clarkson (2011a, 2011b) followed this approach and documented analyses details for the cases of wells producing at constant rate and at constant pressure conditions. The problem with this approach is that the region of influence is not clearly defined and it depends on location of the well relative to reservoir/drainage boundaries.

Chen and Raghavan (2013) came up with an approach that overcomes this drawback. For wells producing at constant pressure, they discovered that numerical solutions that account for variation of $c_t\mu_g$ in the near-fracture region can be closely matched with an analytical solution with constant coefficient $c_t\mu_g$ provided that this coefficient is evaluated at appropriately defined value of pressure. Chen and Raghavan verified that this observation works for vertical wells with single fracture and for horizontal wells with multiple transverse fractures. They provided a very simple recommendation for the pressure p^* at which the coefficient $c_t\mu_g$ should be evaluated $p^* = \beta(p_i + p_{wf})$, where $0.55 \leq \beta \leq 0.6$.

Pseudo-Time Transform for Unconventional Wells

The observation of Chen and Raghavan (2013) can be used to define a pseudo-time transform tailored for unconventional wells. The purpose of this pseudo-time transform is to account for the variation of $c_t\mu_g$ across the near-fracture region and to linearize the fluid flow problem. We define such pseudo-time transform as follows:

$$t_a = c_{ti}\mu_{gi}\int_0^t \frac{d\tau}{c_t(p^*(\tau))\,\mu_g(p^*(\tau))} \quad (9)$$

Here,

$$p^* = p_i - b\left[p_i - p_{wf}(t)\right] \quad (10)$$

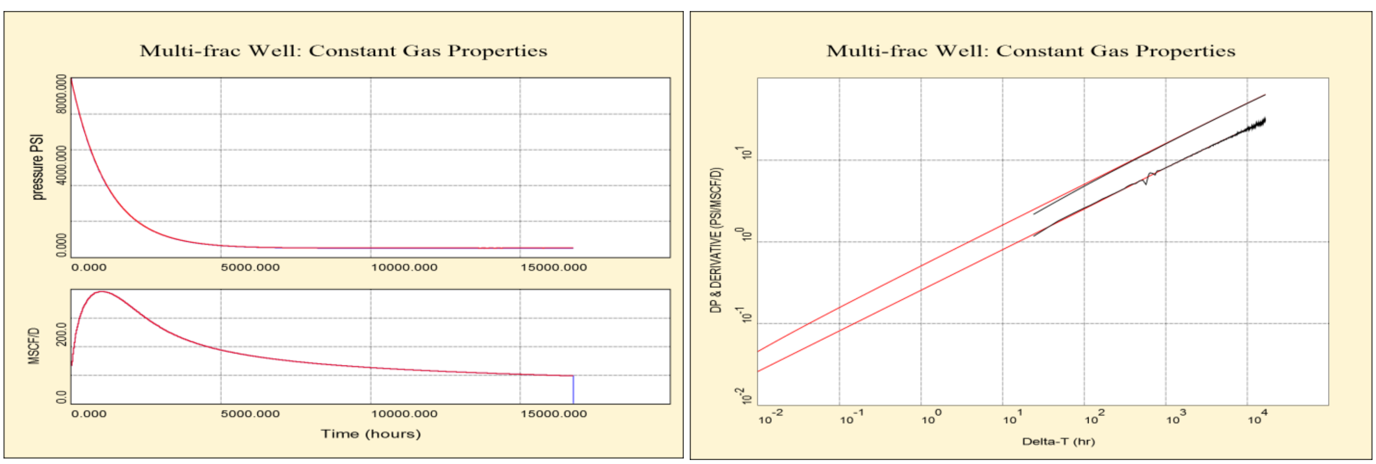


Fig. 10. – Multi-frac Well: Reconstruction of constant rate drawdown response for the case of constant gas properties. Left plot: blue - well pressure data, red – result of convolution of the well rate data (at the lower part of the plot) with the response (in red) from the right plot. Right plot: red – response function, black – derivative plot of the numerically simulated constant rate drawdown pressure.

The weighting coefficient b in Eq. 10 is limited to the range $0 \leq b \leq 1$. At the lower limit of this range, $b = 0, p^* = p_i$ and at the upper range limit $b = 1,\ p^* = p_{wf}$. The optimal value of coefficient b is presented below. Note that the above definition of pseudo-time transform does not limit it to well production under constant well flowing pressure conditions as in Chen and Raghavan (2013) paper. It is a generalization to variable well pressure conditions and as a result it requires appropriate validation. Also note that this pseudo-time transform is specific to the linear flow geometry associated with the flow towards fracture.

Validation of Unconventional Wells Pseudo-Time Transform

We validate the above defined pseudo-time transform by using the pressure and rate data obtained by numerical simulation of gas production from a multi-fractured horizontal well. The numerical well model includes four transverse fractures and accounts for variation of gas properties with pressure. We can also use the same simulation model in the mode when the fluid properties are constant with the gas properties values defined at the initial reservoir pressure. In this case the flow problem is linear and we can validate performance of numerical simulator and the results of response reconstruction in this special case.

We begin the validation of simulator performance and our ability to reproduce the correct response function from simulated pressure and rate data with this special case of constant gas properties. The flow problem in this case is linear and the results of simulation should be consistent with superposition. Response reconstruction in this case does not require the use of pseudo-time and pseudo-pressure transforms. Response reconstruction for this case is presented in **Fig.10**. We are able to reproduce very accurately the pressure data with the result of convolution of well rate and the reconstructed drawdown response function. We validate the reconstructed response function by comparing it with the derivative plot of the well pressure during constant rate production. This constant rate production pressure is obtained in a separate simulation run using the same well model. The simulated derivative in the right plot in **Fig. 10** shows some level of noise in the derivative characteristic of numerical simulation results.

Response reconstruction using simulated pressure and rate data produced by the same reservoir-well model in nonlinear case when gas properties depend on pressure should produce the same response as the one shown in the right plot in **Fig. 10** (red). The problem of response reconstruction in this case is linearized by the use of appropriate pseudo-pressure and pseudo-time transforms. The pseudo-time transform defined by Eq. 9 and Eq. 10 includes a coefficient b the value of which has not been appropriately defined yet. We select the value of coefficient b to have the reconstructed response in the case of variable gas properties to be as close as possible to the response in **Fig. 10**.

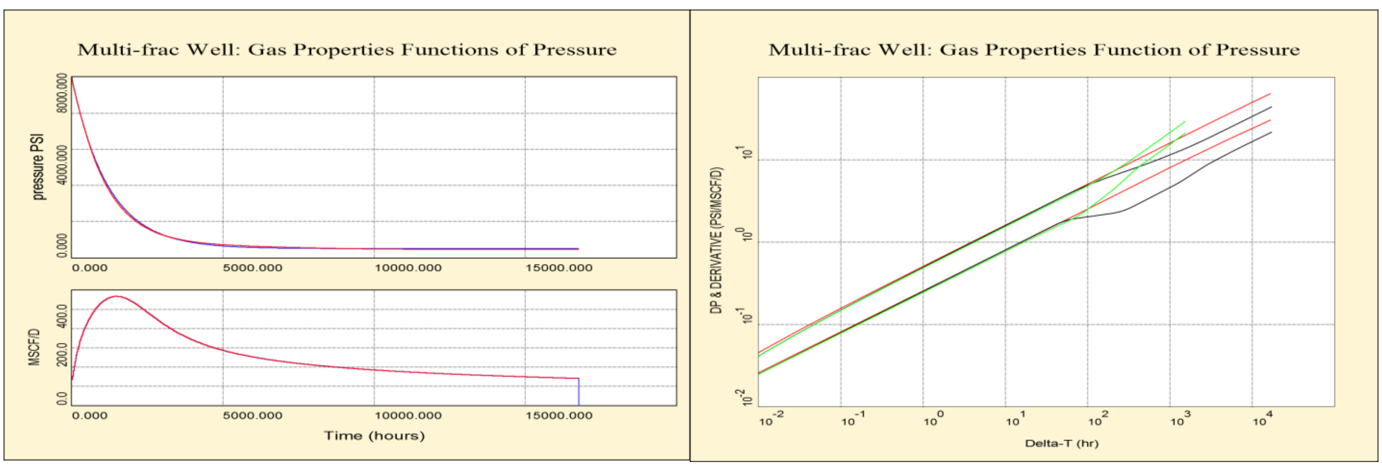


Fig. 11. – Multi-frac Well: Reconstruction of constant rate drawdown response for the case when gas properties are functions of pressure. Left plot: blue - well pressure data, red – result of convolution of the well rate data (at the lower part of the plot) with the response function from the right plot shown in green. Right plot: red – response from Fig. 10 right plot, black – the response function for $b = 0$, green – the response function for $b = 0$.

Fig. 11 demonstrates effect of the value of coefficient b in the definition of pseudo-time transform on the response function reconstructed from simulated pressure and rate data that reflect variation of gas properties with pressure. The right plot in **Fig. 11** presents the response function (black) for the case of $b = 0$ and the response function (in green) for coefficient $b = 1$. The response function shown in red in **Fig. 11** is the response copied from **Fig. 10**. It represents the shape the response should have if the flow problem is linearized through the use of variable transforms correctly. Note that the black and the green responses honor the well pressure data reasonably well. The left plot in **Fig. 11** demonstrates this for the case of green response function.

The black and green response functions in **Fig. 11** significantly deviate from the correct shape (red) because of wrong pseudo-time used. Recall that in the case of $b = 0$, $p^* = p_i$ and pseudo-time $t_a = t$. Hence, the black response function is obtained with no time transform applied to the data. The case of $b = 1$ corresponds to $p^* = p_{wf}$ and this is obviously wrong pressure to use for computation of the term $c_t\mu_g$ in the pseudo-time Eq. 9. Note that pseudo-time contracts compared to regular time and the span of the response function in this case is shorter.

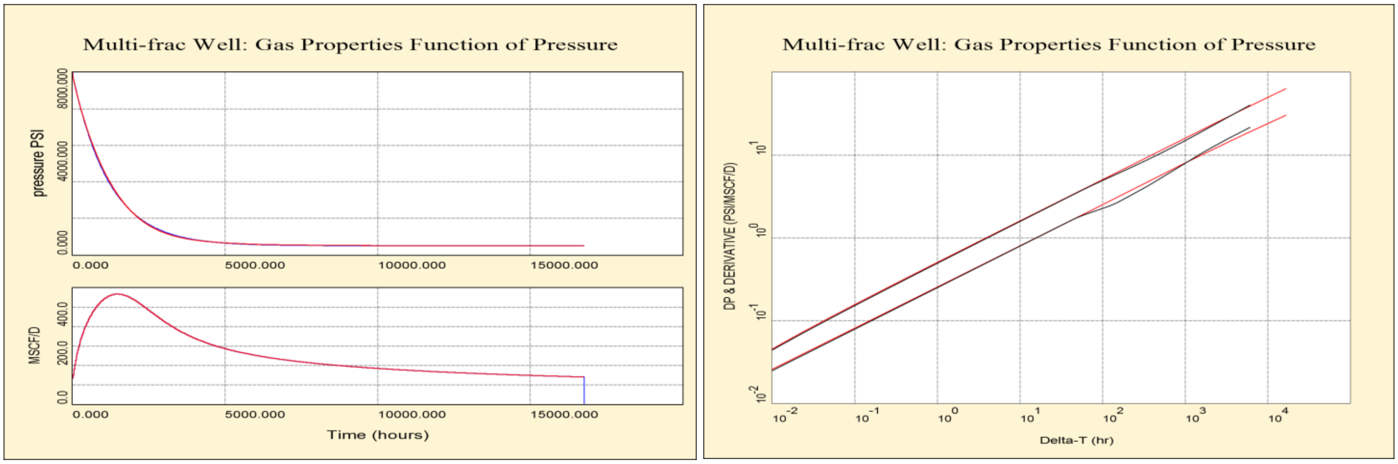


Fig. 12. – Multi-frac Well: Reconstruction of constant rate drawdown response for the case of calibrated value of coefficient b. Left plot: blue - well pressure data, red – result of convolution of the well rate data (at the lower part of the plot) with the response function from the right plot shown in black. Right plot: red – response from the right plot in Fig. 10, black – the response function for $b = 0.6$.

The optimal value of coefficient b is close to $b = 0.6$. The reconstructed response function for this case is shown by black lines in the right plot in **Fig. 12**. The response function still exhibits some minor distortion from the correct shape. With the calibrated pseudo-time transform, the level of distortion in the response function is sufficiently small and the reconstructed response should be acceptable for well evaluation purposes.

Example 4: Unconventional Well

The data in this example are from an unconventional gas well. The well pressure and rate data cover 15 months of the well production history. The bottom part of the wellbore is a horizontal section approximately 5000 ft long. A large number of transverse fractures distributed along this horizontal well section are created in the course of 20-stage hydraulic fracture stimulation treatment.

Fig 13 presents records of pressure and rate data obtained during entire well production history. The pressure and rate data are represented by one pressure and rate sample per day. Pressure is measured at the wellhead and converted to bottomhole conditions using Gray correlation (Kumar, 2005). Each well rate sample represents the average rate for the previous day.

The well was placed on production with no tubing in the wellbore. A two-inch inner diameter tubing was installed two months later. Well gas rate declined from its peak of 4 MMscf/d to slightly less than 1 MMscf/d towards the end of production history. Together with gas, the well also produced condensate, and water. Condensate-gas ratio remained approximately constant while water-gas ratio slowly decreased through the last year of production history.

Reconstruction of constant rate drawdown response in this case is complicated by lack of transient quality PBUs in this well production data stream. The fact that the well produces liquids along with gas may potentially be a cause for inconsistency of the well pressure and rate data with the principle of superposition. Response reconstruction presented below ignores liquids production and treats the well data as if this is a dry gas well. In this response reconstruction we apply pseudo-pressure and pseudo-time transform for unconventional wells discussed earlier in order to account for gas properties variation with pressure. **Fig. 14** presents a response function that reproduces most of the well pressure data. The corresponding well pressure match is shown in **Fig.13** where the red curve in the top plot represents convolution of this response and the gas rate presented in the bottom plot of **Fig. 13**. The convolved curve (red) reproduces the well pressure (blue) sufficiently well except for a short period prior to installation of tubing. This discrepancy is most likely an indication of wellbore loading which is not accounted sufficiently accurately by the correlation used for conversion of wellhead pressure to bottomhole conditions. A small diameter tubing installed in the wellbore resolved the problem of wellbore loading and resulted in stable well operation through the rest of production history. The fact that we are able to reconstruct constant rate drawdown response that reproduces most of the pressure data is an evidence that the well pressure and rate data are consistent with superposition and multi-phase production does not produce non-linear effects that destroy this consistency.

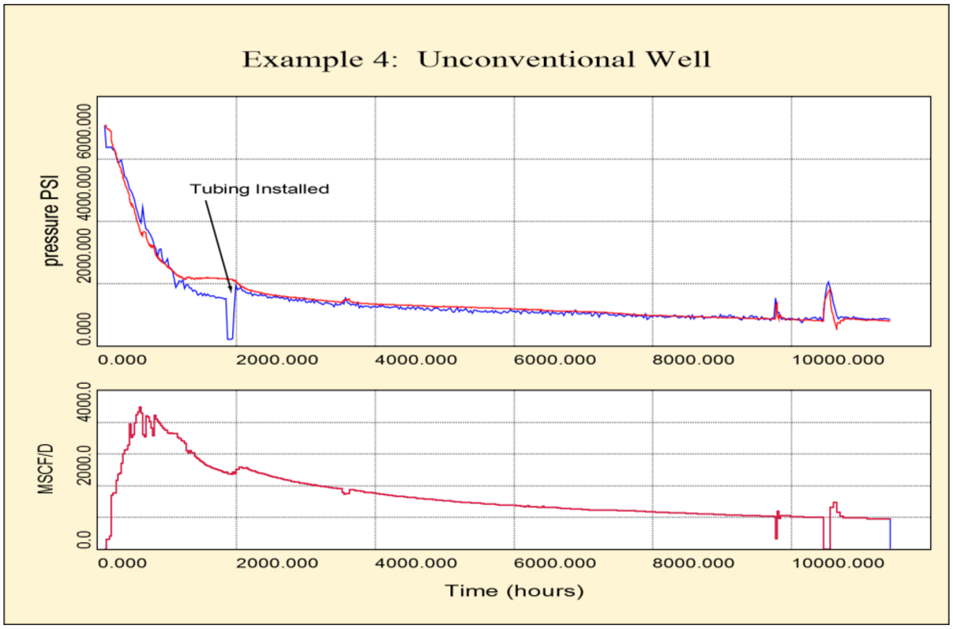
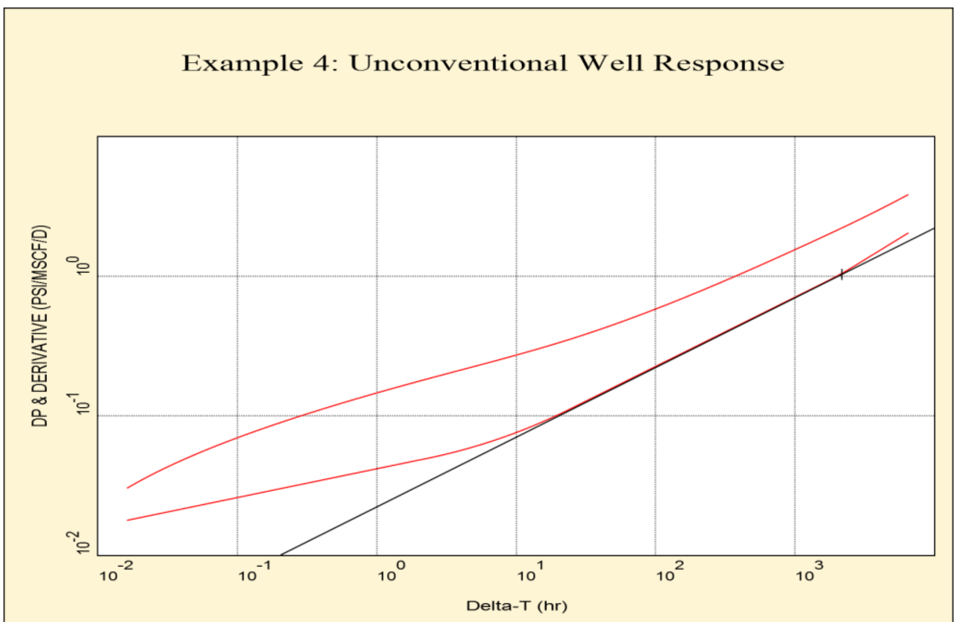


Fig. 13. – Example 4 – Unconventional well field case. Top plot: blue - well surface pressure converted to bottomhole conditions, red – result of convolution of the response from Fig. 14 and the well rate from bottom plot. Bottom plot – well rate.



Permeability, md	5.17e-005	Net thickness, ft	100.00
Permeability-thickness, md-ft	0.005	Wellbore radius, ft	0.354
Diffusivity, ft^2 / hr	0.233	Mid frac distance, ft	45.00
Turbulence coefficient, D / mscf	0.00000	Time of deviation, hrs	2177.36
Initial pressure, psi	7080.000		
Perm-FracLength factor, ft-sqrt(md)	65.4823		
Fracture length, ft	9107.07		

Fig. 14. - Example 4 – Unconventional well field case. Reconstruction of constant rate drawdown response. Red – reconstructed constant-rate drawdown response, black – half-slope analysis line.

The response function in **Fig. 14** has two distinctive features/characteristics that illuminate this well transient pressure behavior. The first feature is an increasing half-slope trend of the response derivative that starts after 20 hours and continues until 2200 hours. The second feature is the deviation of the derivative upward from this half-slope trend after 2200 hours. The half-slope derivative behavior is a characteristic transient pressure behavior of a hydraulically fractured well and it is consistent with this well completion. This well has large number of transverse fractures which during early part of production history operate independently supplying produced fluids into the wellbore. During this period as a result of production a region of decreased pressure develops in close proximity of each fracture. As time increases these individual pressure sinks grow and extend further away from the respective fractures. At the time when the pressure sink regions expand to the mid distance between neighboring fractures the fractures begin to interfere and this causes the derivative of the drawdown response to deviate above the half-slope trend at later time. According to the response in **Fig. 14** this fracture interference starts at about 2200 hours. Based on the geometry of this well completion and the number of fractures created during completion operation the average mid distance between fractures is estimated at 45 ft. The time of 2200 hours for the pressure sink region to expand to this distance gives an estimate of formation permeability of ~50 nD. Position of the half-slope analysis line within the plot plane estimates the product of total fracture length and square root of formation permeability as ~65 ft-sqrt(md). With the 50 nD permeability estimate this then results in the total fracture length of ~9100 ft.

This well production sequence does not include transient quality PBU periods and the well production data have an information gap at early time. For this reason we should expect some degree of uncertainty in the reconstructed response at early time. The later time part of the response including the half-slope derivative trend and and the derivative deviation from this trend at late time are defined by the data very well. **Fig. 15** demonstrates non-uniqueness of response reconstruction. Each of the two responses presented there produces equally good match of the well pressure data similar to the match in **Fig. 13**. At the same time derivative deviation at late time is an essential characteristic feature of the response. **Fig. 16** demonstrates that a response function without this feature would not honor the well pressure data. Note that the analysis in **Fig. 14** discussed above relies on the late-time features of the response and is not negatively affected by non-uniqueness of the response associated with the well data.

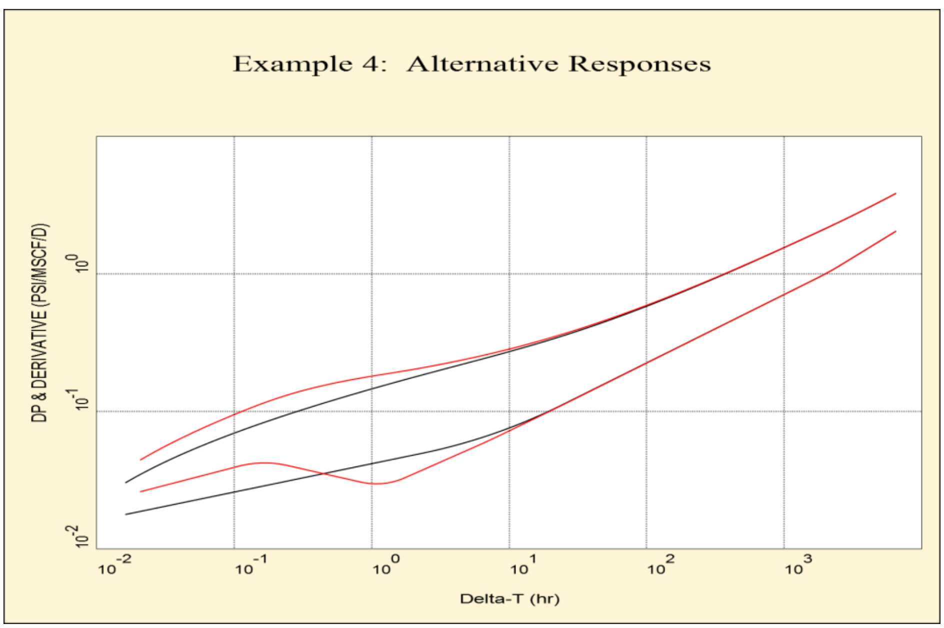


Fig. 15. - Example 4 – Unconventional well field case. Non-uniqueness of response reconstruction.

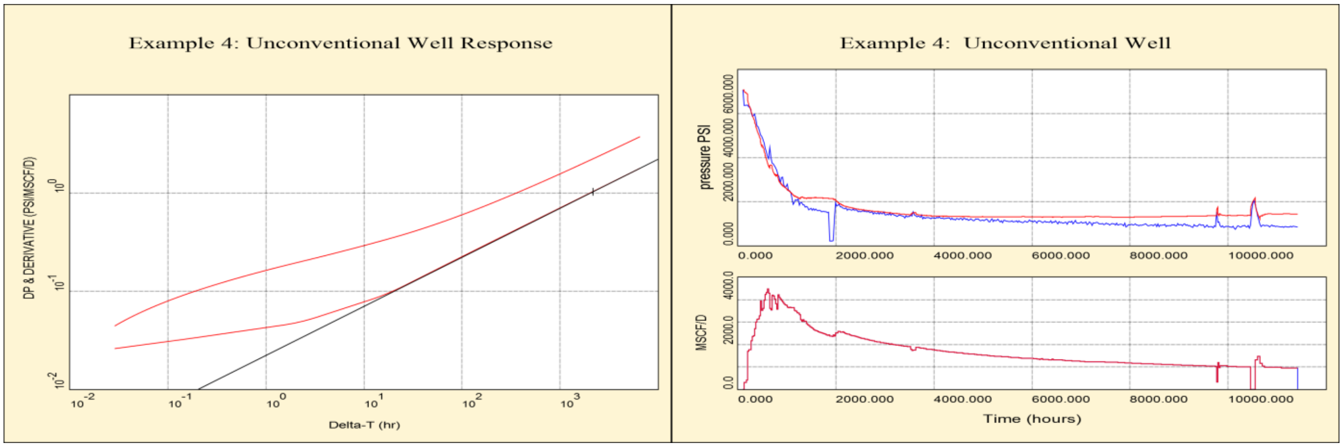


Fig. 16. - Example 4 – Unconventional well field case. A response function without derivative deviation does not match well pressure data.

Relation of Analysis Approach Presented in This Paper to Production Data Analysis

The analysis approach of surveillance pressure and rate data presented in this paper is completely within the realm of regular Pressure Transient Analysis. At the core of this approach is conversion of original pressure and rate data into much simpler form of constant-rate drawdown pressure response which is then analyzed by conventional methods of pressure transient analysis. The reconstruction of constant-rate drawdown response function presented here relies on the pressure transient information of PBU data (if available) as well as on the long term production part of surveillance data. It integrates all this into one characteristic response function of the well. Note that this response reconstruction is general in nature and it is not geared to any specific type of pressure behavior, i.e. pressure transient or boundary dominated (pseudo-steady state). Whatever behavior is reflected in the surveillance pressure and rate data it is replicated in the reconstructed response.

In contrast, rate transient analysis (production data analysis) is focused mostly on boundary dominated flow. It is this flow regime that depends on the reservoir pore volume drained by the well and the main objective of production data analysis is to evaluate this pore volume. Mattar and Anderson (2003) present a very good review of different methods used in production data analysis from decline analysis approach that relies on rate data only to more advanced techniques that use both rate and pressure data such as Palacio-Blasingame, Agarwal-Gardner type-curve matching methods and the Flowing Material Balance method developed by the authors. All these advanced analysis techniques study evolution in time of appropriately normalized well rate. In oil case, the well rate is normalized by $\Delta p = p_i - p_{wf}(t)$ and in gas case it is normalized by the pseudo-pressure drop: $\Delta m = m_i - m_{wf}(t)$. Hence, advanced production data analysis relies not just on well rate but also on well pressure data and in this sense it is similar to the approach presented in this paper. Note that normalized well rate is a function of time even if the well is produced at constant rate.

During routine production operations wells are mostly produced at imposed well pressure constraints. As a result, the rate of the well is not constant but declines with time. In fact, the well rate in this case declines exponentially. Evaluation of connected reservoir volume, however, requires the well to be produced under constant rate conditions. This is the case of so-called harmonic decline in the terminology of Arp`s decline equation. Hence, the well production data have to be converted at least during boundary dominated flow to constant well rate production conditions. Blasingame and Lee (1986) discovered that for boundary dominated flow this can be achieved by simple time transformation

$$\bar{t} = Q(t)/q(t) \tag{11}$$

Here, $Q(t)$ is the cumulative volume produced by the time t and $q(t)$ is the well rate at the time t. The time $\bar{t}$ is called equivalent time or material balance time. It should be noted, however, that this time transform works only for boundary dominated flow when all pressure transients associated with large well rate changes have decayed. However, actual well production data often include pressure data associated with large rate changes caused by changing well operating conditions and the above time transform will not account correctly for the transient features present in the well pressure data.

A crucial element of production data analysis of gas wells is the use of material balance pseudo-time transform introduced by Fraim and Wattenbarger (1987) to account for the variation of $c_t\mu_g$ with pressure as reservoir pressure declines in the course of production. Rate transient analysis in its current form begins with the work of Palacio and Blasingame (1993) who introduced special type-curves, now called Palacio-Blasingame type-curves that allow matching of well production data on a log-log plot. These type-curves can be used for analysis of either oil or gas wells. In the analysis, production rate data are normalized as mentioned above while the time of each rate point is mapped first to the corresponding time $\bar{t}$ and then in gas case to the corresponding material-balance pseudo-time t_a. Note that the Palacio-Blasingame type-curves are developed for vertical well at the center of circular reservoir system.

The next step in the development of rate transient analysis is associated with work of Agarwal et al (1999). This publication presents a very useful review of earlier works in this field. It verified and confirmed through numerical modelling the role of time transforms summarized by Palacio and Blasingame (1993) as a preparatory step for analysis. The paper then introduces several families of type-curves, now called as Agarwal-Gardner type-curves. Separate sets of type-curves are developed for radial systems and for the case of fractured wells. Note that the Agarwal-Gardner approach uses the same rate normalization and the same time transforms as the Palacio-Blasingame method. The main difference is that they match production data to different set of type curves. Compared to Palacio-Blasingame type curves, the Agarwal-Gardner method allows for more reliable identification of the onset of pseudo steady flow and more accurate estimation of the reservoir pore volume drained by the well. The Agarwal-Gardner type-curves are based on respective type-curves for vertical and fractured wells used in pressure transient analysis and are reciprocals of these PTA type-curves.

Both the Palacio-Blasingame and the Agarwal-Gardner type-curves are intended for matching the normalized rate function of a well producing at constant rate. Strictly speaking, rate transient analysis in its current form does not transform the well production pressure and rate data to constant rate production conditions to form the normalized rate function that could be matched by a corresponding set of type-curves. The time transform defined by Eq. 11 which is applied to well production data does not do this correction rigorously. By its design, this time transform is supposed to “correct” pressure behavior during pseudo-steady flow and only if the well during this period is operated under steady operating conditions so that there are no transient features present in the well data. Application of this time transform to the parts that represent transient pressure behavior before an onset of pseudo-steady flow corrupts these data and potentially makes them not suitable for rate transient analysis. In our view, this is the main problem with rate transient analysis in its current form. Another problem is that PDA is completely focused on analysis of production data and does not make any use of the data during PBU periods if such data are available/present in the data stream.

The analysis framework presented in this paper addresses these specific problems. It converts well surveillance data to constant rate drawdown response function. In this process it integrates in the response function the transient information from PBU data if such data are available together with long-term production data. The reciprocal of this response function is the well transient productivity index which is the normalized rate function in the terminology of rate transient analysis. So, after the well surveillance data are converted to response function there are two options available. One can work within the domain of pressure transient analysis (PTA) with this response function, or an alternative approach is to take a reciprocal of this response function and switch to the corresponding RTA type-curve matching techniques.

Conclusions

1. This paper presents a unified framework for analysis of well test and surveillance-type pressure and rate data. The approach is based on conversion of the well pressure and rate data to an equivalent form of constant-rate drawdown pressure response. This pressure response can then be analyzed by the methods of pressure transient analysis (PTA). The reciprocal of this response function is the normalized rate which is used in rate transient analysis. Hence an alternative approach is to apply production data analysis type-curve matching techniques of Palacio-Blasingame or Agarwal-Gardner to this normalized rate function.

2. The approach for reconstruction of constant rate drawdown pressure response presented in the paper does not have the limitations associated with automatic pressure-rate deconvolution algorithms and can be used with production-type data. Response reconstruction is performed interactively with the help of specialized software tool with an engineer adjusting the shape of the response function to match the well pressure data. This approach does not require that PBU flow periods be present in the data stream even though it benefits from such PBU data by integrating early time transient pressure information from PBU data in the reconstructed drawdown response.

3. The reconstructed constant-rate drawdown pressure response is a characteristic property of the well. It reflects the reservoir properties and the well completion and is in a way a “fingerprint” of the well. Comparing the drawdown responses of the wells from the same reservoir provides a way to identify how differences in well completions and well locations within the reservoir area manifest itself in the well characteristic pressure response. This may help for optimization of well completion practices and for better selection of future well locations.

4. Reconstruction of constant-rate drawdown response for gas wells includes application of pseudo-pressure and appropriate pseudo-time transform to the well pressure and rate data. Material-balance pseudo-time transform is applied to the well pressure

and rate data if the well surveillance data indicate reservoir pressure depletion. In this case an estimate of reservoir pore volume drained by the well is obtained in the course of response reconstruction.

5. In the case of unconventional gas wells completed with multiple transverse fractures a specialized pseudo-time transform is presented to account for gas compressibility variation in close proximity to the fractures when the wells are produced at very low well flowing pressure.

6. The response function reconstructed from the observed well surveillance pressure and rate data can be used to forecast future well production for any specified well pressure constraints imposed on the well.

7. Advanced Production Data Analysis techniques are intended for working with normalized rate function of a well producing at constant rate. However, the transformation of well pressure and rate data to constant rate production conditions is too simplistic, focused on the boundary dominated part of pressure and rate data, and is not accurate enough. The analysis approach presented in this paper addresses this problem and elevates production analysis to the rigor level of PTA.

Nomenclature

c = compressibility, Lt^2/m, psi^{-1}
c_g = gas compressibility, Lt^2/m, psi^{-1}
c_{gi} = gas compressibility at initial reservoir pressure, Lt^2/m, psi^{-1}
c_r = rock compressibility, Lt^2/m, psi^{-1}
c_{ri} = rock compressibility at initial reservoir pressure, Lt^2/m, psi^{-1}
c_w = water compressibility, Lt^2/m, psi^{-1}
c_{wi} = water compressibility at initial reservoir pressure, Lt^2/m, psi^{-1}
c_t = total compressibility, Lt^2/m, psi^{-1}
c_{ti} = total compressibility at initial reservoir pressure, Lt^2/m, psi^{-1}
G_{iip} = total volume of gas initially in reservoir at standard conditions, L^3, scf
G_p = total volume of gas produced (at standard conditions), L^3, scf
k = permeability, L^2, md
m = normalized pseudo-pressure, m/Lt^2, psi
m_i = normalized pseudo-pressure at initial reservoir pressure, m/Lt^2, psi
m_u = unit-rate drawdown normalized pseudo-pressure response, m/L^4t, psi d/mscf
p = pressure, m/Lt^2, psi
p_i = initial reservoir pressure, m/Lt^2, psi
p_{ref} = reference pressure in Eq. 3, m/Lt^2, psi
$\overline{p}$ = average reservoir pressure, m/Lt^2, psi
q = flow rate, L^3/t, RB/d
q_{sc} = flow rate at standard conditions, L^3/t, mscf/d, STB/d
s_{wi} = initial water saturation in the reservoir, fraction
s_{gi} = initial gas saturation in the reservoir, fraction
t = time, t, hr
t_a = normalized pseudo-time, t, hr
t_i = the time of start of production, t, hr
$\overline{t}$ = adjusted time according to Eq. 11, t, hr
ϕ = porosity, fraction
ϕ_i = porosity at initial reservoir pressure, fraction
μ = viscosity, m/Lt, cp
μ_g = viscosity of gas, m/Lt, cp
μ_{gi} = viscosity of gas at initial reservoir pressure, m/Lt, cp
ρ = density, m/L^3, lbm/ft^3
ρ_g = gas density, m/L^3, lbm/ft^3
ρ_{gsc} = gas density at standard conditions, m/L^3, lbm/ft^3
ρ_{gi} = gas density at initial reservoir pressure, m/L^3, lbm/ft^3

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Appendix A: Material Balance Equation

The derivation of material balance equation that accounts for the compressibility of rock and water that is immobile and is at connate water saturation is presented in Levitan, Wilson (2012). Here we present the final equation

$$1-\left[1+\frac{1}{1-s_{wi}}\int_{p_i}^{\bar{p}}c_r(p)dp+\frac{s_{wi}}{1-s_{wi}}\int_{p_i}^{\bar{p}}c_w(p)dp\right]\frac{\rho_g(\bar{p})}{\rho_g(p_i)}=\frac{G_p}{G_{iip}} \qquad \text{(A-1)}$$

Given the initial gas in-place volume in the reservoir, G_{iip}, this material balance equation defines the average pressure in the reservoir at the time when the cumulative volume of gas produced from the reservoir is equal to G_p. This average reservoir pressure evolves with time as the reservoir is produced.

Appendix B: Material Balance Pseudo-Time

Material balance pseudo-time was first introduced by Fraim and Wattenbarger (1987) for a producing well. This definition of material balance pseudo-time transform was later generalized by Rahman et al, 2006 to the test sequences that include both production and pressure buildup periods. Note that material-balance pseudo-time is defined in the context of a closed reservoir compartment when the gas production from the compartment causes the average reservoir pressure to decline with time. For the derivation of material-balance pseudo-time that is applicable to the data sequences that include both production and shut-in periods we refer to Rahman et al (2006) and Levitan, Wilson (2012). Here we present the final expressions for the production and shut-in flow periods.

Material balance pseudo-time is a mapping of time to pseudo-time: $t_a(t)$. This mapping function must be continuous. Also, the pseudo-time should monotonically increase with time. Normally, the rate of gas production as a function of time can be approximated on a sequence of flow periods with constant rate during each of these periods. Let us consider the flow period *j* in this sequence. This period starts at the time t_j and the pseudo-time at this moment is t_{aj}. If the gas production rate q_{jsc} during this period is not equal to zero, then at any time *t* during this period the pseudo-time is

$$t_a = t_{aj} - \frac{c_{ti}\, G_{iip}}{s_{gi}\, q_{jsc}} \left[m(\bar{p}) - m(\bar{p}_j) \right] \quad \text{(B-1)}$$

Here: $\bar{p} = \bar{p}(t)$ and $\bar{p_j} = \bar{p}(t_j)$. If, however, the rate q_{jsc} is zero, then the pseudo-time is given by

$$t_a = t_{aj} + \frac{c_{ti}\, \mu_{gi}}{c_t(\bar{p}_j)\, \mu_g(\bar{p}_j)} \left(t - t_j \right) \quad \text{(B-2)}$$

SI Metric Conversion Factors

bbl	x 3.785412	E-01= m^3
cp	x 1.0	E-03= Pa s
ft	x 3.048	E-01= m
lbm	x 4.535924	E-01= kg
md	x 9.869233	E-04= μm^2
psi	x 6.894757	E+00= kPa