Example of Dynamic Analysis Workflow Using Convolution Explorer Application

This example presents an analysis of surveillance pressure and rate data acquired during five years of production from an offshore gas well. The reservoir is developed with three wells. This specific well is completed in a separate fault block. This is a high permeability gas reservoir with the well gas rate of the order of 250 mmScf/D. At the time of reservoir appraisal, it was not clear if this is a separate reservoir compartment or if it is in communication with the rest of the reservoir. It was also possible that the reservoir and this specific fault block could be connected to aquifer. The purpose of this analysis is to develop understanding of the reservoir dynamic behavior and to clarify these specific issues/questions.

We use this well surveillance data example to demonstrate an analysis workflow that integrates the pressure and rate data acquired during production history of this well. In this presentation we also point you to specific capabilities implemented in Convolution Explorer application that provide for straightforward application of this analysis workflow.

Input Data Required for Reservoir Dynamic Analysis

Reservoir dynamic analysis requires data similar to the data used in pressure transient analysis. The input data fall into three groups

1. Fluid property data,
2. Reservoir property data,
3. Well data.

Convolution Explorer application requires that these data be prepared in an appropriately formatted input text file. Convolution explorer does not have the functionalities required for input data preparation. Manual preparation of input data may be tedious and require significant effort. We recommend to use for this purpose **PIE Well Test Analysis** software that has the necessary functionality. Moreover, PIE also has the capability not just to prepare the data but to write it into an input file that could be immediately read in by Convolution Explorer. If you do not have access to PIE software, it is possible to use for this a free version of this software called **PIE Reader** that can be downloaded from PIE web site at: http://www.welltestsolutions.com.

Fluid Property Data

The data used in the analysis depend on whether this is an oil or gas reservoir. For oil reservoir analysis oil properties are assumed constant and do not change with pressure. For this case we need to provide three fluid parameters: (1) oil formation volume factor, (2) oil density, and (3) oil compressibility.

For gas reservoirs, it is assumed that gas properties change with pressure. Gas properties in this case are defined in the form of table that describes variation with pressure of the following gas properties: (1) gas z-factor, (2) gas compressibility, (3) gas viscosity, and (4) gas pseudo-pressure. The range of pressure variation should cover the entire possible range of pressure variation from stock-tank conditions to above the initial reservoir pressure. Normally, PTA software applications have the capabilities to generate these tables by using fluid property correlations. Convolution Explorer does not include such capabilities and expects that this gas PVT description are generated using other tools and included together with other data in the application input file.

Reservoir Property Data

In PTA analysis, rock property data are assumed to be constant. In the simplest case, these data include four parameters: (1) rock porosity, (2) water saturation, (3) rock compressibility, and (4) initial reservoir pressure.

Well Data

Well data represent the bulk of the data in the application input file. The data for each well include rate and pressure data as functions of time. The well pressure and rate data acquired by pressure and rate gauges serve as the source information for the data used in the analysis. These raw gauge data are sub-sampled and turned into a form that in PIE terminology is called Analysis Data. In the process of derivation of analysis data, we review the gauge pressure and rate data and identify the time intervals within the time span of the data stream when the rate of the well is approximately constant. Such time intervals are called flow periods. Note that in this process of defining flow periods we synchronize the start and the end of a flow period with respective changes in the pressure behavior with time. Such synchronization is especially important for pressure buildup periods when the well is closed and the well rate changes to zero. For each flow period, we set the well rate value equal to the average of the rate samples within the flow period. As a result, we end up with the well rate approximated as a step-wise constant function. After a sequence of flow periods is defined, we then select a subset of pressure samples within each flow period that are sufficient to accurately represent the transient pressure behavior during the flow period. Normally, we use log-distributed (along time axis) pressure samples that are concentrated at the beginning of a flow period when well pressure changes rapidly as a result of the well rate change that occurs at the start of the flow period.

Fig. 1 presents the raw surveillance pressure and rate data and the corresponding analysis data for the gas well that is analyzed in this paper. This is a PIE plot. The total number of pressure samples in the surveillance data is 3,267,028. The analysis data are reduced to only 6432 pressure points and 609 flow periods. Analysis rate function is presented as a step-wise constant function approximating the rate history of the well.

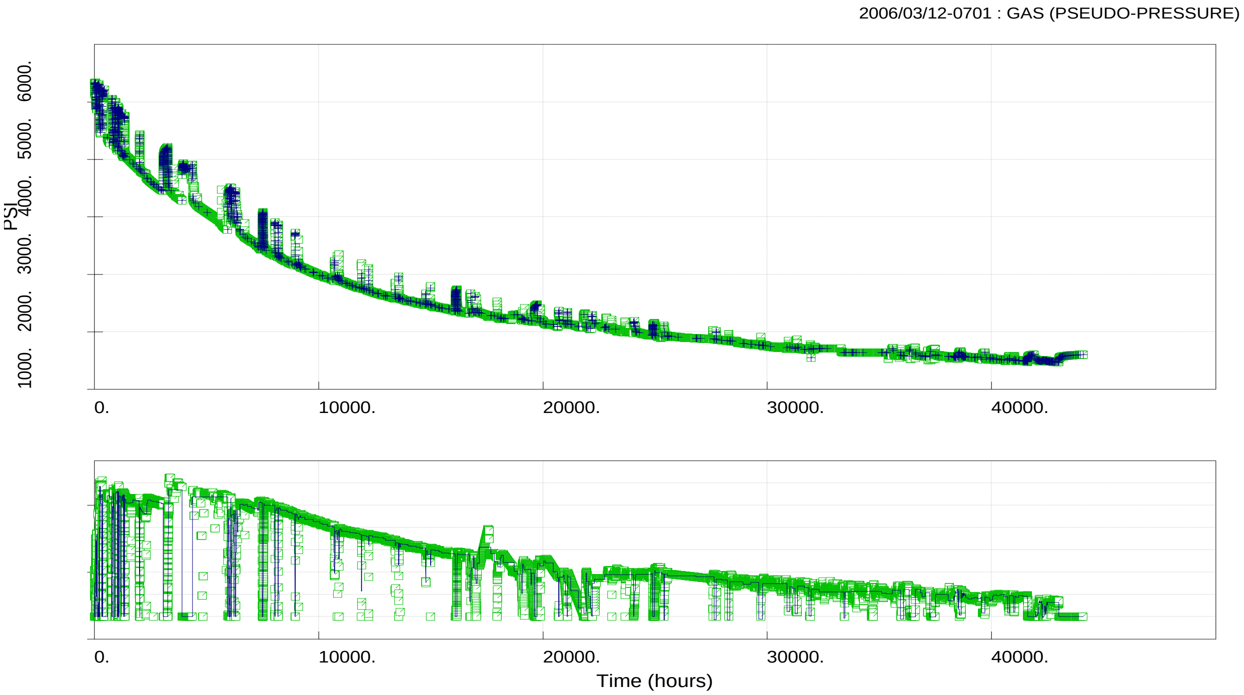


Fig. 1. An example of raw surveillance and analysis data and of the analysis data derived from it. Surveillance data are shown as green markers. Analysis data are shown in dark blue.

Fig. 2 presents our well analysis data after the data are imported into Convolution Explorer. This type of plot in Convolution Explorer is called Data Plot. The horizontal axis in this plot presents regular time in hours and the vertical axis presents well rate (in the lower plot area) and pressure (the upper plot area). This is conventional presentation of well pressure and rate data used in well test analysis. The rate data in the plot are in the form of step-wise constant approximation of the well rate function. The well pressure data in the upper part of the plot are presented in blue color. Convolution Explorer can present pressure data as markers or as solid line. We normally use solid line to see observed pressure features more clearly. The plot in **Fig. 2** also presents another pressure function shown as red solid line. Please ignore this curve at the moment. The meaning of this curve will become clear later.

Fig. 2 shows that at the beginning of production the well rate is between 250 to 300 mmscf/D. However, several months later the rate starts to decline and this declining trend persists through the rest of production history. However, even at the end of production the well still produces at a relatively high rate of 42 mmScf/D.

In the upper part of the plot, well pressure also declines throughout production. At the beginning of production, the pressure was around 6300 psi and towards the end it declined to around 1500 psi. Well production is halted when the pressure drops to the level when it is not possible to flow directly into a transportation pipeline. The declining pressure trend in **Fig. 1** is a sign of reservoir depletion.

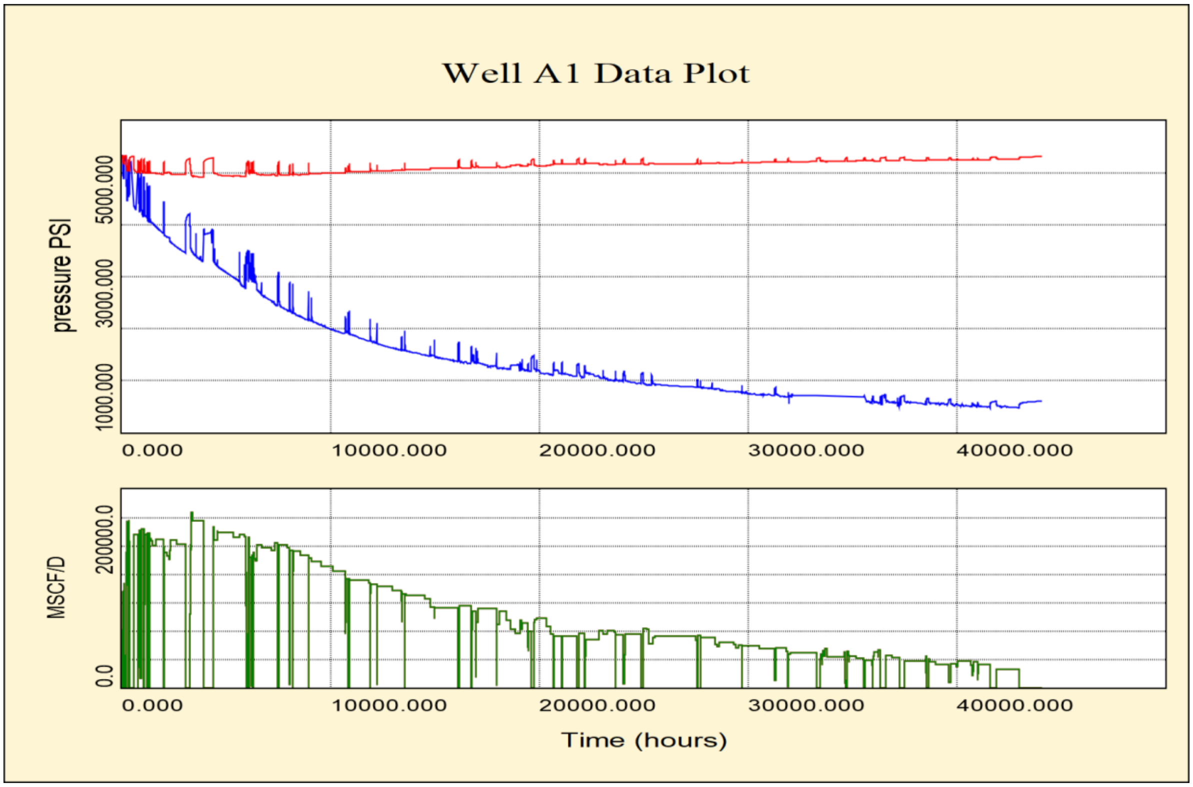


Fig. 2. Well analysis data

The pressure data in **Fig. 2** include large number of pressure buildup periods. Not all of these PBUs have good quality data. Many of them are very short and are caused by emergency shutdown system. However, some of pressure buildups are of reasonably long duration and have transient quality data that can be used in derivative analysis.

Pressure Transient Analysis (PTA) and Superposition Principle

The analysis discussed here is based on conventional PTA analysis approach. The central point in this approach is the assumption that fluid flow problem in the reservoir is governed by linear flow equations and that the principle of superposition is consistent with the well pressure and rate data. This is not always the case. For example, it does not work in multi-phase flow conditions. However, in our case we have a dry gas reservoir and multi-phase flow in not a problem. If our reservoir is attached to aquifer, this could create multi-phase flow conditions. Even in this case we could expect that at the beginning of production history the reservoir will behave as single-phase system because it takes some time before aquifer is mobilized and starts affect pressure behavior in the well. In our case the pressure data in **Fig. 2** show reservoir depletion and significant variation of pressure during production. This affects gas properties (gas density, viscosity, compressibility) that depend on pressure and as a result the flow equations become non-linear. This problem of pressure dependent gas properties has been addressed in PTA analysis long time ago by the use of special variable transforms that linearize the flow problem. Specifically, we transform pressure to pseudo-pressure and this accounts for variation of gas density and viscosity with pressure. In addition, in the case of a gas reservoir showing reservoir depletion we have to also transform time to another time variable called material balance pseudo-time and this accounts for variation of gas compressibility with pressure. This pseudo-time transform requires as an input the value of the reservoir pore volume which should be obtained from dynamic analysis of the well pressure and rate data. This makes the whole analysis work flow an iterative process described in SPE-134261. Every time when we change an estimate of reservoir pore volume, we update the pseudo-time transform applied to the time variable of both pressure and rate data. Note, that pseudo-pressure and pseudo-time transforms are applied to the entire data streams of well pressure and rate data.

In addition to these global transforms we also use superposition time transform when displaying pressure data during specific flow period on derivative analysis plots. This transform is local and is applied to pressure data during a specific flow period selected for analysis. Superposition time transform is used to account for variation of well rate prior to the flow period selected for analysis.

The above variable transforms are implemented in the Convolution Explorer application and are applied automatically and transparently to the user at the moment when the user selects a flow period for analysis and displays the flow period pressure data on Bourdet derivative plot.

Consistency Assessment of Transient Pressure Behavior

PTA type of analysis normally begins with assessment of transient pressure behavior reflected in a series of PBUs of the recorded production history. This is done by comparing PBU derivative plots of several PBUs selected at different times throughout the well pressure record. We normally identify PBUs with better quality data, display them on derivative plots, and then overlay several such plots to identify the features in transient behavior that are consistent between PBUs and the features that change from one PBU to another. An example of such assessment for our well is presented in **Fig. 3**.

Convolution Explorer has special plot called Derivative Plot for displaying and overlaying flow period data on Bourdet derivative plot. This functionality is accessed from the Plots menu of the application main window. A flow period for display on derivative plot is selected on Data plot. Context menu of Data plot includes Select PFA (period for analysis) item for such selection. Another menu item Select FP for Plot Overlay in the same Context menu is used to select several PBU periods for derivative plot overlay.

Fig. 3 compares five derivative plots selected through the entire pressure record in **Fig. 2**. This plot demonstrates that after 0.1 hrs. from the start of pressure buildups derivative curves for all these PBUs overlay remarkably well. This later time PBU derivative behavior reflects rock properties and the flow geometry in the reservoir. The differences seen in the derivative curves at the beginning of PBUs at very early time are wellbore related and of no consequence for our analysis. The ΔP curves of these derivative plots separate vertically and this is an indication of changing skin factor from one pressure buildup to the next. Correlating the timing of PBU to vertical separation between ΔP and derivative curves on the plot, we conclude that well skin factor decreases steadily throughout production history of the well. Recall that the well rate according to **Fig. 2** also declines with time during production history of the well. Hence, we conclude that the skin variation indicated by **Fig. 3** is a so-called rate-dependent skin behavior associated with turbulence effect in the near well region in close proximity to the wellbore. Such skin behavior is very common for high-rate gas wells and it manifests itself in our case. Note that the derivative curves separation at the beginning of these PBUs could in part be also caused by this turbulence effect.

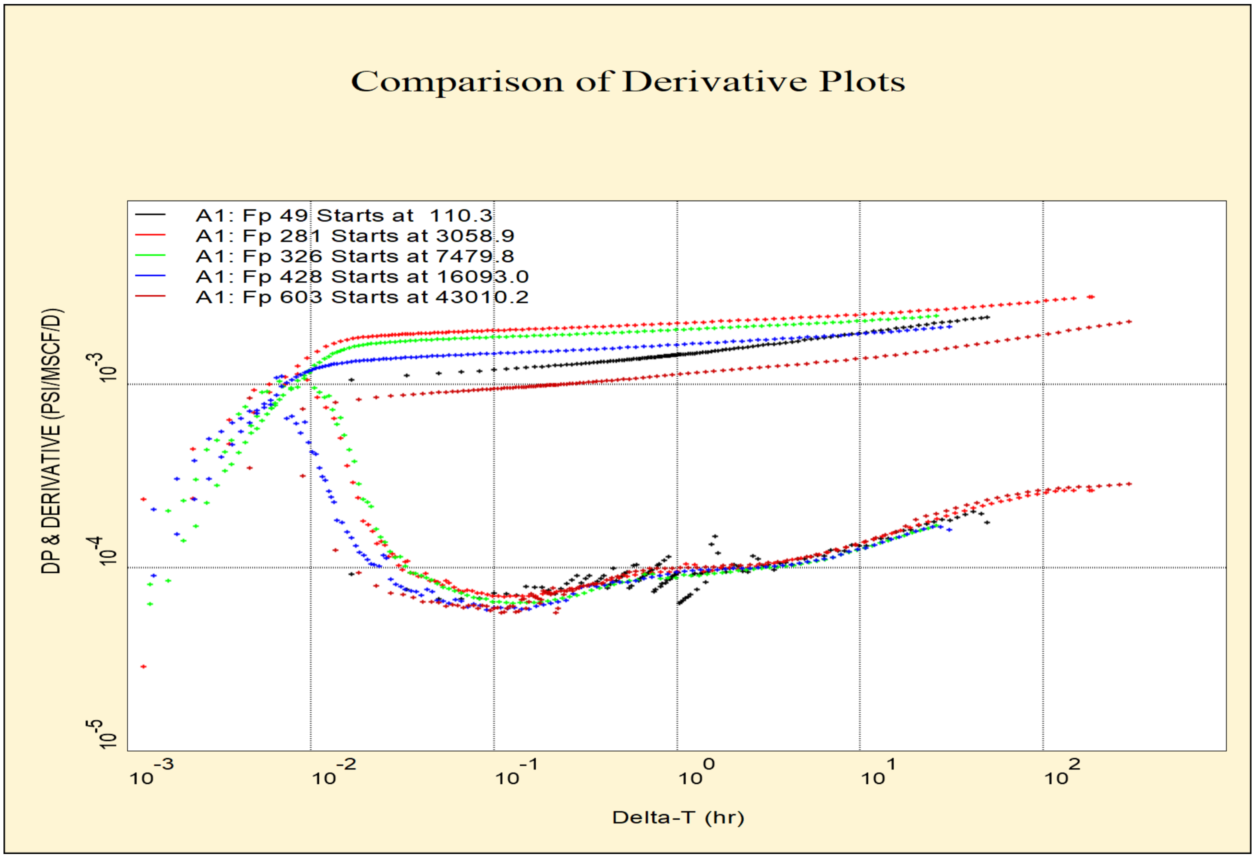


Fig. 3. Consistency of transient pressure behavior during well production history

Let us summarize our findings from the comparison of transient pressure behavior in a series of PBUs selected throughout the production history of the well presented in **Fig. 3**:

1. The pressure behavior controlled by reservoir rock properties and flow geometry (reservoir boundaries) does not change from one PBU to the next. It is remarkably consistent.
2. Well skin factor decreases with time throughout production history of the well. This skin variation is caused by turbulence effect associated with concentration of fluid flow in close proximity to the well. It could also be caused by turbulence pressure drop in the part of the wellbore tubing between location of the pressure gauge and the well perforations/well completion.

The assessment of consistency in transient pressure behavior in a series of PBUs presented here is a common practice in modern Pressure Transient Analysis. We took a sequence of pressure buildups, presented pressure the data during these PBUs on a specialized analysis plot (in our case here this is Bourdet PBU derivative plot), compared these plots, and suddenly this data manipulation/comparison revealed some characteristics of the pressure behavior associated with our reservoir that could not be noticed in the original data in **Fig. 2**. You could look at what we just presented here as a process of data exploration, the process of revealing something hidden in the data that is important for understanding the reservoir properties and the dynamic reservoir behavior reflected in the data.

In conventional derivative analysis based on Bourdet derivative plot it is possible to take a step further and translate some features present in this derivative plot into estimates of reservoir and rock properties, such as permeability, skin, distances to boundaries, reservoir channel width, fracture length and so on. The problem with this approach is that these estimates are supported only by the pressure data during one specific PBU and each PBU can produce different estimates of these properties. This is one of the reasons for comparing PBU derivative plots because it helps to understand if parameter estimated resulting from derivative analysis make sense or not.

Derivative Plot that was first introduced in early 1980th and is a great advancement compared to what was used in transient analysis before. It still to our days remains a tool of choice for presenting in visual graphical form the character of transient pressure behavior. However, there are two main problems with the analysis based on derivative plot:

1. It is focused only on pressure behavior during one flow period. In this approach there is no attempt to integrate the information from the entire data sequence into one integrated analysis.
2. There is a flaw in derivative plot presentation of transient pressure behavior during a flow period. Ideally, we would wish to have a presentation of transient behavior that reflects the reservoir and well properties and is not affected by anything else. Derivative plot representation, however, is distorted by variations of well rate prior to the flow period being analyzed.

The analysis approach implemented in Convolution Explorer attempts to address these two problems of conventional PTA analysis.

Pressure Rate Deconvolution

If fluid flow in a reservoir is governed by linear equations then superposition principle is valid for the solution of this problem in the reservoir. According to this principle, the well sand face pressure $p(t)$ is related to the well rate $q(t)$ by the following relationship

$$p(t) = p_i - \int_0^t q(\tau) \frac{dp_u(t-\tau)}{dt} d\tau \qquad (1)$$

where $p_u(t)$ is the well unit-rate response function and p_i is the initial reservoir pressure referenced to the depth of the pressure gauge that recorded the pressure $p(t)$.

Note that the $p_u(t)$ in **Eq. 1** is defined on the time interval equal to the entire time span of pressure and rate data, it does not depend on the well rate history and represents the pressure behavior characteristic of the fluid flow problem in the reservoir. **Eq. 1** offers a way to integrate information from the entire pressure and rate data records into one response function $p_u(t)$. We just need to solve **Eq. 1** for $p_u(t)$ for given functions $p(t)$ and $q(t)$. This kind of problem is called pressure-rate deconvolution.

There are a number of complications associated with pressure-rate deconvolution. The main problem is that we do not have sand face pressure data to feed into the deconvolution process. The well pressure data we do have come from a pressure gauge located somewhere in the wellbore and these data are affected by wellbore effects. The main among these effects are skin factor and wellbore storage. We can use the pressure gauge-measured data as a proxy for the sand face pressure only if the wellbore effects (skin factor, wellbore storage) remain constant during the entire duration of pressure record. This imposes additional requirements that has to be satisfied for successful solution of pressure-rate deconvolution. If we are not careful and ignore these additional requirements, we may end up with erroneous deconvolution results.

In the case of our analysis example and based on **Fig. 3**, we already concluded that well skin factor is not constant and decreases throughout production history of the well. Hence, the conclusion in this case is that pressure-rate deconvolution cannot and will not produce valid unit-rate response function if we attempt to use the well pressure record in its entirety. On the other hand, skin factor affects pressure only during flow periods when the well is open to flow. During flow periods when the well is shut in, the pressure is not influenced by skin factor. Hence, if we use the parts of the pressure record that are associated with shut-in periods, we potentially could deconvolve this subset of pressure data and produce a meaningful drawdown response. The complications with wellbore storage effect can be handled similarly. Wellbore storage affects pressure behavior in our well only during the first several minutes of a pressure buildup period. If we exclude from deconvolution process the pressure data during the first several minutes of each pressure buildup period, this will address this other complication with pressure data.

Deconvolution Analysis Workflow in Convolution Explorer Application

The analysis workflow implemented in Convolution Explorer relies on pressure rate deconvolution for integration of the information encoded in long-term surveillance data acquired in routine production operations. Existing automatic deconvolution algorithms used in the industry are not robust enough for this type of data.

The deconvolution approach in Convolution Explorer is different from automatic deconvolution algorithms and does not depend on data quality. It is an iterative process that involves only convolution computations of a user-defined response function with well rate data. User adjusts the shape of response function on a derivative plot interactively trying to match observed pressure data with the result of convolution of this assumed response function with the well rate. This is different from automatic deconvolution algorithms that reconstruct response function by solving **Eq. 1** for $p_u(t)$. Automatic deconvolution approach is fundamentally unstable, requires special regularization to stabilize it, and is very sensitive to the data that are fed into this solution algorithm.

In Convolution Explorer, in single well case, we perform pressure-rate deconvolution by working with two plots: (1) Response plot, and (2) Data Plot. The Data plot has been discussed earlier (**Fig. 1, Fig. 2**). The Response Plot is used for manual reconstruction of response function. Response Plot presents a response function on Bourdet derivative plot. It has special built-in graphical functionality that allows the user to adjust shape of the response function interactively on the screen. At some point after response function adjustment the user sends this response to a convolution algorithm that computes convolved pressure, and this convolved pressure is displayed immediately on data plot together with observed well pressure.

Fig. 4 is an example of Convolution Explorer response plot. Response plot displays drawdown response function (red curves) on derivative plot. **Fig. 4** plot presents the starting point of response reconstruction process. We always begin response reconstruction with the response derivative curve in the form of a horizontal line and the ΔP curve is obtained by integrating this constant derivative. The plot in **Fig. 4** also shows three green dots at the ends of derivative curve and at the beginning of ΔP curve.

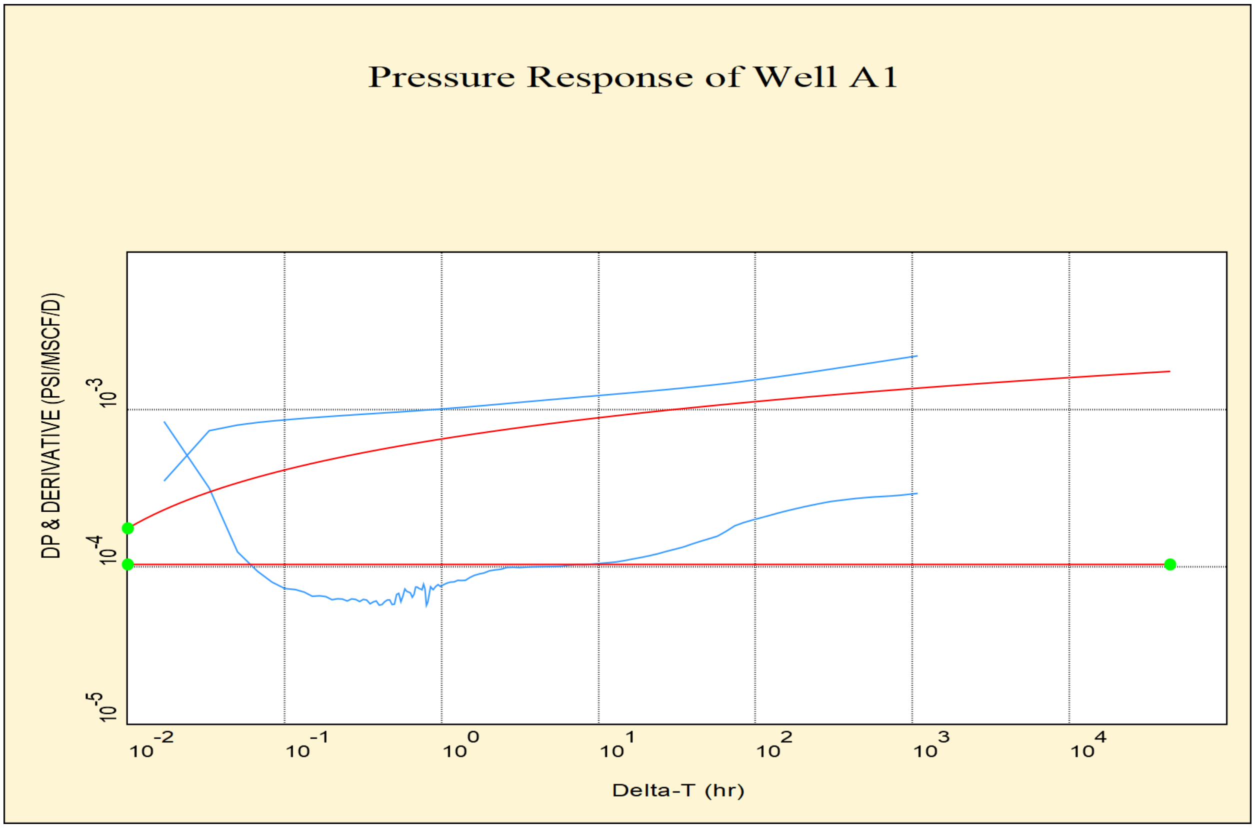


Fig. 4. Bourdet derivative of the response function (red) at the start of response reconstruction process. The blue curves represent derivative plot of the last PBU in the well pressure sequence in Fig. 2.

These are control points that are used to define and interactively manipulate the shape of response function. The time span of the response function on this plot is equal to the total time span of the well production history. The blue curves in **Fig. 4** present derivative plot of a reference PBU. The reference PBU in this case is the last PBU period in **Fig. 2**.

The user may place additional control points and distribute them along the response derivative curve on the plot. Response Plot functionality in Convolution Explorer includes a special interpolation algorithm that translates the set of control point coordinates on the plot into a respective response function description. The user may select and move individual control points on the plot using computer mouse and the respective response function will change accordingly. At some point the user may send the response function description to a convolution algorithm that computes the result of convolution of the response function with the well rate. This produces convolved pressure according to **Eq. 1**. This convolved pressure is immediately displayed on the data plot. For example, the red curve in **Fig. 2** presents the convolved pressure for the case of response function presented in **Fig. 4**.

Hopefully, one could construct a response function such that the convolved pressure matches observed well pressure on data plot. To be more precise, we should aim to reproduce only parts or sections of observed pressure data that are consistent with the principle of superposition. Determination of such subset of pressure data must be done before one proceeds with response reconstruction. For our gas well example, we demonstrated identification of the subset of pressure data consistent with the principle of superposition earlier when we discussed consistency of transient pressure behavior in our well dynamic data.

Matching appropriate sections of observed pressure data is a necessary but not sufficient requirement when reconstructing response function. Pressure-rate deconvolution is not a sufficiently constrained problem. It is possible to match observed pressure data with different/multiple response functions. Our task is to produce a response function that in addition to honoring observed pressure data is physically meaningful. A response function is a solution of diffusivity equation and diffusive processes are slow, they evolve on a time scale of longer than one log cycle when presented on derivative plot. This means that reconstructed response function should not have short-lived features that evolve on a time interval of less than one log cycle or less. Since response reconstruction in Convolution Explorer application is done by the user manually, it is easy to satisfy this requirement if the user has a good understanding of what response shape is physically meaningful.

Note that response plot in **Fig. 4** along with the drawdown response function also displays a PBU derivative plot. This derivative plot serves as a blueprint that guides the user on the shape of drawdown response at early time. It is a well-known fact in PTA behavior that constant rate drawdown response when displayed on derivative plot behaves similar to PBU derivative plot at early time. This similarity of drawdown and PBU behavior extends through the end of radial flow regime. We use this prior knowledge of transient pressure behavior in defining the drawdown response at early time. This is shown in **Fig. 5** where we defined the shape of the response based on the shape of PBU derivative plot. We placed several control points along the PBU derivative curve and this produced the drawdown response derivative curve that is similar to the PBU derivative.

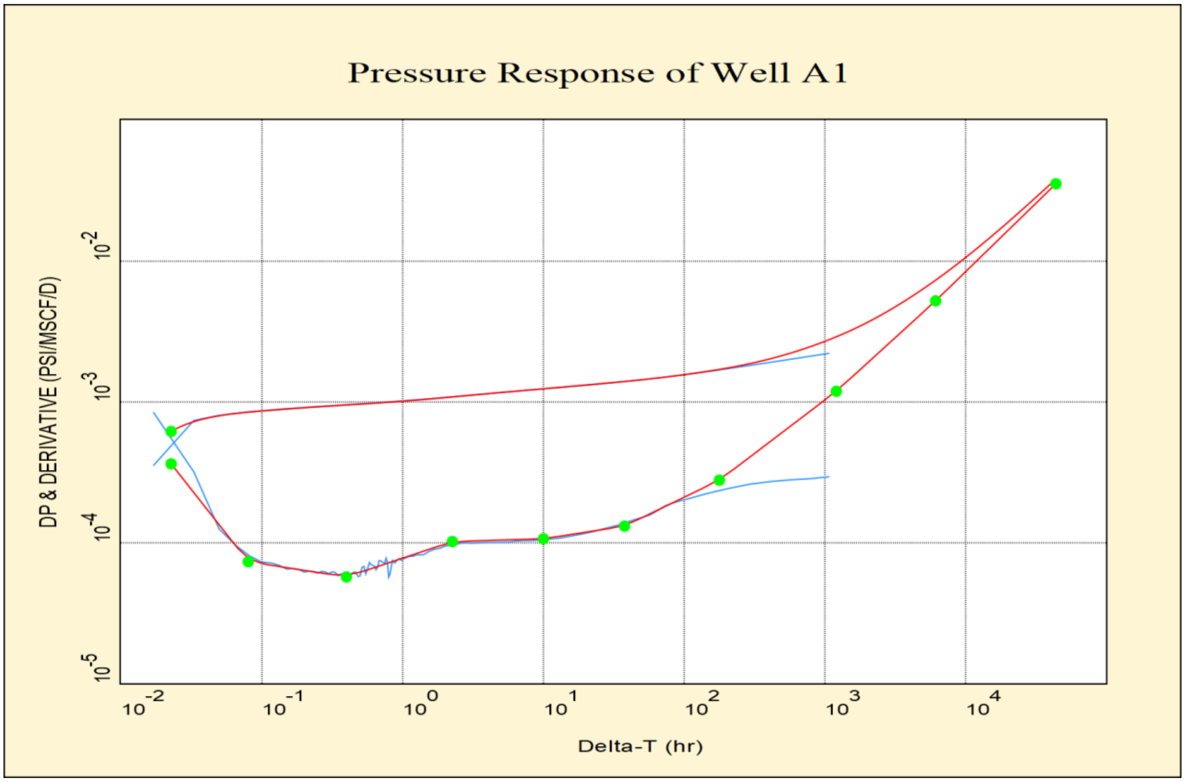


Fig. 5. Intermediate step in reconstruction of drawdown response function

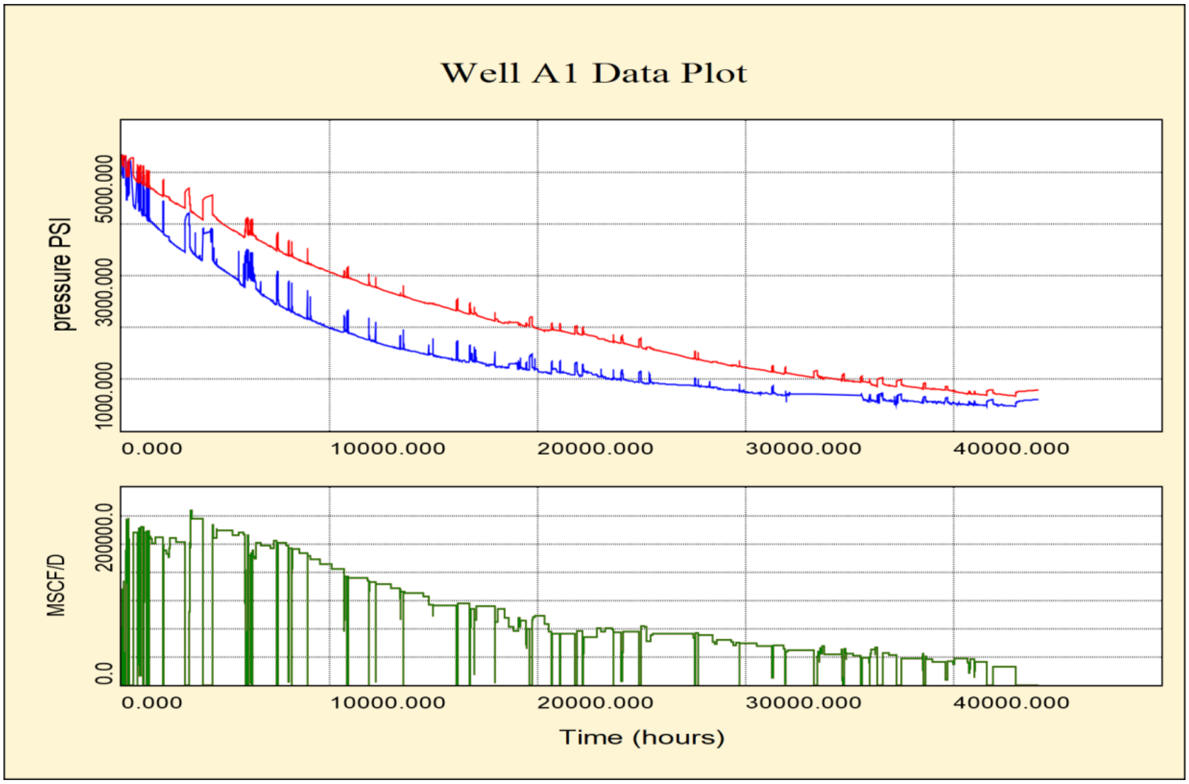


Fig. 6. Convolved pressure resulting from response function in Fig.5 vs. observed well pressure

At late time, we direct response derivative curve up in order to bring the convolved pressure in **Fig. 6** closer to the observed pressure. However, by experimenting with different response derivative shapes at late time while keeping them "physically meaningful" we concluded that in our case it is not possible to reproduce the observed pressure behavior over the entire production history of the well. This conclusion in itself is very important because it points us to a conclusion that there is some physical effect reflected in the observed pressure data that is not accounted by the superposition expression of **Eq. 1**. In other words, observed pressure data are not consistent with the superposition principle as expressed by **Eq. 1**. Indeed, we are dealing with the pressure data from a gas well. Pressure variation during production history of the well is large and it affects gas properties. Convolution Explorer in gas case automatically applies pseudo-pressure transform to account for the gas density and viscosity variation with pressure. This effect is accounted in the convolved pressure presented in **Fig. 6**.

However, variation of gas compressibility with pressure is not accounted and this is why we are not able to reproduce observed well pressure behavior. In order to account for gas compressibility variation with pressure we need to apply material balance pseudo-time transform. This transform should be applied when well pressure data indicate pressure depletion over production history of the well. This is indeed the case with our observed pressure data. In order to apply this form of pseudo-time transform we need to provide the value of pore volume of the reservoir compartment drained by the well. This pore volume is itself reflected in the well pressure and rate data and should be recovered in the course of response reconstruction process. We determine this pore volume iteratively while we proceed with reconstruction of drawdown response function.

In a closed reservoir, drawdown response function develops an asymptotic unit-slope trend of response derivative curve at late time. Position of this unit-slope trend on the plot reflects the value of pore volume. The Response Plot in Convolution Explorer is not just a window for drawing a response derivative plot. It is a tool that implements analysis functionality that allows user to translate some features/trends present in the reconstructed response function into estimates of a number of reservoir and well properties. This analysis functionality includes a unit-slope analysis line called PV Line. The PV Line functionality translates position of the asymptotic late time unit-slope derivative trend into an estimate of reservoir compartment pore volume. Hence, if we position the PV Line through the late-time response derivative trend on the plot, this will provide an estimate of pore volume. This value of pore volume estimate automatically triggers material balance pseudo-time transform of the pressure and rate data for this value of pore volume. As a result, the convolution expression, **Eq. 1**, is transformed to a form where integration is done with respect to pseudo-time and this affects the resulting convolved pressure. Note, that this series of actions is triggered by just one mouse button click that positions the PV Line on the plot. The response plot resulting from this this mouse button click is presented in **Fig. 7**. Please note that the horizontal axis in this plot is not regular time but material balance pseudo-time. It is expressed in hours as before. However, it is contracted compared to **Fig. 5**. As a result of this time transformation, the PBU derivative plot changed and shifted relative to the response function defined by its control points. We need to move response control points to their new locations suggested by the transformed PBU derivative plot in **Fig. 7**.

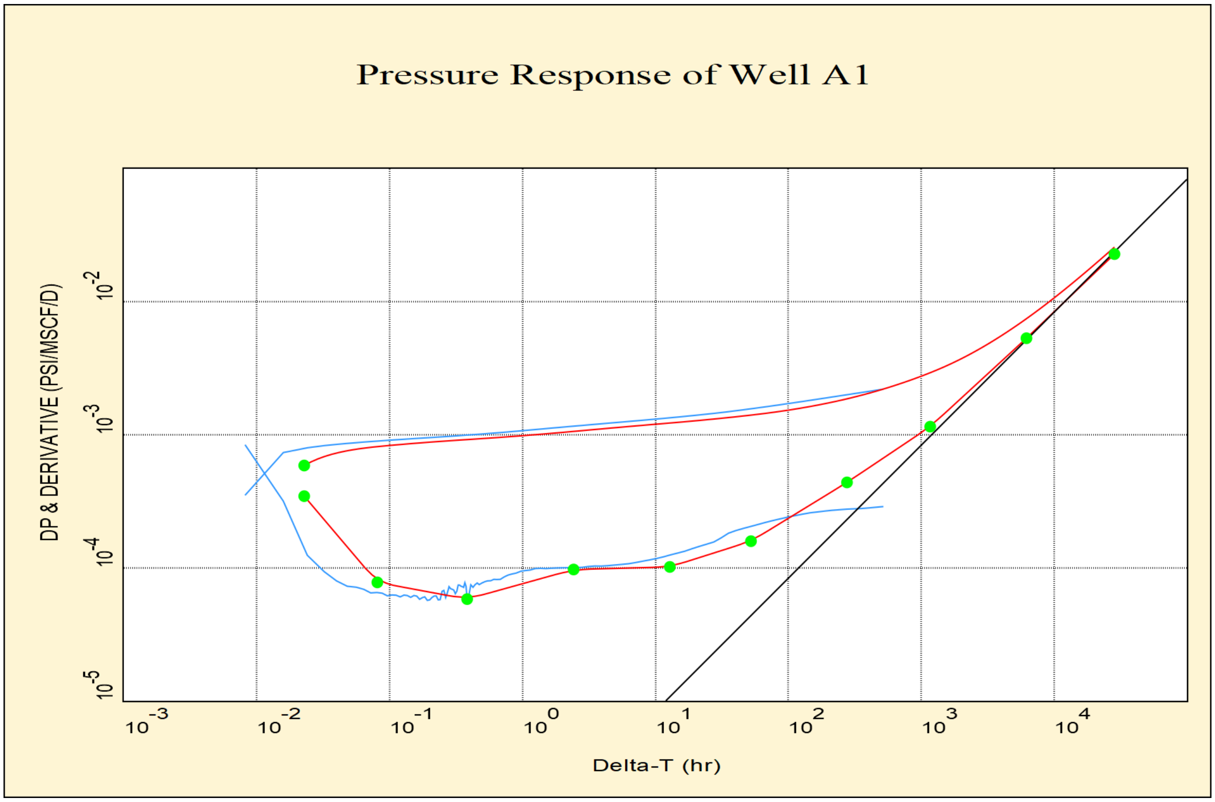


Fig. 7. Response plot transformation after positioning PV Line to estimate pore volume.

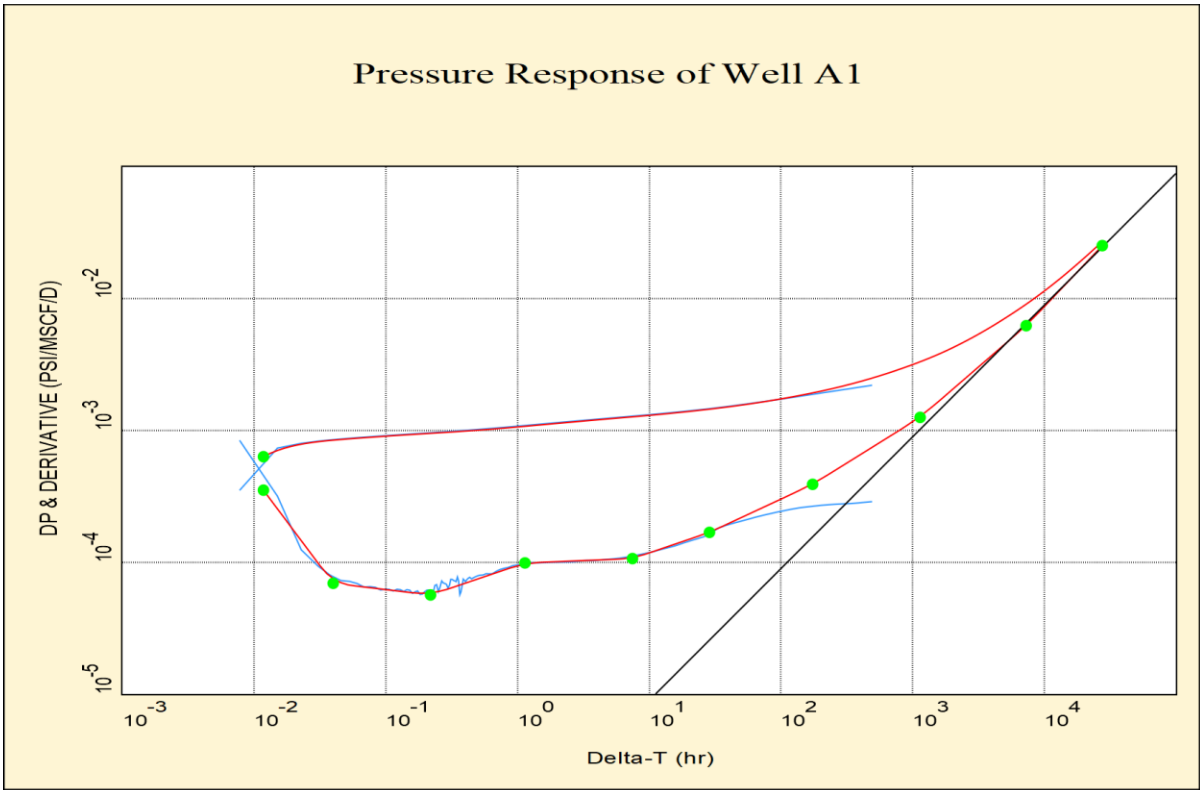


Fig. 8. Adjustment of response function to keep it consistent with PBU derivative plot.

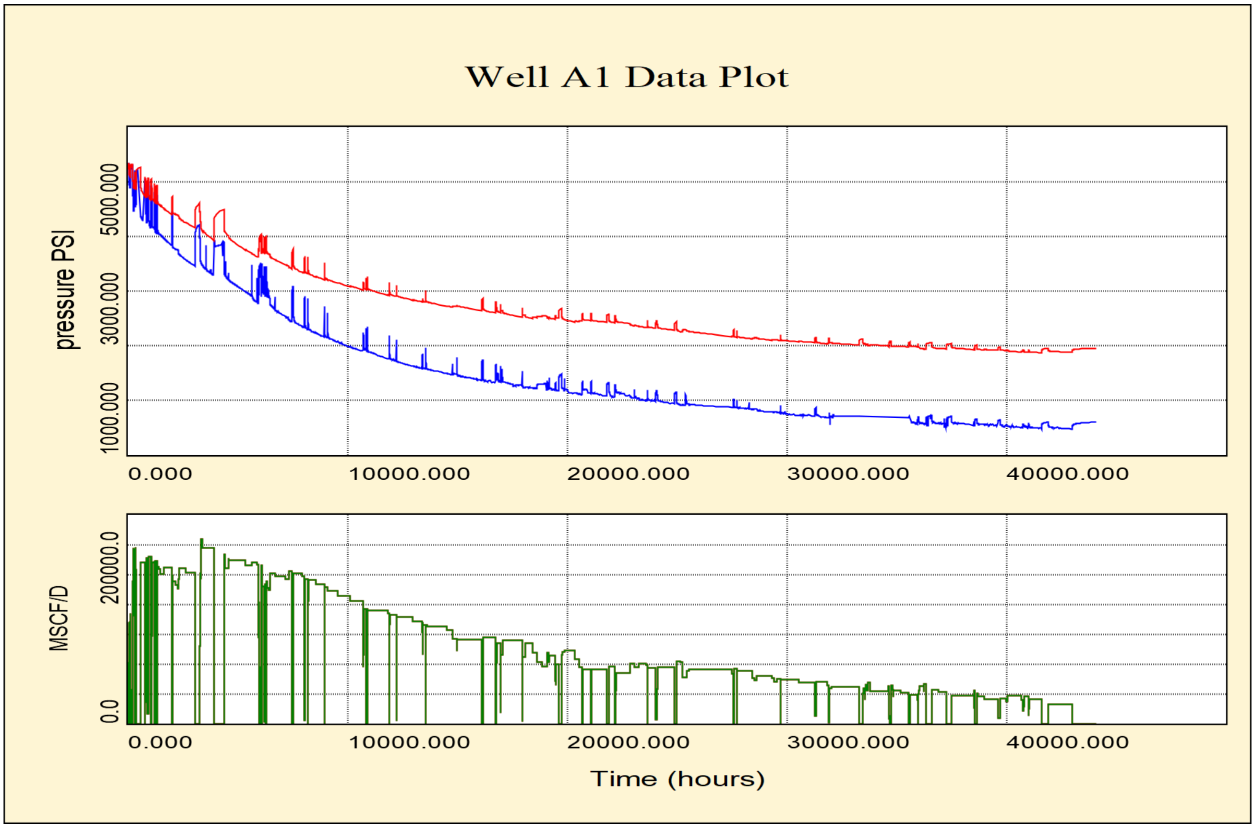


Fig. 9. Convolved pressure resulting from response function in Fig. 8 vs. observed well pressure. The pore volume associated with the response function in Fig. 8 is 401 mmRb.

After this response control points adjustment we end up with the plot shown in **Fig. 8**. The corresponding data plot after application of this pseudo-time transform is presented in **Fig. 9**. The pore volume associated with the PV line in **Fig. 8** is 401 mmRb. The pressure comparison in **Fig. 9** suggests that observed pressure behavior indicates smaller pressure support compared to that reflected in the convolved pressure curve. This means that we need to reduce the pore volume estimate by moving the PV Line on the plot slightly to the left. As we move the PV Line to the left, we also have to move the last two control points of the response derivative curve together with this analysis line. After several such PV line adjustments we determine the value of the pore volume that allows us to match observed pressure data. This value of pore volume in our case is close to 255 mmRb. Note that this reservoir pore volume is supported by the dynamic reservoir pressure and rate data and is recovered in our analysis through the process of reconstruction of constant rate drawdown response function. The final response plot and the corresponding pressure match are demonstrated in **Fig. 10** and **Fig. 11**. Please note that in the **Fig. 11** match we honor only the pressure data during flow periods when the well is shut in. Convolved pressure does not reproduce the pressure during flow periods. This is clearly evident in the early part of production history when the well produces at high rate and the total skin factor is much higher due to turbulence effect reflected in the observed pressure data. Also note that the reference PBU used in the analysis to guide us on the response shape at early time is the last PBU in the well record. This last PBU reflects the total well skin factor at the end of production history. This skin factor is reflected in the reconstructed response function and this is why the convolved pressure reproduces flowing pressure during the later part of production history. The difference between convolved flowing pressure and observed flowing pressure at the beginning of well production history is the pressure drop associated with turbulence effect. **Fig. 11** also presents evolution of average reservoir pressure with time that is shown as dark green curve. This average pressure evolution is also a result of analysis.

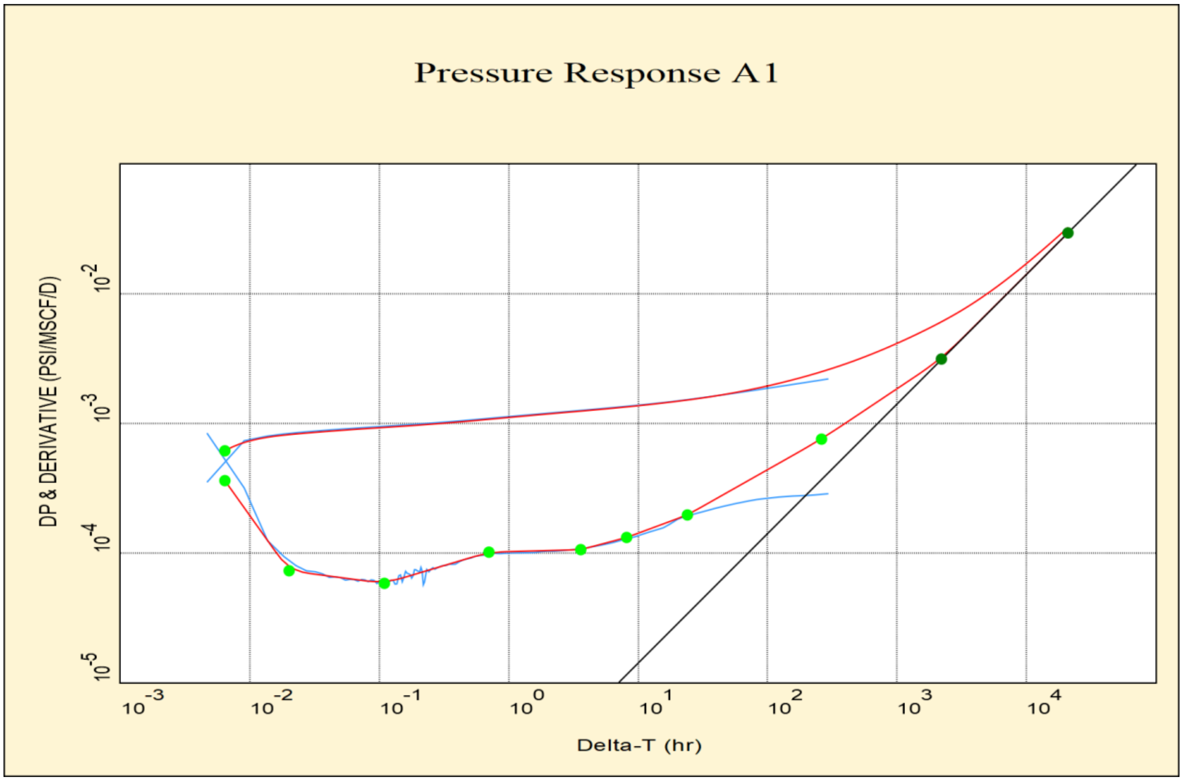


Fig. 10. The final result of response reconstruction. The pore volume associated with this response is 255 mmRb.

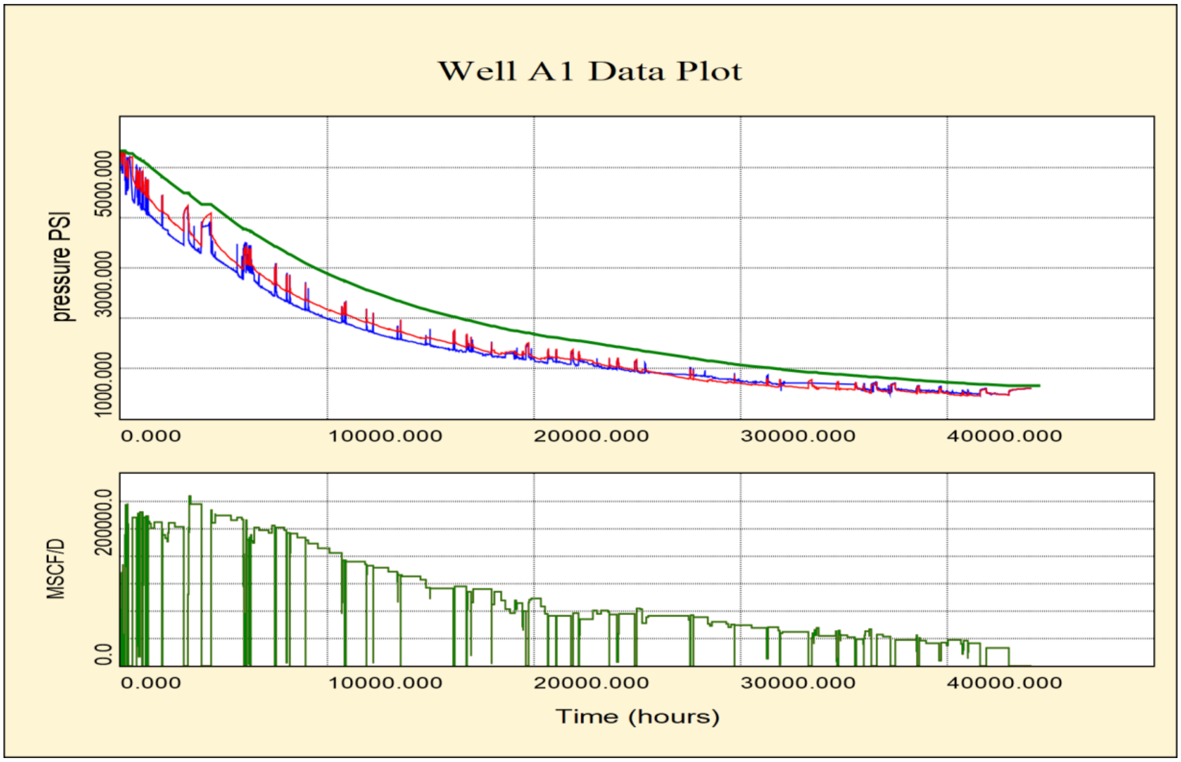


Fig. 11. Final match of observed well pressure.

Let us summarize what we did and what specific features we discovered in the well pressure and rate data by using manual pressure-rate deconvolution offered by the Convolution Explorer application:

1. Our initial attempt to apply pressure-rate deconvolution was unsuccessful. We failed to reconstruct a physically meaningful constant-rate drawdown pressure response and match the well pressure data.
2. This led us to conclusion that in this initial deconvolution attempt we did not account for the variation of gas compressibility with pressure. This effect manifests itself in gas reservoirs experiencing significant pressure depletion. As reservoir pressure declines, gas compressibility increases and this adds pressure support to the reservoir slowing reservoir pressure decline. This effect can be accounted for by applying material balance pseudo-time to the well pressure and rate data. Application of this transform requires as input the value of reservoir pore volume that in itself should be recovered in the analysis.
3. Convolution Explorer deconvolution workflow allows us to recover from the well pressure and rate data the value of reservoir pore volume as well as the constant-rate drawdown pressure response function. The pore volume recovered from the well dynamic data is 255 mmRb.

Please note that the analysis workflow implemented in Convolution Explorer is a process of interaction with the dynamic data acquired in the course of field production. The user assesses the data, data quality, consistency of transient pressure behavior. As a result of this assessment, the user decides on the specific subset of pressure data that should be used in the analysis. Following this initial assessment, the user proceeds with next step of data exploration. The main approach here is to determine if the data are consistent with the principle of superposition. This determination requires special software tool that allows for this data exploration. This is why this software is named Convolution Explorer. If the conclusion from this investigation is that the data are, indeed, consistent with superposition, this step of analysis then yields reconstructed response function and reveals the reservoir properties reflected in the dynamic data.

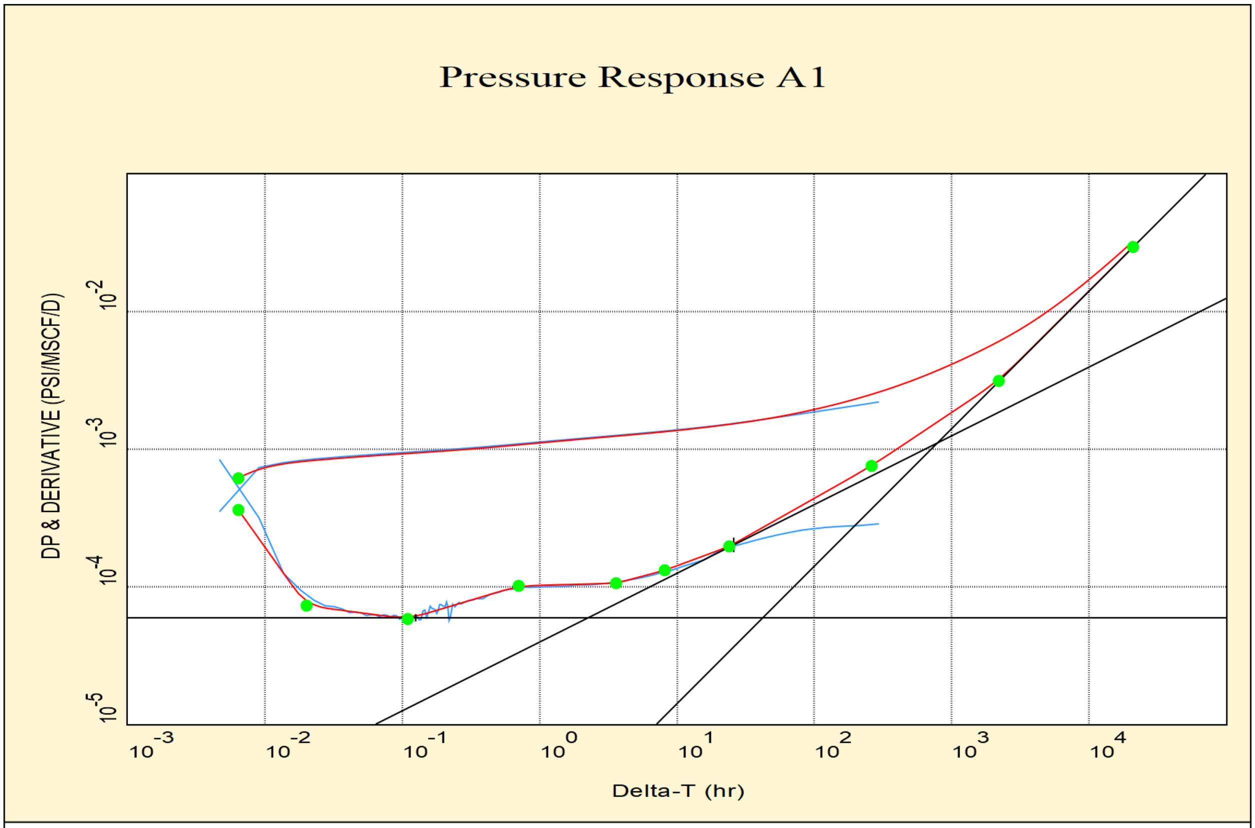
Interpretation of Deconvolved Drawdown Response Function

Reconstruction of constant-rate drawdown response function is not an end in itself. This function is a characteristic dynamic signature of the reservoir, its fingerprint. It contains information about the reservoir and well properties, the flow geometry in the reservoir that is controlled by reservoir boundaries and its architecture, as well as by the well completion and the completion geometry.

As was discussed earlier, the drawdown response at early time is defined based on the reference PBU data. Derivative curve of the response function in **Fig. 10** shows decreasing derivative behavior at very early time. Later, derivative evolves into a very short horizontal behavior and after 0.12 hrs. begins to increase and later levels off and evolves into a second horizontal stabilization that continues from 0.7 to 3 hrs. After this early period of about 20 hrs., the derivative curve is defined by matching the long term observed pressure behavior on data plot.

The decreasing derivative at the very early time is the later part of wellbore storage derivative hump. The hump itself is not resolved by PBU pressure measurements. In general, in high productivity gas wells wellbore storage effect lasts for very short time and the PBU data in **Fig. 10** reflect this. The first derivative stabilization after the end of wellbore storage reflects radial flow in close proximity of the well. The value of stabilized derivative during this first stabilization is obtained by placing horizontal analysis line through this part of the response derivative curve. This provides an estimate of permeability-thickness product of 19000 md-ft. With the net thickness of 255 ft, this results in the permeability estimate of 74 md. The same horizontal analysis line produces an estimate of well skin factor. The skin value is close to 2. This is the well skin at the very end of production history because in the process of response reconstruction we used as reference PBU the last pressure buildup of the pressure data stream.

Radial flow ends at around 0.12 hrs. from the start of response function. The radius of investigation at this time is estimated at about 173 ft. Drawing horizontal analysis line through the second derivative stabilization period provides permeability estimate of about 42 md. This almost factor of two decrease of the stabilized derivative value is a sign of a no-flow reservoir boundary. The distance to this boundary is defined by the time of the end of radial flow. As we already estimated above, the distance from the well to this boundary is close to 173 ft. The



Permeability, md	74.5025	Net thickness, ft	255.00
Skin total	2.012	Wellbore radius, ft	0.354
Permeability-thickness, md-ft	18998.148	Perm-ChanWidth factor, ft-sqrt(md)	5614.7178
Radius of investigation, ft	172.79	Channel half-width, ft	650.49
at time, hr	0.12		
Diffusivity, ft^2 / hr	59762.902		
Pore Volume, mmRb	255.00		
Hiip, Bcf	307.65		
Initial pressure, psi	6335.850		

Fig. 12. Diagnostic analysis of drawdown response function.

second derivative stabilization period ends around 5 hrs. and after 10 hrs. derivative evolves to a ½ slope trend that continues until around 120 hrs. The ½ slope derivative trend is a sign of linear flow that occurs between two parallel boundaries. Hence, the response indicates that the reservoir geometry is similar to a long channel formed by reservoir boundaries. Drawing a ½ slope analysis line through this trend provides an estimate of the reservoir width of close to 1300 ft. One of the two reservoir boundaries is 173 ft from the well. With the channel width of 1300 ft, the distance from the well to the second boundary is then about 1130 ft.

Following this ½ slope derivative trend the response derivative eventually evolves into a unit-slope asymptotic trend at late time indicating closed reservoir behavior. This is when transient flow in the reservoir ends and evolves into pseudo steady-state regime. The late time unit-slope derivative trend provides an estimate of the reservoir pore volume of about 255 mmRb. The above analysis of the drawdown response function is presented in **Fig. 12.** It demonstrates the corresponding analysis lines positioned on the plot and the resulting parameter estimates associated with this interpretation.

Uncertainty Assessment

The problem of dynamic reservoir analysis is an inverse problem and in general it does not lead to unique results. The main result in our case is the reconstructed response function. It is reconstructed in the process of matching observed pressure and rate data and the result of such reconstruction is non-unique. It is possible to reproduce the same reservoir behavior within some tolerance with different response functions that could be qualified as "physically meaningful. Here we assess the level of uncertainty of the response function reconstructed earlier. This response function is displayed in **Fig. 10**. By its construction this response function is defined by its control points. In our reconstruction we used 11 control points. A small displacement of any of these control points up or down on the plot will change the response function and this will affect the accuracy of the match presented in **Fig. 11**. As long as the maximum change of the convolved pressure function resulting from this control point displacement is within some tolerance, we could assume that the "disturbed" response function is also an acceptable response reconstruction result.

We can determine an uncertainty bar in the vertical position for each control point. This uncertainty bar would indicate that as long as the control point is within this bar the max pressure change of the convolved pressure function is less than the specified pressure tolerance.

For this uncertainty assessment we used the pressure tolerance value defined as 1% of the pressure variation range during the entire production history of the well. We also included in the assessment the control points of only the derivative curve of the response. The resulting set of uncertainty bars for each control point is shown in **Fig. 13**.

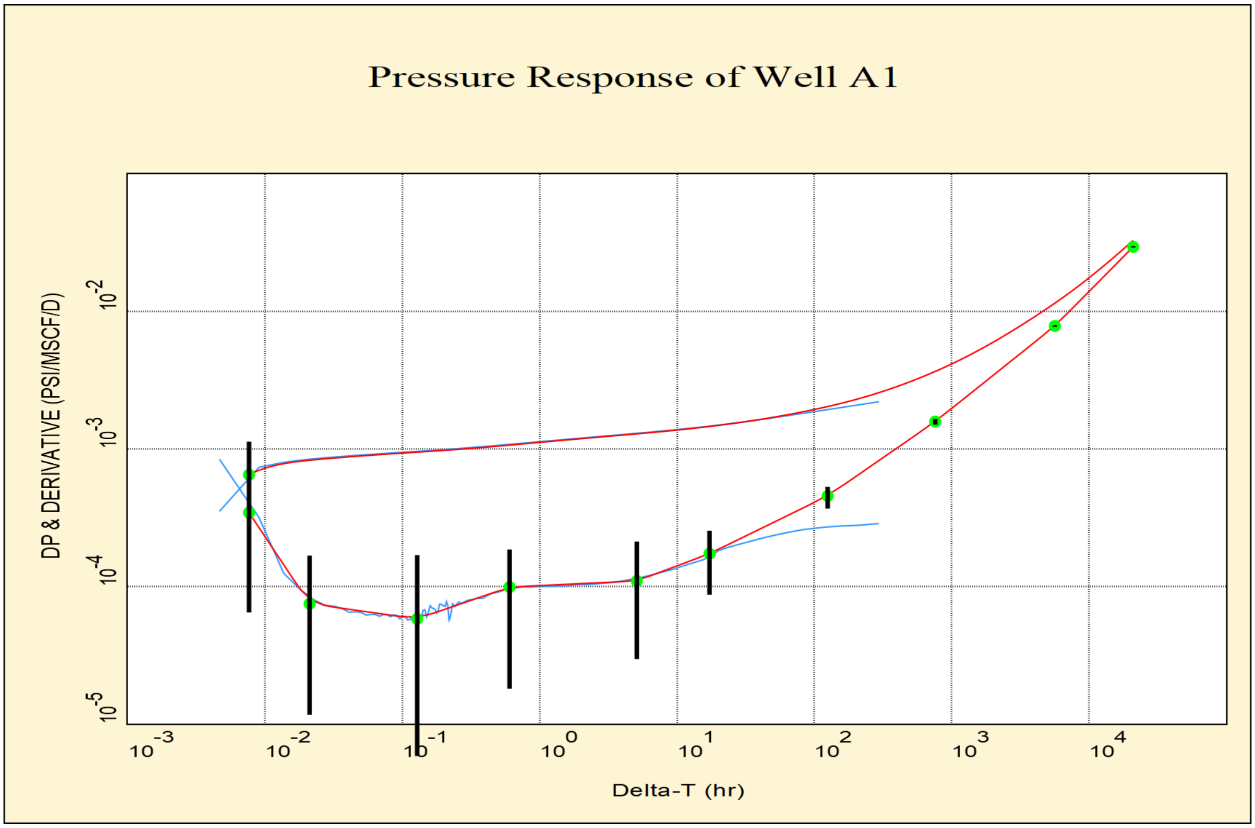


Fig. 13. Uncertainty assessment of response function.

The results of this uncertainty assessment present not an encouraging picture. It basically indicates that the shape of the drawdown response during the first 20 hrs. is not well- defined by the long-term pressure trend defined by the sequence of pressure buildups on the data plot in **Fig. 11.** It is this pressure trend which we try to reproduce in the course of response reconstruction. In other words, this long-term pressure trend has information gap regarding early-time pressure transient behavior and this is why the level of uncertainty indicated by **Fig. 13** is so large. At the same time, the level of uncertainty in the late time response pressure behavior is low and the uncertainty decreases with time.

Fig. 13 is useful because it provides indication about information content of the data. However, this plot is also misleading because it does not reflect how we actually reconstruct the drawdown response function. We define the shape of response function at early time from the reference PBU derivative plot and not from the long-term pressure trend. This fundamentally reduces the uncertainty level in early time transient behavior of response function. It does not mean that there is no uncertainty in early time transient behavior of response function. The level of uncertainty is actually reflected in **Fig. 3** that compares derivative plots of several PBUs present in the data sequence of the well. We could choose any of these PBUs as reference PBU for response reconstruction and the resulting response would be slightly different. If we include information from **Fig. 3** in our uncertainty assessment, we end up with the plot shown in **Fig. 14.** It basically tells us that if have good quality PBUs in the well production sequence and if we follow the response reconstruction workflow implemented in Convolution Explorer then the response function produced in such reconstruction is well defined. We may have a problem with data that do not include pressure buildup periods. This is often the case for unconventional reservoirs. We definitely do not have a problem with this gas well we analyze.

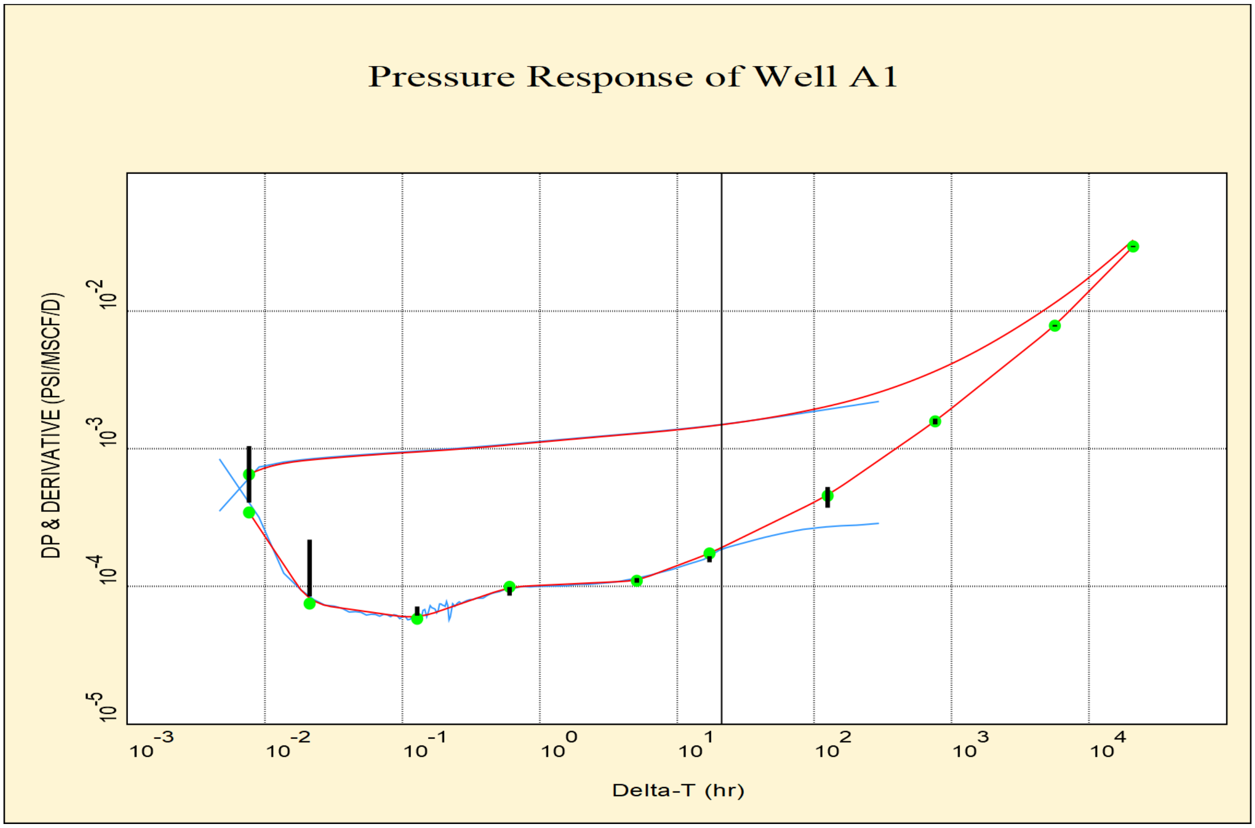


Fig. 14. Uncertainty assessment of response function.

Turbulence Analysis

Fig. 11 clearly demonstrates turbulence effect present in the observed pressure data. Convolution Explorer has the functionality that allows one to evaluate the turbulence factor. The approach here is similar to how it is done with other PTA software tools. We choose a reference PBU at the beginning of well production history when the well produces at high rate and go through the analysis workflow with this reference PBU. After the response function is reconstructed, we draw horizontal analysis line through the radial flow stabilized derivative data and estimate permeability and the total skin factor. Next, we repeat a similar analysis for a reference PBU at the end of the well production history when the well produces at low rate. This gives us two values of total skin factor at two values of well rate. This allows us to estimate the value of turbulence factor.

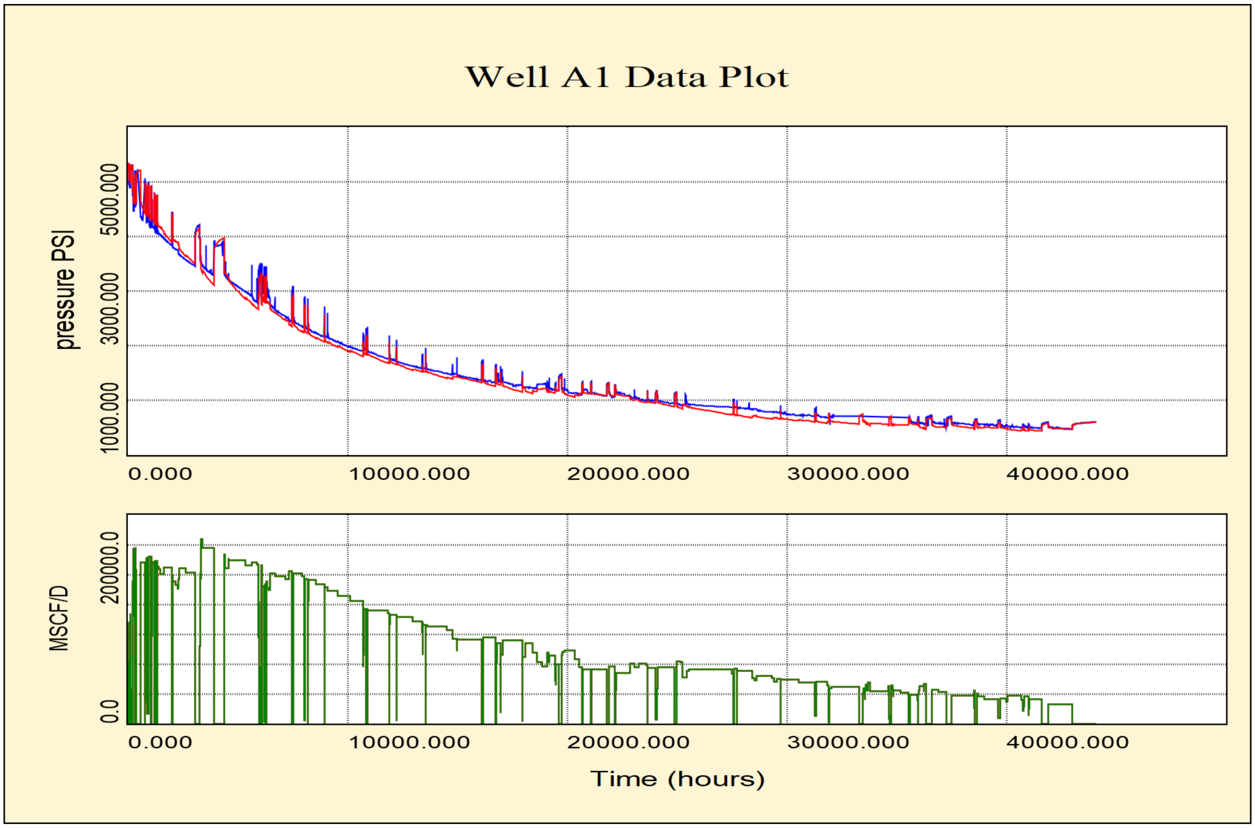


Fig. 15. The pressure match when turbulence effect is accounted for through turbulence factor.

The convolution algorithm implemented in Convolution Explorer application allows us for given value of turbulence factor account for the turbulence pressure drop when computing convolved pressure. The turbulence factor for our well is estimated as 0.000025 D/mScf. The pressure match for this value of turbulence coefficient is shown in **Fig. 15**. At early part of production history, convolved pressure function in this case is much closer to the observed well pressure during well flowing periods.

Well Production Forecasting

Convolution Explorer has the capability to forecast future well performance for given bottom hole pressure constraints imposed on the well during forecast period. This forecasting is not based on reservoir simulation and on constructing a reservoir simulation model. It relies only on the analysis results already recovered in the course of analysis presented above.

Well rate forecasting relies on the same superposition equation, **Eq. 1.** However, this time we solve it for well rate for some specified bottomhole pressure that controls this rate. Hence, when forecasting future well rate, the left-hand side of **Eq. 1**, $p(t)$, defines the bottomhole pressure constraint function, the $p_u(t)$ is the unit-rate response function that has been already recovered/reconstructed in the course of the analysis presented above. Recall, this response reconstruction is based on the well's earlier production history. We just have to solve this equation for the well rate $q(t)$. When solving this equation, we do need to know the response function that is defined on the longer time interval than the time interval on which it was reconstructed. This, however, is easy to do because towards the end of production history the response derivative evolved into an asymptotic unit-slope trend that is controlled only by the reservoir pore volume and cannot change. Hence, this asymptotic trend will continue into the future. The only input required for this rate forecasting is the pressure constraints that are defined by the user interactively on the data plot. **Fig. 16** presents an example of such well rate prediction.

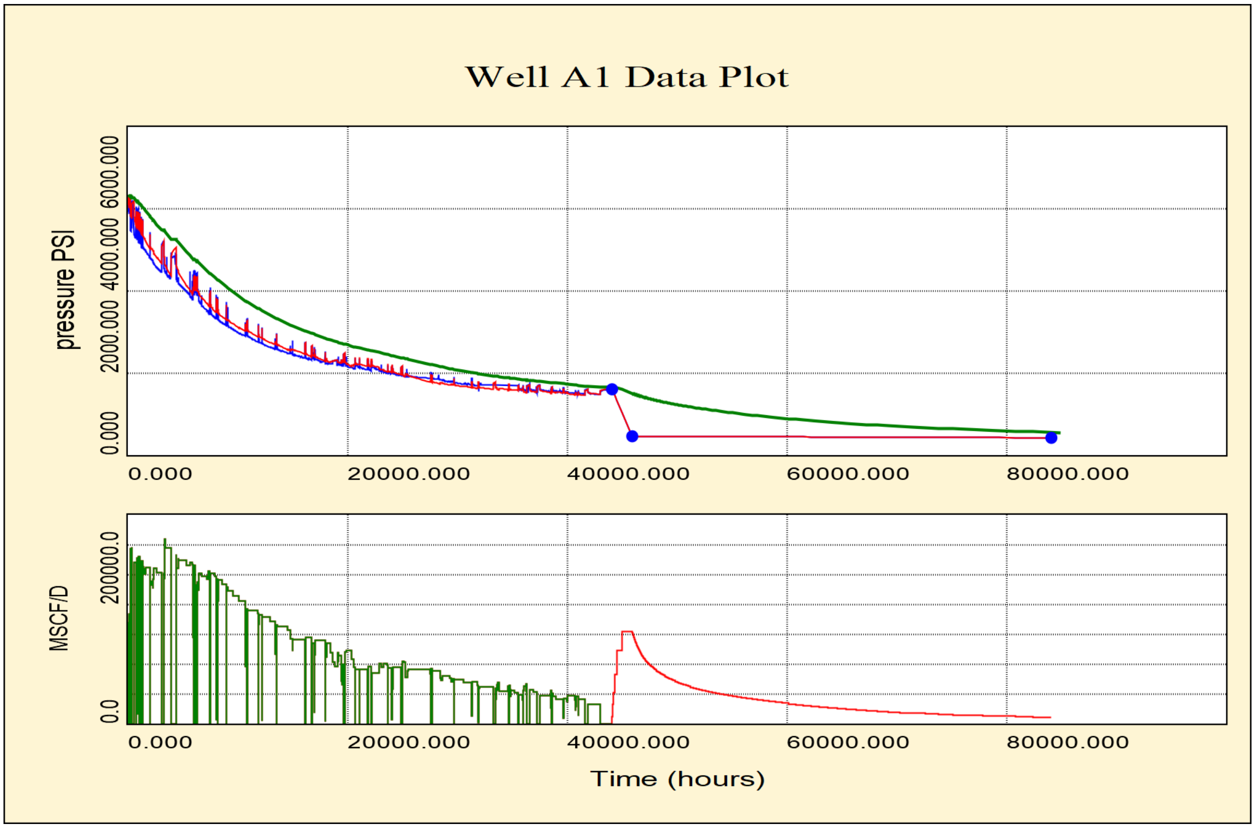


Fig. 16. Forecasting of future production for given bottomhole pressure constraints

In this example, production is forecasted for the next 40000 hrs. which is slightly less than the production history of the well. The bottomhole pressure constraint imposed on the well is shown in the upper part of the plot by red line. In this forecast we flow the well against the backpressure of 500 psi. Predicted well rate is shown by the red curve in the lower part of the plot. The dark green curve in the upper part of the plot presents evolution of average reservoir pressure with time. As this forecast demonstrates, it is only possible to reduce average reservoir pressure in this case to about 800 psi.