

5. Well Test Analysis Techniques

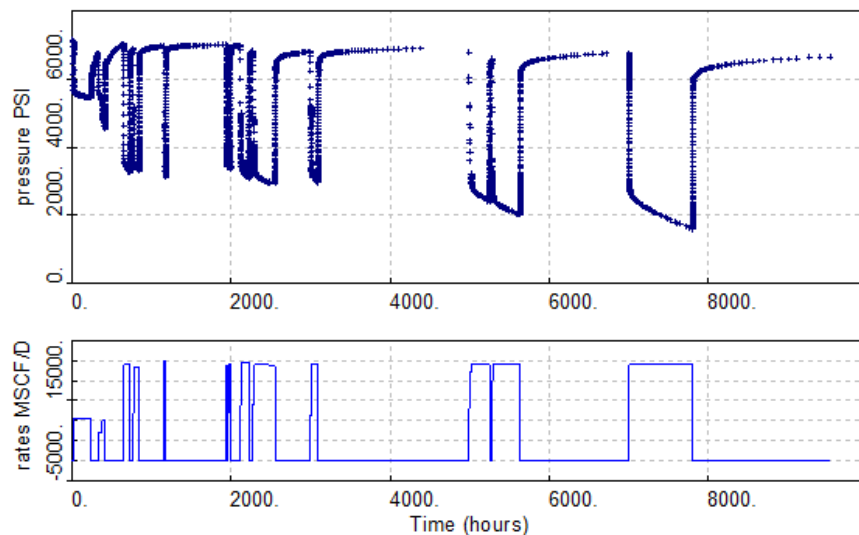
Once familiar with the well testing tools, the user can perform well test analysis to extract the well and reservoir information from the rate and pressure data.

5.1 Exploring the data using the well testing tools

5.1.1 Qualitative interpretation with the Data-Plot

The Data-Plot, also called Production History Plot, will first help with a qualitative interpretation, giving some indication on the skin, permeability-thickness and pressure support over time.

Several PBU tests of different durations could be noticed.

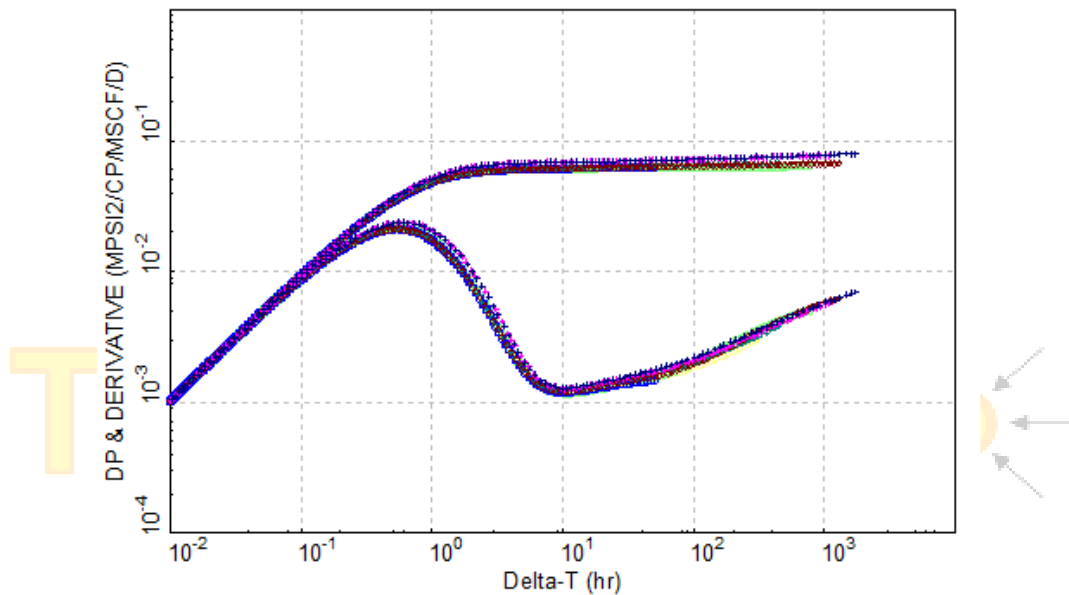


In the example above, the well has been producing at about the same rate ~24MMscf/d but with an increase in drawdown over time. The skin is probably increasing over time. We could also note a slight “depletion” trend which could

support the presence of boundaries. It doesn't necessarily mean that the reservoir is closed at this stage and a more detailed look will be needed.

5.1.2 Evolution of the derivative shape over time

It is recommended to plot the PBU tests (at least those of duration above 12hrs) in the same log-log plot to see the evolution of the derivative shape over time.



This will bring some confidence in the derivative data and help identify the flow regimes and any dynamic effects. Bad quality data should be removed from the PBU tests in the Data-Plot. Any tidal effect should be corrected by using a reference tidal signal, likely from a seabed gauge. This will help when investigating Deconvolution later on.

- If no derivative stabilization is visible, it probably means that radial flow regime has not been reached and the test interpretation is non-unique. Information from other flow regimes, from a valid deconvolution and from the core & log data could be used to reduce the non-uniqueness.

- If the PBU tests do not share the same derivative stabilization level, it could mean that the stabilization is a distortion (“false stabilization”), that the flow conditions around the well have changed (new perforations, development of fluid bank, deposits, sand fill, frac height, etc...), or that the rates have to be adjusted.

Changes in the ΔP plot will indicate some changes in total skin over time.

5.1.3 Investigate the validity of Deconvolution

With favourable reservoir conditions (single phase flow in the reservoir, no interference effects, no commingled layers with different P_i values), single-well Deconvolution should be investigated. Once a reliable deconvolved response is generated with a refined initial pressure P_i , it could be copied and pasted into the log-log plot so as to compare the conventional and deconvolved derivatives. Any discrepancy is likely explained by some distortions in the conventional derivative, due to the way it is calculated.

5.1.4 Identify the possible well-reservoir responses by detecting the different flow regimes in the conventional and deconvolved derivatives

Deconvolution brings more confidence in the derivative shape. Any derivative stabilization which is shared between the conventional and deconvolved derivatives is probably indicative of radial flow regime. The radial flow regime could also be confirmed by overlaying the different PBU tests on the Superposition Plot.

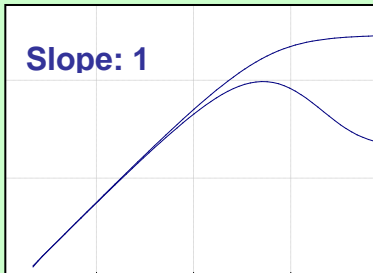
More generally, the shape of the conventional and deconvolved derivatives can be used to detect the different flow regimes over the test duration (see table 1) and to identify the possible well and reservoir responses.

The following section represents the characteristic derivative shapes for the most usual well and reservoir configurations at early, intermediate and late times.

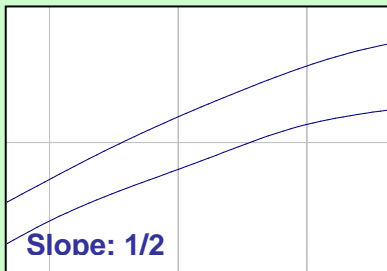


Early Times, Near Wellbore Region

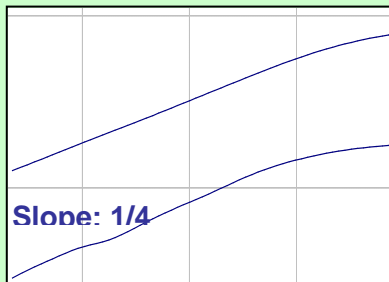
Wellbore storage and skin



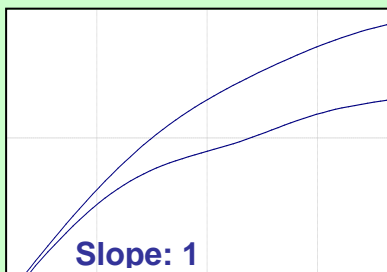
Infinite conductivity fracture



Finite conductivity fracture



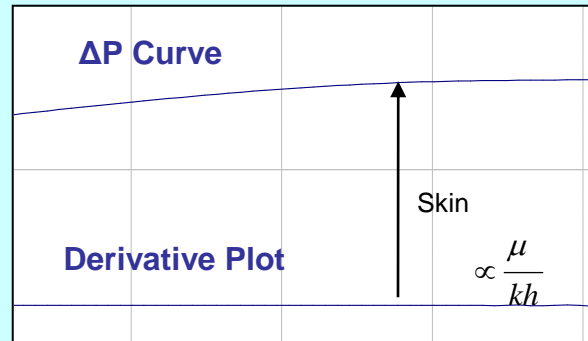
Fracture with wellbore storage and skin



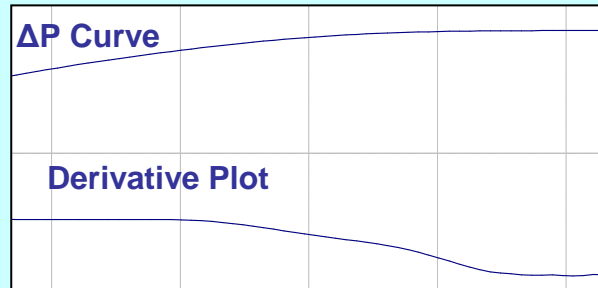
Middle Times, Away from the well

Some flow regimes at middle times could be masked by early-time effects or not be developed due to near wellbore boundaries

Radial flow regime in a homogeneous reservoir

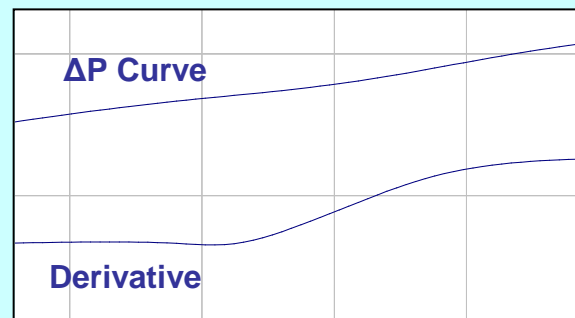


- Increase in mobility (kh/μ) and/or storativity ($\Phi c_i h$) away from the well (linear composite)
- Partial Penetration Effects
- Fluid bank developing around the well (radial composite)
- Poor horizontal well



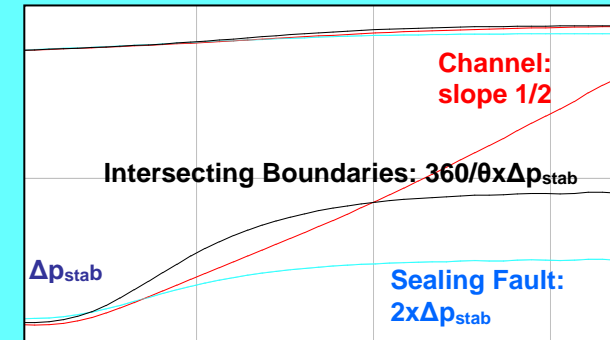
- Decrease in mobility (kh/μ) and/or storativity ($\Phi c_i h$) away from the well (linear composite)

- Good horizontal well

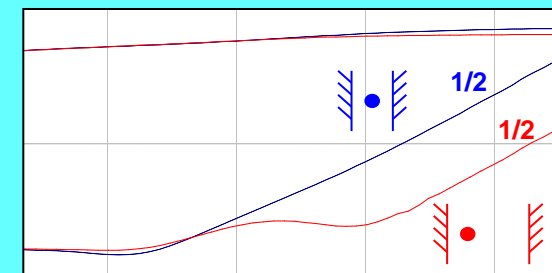


Late Times, Further Away from the well

Presence of sealing fault, channel or intersecting boundaries

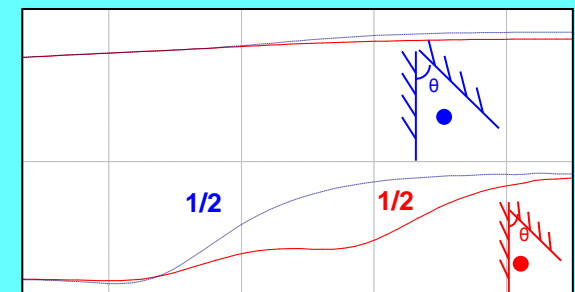


Presence of channel (parallel sealing faults)

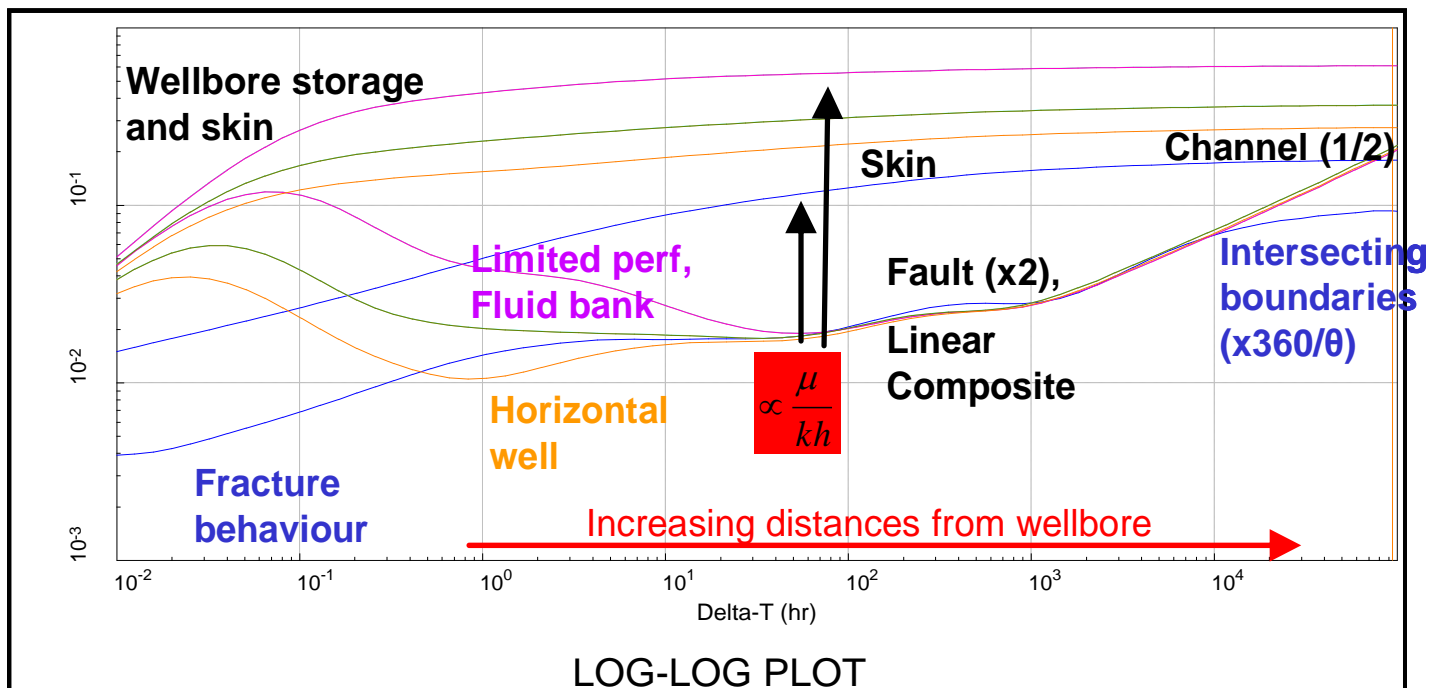


A slope of 1 could sometimes be visible if the channel is closed by one side.

Presence of intersecting boundaries

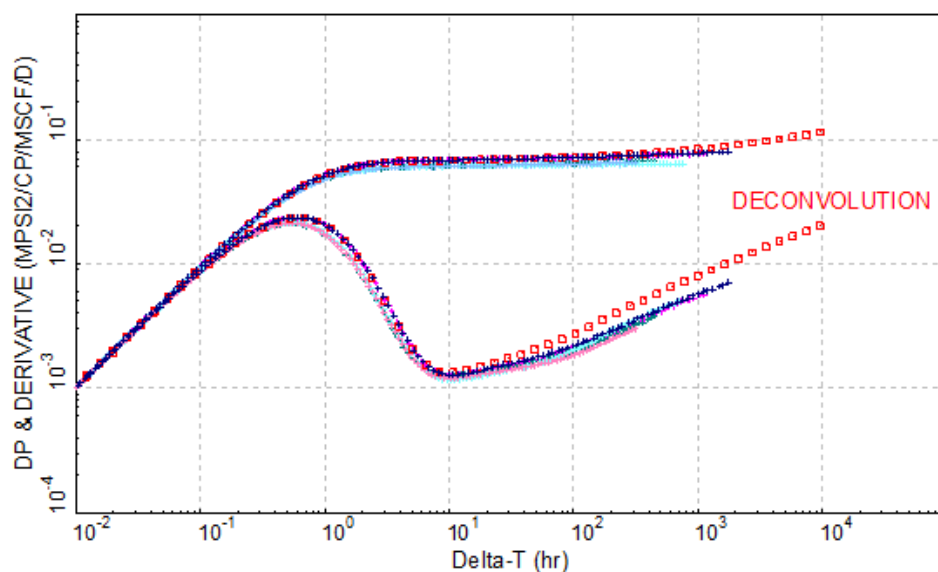


The figure below shows various combinations of flow regimes on a log-log plot, defining some possible well and reservoir responses.



Deconvolution should be used to investigate the presence of boundaries at late times. This could be supported by a declining PBU trend in the Data-Plot and a downward shift of the PBU data in the Superposition plot.

The figure below shows an example of log-log plot with the conventional and deconvolved derivatives.



After wellbore storage, both derivatives show a short stabilization at about 10 hours which could be indicative of radial flow regime. The discrepancy between the two derivatives from 10-20 hours onwards is due to a distortion on the conventional derivative. The derivative looks delayed in time compared with Deconvolution.

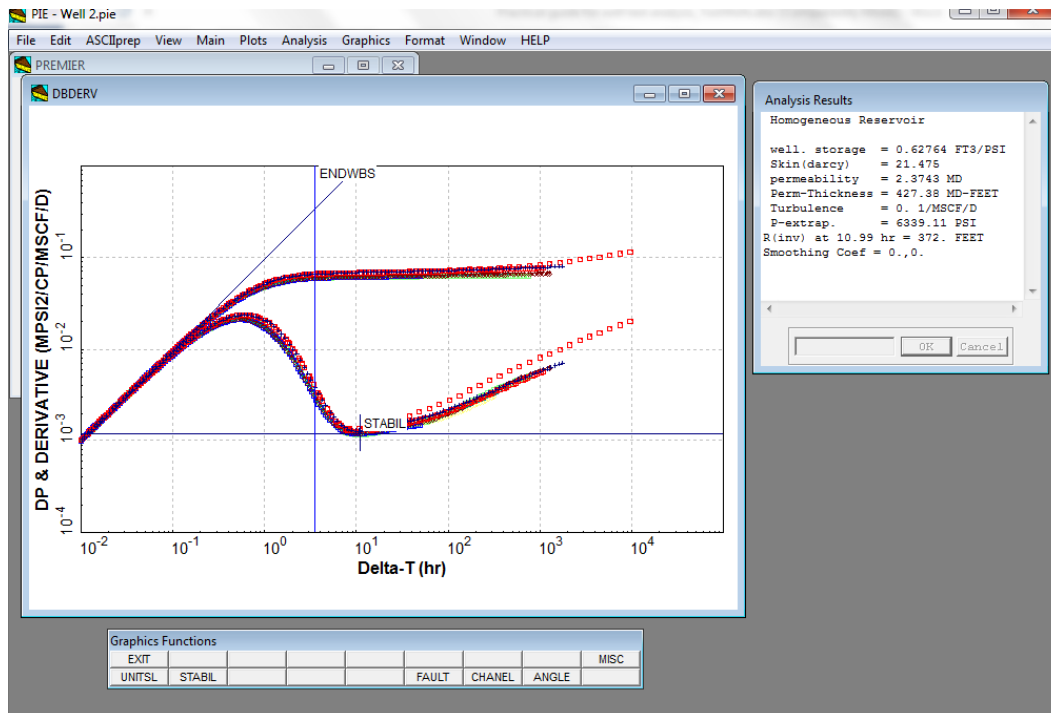
The increase in the derivative at late times would suggest the presence of boundaries and/or heterogeneities. The deconvolved derivative will then be used to calculate the well and reservoir parameters.

5.2 Calculation of well and reservoir parameters with an interpretation model

In the log-log plot, flow regimes can be identified with a series of straight lines fitting the derivative data. This is the straight line analysis.

The permeability-thickness product can be calculated directly from the radial flow stabilization line and the wellbore storage can be obtained from the unit slope straight line.

As shown below, radial flow regime is identified with the stabilization line in the derivative plot.



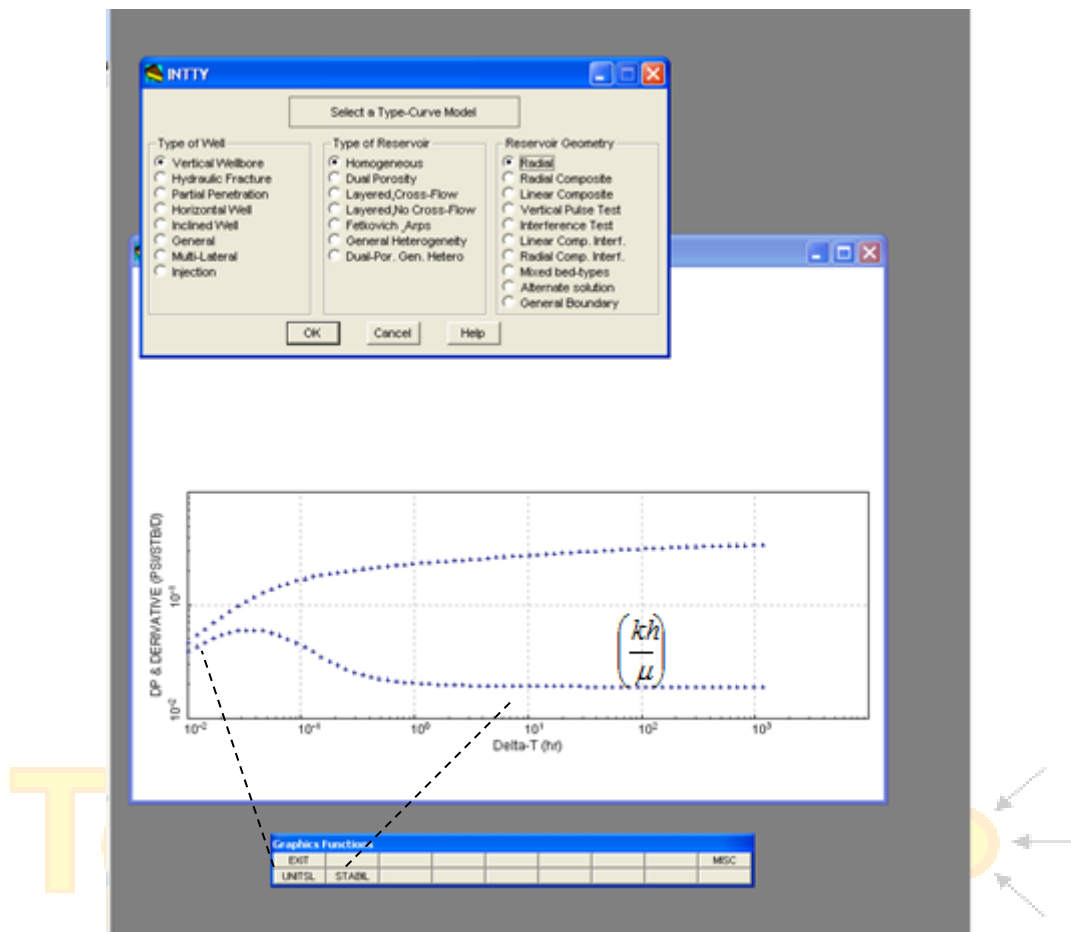
The permeability-thickness product and the radius of investigation are directly calculated from the stabilization line.

Once an interpretation model has been identified from a combination of flow regimes, other well and reservoir parameters can be *estimated* with straight-line analysis.

5.2.1 Selection of an interpretation model

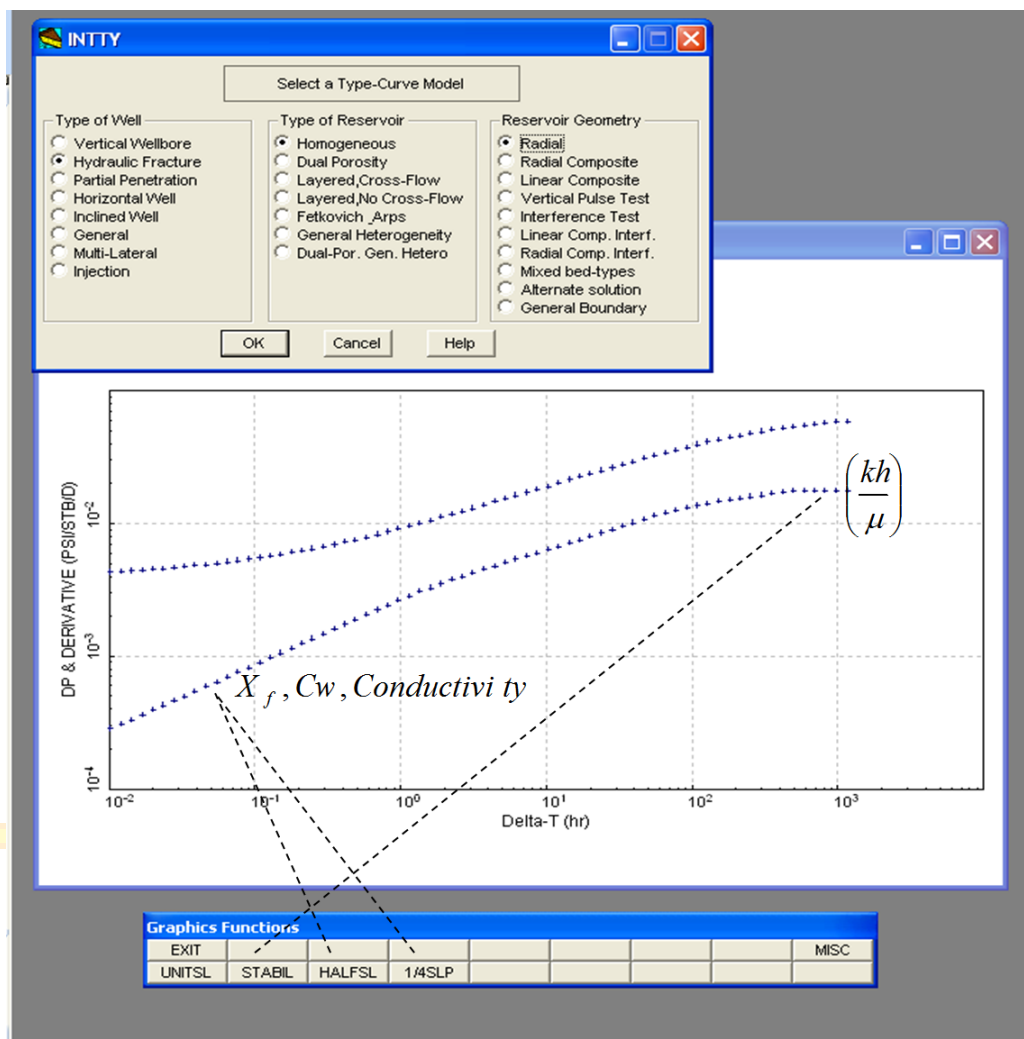
The following sections show the most common type curve models:

- Vertical well in a homogeneous radial reservoir of infinite extent



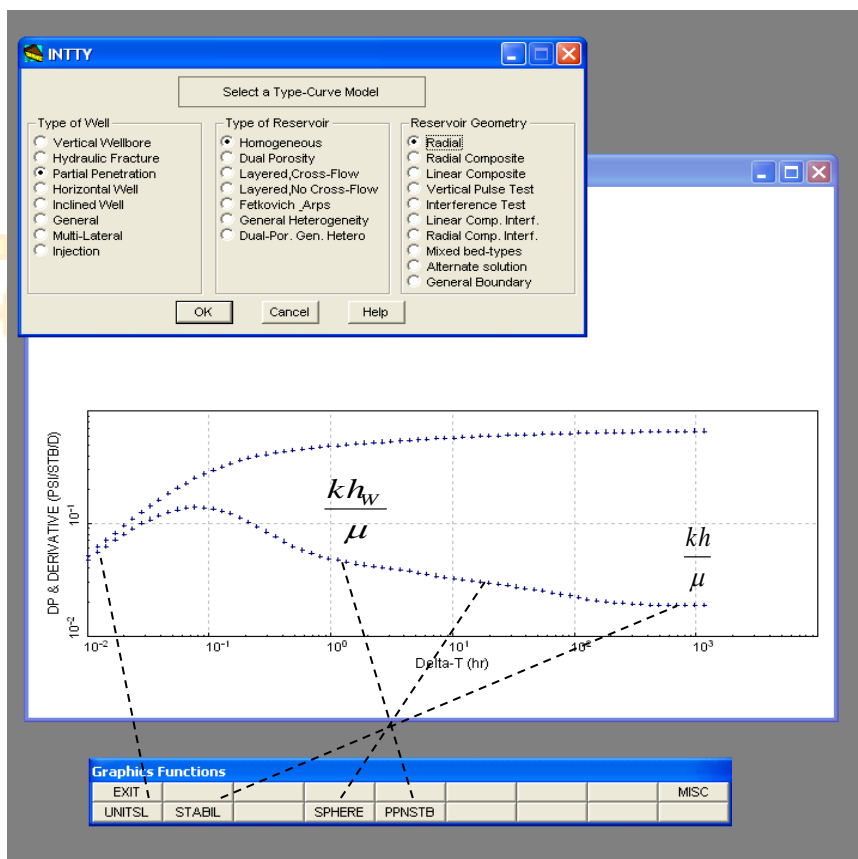
- A unit-slope straight line is available to define the wellbore storage and obtain the wellbore storage coefficient $C = C_w V_w$.
- A derivative stabilization ("STABIL") is available to define the radial flow regime and obtain the total skin and the permeability-thickness KH.

- Fractured well in a homogeneous reservoir of infinite extent



- A unit-slope straight line is available to define the wellbore storage at early times and obtain the wellbore storage coefficient.
- A quarter-unit slope straight line is available for a finite conductivity fracture to identify the bi-linear flow regime in the fracture behaviour. This flow regime should develop after wellbore storage and before the linear flow regime. It characterizes the dimensionless conductivity of the fracture $\frac{K_f W_f}{K X_f}$ with K_f : the permeability in the fracture, W_f : the fracture width, K : the formation permeability and X_f the fracture half-length.

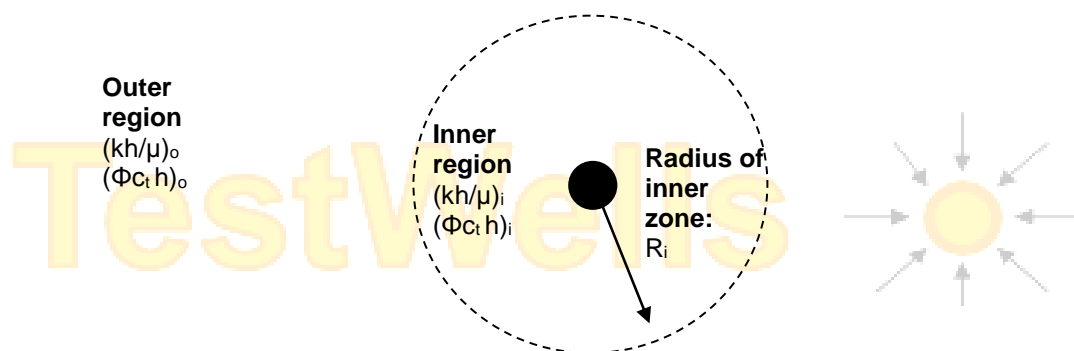
- A half-unit slope straight line is available to identify the linear flow regime in the fracture behavior and obtain KX_f with K : the formation permeability and X_f : the fracture half-length.
- A derivative stabilization defines the radial flow regime KH/μ outside the fracture.
- **Well with limited perforations/partial penetration in a homogeneous radial reservoir of infinite extent**

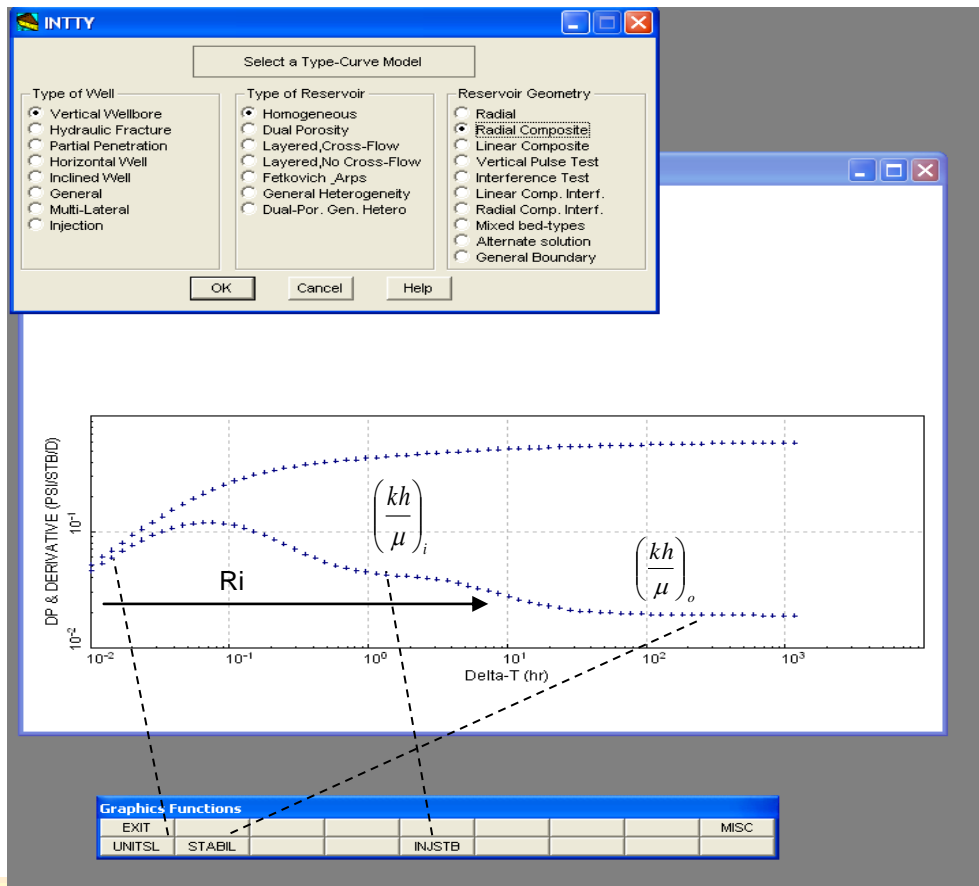


- A unit-slope straight line is available to define the wellbore storage.
- A derivative stabilization ("PPNSTB") is available to identify the radial flow regime over the perforated reservoir interval KH_w/μ .

- A negative half-unit slope straight line (“SPHERE”) is available to select the spherical flow regime (3-dimensional flow).
- A derivative stabilization (“STABIL”) is available to identify the radial flow regime over the entire reservoir thickness KH/μ .
- **Vertical well in a homogeneous radial composite reservoir of infinite extent.**

The reservoir is divided into 2 main circular regions with different mobility (kh/μ) and/or storativity $(\Phi C_t h)$ ratios.





- Unit slope straight line is available to define the wellbore storage.
- Derivative stabilization (“INJSTB”) is available to identify the radial flow regime in the inner region of the reservoir.
- Derivative stabilization (“STABIL”) is available to identify the radial flow regime over the entire reservoir thickness.

This interpretation model shouldn’t be used to characterize the reservoir but to represent dynamic production changes (development of fluid banks when producing below saturation pressure, waterflooded region, acidized zone, etc...).

- **Vertical well in a linear composite reservoir of infinite extent.**

The reservoir is divided into 2 or more regions with different mobility (kh/μ) and/or storativity ($\Phi C_t h$) ratios separated by a linear interface.

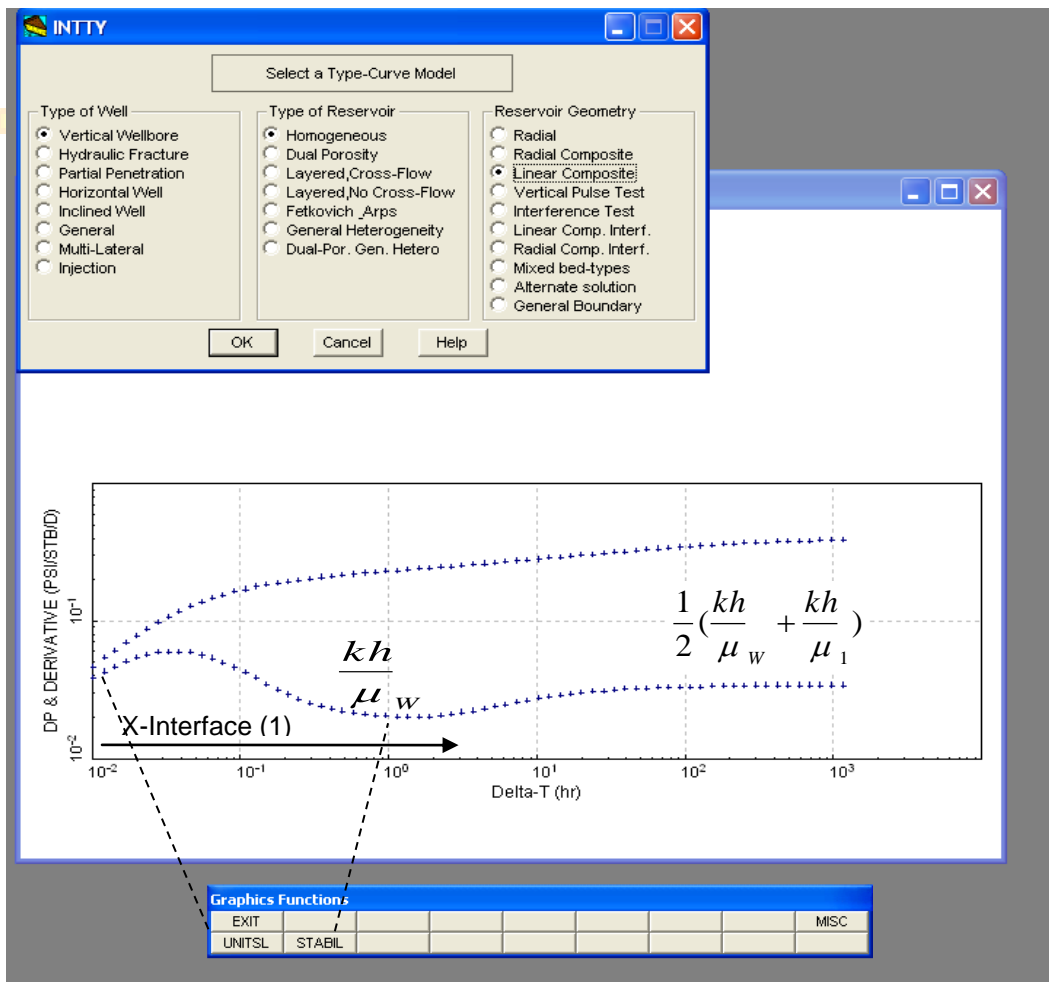
Region where the well is located

$(kh/\mu)_w$
 $(\Phi C_t h)_w$

X-Interface (1)

Region (1)

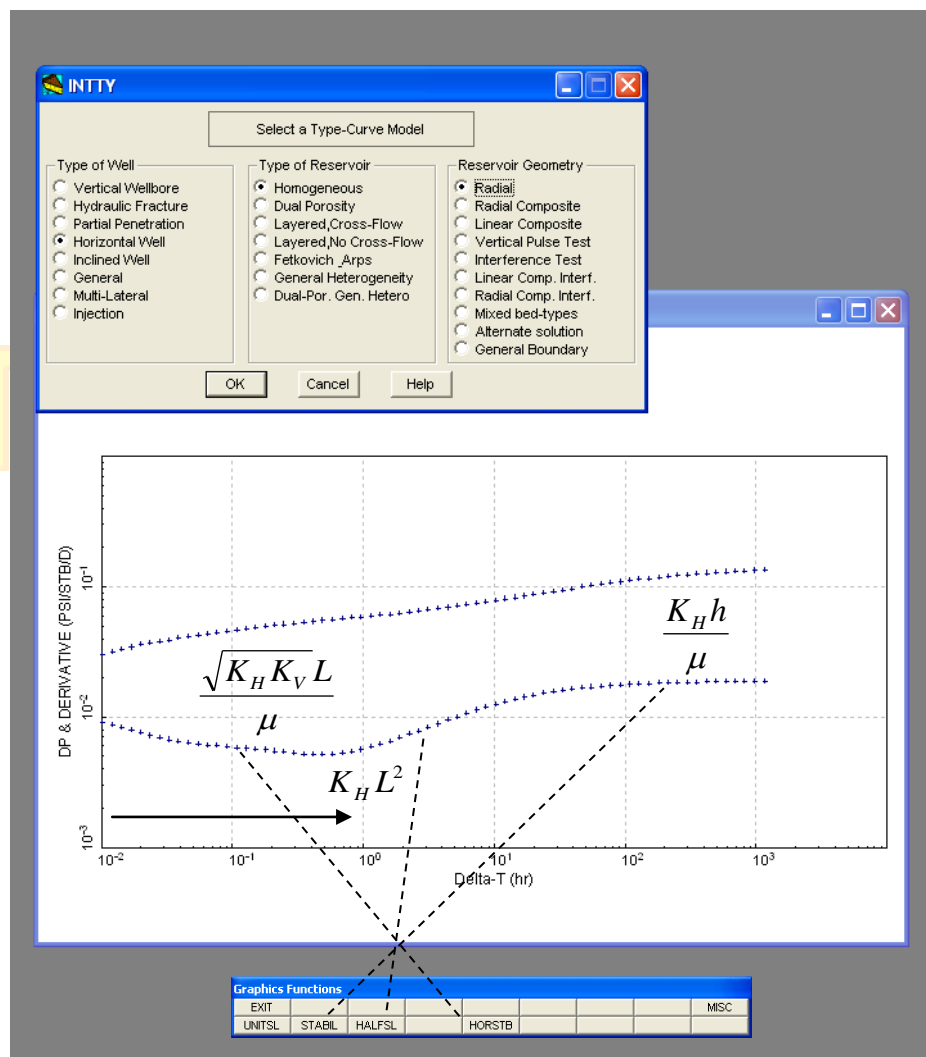
$(kh/\mu)_1 = \text{Mob. Ratio}(1) \times (kh/\mu)_w$
 $(\Phi C_t h)_1 = \text{Stor. Ratio}(1) \times (\Phi C_t h)_w$



- Unit slope straight line is available to define the wellbore storage.
- Derivative stabilization (“STABIL”) is available to identify the radial flow regime in the wellbore region.

The linear composite model is best suited to represent fluid contacts (GOC, WOC, GWC) and changes in rock properties, fault and fracture density.

- **Horizontal well in a homogeneous reservoir of infinite extent.**



In this plot, L represents the productive horizontal length, K_H the permeability in the bedding plane, K_V the permeability in the plane normal to the well direction.

- Unit slope straight line defines the wellbore storage.
- Derivative stabilization (“HORSTB”) identifies the radial flow regime in the plane normal to the well direction (“vertical radial flow regime”).
- A half-unit slope straight line (“HALFSL”) defines the intermediate flow regime, usually the linear flow, between the two radial flow.
- Derivative stabilization (“STABIL”) identifies the radial flow regime in the bedding plane (“horizontal radial flow regime”).

When the horizontal radial flow regime is identified in the log-log plot, the derivative stabilization will yield the permeability-thickness $K_H h$.

The intermediate flow regime (half-unit slope straight line on the derivative data) gives $K_H L^2$. Knowing K_H from the final derivative stabilization, the user can then obtain the productive horizontal length L .

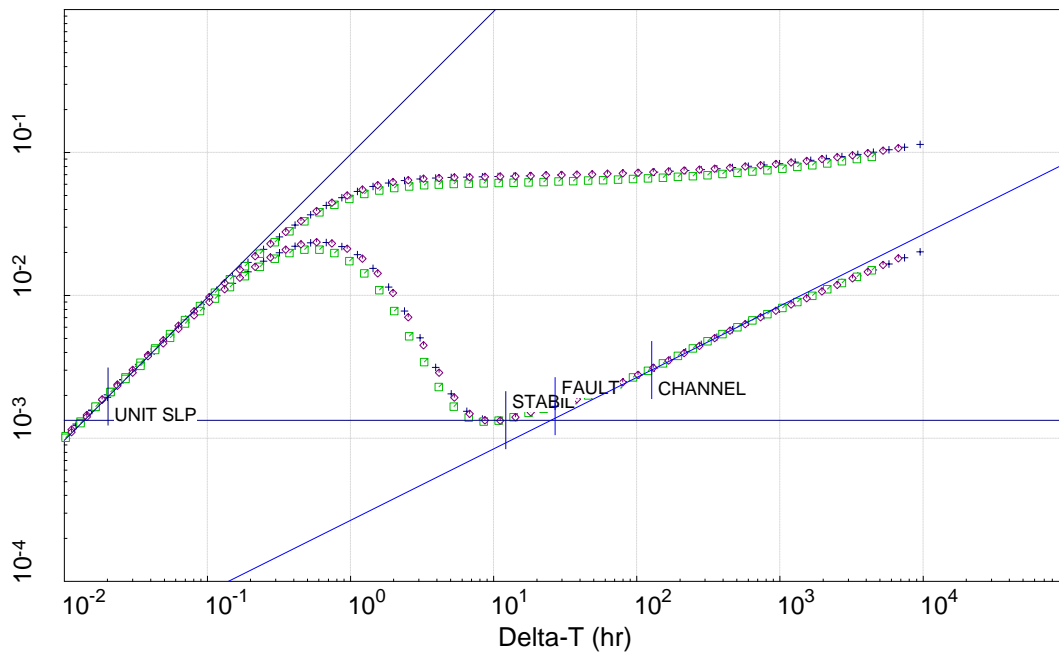
Finally, the earlier derivative stabilization indicative of vertical radial flow regime is used to extract the permeability anisotropy $\frac{K_V}{K_H}$ value. If the vertical radial flow regime is not present, the permeability anisotropy will be uncertain.

If the test ends before the final radial flow regime, the permeability in the bedding plane and total skin are not fixed. However, the range of possible K_H values can be narrowed thanks to some constraints from the intermediate linear flow regime, Deconvolution and the production history plot.

5.2.2 Straight line analysis and matching process

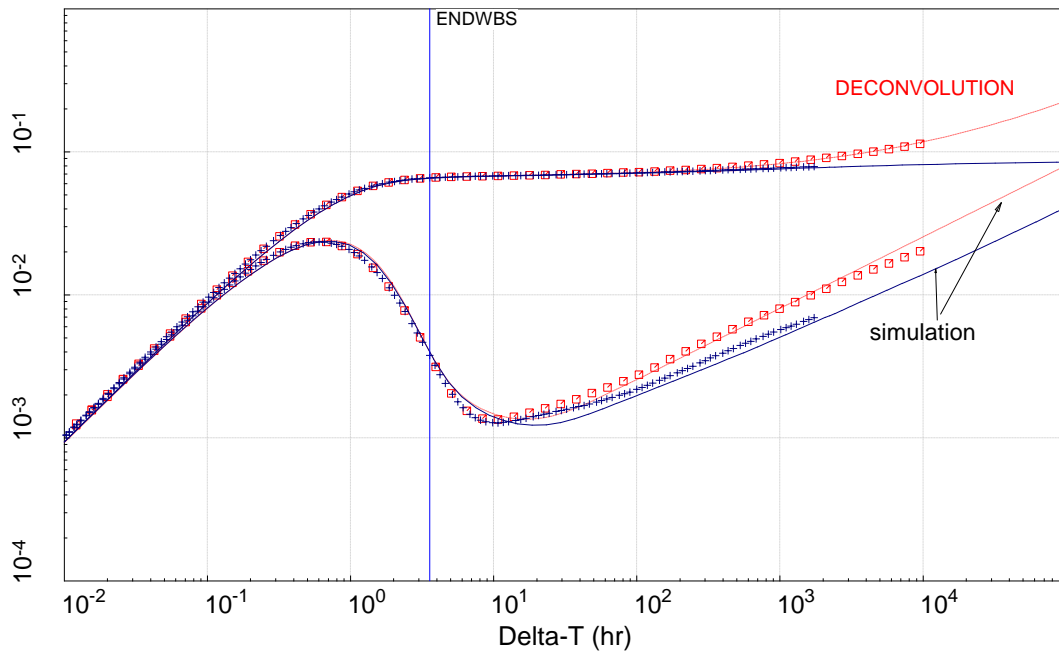
Once an interpretation model has been identified, straight-line analysis is performed on the derivative plot to confirm the different flow regimes and get some estimates of the well and reservoir properties.

This is shown in the figure below.



The well and reservoir parameters are then refined by matching the derivative with the interpretation model. As for the ΔP plot, the match will be obtained by adjusting the skin value.

The plot below shows the match on the log-log plot using the estimates from the straight-line analysis. It will be our starting point.

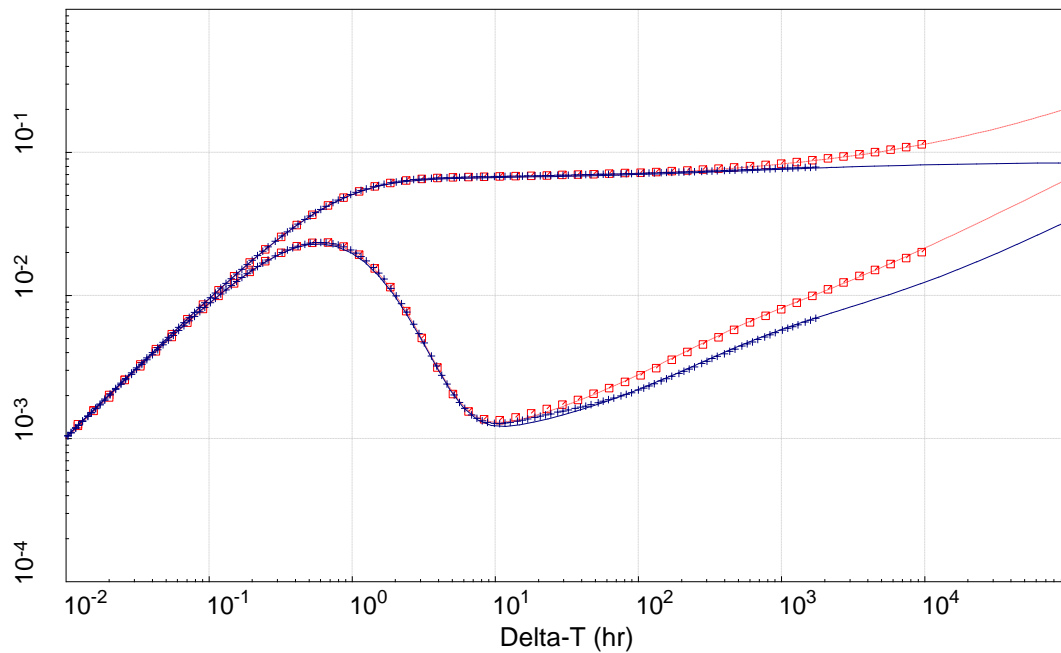


To further refine the match between the actual and simulated data, the well and reservoir parameters can be updated manually or automatically with the regression tool.

If valid, Deconvolution should drive the matching process. If the deconvolved response is not matched at late times, it probably means that the user needs to change the distances to the boundaries or to add/remove some boundaries and/or heterogeneities.

In the above example, the user will need to add an increase in mobility and/or storativity further away from the well to drive the simulated deconvolved derivative downwards at late times.

Once Deconvolution is matched, the conventional derivative should then be automatically matched. If not, it could mean that the interpretation model is wrong or that Deconvolution is not correct. The analyst will then need to spend more time to recover a reliable Deconvolution response.



The results should also be checked by looking at the Superposition and Data plots:

- The Superposition plot should be matched. If not, it could mean that KH, skin or initial pressure P_i is not correct or that boundaries/heterogeneities should be added or removed.
- The PBU tests in the Data Plot (Production History Plot) should be matched. If not, it could mean that KH or initial pressure is not correct or that boundaries/heterogeneities should be added or removed. If the flowing periods are not matched, it means that the skin value is not correct. In the case of gas and gas condensate wells, the turbulence skin (also called non-Darcy skin) should be adjusted by changing the mechanical skin but keeping the total skin constant.

Lack of pressure match in any plot should be understood. If not, it could mean that the interpretation model with the current parameters is wrong.

5.2.3 Guidelines on the matching process

The matching process should be an iterative one with some trials and errors.

The following section attempts to make the user more efficient with the matching process.

a) Initial pressure P_i is a known variable

At the start of the matching process, the initial pressure P_i value should be known either from Deconvolution or from the Data-plot, and compared with other sources of information (RFT/MDT). When using the regression tool to match the data, there is no need to change this value.

b) Obtain the permeability value and skin

Once the user selects a derivative stabilization as radial flow regime, the straight line analysis will give KH and total skin. Based on the input net reservoir thickness, the software will extract the permeability value. The KH value shouldn't be changed by the regression tool as it has been selected by the user. In some exceptional cases, the user may want to play with KH to investigate a "false" derivative stabilization.

When performing a simulation with an interpretation model, the radial flow regime in the bedding plane should be matched. If not, there could be two reasons: a high wellbore storage or short distances to the boundaries. The wellbore storage coefficient could be set to a low value to avoid any interference with the matching process. This will shift the initial unit-slope straight line towards the left of the plot. Likewise, the distances to the boundaries could be momentarily increased to shift the boundary effects towards the right of the derivative plot.

If the radial flow regime in the bedding plane is not present, KH and skin are non-unique. A permeability value should be assumed by using other sources

of information, and then the data should be matched by changing other parameters and keeping KH fixed. The matching process should be repeated with other permeability values to define a range of KH values. As Deconvolution is recovered over a long time interval, it will bring more constraints and reduce the range of possible values.

c) Detect the boundaries

- If Deconvolution is valid, the deconvolved derivative is used to identify the boundaries and associated distances from the well. Since the test duration Δt is linked to the distance from the well, a larger distance to a boundary will shift the simulated derivative response towards the right, towards late times. This involves an iterative process with some trials and errors. For each iteration, the distances to the boundaries can be updated, boundaries added or removed.

If the deconvolved derivative cannot be successfully matched, the pressure behaviour at late times could probably be explained by some reservoir heterogeneities. Away from the wellbore, the presence of a region of different mobility (kh/μ) and/or storativity (Φc_h) could provide a better match. One or more linear composite region(s) should therefore be added to the interpretation model. As it is often the case with complicated test behaviour, heterogeneity arrangements are highly non unique and knowledge from the geology and seismic should be used to guide the matching process.

- If Deconvolution is not valid and the duration of the PBU test is long enough to see some boundaries, the conventional derivative and superposition plots should be used to achieve a match after the radial flow regime. Then the user should use the data-plot to match the long term pressure behaviour. This involves some trials and errors, and boundaries may have to be added or removed. The solution is non-unique but knowledge from the geology & seismic could be used to drive the match.

d) Match the derivative at early times

At this stage, the derivative response at middle and late times should be matched. This section describes how to match the derivative data at early times. This could involve the following:

- **Fracture behaviour:**

- The radial flow regime should be matched. Fracture half-length X_f can be updated either manually (a lower X_f will shift the simulated fracture response towards the left, towards the early times) or automatically with the regression by matching the linear flow regime and fixing the other parameters.
- Then the wellbore storage coefficient should be updated either manually or automatically by fixing the other parameters (a large C_w will shift the simulated derivative data towards the right, towards later times).
- Finally for a finite conductivity fracture, conductivity should only be adjusted to match the bilinear flow regime. For an infinite conductivity fracture, fracture-skin value could be adjusted to ensure that the derivative and ΔP plots are matched.

- **Partial penetration behaviour:**

- Step 1: the radial flow regime over the entire reservoir thickness should be matched. If the “effective thickness” value h_{eff} in the software is different from the known net reservoir thickness h , then the effective thickness should be changed to h . The user should then update the permeability value with the former permeability-thickness value kh_{eff} divided by h .
- Step 2: The intermediate flow regime, usually the spherical flow regime following a $-1/2$ slope straight line, can be matched by changing the vertical permeability value K_v either manually or automatically by fixing the other parameters in the regression tool. A lower K_v value will increase the duration

of the first radial flow regime and shift the intermediate flow regime towards the right, towards late times.

- Step 3: If the radial flow regime across the limited perforations h_w was initially matched thanks to the straight line analysis (with $h_{eff} \neq h$), then the perforation interval can be updated by keeping the same penetration ratio $\frac{h_w}{h}$.

More generally if the radial flow regime over the limited perforations is visible in the derivative plot, then the perforation interval can be updated with

$$h_w = h \frac{\Delta p_{2nd\ stabilization}}{\Delta p_{1st\ stabilization}} .$$

A smaller h_w value will shift the early stabilization upwards. Then step 2 can be repeated to refine the vertical permeability value K_v .

- **Radial composite behaviour:**

After identifying the radial flow regime over the inner reservoir region with straight line analysis, this early radial flow regime should be matched. If not, the inner permeability value can be manually adjusted.

The transition between the two radial flow regimes can be matched manually by changing the inner radius or automatically by fixing the other parameters in the regression tool. A larger radius will increase the duration of the first radial flow regime and shift the transition towards the right, towards late times.

The storativity ratio $\frac{\Phi c_t h_{outer\ region}}{\Phi c_t h_{inner\ region}}$ can also be updated to represent a change in

fluid or reservoir properties and provide a better match of the transition.

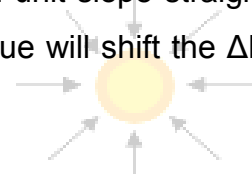
Sometimes the transition may not be perfectly matched, as in the case of a water front (transition between waterflooded zone and single phase oil region).

- **Horizontal well response**

- At this stage, the radial flow regime in the bedding plane should be matched and the permeability value K_H known.
- The intermediate flow regime, usually linear flow, can be matched by changing the productive horizontal length either manually or automatically by fixing the other parameters in the regression algorithm. A smaller length value will shift the intermediate flow regime towards the left, towards early times.
- Then the vertical radial flow regime can be matched by only changing the vertical permeability value K_V either manually or automatically by fixing the other parameters in the regression algorithm. A lower K_V value will shift the early derivative stabilization upwards.

- **Wellbore storage and skin:**

A larger wellbore storage coefficient C_W will shift the initial unit-slope straight line towards the right, towards late times. A larger skin value will shift the ΔP plot upwards.



5.3 Report more than one solution

The straight-line analysis and matching process can now be repeated to identify other possible solutions with the same interpretation model. Other models should also be investigated.

Well test analysis is non-unique and as a result, a range of possible interpretations that are consistent with the data should be provided. The solutions should also be integrated with other sources of subsurface information (geology, geophysics, petrophysics).

The calculated well and reservoir parameters should be reported as meaningful numbers: distances to the boundaries as integers, skin and permeability-thickness values with one decimal digit at most.

Skin values should be within ± 0.5 and permeability-thickness KH values within 10%.

