The Nuts and Bolts of Falloff Testing

Sponsored by EPA Region 6

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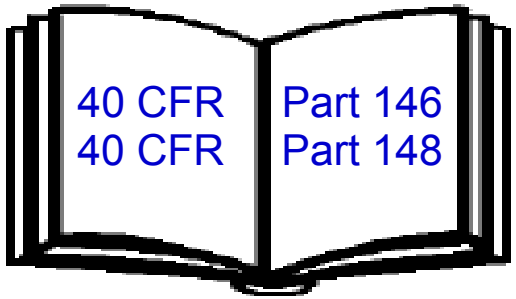
What's the Point of a Falloff Test?

- **Satisfy regulations**

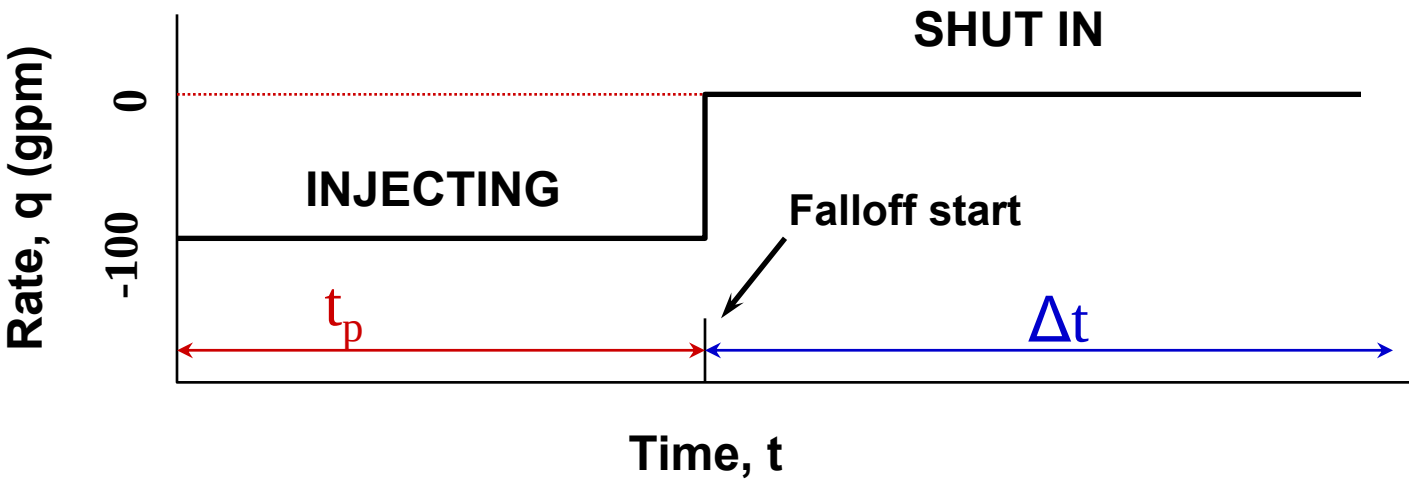


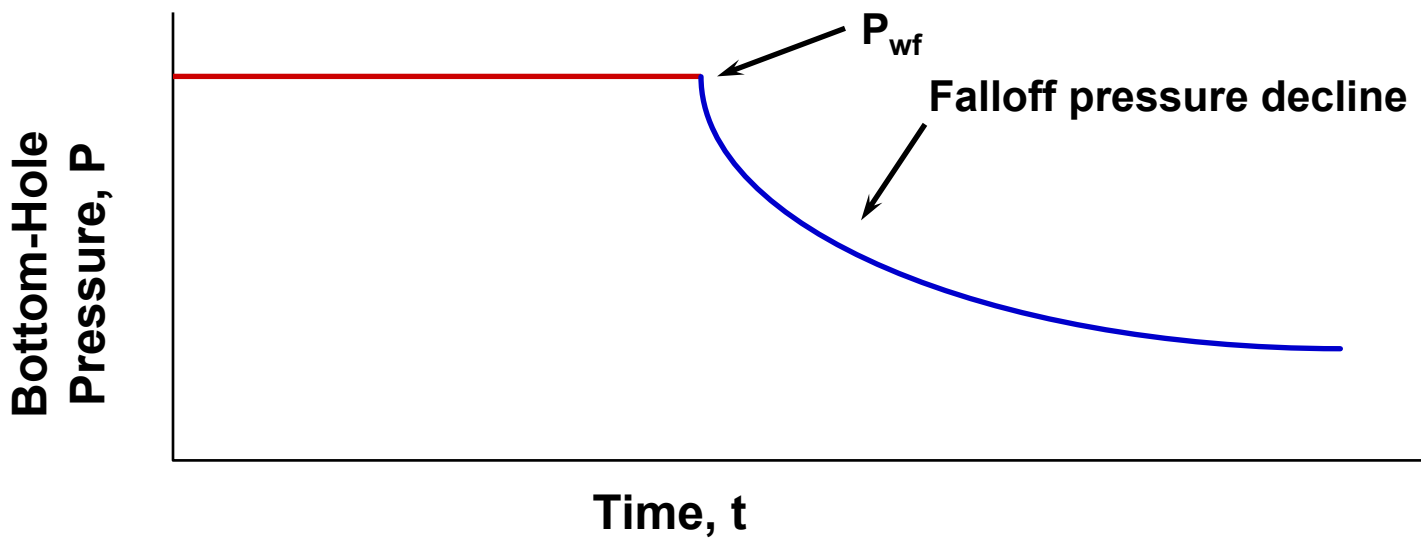
- **Measure reservoir pressures**
- **Obtain reservoir parameters**
- **Provide data for AOR calculations**

What's the Point of a Falloff Test?

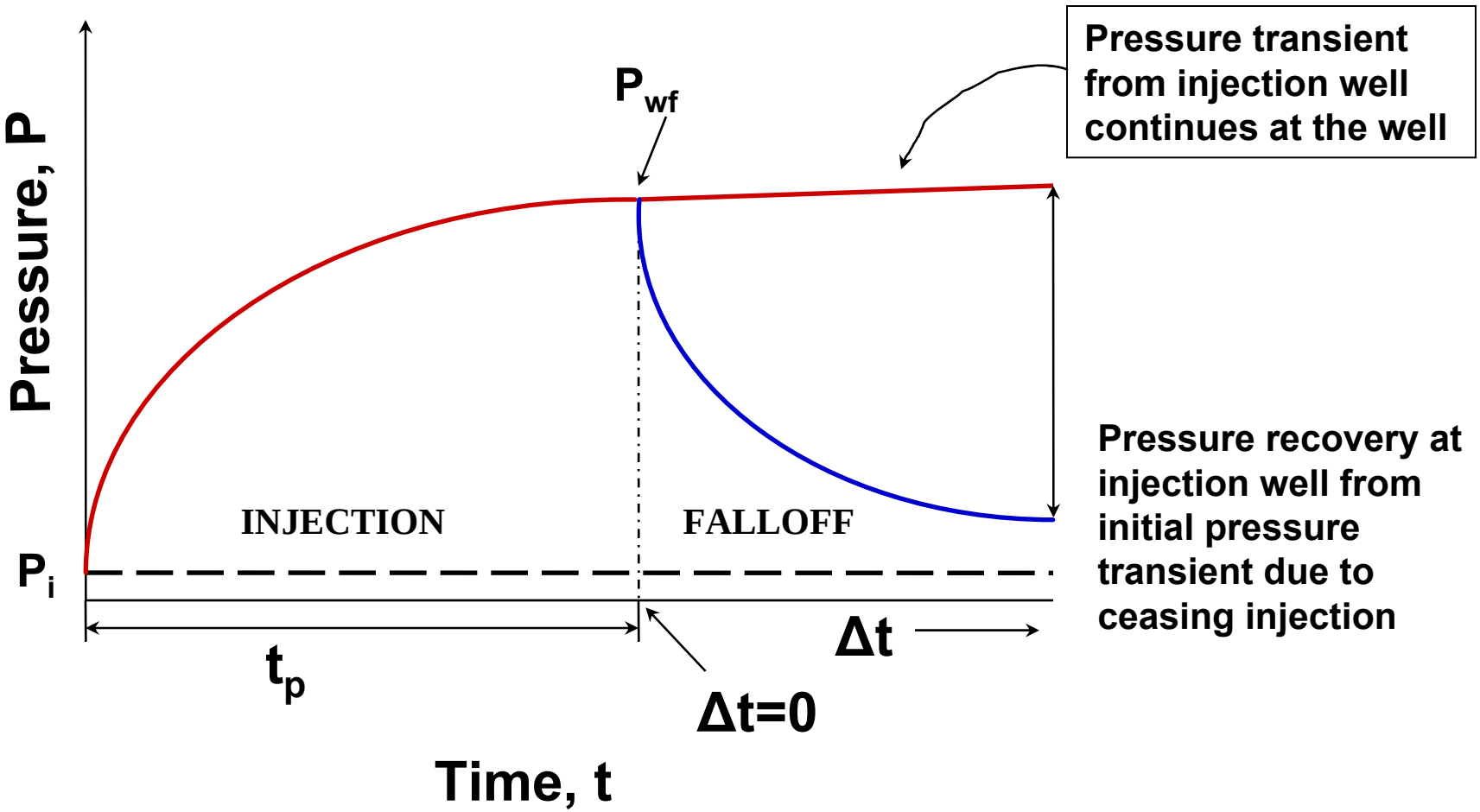
- Characterize injection interval
- Identify reservoir anomalies
- Evaluate completion conditions
- Identify completion anomalies

What Is a Falloff Test?





Effect of Injection and Falloff



Pressure Transients

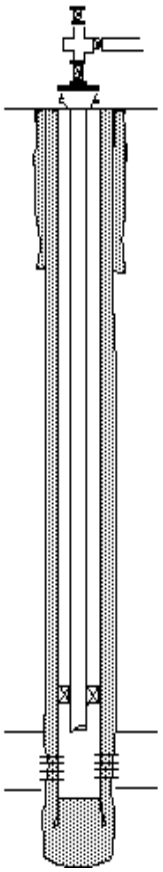
- Rate changes create pressure transients
- Simplify the pressure transients
  - Do not shut-in two wells simultaneously
  - Do not change the rate in two wells simultaneously

Falloff Test Planning

General Planning

- Most problems are avoidable
- Preplanning
- Review procedures

Operational Considerations



- Injection well constraints
  - Type of completion
  - Downhole condition
- Wellhead configuration
  - Pressure gauge installation
  - Shut-in valve

Operational Considerations

- **Surface facility constraints**
  - **Adequate injection fluid**
  - **Adequate waste storage**
- **Offset well considerations**

Operational Considerations

- **Recordkeeping:**
  - **Maintain an accurate record of injection rates**
  - **Obtain viscosity measurements**

Rule of thumb: At a bare minimum, maintain injection rate data equivalent to twice the length of the falloff

Instrumentation

- Pressure gauges
  - Use two
  - Calibration
- Types of pressure gauges
  - Mechanical
  - Electronic
  - Surface readout (SRO)
  - Surface gauge

Pressure Gauge Selection

- Selection criteria
  - Wastestream
  - Well goes on a vacuum
  - Wellbore configuration
  - Pressure change at the end of the test
  - Accuracy and resolution

Example: Pressure Gauge Selection

- **What pressure gauge is necessary to obtain a good falloff for the following well?**
  - **Operating surface pressure: 500 psia**
  - **Injection interval: 5000'**
  - **Specific gravity of injectate: 1.05**
  - **Past falloff tests have indicated a higher permeability reservoir of 500 md**
  - **Injection well goes on a vacuum toward the end of the test**
  - **Expected rate of pressure change during radial flow portion of the test is 0.5 psi/hr**

Example: Pressure Gauge Selection

- **Calculate the flowing bottomhole pressure**

500 psi+(0.433 psi/ft)(1.05)(5000) = 2773 psi (neglect tubing friction)

- **Pick a downhole pressure gauge type and range**
  - **2000 psi gauge is too low**
  - **5000 and 10,000 psi gauges may both work**
  - **Resolution levels:**
    - **Mechanical gauge - 0.05% of full range**
    - **Electronic gauge - 0.0002% of full range**

Mechanical gauge:

5000(0.0005) = 2.5 psi 10,000(0.0005)= 5 psi

Electronic gauge:

5000(0.000002)=.01 psi 10,000(0.000002)=.02 psi

Falloff Test Design

- Questions that must be addressed:
  - How long must we inject?
  - How long do we shut-in?
  - What if we want to look for a boundary?
- Radial flow is the basis for all pressure transient calculations
  - Confirm that the test reaches radial flow during both the injection and falloff periods

Falloff Test Design

- The radial flow period follows the wellbore storage and transition periods
- Wellbore storage: Initial portion of the test governed by wellbore hydraulics
- Transition period: Time period between identifiable flow regimes
- Radial Flow: Pressure response is only controlled by reservoir conditions

Falloff Test Design

- Falloff is a replay of the injection period
- Both the injection period and falloff must reach radial flow
- Calculate the time to reach radial flow
- Different calculations for the injectivity and falloff portions of the test

Time to Radial Flow Calculation

- **Wellbore storage coefficient, C in bbl/psi**
  - **Fluid filled well:**

$$C = V_w \cdot c_{waste}$$

Based on fluid filled wellbore so that pressure is maintained at the surface throughout the duration of the test

  - **Well on a vacuum:**

$$C = \frac{V_u}{\frac{\rho \cdot g}{144 \cdot gc}}$$

Falling fluid level in the wellbore so that the well goes on a vacuum at the surface

Time to Radial Flow Calculation

- **Small C: The well is connected with the reservoir within a short timeframe if the skin factor is not excessively large**
- **Large C: A longer transition time is needed for the well to display a reservoir governed response**

Time to Radial Flow Calculation

- **Calculate the time to reach radial flow for an injectivity test:**

$$t_{radial\ flow} > \frac{(200000 + 12000\, s) \cdot C}{\frac{k \cdot h}{\mu}} \qquad hours$$

- **Calculate the time to reach radial flow during the falloff test:**

$$t_{radial\ flow} > \frac{170000 \cdot C \cdot e^{0.14 \cdot s}}{\frac{k \cdot h}{\mu}} \qquad hours$$

- **Note the skin factor,s, influences the falloff more than the injection period**

Example Radial Flow Calculation

- **What injection and falloff timeframes are necessary to reach radial flow given the following injection well conditions?**
- **Assumptions:**
  - **Well maintains a positive wellhead pressure**

Parameters:

Reservoir	Wellbore
h=120 ft	7” tubing (6.456” ID)
k=50 md	9 5/8” casing (8.921” ID)
s=15	Packer depth: 4000’
μ=.5 cp	Top of the injection interval: 4300’
c_w=3e-6 psi^{-1}	

Example Radial Flow Calculation

- **Calculate wellbore volume, V_w:**
  - **tubing volume + casing volume below packer**

$$V_w = \left[\pi \left(\frac{6.456}{2 \cdot 12} \right)^2 (4000) + \pi \left(\frac{8.921}{2 \cdot 12} \right)^2 (300) \right] \left(\frac{1\, bbl}{5.615\ ft^3} \right) = 185.1\, bbls$$

- **Calculate wellbore storage coefficient, C**
  - **$C = V_w c_w$**

$$C = 185.1\, bbls \cdot \frac{3x10^{-6}}{psi} = 5.5x10^{-4}\ \frac{bbl}{psi}$$

Note: assume the wellbore storage coefficient is the same for both the injection and falloff periods

Example Radial Flow Calculation

- **Calculate minimum time to reach radial flow during the injection period, $t_{radial\ flow}$**

$$t_{radialflow} > \frac{(200000 + 12000\,s)\cdot C}{\frac{k\cdot h}{u}} \qquad hours$$

$$t_{radialflow} > \frac{(200000 + 12000\cdot 15)\cdot 5.5x10^{-4}}{\frac{50\cdot 120}{0.5}} = 0.017\ hours$$

- **Note: The test should not only reach radial flow, but also sustain a timeframe sufficient for analysis of the radial flow period**

Example Radial Flow Calculation

- **Calculate minimum time to reach radial flow during the falloff, $t_{radial\ flow}$**

$$t_{radial\ \ flow} > \frac{170000\ \cdot C \cdot e^{0.14 \cdot s}}{\dfrac{k \cdot h}{\mu}} \qquad hours$$

$$t_{radial\ \ flow} > \frac{170000\ \cdot 5.5x10^{-4} \cdot e^{0.14(15)}}{\dfrac{50 \cdot 120}{0.5}} = 0.064\ hours$$

- **Use with caution!**
  - **This equation tends to blow up in large permeability reservoirs or wells with high skin factors**

Additional Test Design Criteria

- Decide on the test objectives
  - Completion evaluation
  - Determining the distance to a fault
  - Seeing “x” distance into the reservoir

Note: Equations for transient test design are discussed in detail in SPE 17088 provided in the reference portion of this presentation

Additional Test Design Criteria

- Type of test:
  - Falloff
  - Multi-rate
  - Interference test
- Simulate the test
- Review earlier test data if available

Falloff Test Design

- **What if no falloff data is available?**
  - **Review the historical well pressure and rate data**
  - **Look for "pressure falloff" periods when the well was shut-in**
  - **This information *may* provide some information that can be used to design the falloff test**

Data Needed To Analyze a Falloff

- Time and pressure data
- Rate history prior to the falloff
- Basic reservoir and fluid information
- Wellbore and completion data

Time and Pressure Data

- Record sufficient pressure data
  - Consider recording more frequently earlier in test
  - Consider plotting data while test is in progress to monitor the test

Reservoir Parameters

- net thickness (h)
  - well log and cross-sections
- permeability (k)
  - core data and previous well tests
- porosity (Φ)
  - well log or core data
- viscosity of reservoir fluid (μ_f)
  - direct measurement or correlations
- total system compressibility (c_t)
  - correlations, core measurement, or well tests

Injectate Fluid

- viscosity of waste (μ_w)
  - direct measurement or correlation
- specific gravity (s.g.)
  - direct measurement
- rate (q)
  - direct measurement

Rule of thumb: No q, no k

“Quick” Falloff Planning Checklist

- Wellbore construction - depths, dimensions, configuration, obstructions, fill depth
- Injectivity period – constant rate if possible, record rate history, sufficient test duration, waste storage capacity
- Falloff period – time and pressure data, rate history, sufficient test duration, waste storage capacity

Checklist (cont.)

- **Instrumentation – resolution, surface vs. bottomhole gauges, backup gauge**
- **General reservoir and waste information – h, Φ, c_t, μ_f, μ_{waste}**
- **Area geology – boundaries, net thickness trends, sandstone or carbonate formation**

Pressure Transient Theory Overview

Pressure Transient Theory Overview

- P-T theory correlates pressures and rates as a function of time
- P-T theory is the basis for many types of well tests
- Used in petroleum engineering, groundwater hydrology, solution mining, waste disposal, and geothermal projects

Pressure Transient Theory

- Involves working the problem backwards:
  - From the measured pressure response, determine the reservoir parameters
  - Start at the wellbore
  - Work out to the reservoir boundaries

Pressure Transient Theory

- **Start with what you know:**
  - **Well and completion history**
  - **Geology**
  - **Test conditions**
- **Pressure responses show dominant features called flow regimes**

P-T Theory Applied to Falloffs

- Falloff testing is part of P-T theory
- Falloff tests are analyzed in terms of flow models
- Flow models are solutions to the flow equations

P-T Theory Applied to Falloffs (cont.)

- The starting point is a partial differential equation (PDE)
- The PDE is solved for a variety of boundary conditions
- The solution allow calculation of pressure or rate as a function of time and distance

Partial Differential Equation (PDE)

For Non-Steady State Flow, the PDE, is:

$$\frac{\partial^2 P}{\partial r^2} + \frac{1}{r} \cdot \frac{\partial P}{\partial r} = \frac{1}{0.000264} \cdot \frac{\phi \cdot \mu \cdot c_t}{k} \cdot \frac{\partial P}{\partial t}$$

What's the Point of the PDE?

- Why do we need all these equations and assumptions?
  - Provide an injection well behavior model
  - Provide a method for reservoir parameter evaluation
  - Only work during radial flow

How Do We Solve the PDE?

- **Assume conditions to solve the PDE and obtain a model**
- **Typical constraints:**
  - **At the well**
    - **Finite wellbore radius**
    - **Constant rate injection**
  - **Away from the well**
    - **Infinite-acting**
    - **Uniform reservoir properties and initial pressure**

Solution to the PDE

- **The exact solution to the PDE is in terms of cumbersome Bessel functions**
- **Fortunately an approximate solution based on the exponential integral (Ei) gives almost identical results:**

$$P = P_i + 70.6 \frac{q \cdot B \cdot \mu}{k \cdot h} \cdot Ei\left(\frac{-948 \cdot \phi \cdot \mu \cdot c_t \cdot r_w^2}{k \cdot t} \right)$$

where:

$$Ei(-x) = -\int_x^{\infty} \frac{e^{-u}}{u} du$$

Simplifying the PDE Solution

- **Ei functions:**
  - **tabulated and easy to use**
  - **valid until boundary effects occur**
  - **give the pressure in the reservoir as a function of both time and distance from the well center**
  - **simplified with a log approximation:**

$$Ei = \ln(1.781 \cdot x)$$

- **This leads us to our flow model for falloff analysis:**

Simplifying the PDE Solution

$$P_{wf} - P_i = \left(\frac{141.2 \cdot q \cdot \mathrm{B}_w \cdot \mu}{k \times h} \right) \cdot \left(P_D + s \right)$$

where:

$$P_D = -\frac{1}{2} \cdot Ei\left[-\frac{r_D^2}{4 \cdot t_D} \right] \cong \frac{1}{2} \cdot \left\{ \ln\left[\frac{t_D}{r_D^2} \right] + 0.809 \right\}$$

$$t_D = \frac{0.0002637 \cdot k \cdot t}{\phi \cdot \mu \cdot c_t \cdot r_w^2} \qquad r_D = \frac{r}{r_w}$$

Predicting Injection Well Pressure Using the PDE Solution

- **Example: Estimate the pressure of an injection well located in an infinite acting reservoir with no skin (s=0). The well has injected 100 gpm for 2 days. Other reservoir data are:**
  - P_i = 2000 psi
  - k = 200 md
  - μ = 0.6 cp
  - Φ = 30 %
  - h = 50 ft
  - B_w = 1 rvb/stb
  - c_t = 6e-6 psi^{-1}
  - r_w = 0.4 ft

$$q = \left(\frac{100\,gal}{\min}\right)\left(\frac{bbl}{42\,gal}\right)\left(\frac{1440\min}{day}\right) = 3428.6\,bpd$$

$$t = (2\,days)\left(\frac{24\,hrs}{day}\right) = 48\,hrs$$

Example (cont.)

First, let's calculate the dimensionless variables: r_D, t_D, and P_D

$$r_D = \frac{r}{r_w}$$

Since we're calculating the pressure at the well $r = r_w$ and $r_D = 1$

$$t_D = \frac{0.0002637 \cdot k \cdot t}{\phi \cdot \mu \cdot c_t \cdot r_w^2}$$

$$t_D = \frac{0.0002637\ (200\ md)(48\ hours)}{(0.3)(.6\ cp)(6e-6\ psi^{-1})(0.4^2\ ft^2)}$$

$$t_D = 14.65x10^6$$

Example (cont.)

Now look up P_D on the graph or calculate P_D from the following equation:

$$P_D \cong \frac{1}{2} \cdot \left\{ \ln\left[\frac{14650000}{1^2}\right] + 0.809 \right\}$$

$$P_D \cong 8.65$$

From Figure C.2 in SPE Monograph 5: at t_D= 14.65x10^6 and r_D=1

$$P_D = 8.5$$

Example (cont.)

At t_D= 1.465x10^7 and r_D=1, P_D= 8.5 (Figure C.2 in SPE Monograph 5)

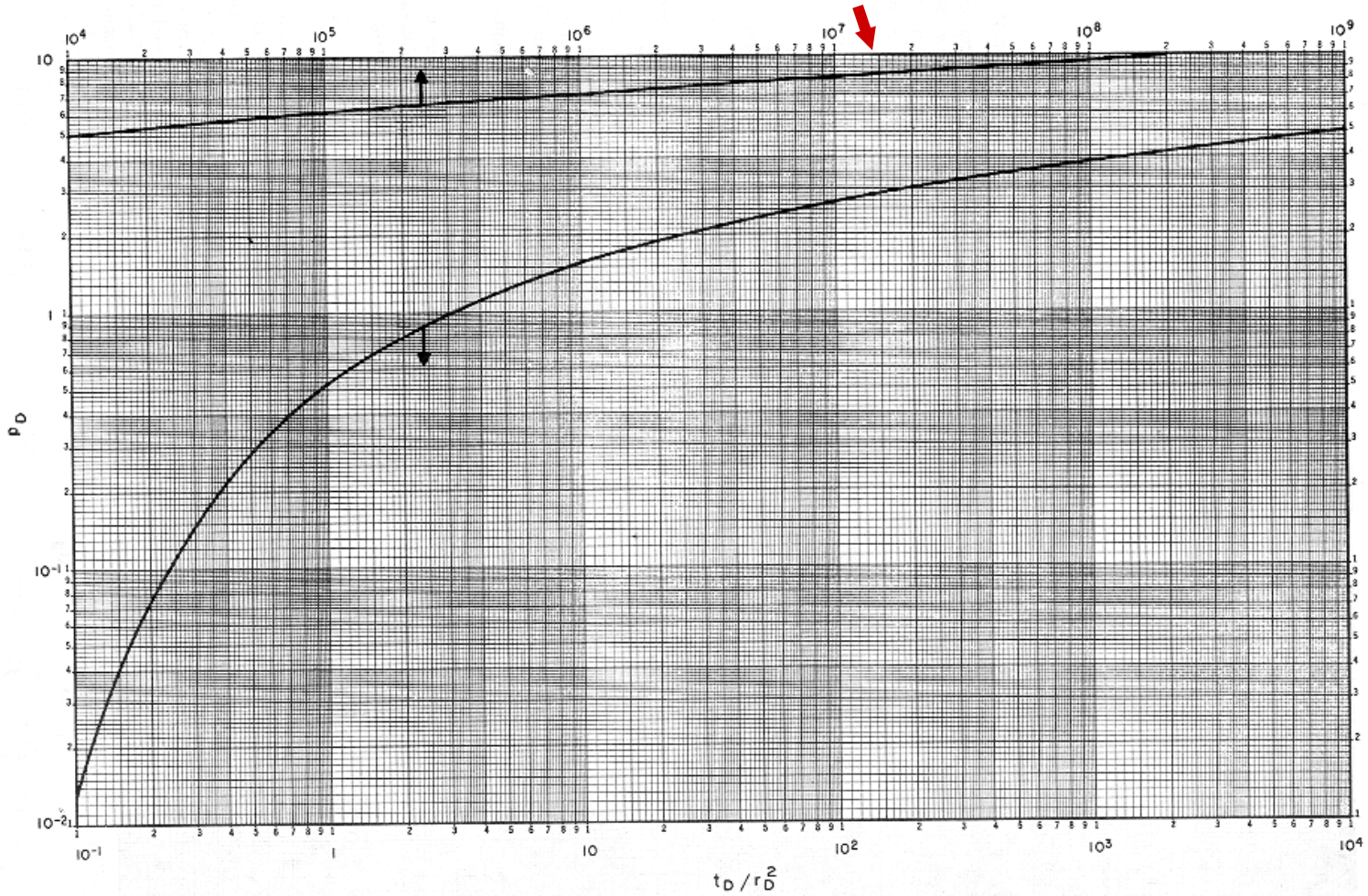


Fig. C.2 Dimensionless pressure for a single well in an infinite system, no wellbore storage, no skin. Exponential-integral solution.

Example (cont.)

Now calculate the pressure increase at the well:

$$P_{wf} - P_i = \left(\frac{141.2 \cdot q \cdot \mathrm{B}_w \cdot \mu}{k \times h} \right) \cdot P_D + s$$

$$P_{wf} - 2000 = \left(\frac{141.2(3428.6)(1)(0.6)}{(200)(50)} \right) \cdot (8.65 + 0)$$

$$P_{wf} = 2251 psi$$ (a pressure increase of 251 psi)

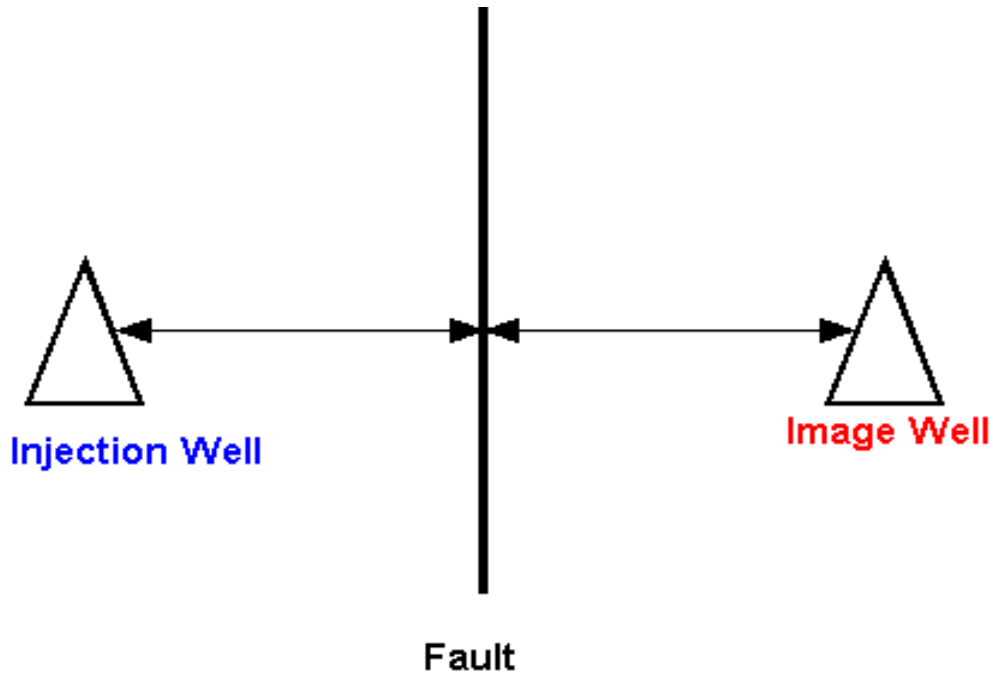
What happens if the injection reservoir isn't infinite?

- Not infinite if limited by a fault or pinchout
- Represent limits as virtual barriers using "image" wells
- A linear PDE means we can add Ei solutions to consider pressure changes from multiple wells

How to Account for Boundary Effects

- Add the real injector and image well to account for the boundary
- 1 injector with 1 boundary requires 1 image well
- Image wells are more complex with multiple boundaries

Boundary Effects (cont.)



$$\Delta P_{total} = \Delta P_{(injector - effect)} + \Delta P_{(fault - effect)}$$

How to Account for Boundary Effects

- Add the real injector and image well to account for the boundary
- 1 injector with 1 boundary requires 1 image well
- Image wells are more complex with multiple boundaries

What happens if the pre-falloff injection rate varies?

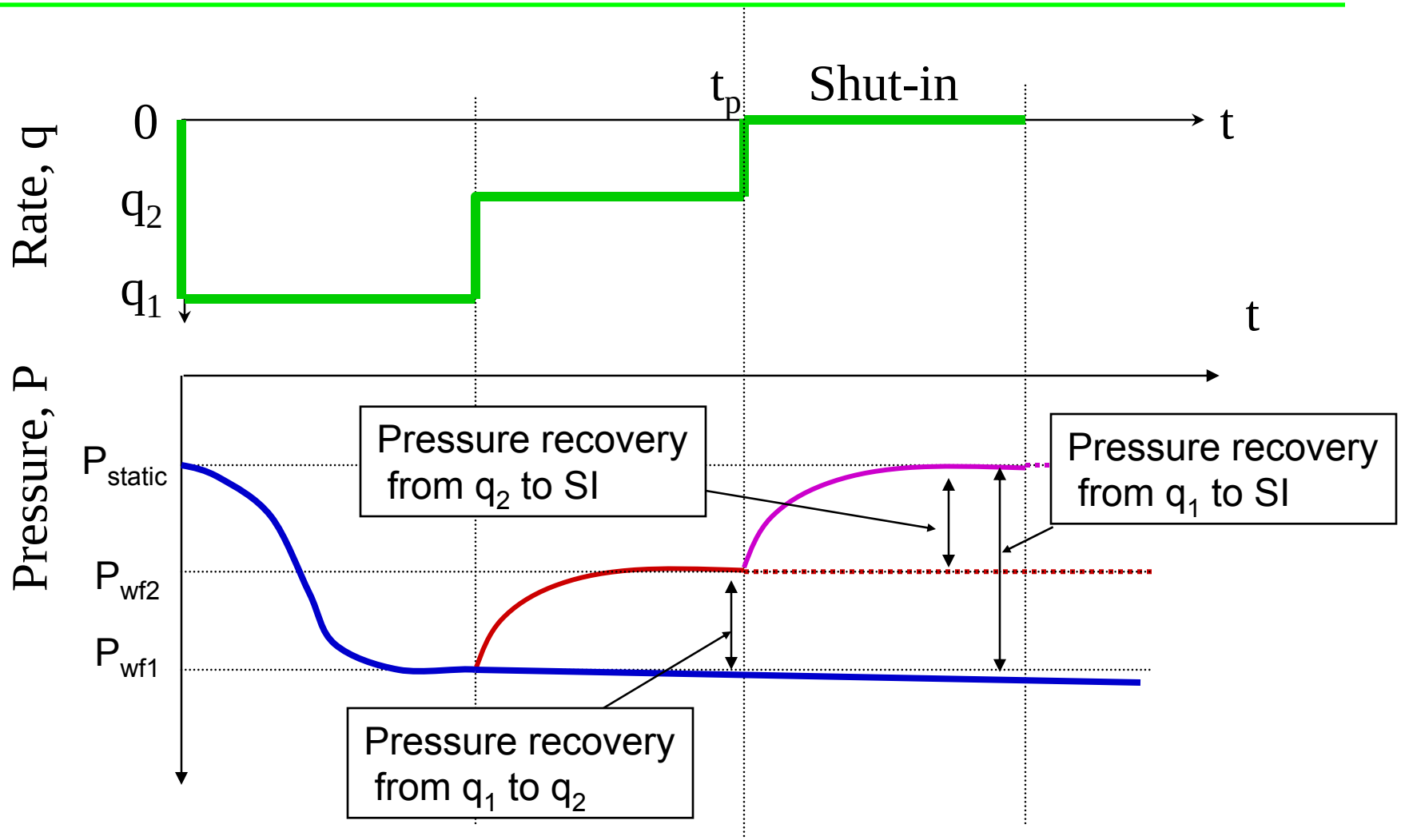
- Again, the PDE is linear
- Each rate change creates a new pressure response to be added to the previous response
- Account for each rate change by using an image well at the same location

Superposition

Superposition is the method of accounting for the effects of rate changes on a single point in the reservoir from anywhere and anytime in the reservoir including at the point itself using the PDE solution

$$\Delta P_{total} = \Delta P_{injector} + \sum \text{Image well contribution}$$

Superposition (cont.)



"Kitchen Sink" Solution to the PDE

- **If we were to account for all wells and potential boundaries (image wells) in a reservoir, the pressure change at any point could be given by:**

$$p(x,y,t) = p_o + \sum_{j=1}^{N} \frac{70.6 q_1^j \mu}{kh} Ei\left(\frac{-39.5\phi\mu c_t \left[(x - x_j)^2 + (y - y_j)^2 \right]}{k\,t} \right)$$

$$+ \sum_{j=1}^{N} \sum_{i=1}^{n_{j-1}} \frac{70.6\left[\left(q_{i+1}^j - q_i^j \right) \mu \right]}{k\,h} Ei\left(\frac{-39.5\phi\mu c_t \left[(x - x_j)^2 + (y - y_j)^2 \right]}{k\left(t - t_i^j \right)} \right)$$

This is essentially what an analytical reservoir simulator does!

PDE Solution At The Injector

- **The PDE can give the pressure at any reservoir location**

- **At the wellbore, r_D =1, so:**

$$P_{wf} = P_i - \left[\frac{162.6 \cdot q \cdot B \cdot \mu}{k \cdot h}\right] \cdot \left[\log(t) + \log\left(\frac{k}{\phi \cdot \mu \cdot c_t \cdot r_w^2}\right) + 3.23 + 0.87s\right]$$

Semilog Plot

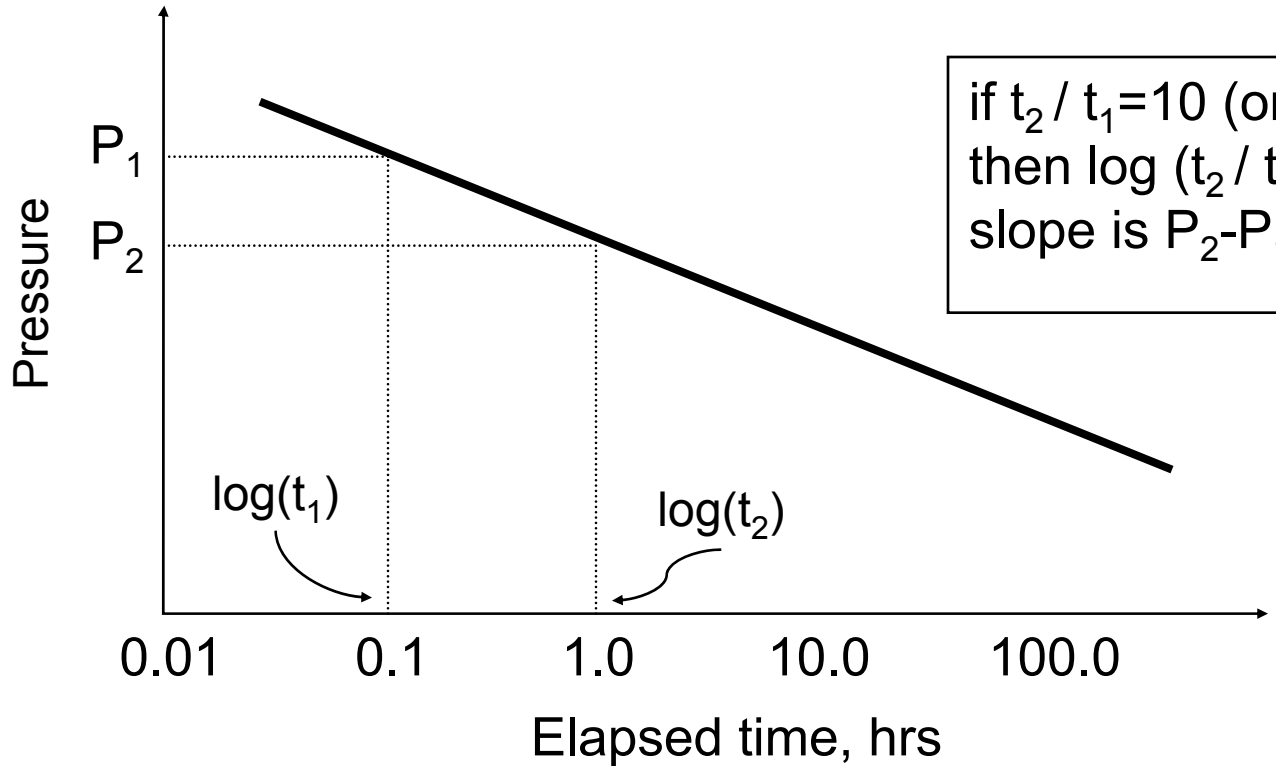
- **Applies <u>only</u> during radial flow!**
- **Write PDE solution as a straight line equation with a slope and intercept:**

$$P_{wf} = m \cdot \log(t) + P_{1hr}$$

Where m is the semilog plot slope:

$$m = -\frac{162.6 \cdot q \cdot B_w \cdot \mu}{k \cdot h}$$

Finding the Semilog Slope, m



if t_2 / t_1=10 (one log cycle), then log (t_2 / t_1) = 1 and the slope is P_2-P_1

$$\text{slope} = \frac{\Delta P}{\Delta \log(\Delta t)} = \frac{P_2 - P_1}{\log(t_2) - \log(t_1)} = \frac{P_2 - P_1}{\log\left(\frac{t_2}{t_1}\right)}, \quad \text{psi / log cycle}$$

The Many Faces of the Semilog Plot

- **4 semilog plots typically used:**
  - **Miller Dyes Hutchinson (MDH) Plot**
    - **Pressure vs log Δt**
  - **Horner Plot**
    - **Pressure vs log $(t_p + \Delta t)/\Delta t$**
  - **Agarwal Time Plot**
  - **Superposition Time Plot**

Miller Dyes Hutchinson (MDH) Plot

- **Applies to wells that reach pseudo-steady state during injection**
  - **Plot pressure vs log Δt**
  - **Means response from the well has encountered all limits around it**
  - **Only applies to <u>very</u> long injection periods at a constant rate**

Horner Plot

- Plot pressure vs. log $(t_p+\Delta t)/\Delta t$
- Used only for a falloff preceded by a constant rate injection period
- Calculate injecting time, $t_p = V_p/q$ (hours)
  - Where V_p = injection volume since last pressure equalization
  - V_p is often taken as cumulative injection volume since completion
- Caution: Horner time can result in significant analysis errors if the injection rate varies prior to the falloff

Agarwal Time Plot

- Plot pressure vs log equivalent time, Δt_e
  - $\Delta t_e = \log(t_p\ \Delta t)/(t_p+\Delta t)$
    - Where t_p is as defined for a Horner plot
  - Similar to Horner plot
  - Time function scales the falloff to make it look like an injectivity test

Superposition Time

- Accounts for variable rate conditions prior to a falloff test
- Most rigorous semilog analysis method
- Requires operator to track rate history

Rule of thumb: At a bare minimum, maintain injection rate data equivalent to twice the length of the falloff

Calculating Superposition Time Function

- **Superposition time function:**
  - **Can be written several ways – below is for a drawdown or injectivity test:**

$$\Delta t_{sp} = \left[\sum_{j=1}^{n} \left(\frac{q_j - q_{j-1}}{q_n} \right) \log \left[\Delta t - \Delta t_{j-1} \right] \right]$$

- **Pressure function is modified also:**

$$\Delta P_{sp} = \frac{\left(P_{initial} - P_{wf} \right)}{q_n}$$

Which Time Function Do I Use?

- **Depends on available information and software:**
  - **If no rate history, use Horner**
  - **If no rate history or cumulative injection total, use MDH**
  - **If you have rate history equal to or exceeding the falloff test length, use superposition**
  - **Horner or MDH plots can be generated in a spreadsheet**
  - **Superposition is usually done with welltest software**

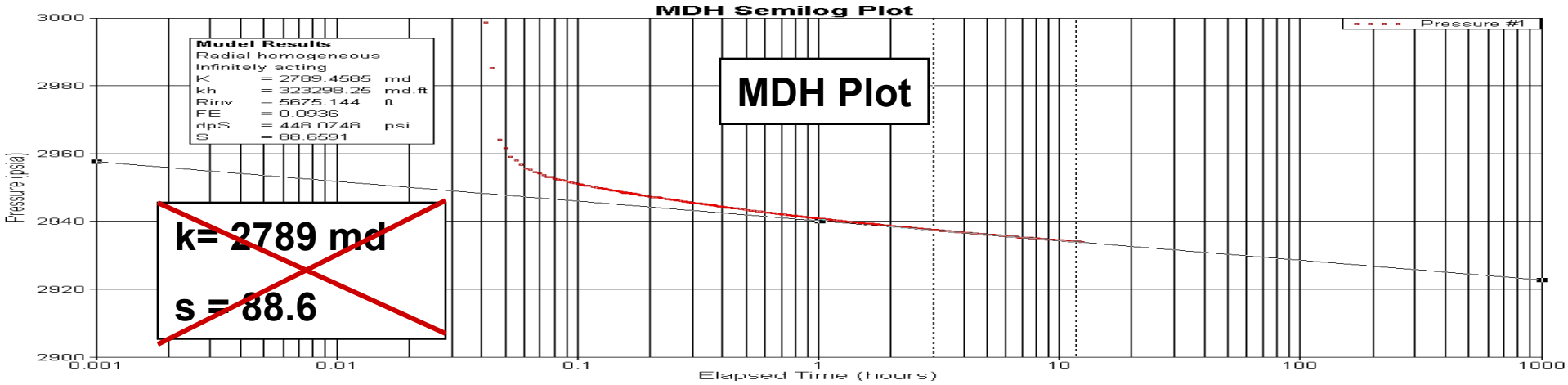
Which Time Function Do I Use?

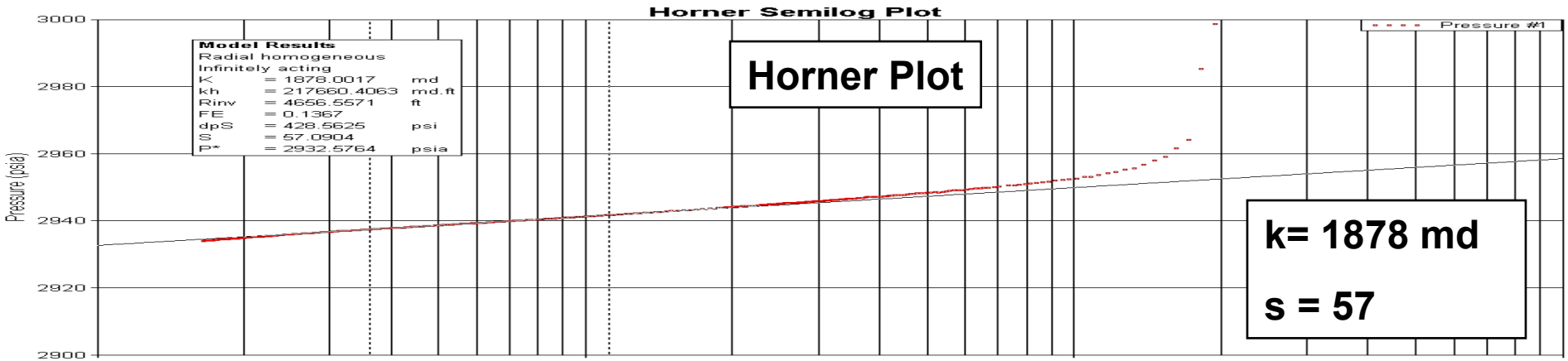
- **Rules of thumb:**
  - **Use MDH time only for very long injection times (e.g., injector at pseudo-steady state)**
  - **Use Horner time when you lack rate history or software capability to compute the superposition function**
  - **Superposition is the preferred method if a rate history is available**

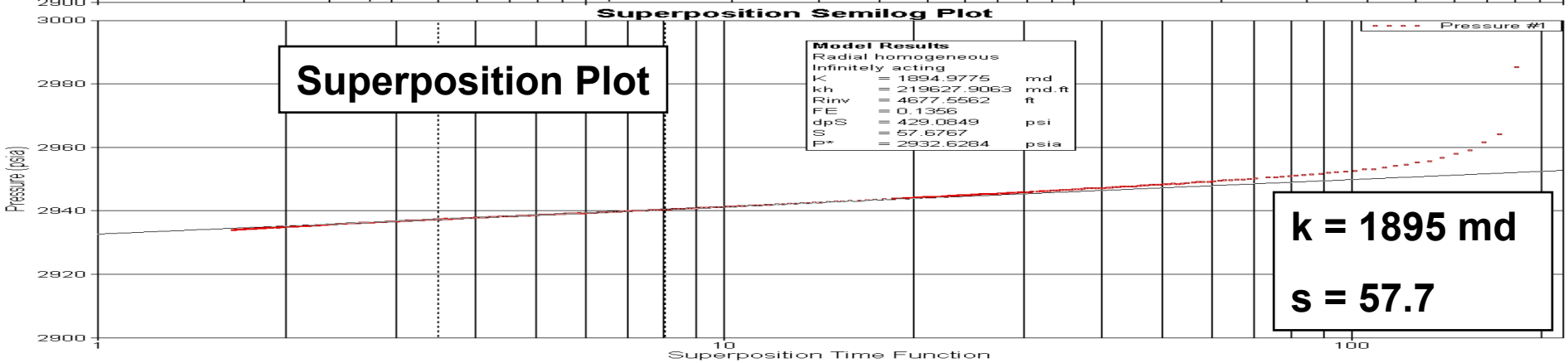
Which Time Function Do I Use?

- Horner <u>may</u> substitute for superposition if:
  - The rate lasts long enough to reach the injection reservoir limits (pseudo-steady state)
  - The rate prior to shut-in lasts twice as long as the previous rate
  - At a minimum, the rate prior to shut-in lasts as long as the falloff period
  - Horner is a single rate superposition case

One Falloff Test Plotted with Three Semilog Methods







Other Uses of a Semilog Plot

- Calculate radius of investigation, r_i
- Completion evaluation, skin factor, s
- Skin pressure drop, ΔP_{skin}
- False extrapolated pressure, P^*

Radius of Investigation

- Distance a pressure transient has moved into a formation following a rate change in a well (Well Testing by Lee)
- Use appropriate time to calculate radius of investigation, r_i
  - For a falloff time shorter than the injection period, use t_e or the length of the injection period preceding the falloff to calculate r_i

Radius of Investigation

- **There are numerous equations that exist to calculate r_i in feet**
- **They are all square root equations, but each has its own coefficient that results in slightly different results (OGJ, Van Poollen, 1964)**
  - **Square root equation based on cylindrical geometry**

$$r_i = \sqrt{0.00105 \frac{k\,t}{\phi\,\mu\,c_t}} \equiv \sqrt{\frac{k\,t}{948\,\phi\,\mu\,c_t}}$$

From SPE Monograph 1: (Eq 11.2) and Well Testing, Lee (Eq. 1.47)

Skin Factor

- The skin factor, s, is included in the PDE
- Wellbore skin is the measurement of damage near the wellbore (completion condition)
- The skin factor is calculated by the following equation:

$$s = 1.1513\left[\frac{p_{1hr} - p_{wf}}{m} - \log\left(\frac{k\,t_p}{(t_p + 1)\phi\,\mu\,c_t\,r_w^2}\right) + 3.23\right]$$

Skin Factor

- Wellbore skin is quantified by the skin factor, s
  - "+" positive value - a damaged completion
    - Magnitude is dictated by the transmissibility of the formation
  - "-" negative value - a stimulated completion
    - - 4 to - 6 generally indicates a hydraulic fracture
    - -1 to - 3 typical acid stimulation results in a sandstone reservoir
    - Negative results in a larger effective wellbore

Effective Wellbore Radius Concept

- **Ties the skin factor into an effective wellbore radius (wellbore apparent radius, r_{wa})**
- $r_{wa} = r_w e^{-s}$
- **A negative skin results in a larger wellbore radius and therefore a lower injection pressure**

Effective Wellbore Radius

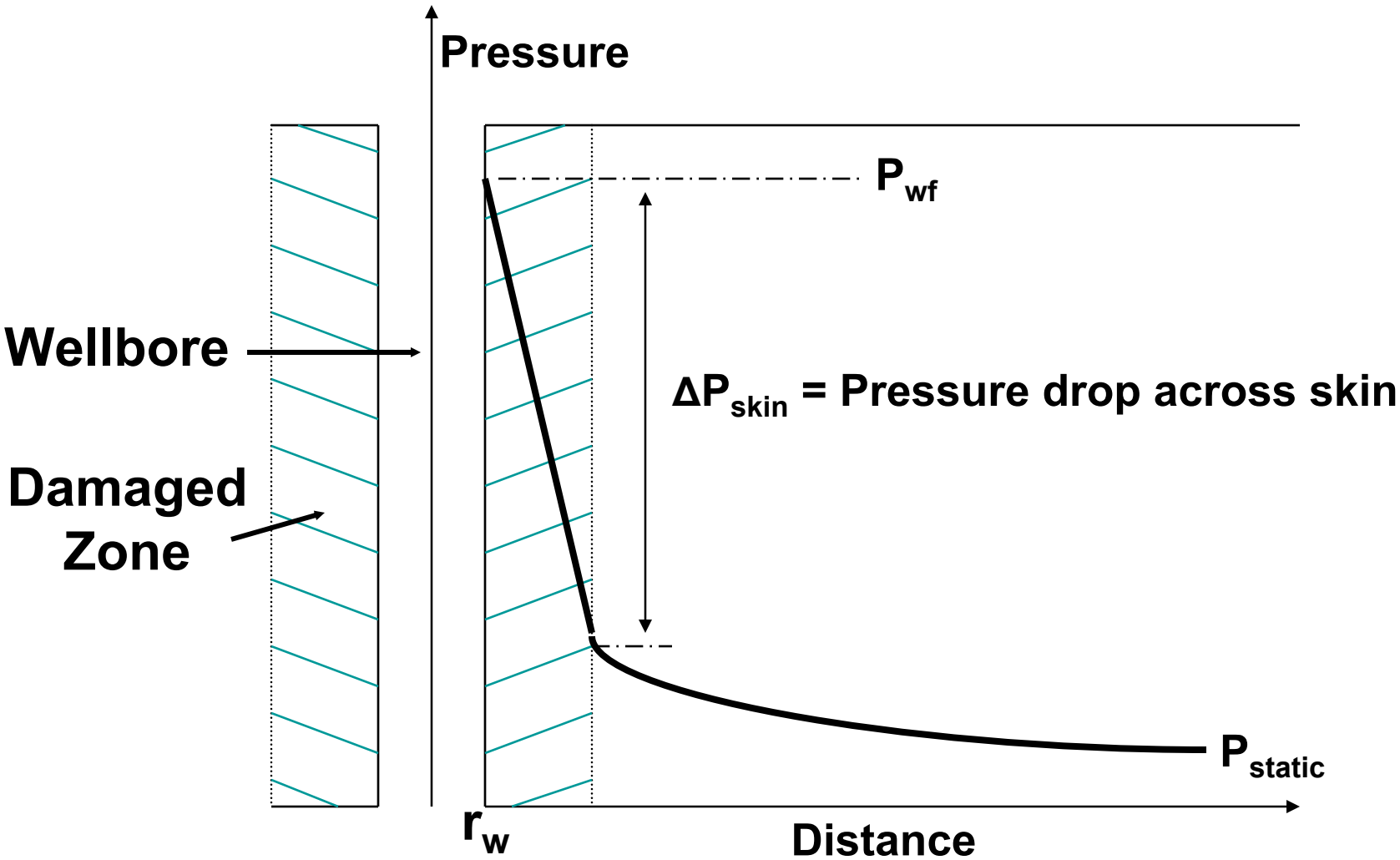
- **Example: A well with a radius of 5.5" had a skin of +5 prior to stimulation and –2 following the acid job. What was the effective wellbore radius before and after stimulation?**
- **$r_{wa} = r_w e^{-s}$**

$$r_{wa} = (5.5\,in)\left(e^{-5}\right) = 0.037\,in$$ **Before**

$$r_{wa} = (5.5\,in)\left(e^{-(-2)}\right) = 40.6\,in$$ **After**

- **A little bit of skin makes a big impact on the effective wellbore radius**

Pressure Profile with Skin Effect



Completion Evaluation

- The assumption that skin exists as a thin sheath is not always valid
  - Not a serious problem in the interpretation of the falloff test
  - Impacts the calculation of correcting the injection pressure prior to shut-in
- Note the term $t_p/(t_p+\Delta t)$, where $\Delta t = 1$ hr, appears in the log term and this term is assumed to be 1
  - For short injection periods this term could be significant (DSTs)

Completion Evaluation

- **Wellbore skin**
  - **Increases the time needed to reach radial flow in a falloff**
  - **Creates a pressure change immediately around the wellbore**
  - **Can be a flow enhancement or impediment**

Completion Evaluation

- **Too high a skin may require excessively long injection and falloff periods to establish radial flow**
- **The larger the skin, the more of the falloff pressure drop is due to the skin**

Skin Pressure Drop

- **Skin factor is converted to a pressure loss using the skin pressure drop equation**
- **Quantifies what portion of the total pressure drop in a falloff is due to formation damage**

$$\Delta P_{skin} = 0.868\, m\, s$$

Where,

P_{skin} = pressure due to skin, psi

m = slope of the Horner plot, psi/cycle

s = skin factor, dimensionless

Corrected Injection Pressure

- **Calculate the injection pressure with the skin effects removed**

$$P_{corrected} = P_{inj} - \Delta P_{skin}$$

Where:

$P_{corrected}$ = adjusted bottomhole pressure, psi
P_{inj}= measure injection pressure at ☽t = 0, psi
P_{skin} = pressure due to skin, psi

- **$P_{corrected}$ is injection pressure based on pressure loss through the formation only**

False Extrapolated Pressure

- **False Extrapolated Pressure, P^*, is the pressure obtained from the semilog time of 1**
- **For a new well in an infinite acting reservoir, it represents initial reservoir pressure**

False Extrapolated Pressure

- For existing wells, it must be adjusted to $\overline{P}$, average reservoir pressure
  - Requires assumption of reservoir size, shape, injection time, and well position within the shape
  - For long injection times, P^* will differ significantly from $\overline{P}$
  - P^* to $\overline{P}$ conversions are based on 1 well reservoirs, simple geometry
- We don't recommend using P^*
- Use the final measured shut-in pressures, if well reaches radial flow, for cone of influence calculations

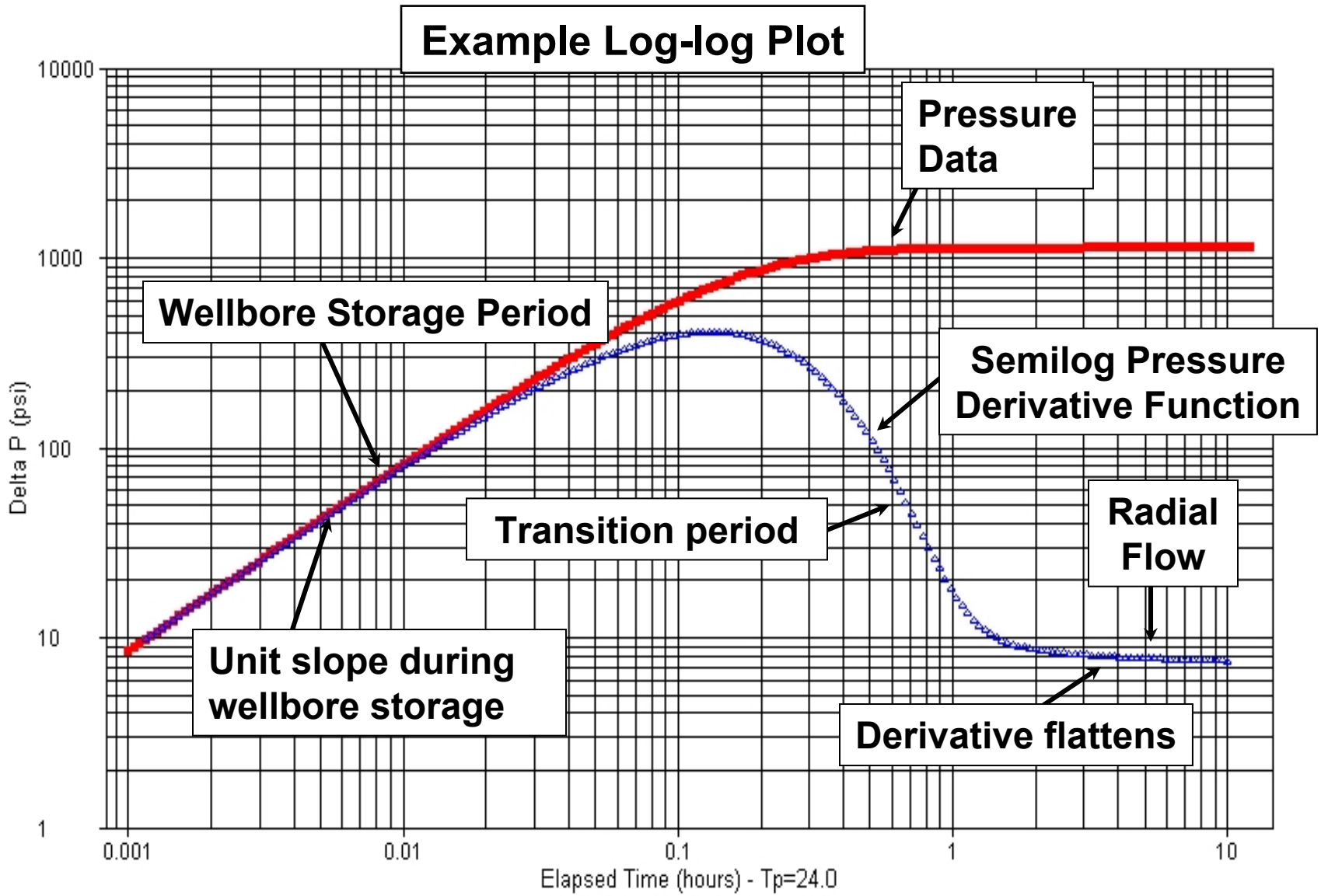
Semilog Plot Usage Summary

- A semilog plot is used to evaluate the radial flow portion of the well test
- Reservoir transmissibility and skin factor are obtained from the slope of the semilog straight line during radial flow
- Superposition is used for rate variations

Identifying Flow Regimes

Identifying Flow Regimes

- Create a master diagnostic plot, the Log-log plot
- Log-log plot contains two curves
- Individual flow regimes:
  - Characteristic shape
  - Sequential order
  - Specific separation
- Critical flow regime - radial flow


Example Log-log Plot
Pressure Data
Wellbore Storage Period
Semilog Pressure Derivative Function
Transition period
Radial Flow
Unit slope during wellbore storage
Derivative flattens
10000
1000
100
10
1
Delta P (psi)
0.001
0.01
0.1
1
10
Elapsed Time (hours) - Tp=24.0

Log-log Plot Pressure Functions

Rate variations prior to falloff test determine how the pressure function is to be plotted

- **Constant rate - Plot pressure**
- **Variable rate - Normalize pressure**

Log-log Plot Time Functions

- **Rate variations prior to shut-in dictate the log-log plot time function:**
  - **Use if the injection rate is constant <u>and</u> the injection period preceding the falloff is significantly longer than the falloff**
  - **Elapsed time, Δt**

Log-log Plot Time Functions

- **Agarwal equivalent time, t_e**
  - **Calculate as:** $$t_e = \frac{t_p \, \Delta t}{t_p + \Delta t}$$
  - **Use if the injection period is short**
- **Superposition time function**
  - **Use if the injection rate varied**
    - **Most rigorous time function**

Pressure Derivative Function

- Magnifies small changes in pressure trends
- Good recording device critical
- Independent of skin
- Popular since 1983

Pressure Derivative Function

- Combines a semilog plot with a log-log plot
- Calculates a running slope of the MDH, Horner, or superposition semilog plots
- The logarithmic derivative is defined by:

$$P' = \frac{d\left[P\right]}{d\left[\ln(\Delta t)\right]} = \Delta t \cdot \frac{d\left[P\right]}{d\left[\Delta t\right]}$$

Pressure Derivative Function

- Recent type curves make use of the derivative by matching both the pressure and derivative simultaneously
- A test can show several flow regimes with “late time” responses correlating to distances farther from the wellbore

Pressure Derivative Function

- **Example: For a well in an infinite acting reservoir with radial flow**

$$P_D = 0.5\left(\ln\left[t_D\right] + 0.80907\right)$$

so that

$$P'_D = t_D \cdot \frac{d\left[P_D\right]}{d\left[t_D\right]} = 0.5$$ constant value

- **The constant derivative value plots as a "flat spot" on the log-log plot**

Pressure Derivative Function

- **Usually based on the slope of the semilog pressure curve**
- **Can can be calculated based on other plots:**
  - **Cartesian**
  - **Square root of time:** $\sqrt[2]{time}$
  - **Quarter root of time:** $\sqrt[4]{time}$
  - **1/square root of time:** $\frac{1}{\sqrt[2]{time}}$

What Flow Regimes Are Active?

- Examine what might happen in and near the wellbore to determine early time behavior
- Examine the reservoir geology, logs, etc., to determine late time behavior

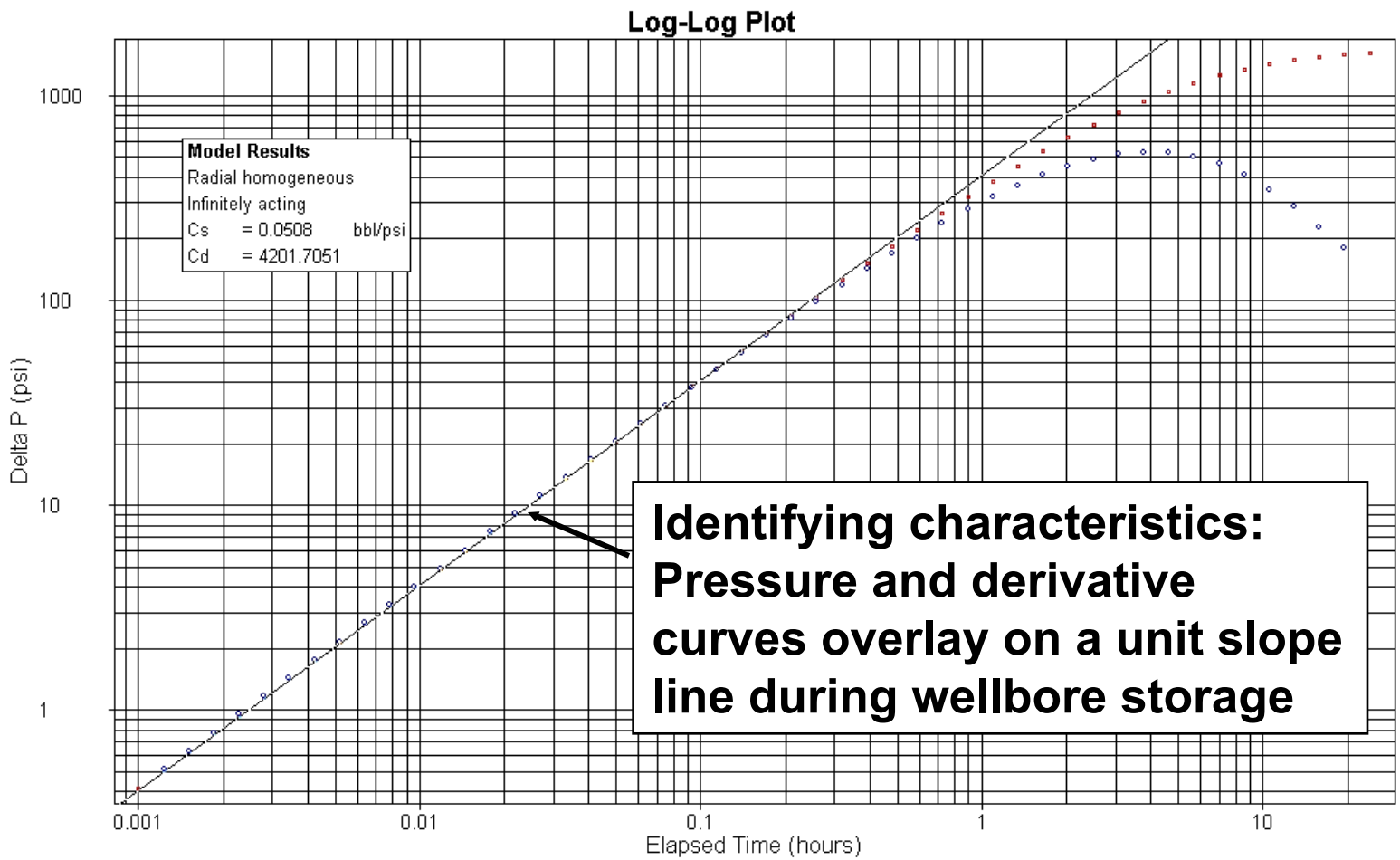
Wellbore Storage

- Occurs during the early portion of the test
- Caused by shut-in of the well being located at the surface rather than at the sandface
  - After flow - fluid continues to fall down the well after well is shut-in
  - Location of shut-in valve away from the well prolongs wellbore storage

Wellbore Storage

- Pressure responses are governed by wellbore conditions not the reservoir
- High wellbore skin or low permeability reservoir may prolong the duration of the wellbore storage period
- A wellbore storage dominated test is unanalyzable

Wellbore Storage Log-log Plot



Identifying characteristics: Pressure and derivative curves overlay on a unit slope line during wellbore storage

Radial Flow

- The critical flow regime from which all analysis calculations are performed
- Used to derive key reservoir parameters and completion conditions
- Radial flow characterized by a straight line on the semilog plot
- Characterized by a flattening of the derivative curve on log-log plot

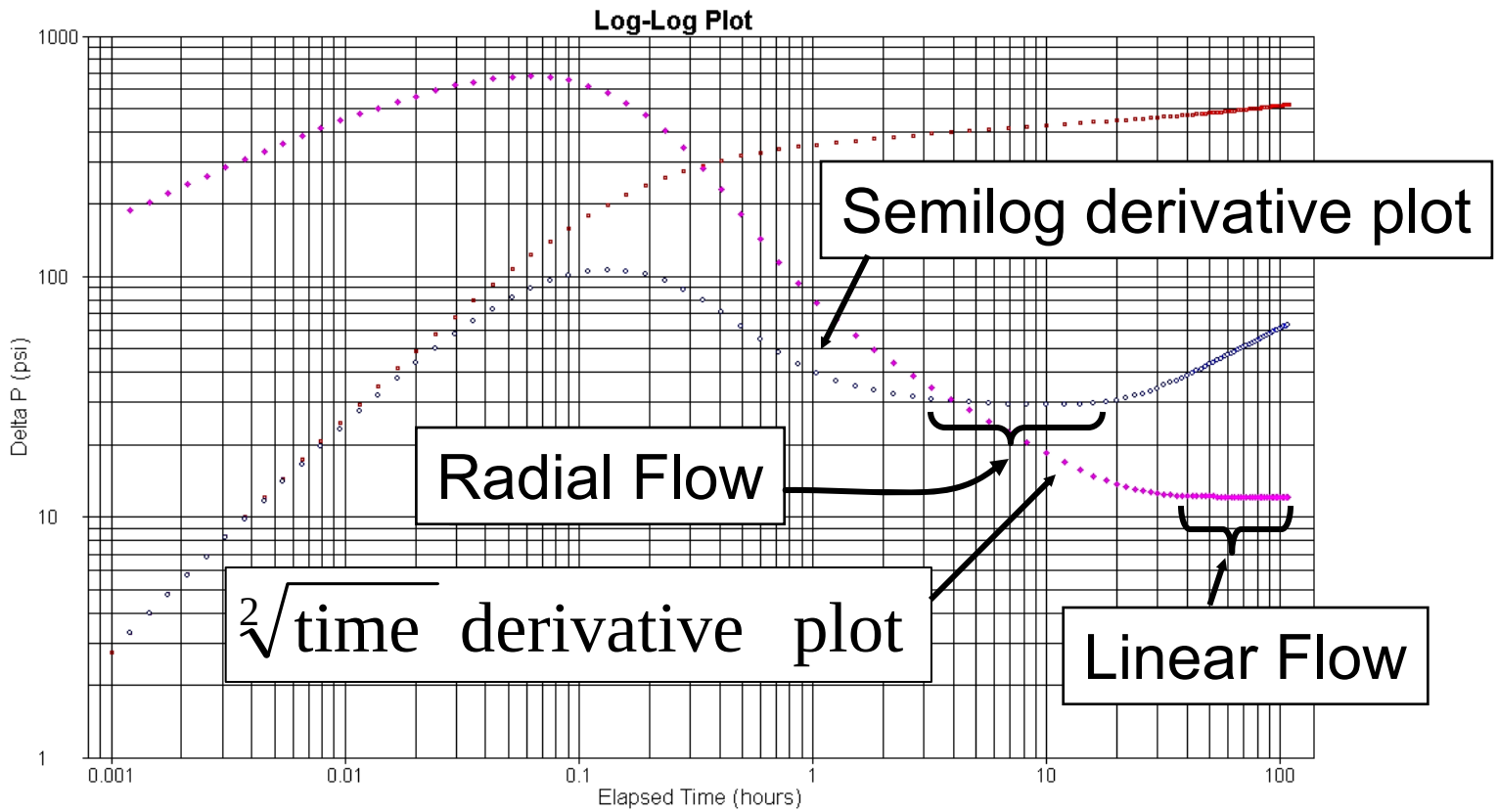
Radial Flow

- A test needs to get to radial flow to get valid results
- May be able to obtain a minimum permeability value using the derivative curve on the log-log plot if well does not reach radial flow
- Try type curve matching if no radial flow

Rule of thumb: Leave the well shut-in for an additional 1/3 log cycle after reaching radial flow to have an adequate radial flow period to evaluate

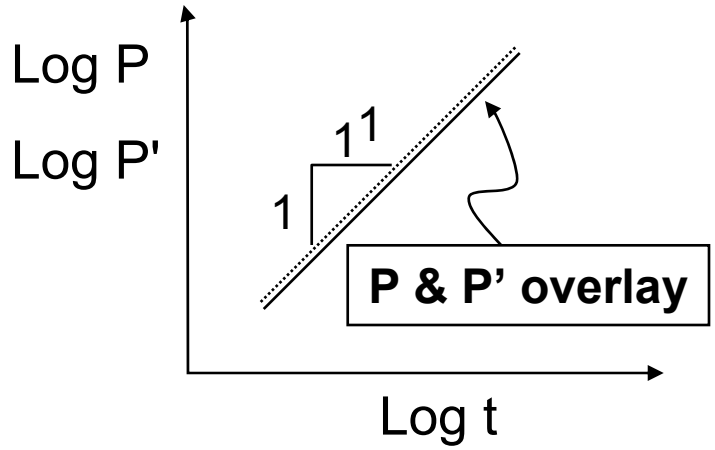
Example: Well in a Channel

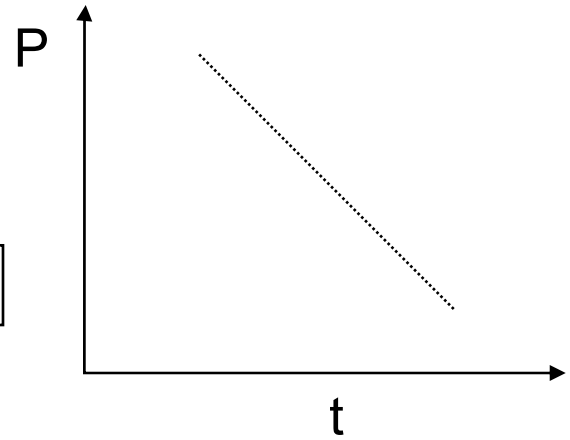
- **Well observes linear flow after reaching the channel boundaries**



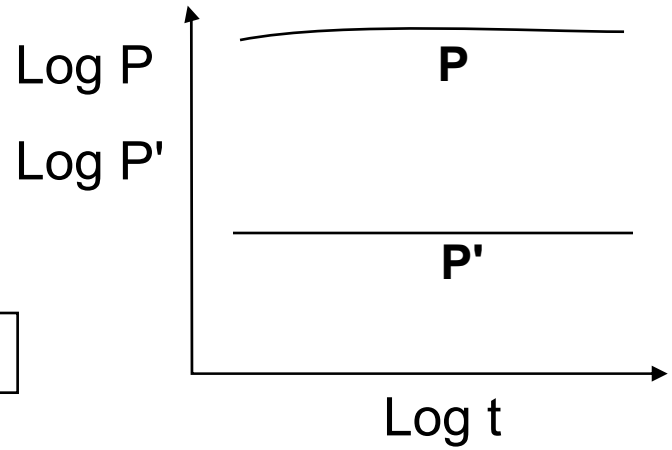
Typical Log-log Plot Signatures

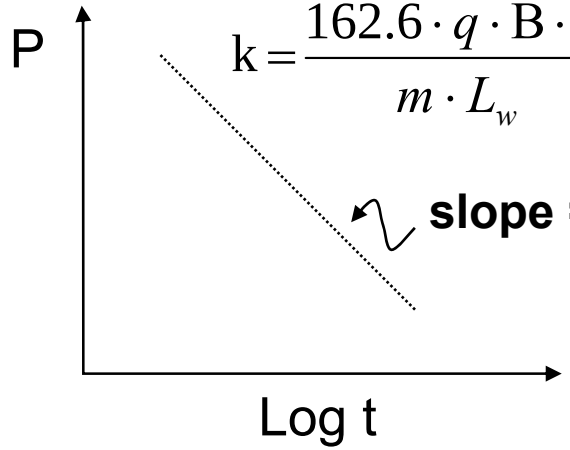
Wellbore Storage





Radial Flow

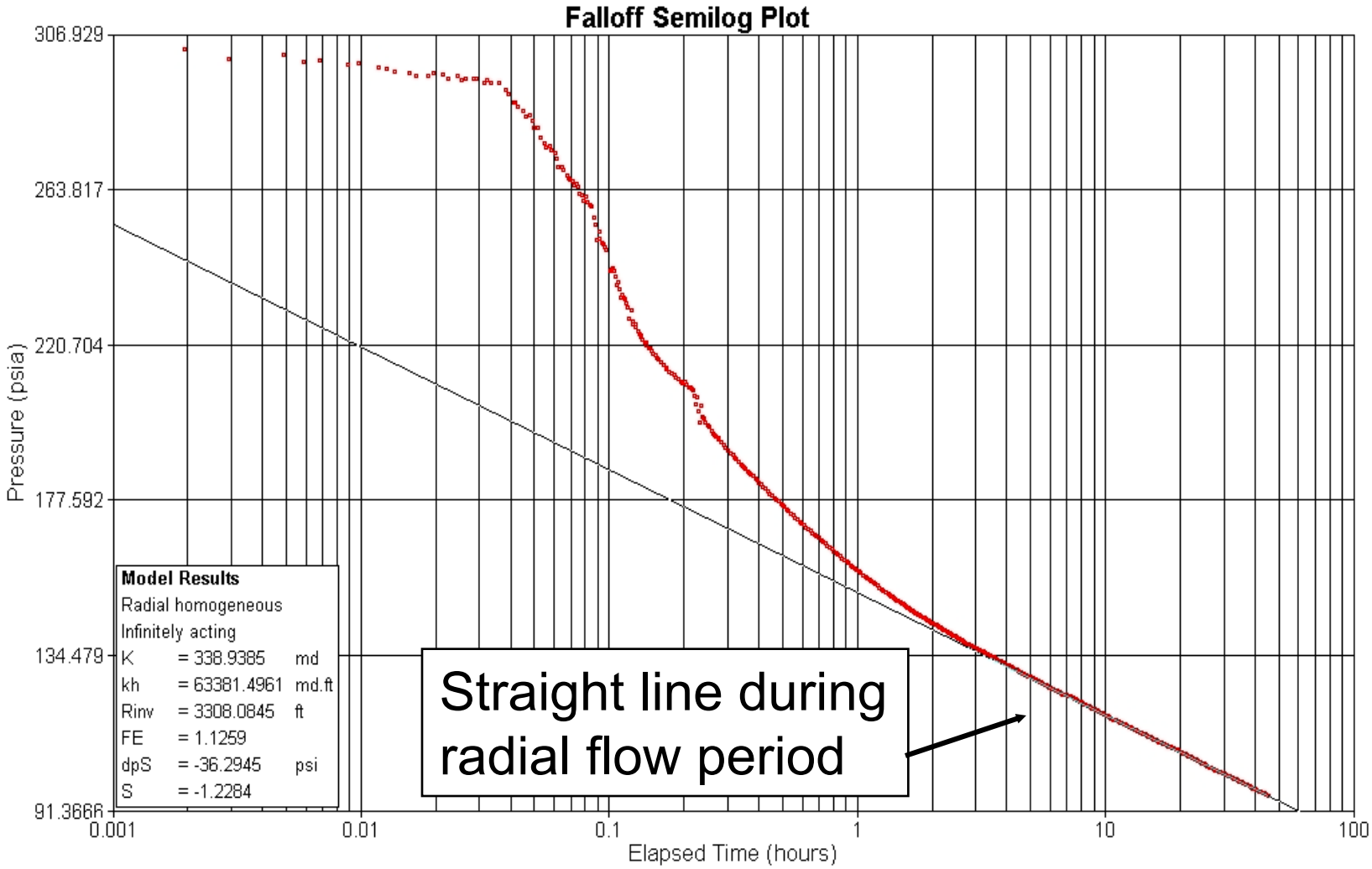




$$k = \frac{162.6 \cdot q \cdot B \cdot \mu}{m \cdot L_w}$$

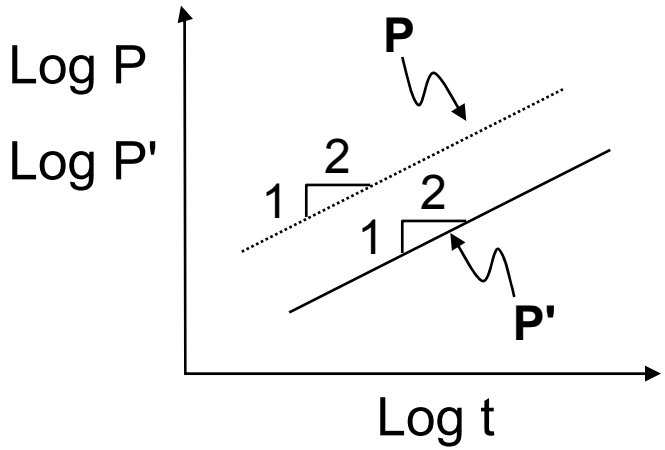
P' = dP/d(log t)

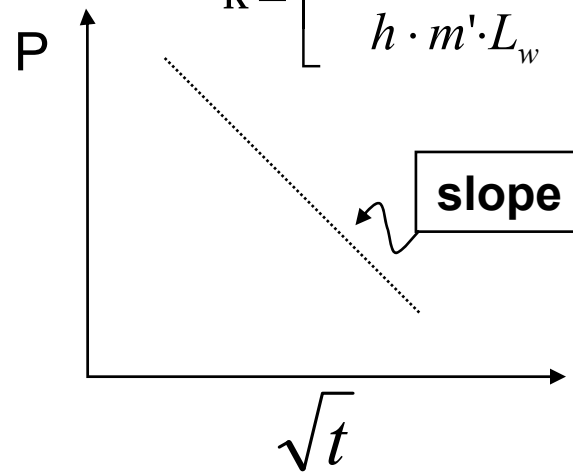
Example SemiLog Plot



Typical Log-Log Plot Signature

Linear Flow

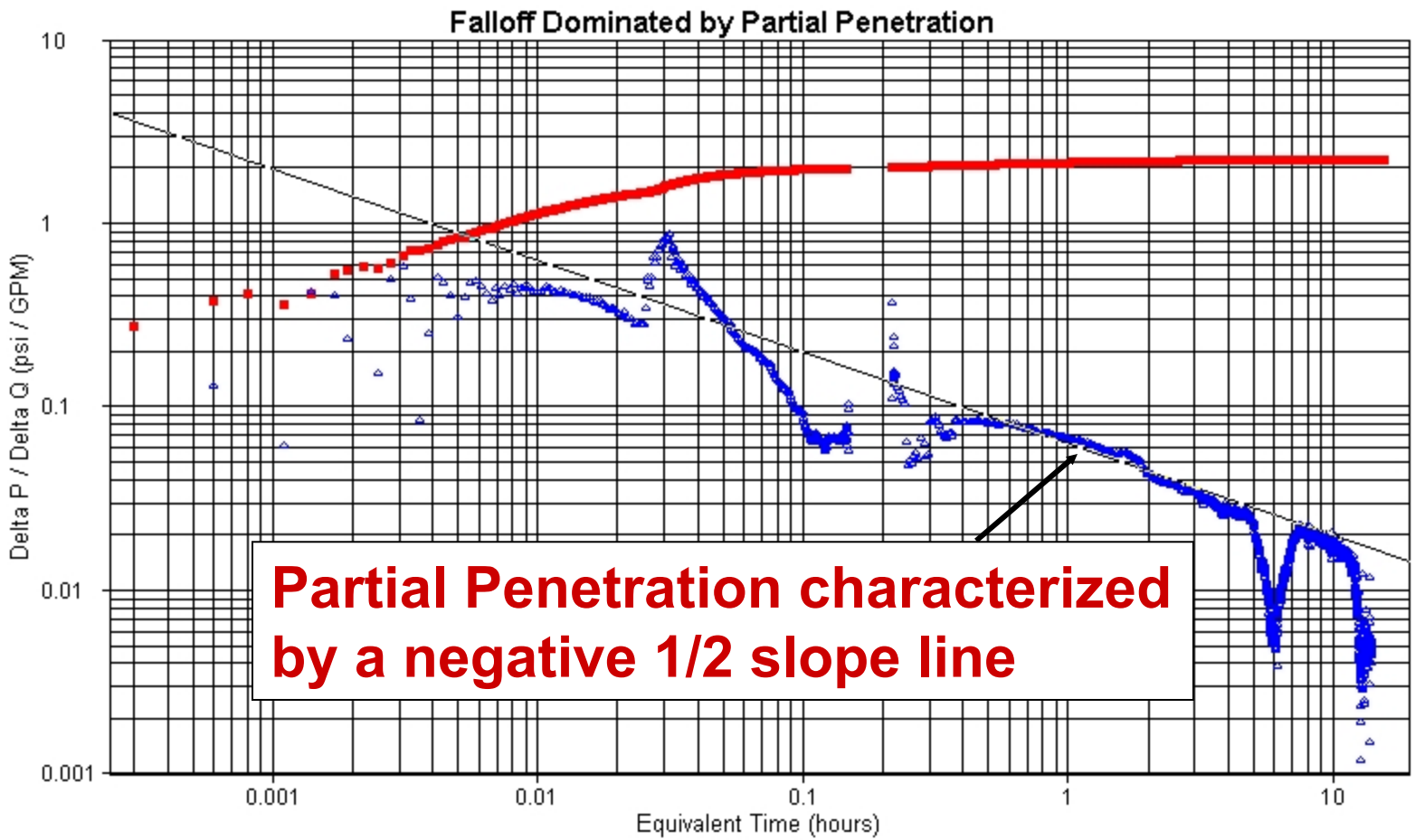




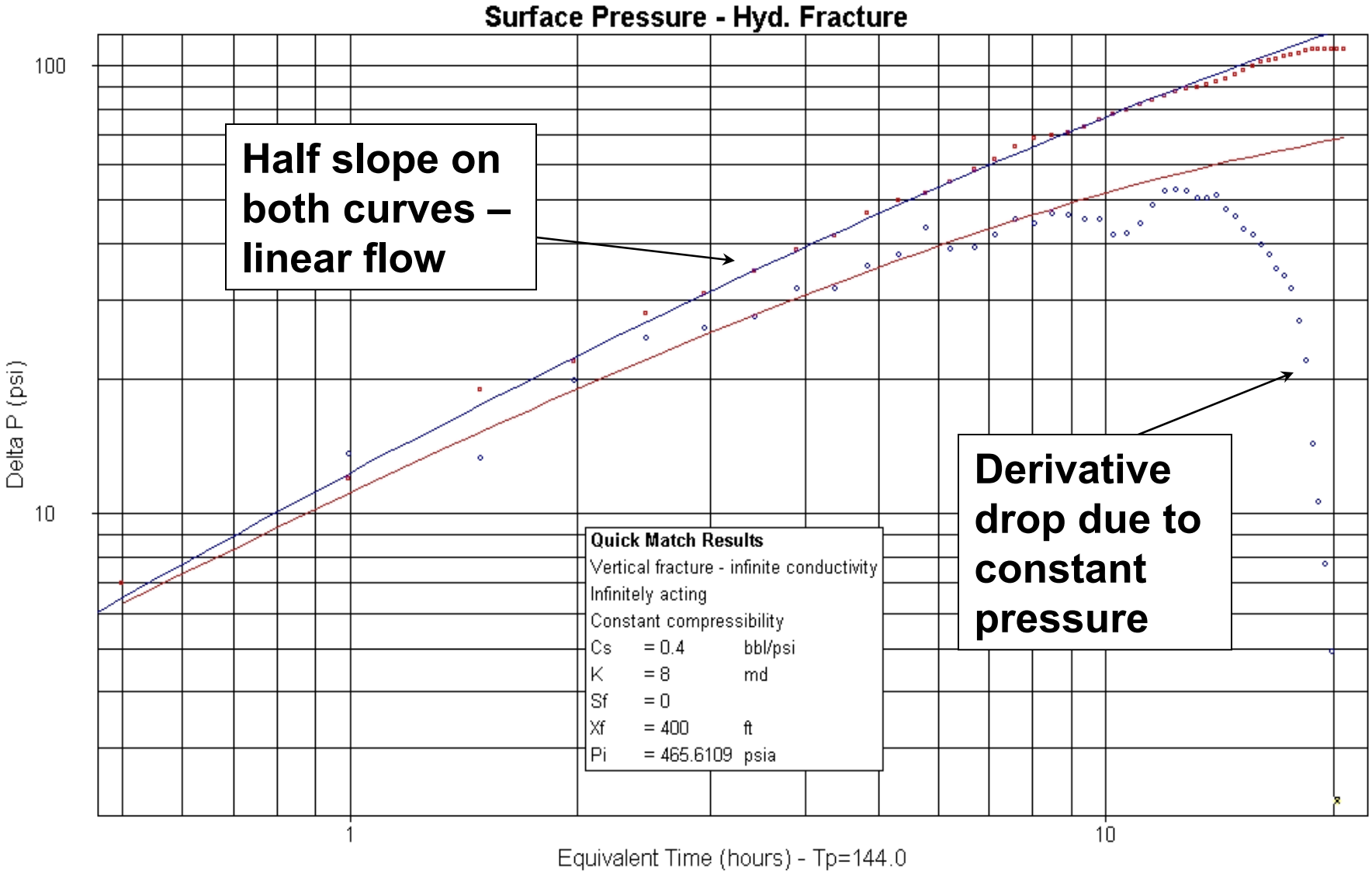
$$k = \left[\frac{8.128 \cdot q \cdot B}{h \cdot m' \cdot L_w} \right]^2 \cdot \frac{\mu}{\phi \cdot c}$$

P' = dP/d(log t)

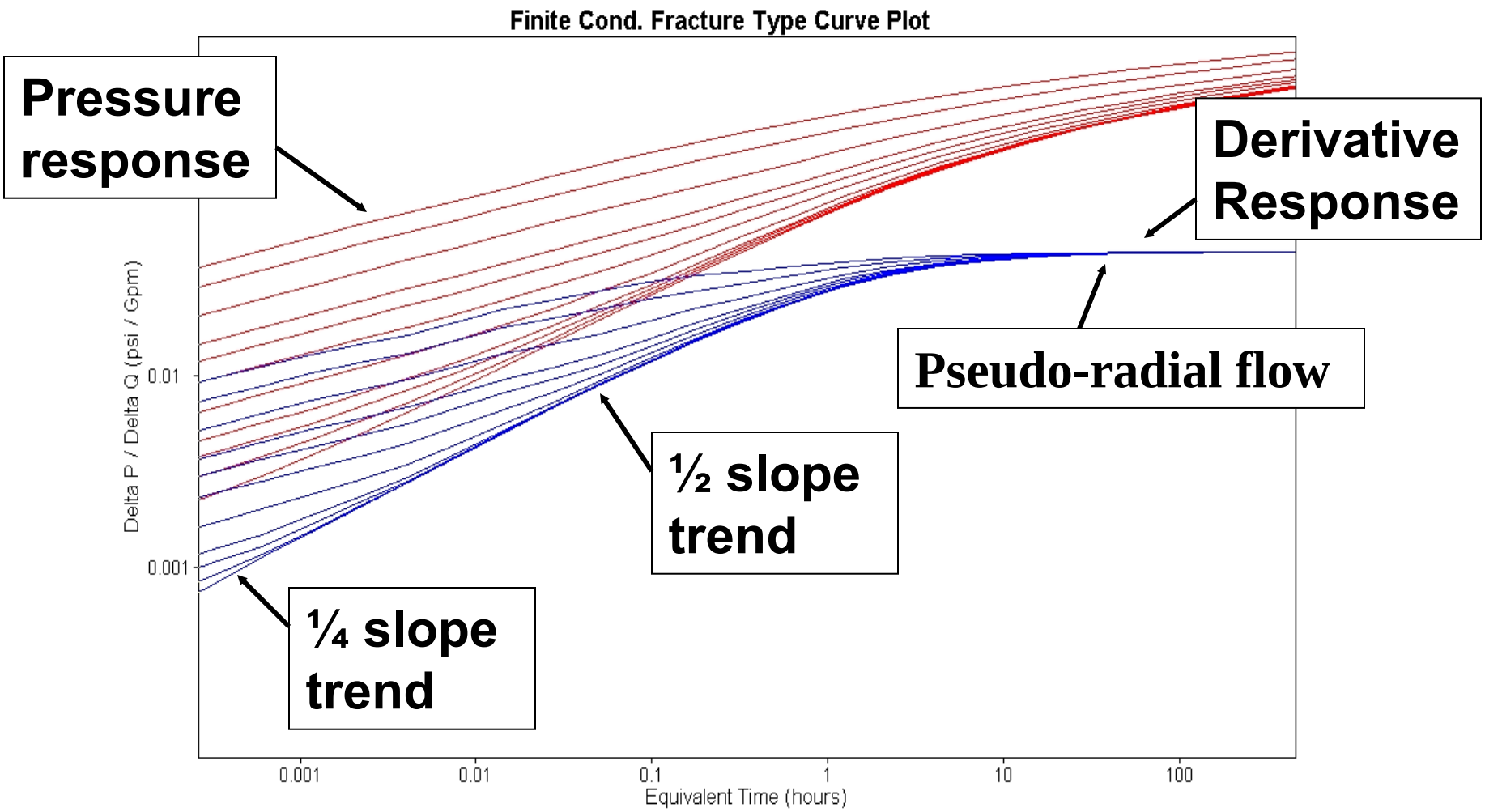
Log-log Plot Dominated by Spherical Flow



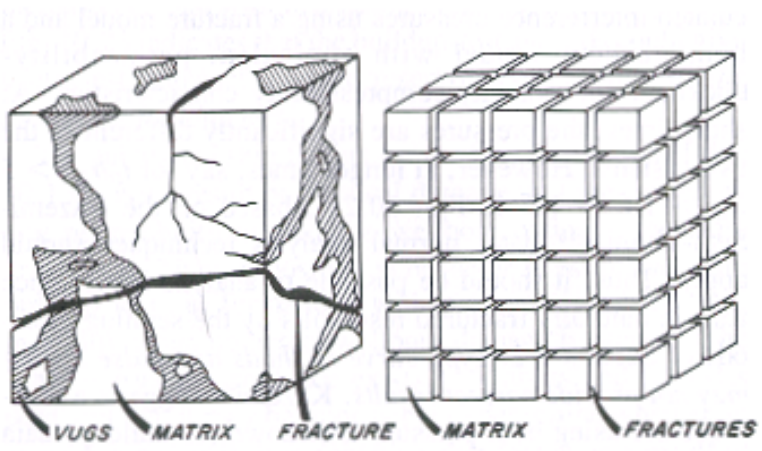
Hydraulic Fracture Log-log Plot



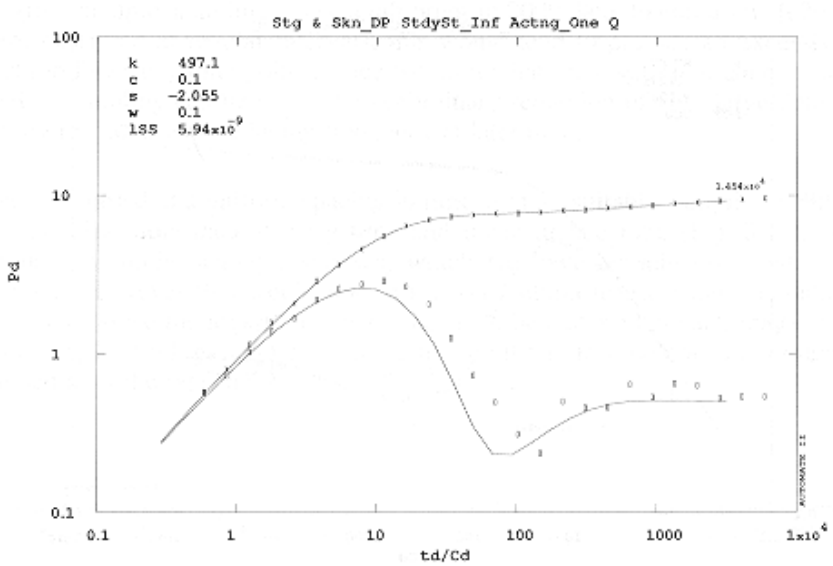
Hydraulic Fracture Response



Naturally Fractured Rock

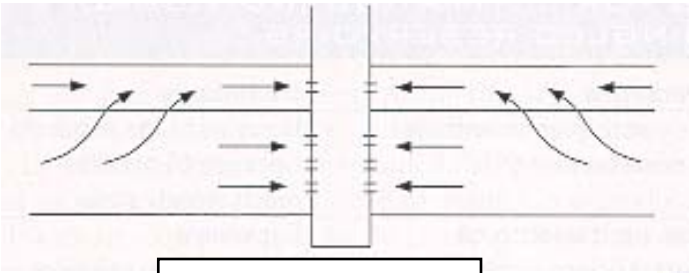


Dual Porosity Log-log Plot



- **Fracture system will be observed first on the falloff followed by the total system (fractures + tight matrix rock)**
- **Complex falloff analysis involved**
- **Falloff derivative trough indicates the level of communication between fractures and matrix rock**

Layered Reservoirs



Crossflow

Layered System with Crossflow

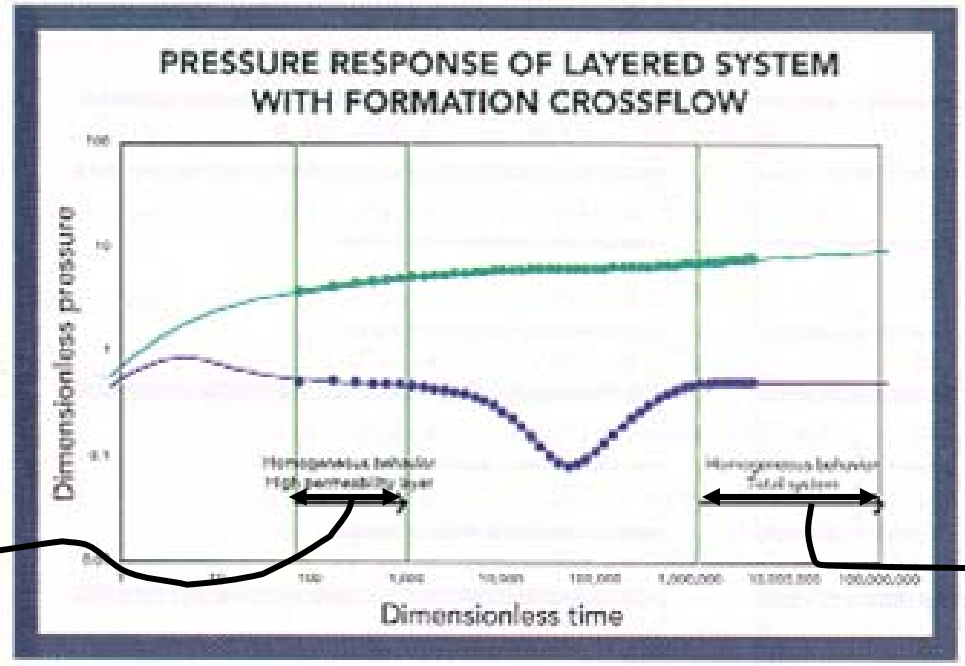


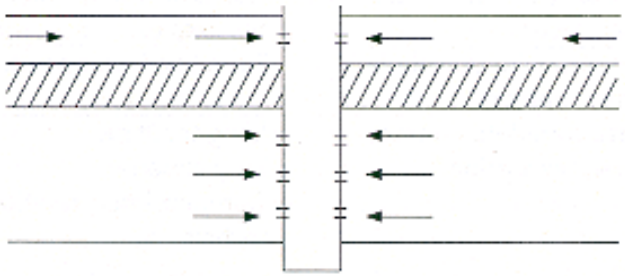
Fig. 6. In a layered reservoir, homogeneous behavior is exhibited during two different periods.

Homogeneous behavior of the higher permeability layer

Homogeneous behavior of the total system

Figures taken from Harts Petroleum Engr Intl, Feb 1998

Layered Reservoirs



Commingled

Layered system response

Homogeneous system response

Homogeneous behavior
Both layers infinite acting

High perm layer bounded
Low perm layers infinite acting

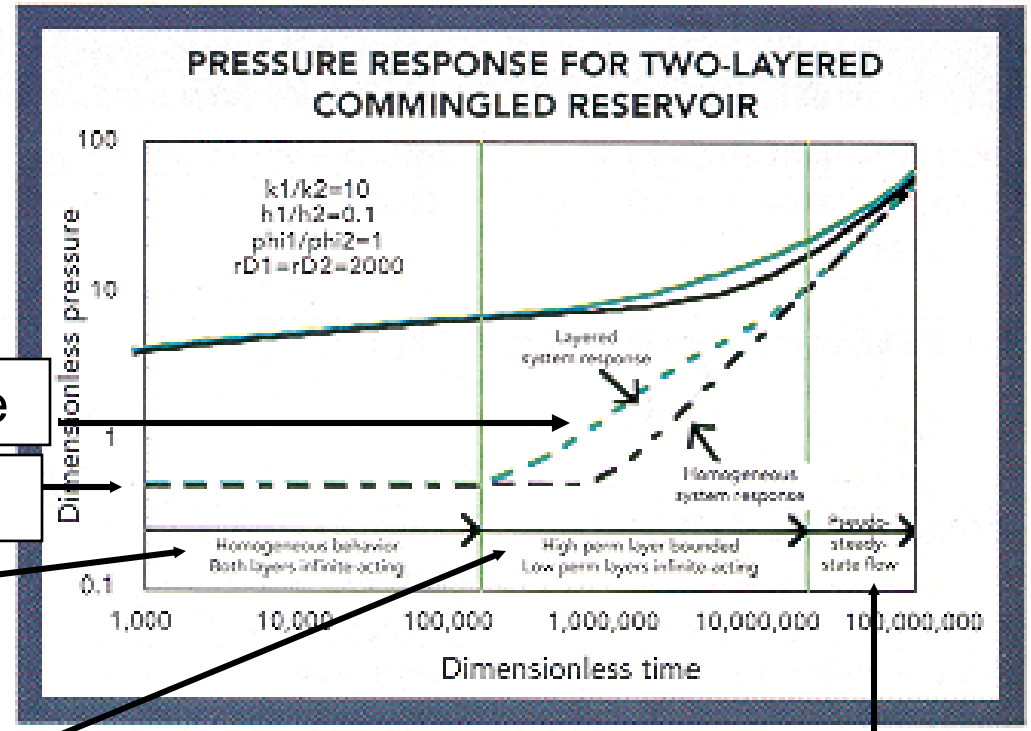


Fig. 7. Homogeneous behavior is exhibited during early times for a commingled reservoir.

Psuedo-steadystate flow

Figures taken from Harts Petroleum Engr Intl, Feb 1998

Layered Reservoirs

- Analysis of a layered reservoir is complex
  - Different boundaries in each layer
- Falloff objective for UIC purposes is to get a total transmissibility from the whole reservoir system

Pressure Derivative Flow Regime Patterns

Flow Regime	Derivative Pattern
Wellbore Storage …….	Unit slope
Radial Flow ……	Flat plateau
Linear Flow ……	Half slope
Bilinear Flow …….	Quarter slope
Partial Penetration …..	Negative half slope
Layering ……	Derivative trough
Dual Porosity ……	Derivative trough
Boundaries ……	Upswing followed by plateau
Constant Pressure …..	Sharp derivative plunge

Log-log Plot Summary

- Logarithmic derivative combines the slope trend of the semilog plot with the log-log plot to magnify flow regime patterns
- The derivative trend determines what portion of the test can be used to evaluate the semilog straight line
- Various flow regimes show up on the derivative plot with specific patterns

Falloff Test Evaluation Procedure

- **Data acquisition:**
  - **Well information**
  - **Reservoir and injectate fluid parameters**
  - **Reservoir thickness**
  - **Rate histories**
  - **Time sync injection rate data with pressure data**

Falloff Evaluation Procedure

- Prepare a Cartesian plot of pressure and temperature versus time
  - Confirm stabilization of pressure prior to shut-in
  - Look for anomalous data
  - Did pressure change reach the resolution of the gauge?

Falloff Evaluation Procedure

- Prepare a log-log plot of the pressure and the derivative
  - Use appropriate time scale
  - Identify the radial flow period
    - Flattening of the derivative curve
  - If there is no radial flow period, resort to type curve matching

Falloff Evaluation Procedure

- Make a semilog plot
  - Use the appropriate time function
    - Horner or Superposition time
  - Draw a straight line of best fit through the points located within the equivalent time interval where radial flow is indicated by the derivative curve on the log-log plot
  - Determine the slope m and P_{1hr} from the semilog straight line

Falloff Evaluation Procedure

- Calculate reservoir and completion parameters
  - transmissibility, kh/μ
  - skin factor, s
  - radius of investigation, r_i, based on Agarwal equivalent time, t_e
- Check results using type curves (optional)

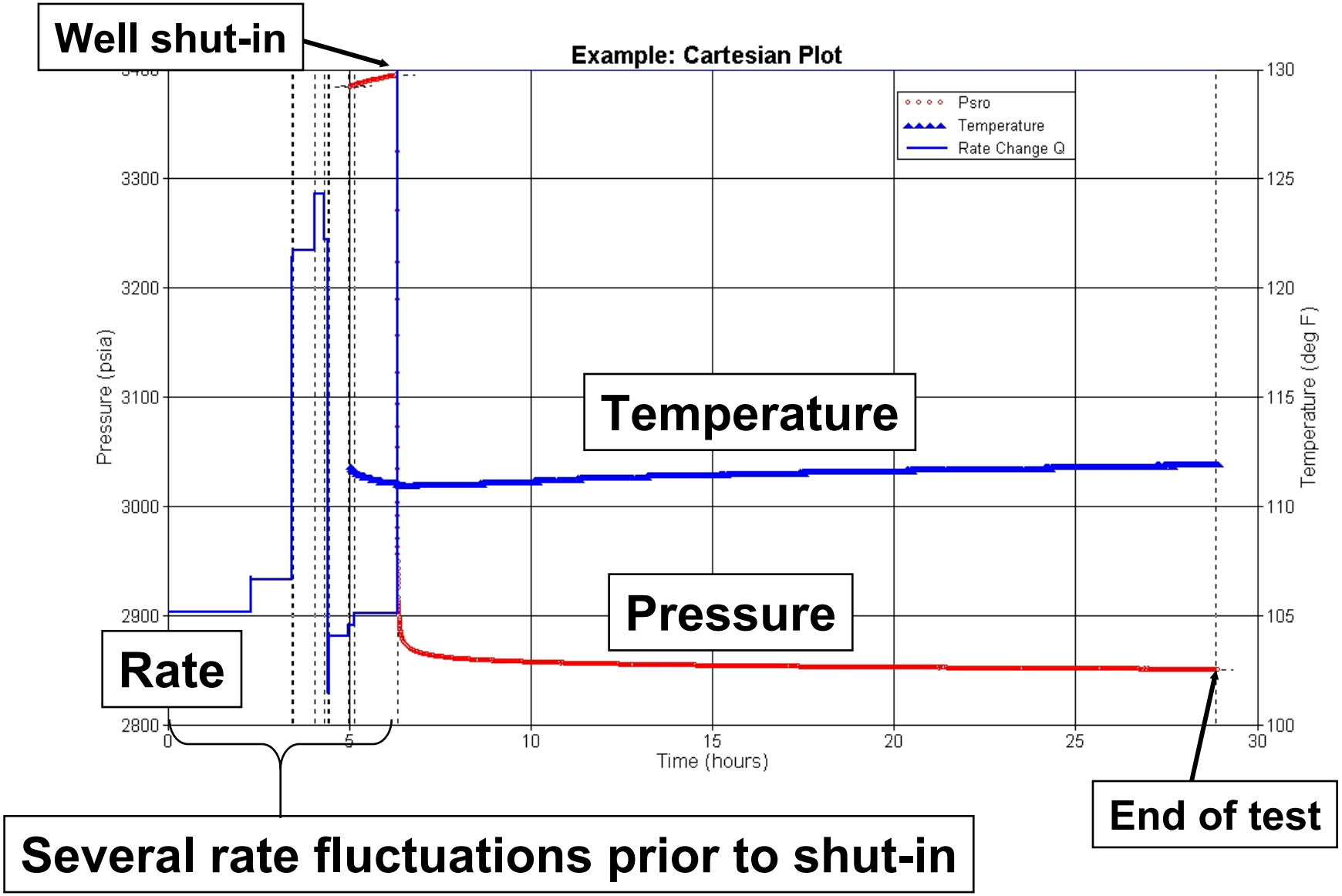
Gulf Coast Falloff Test Example

- **Well Parameters:**
  - r_w= .4 ft
  - cased hole perforated completion
    - 6020’- 6040’
    - 6055’- 6150’
    - 6196’- 6220’
  - Depth to fill: 6121’
  - Gauge depth: 6100’
    - Panex 2525 SRO

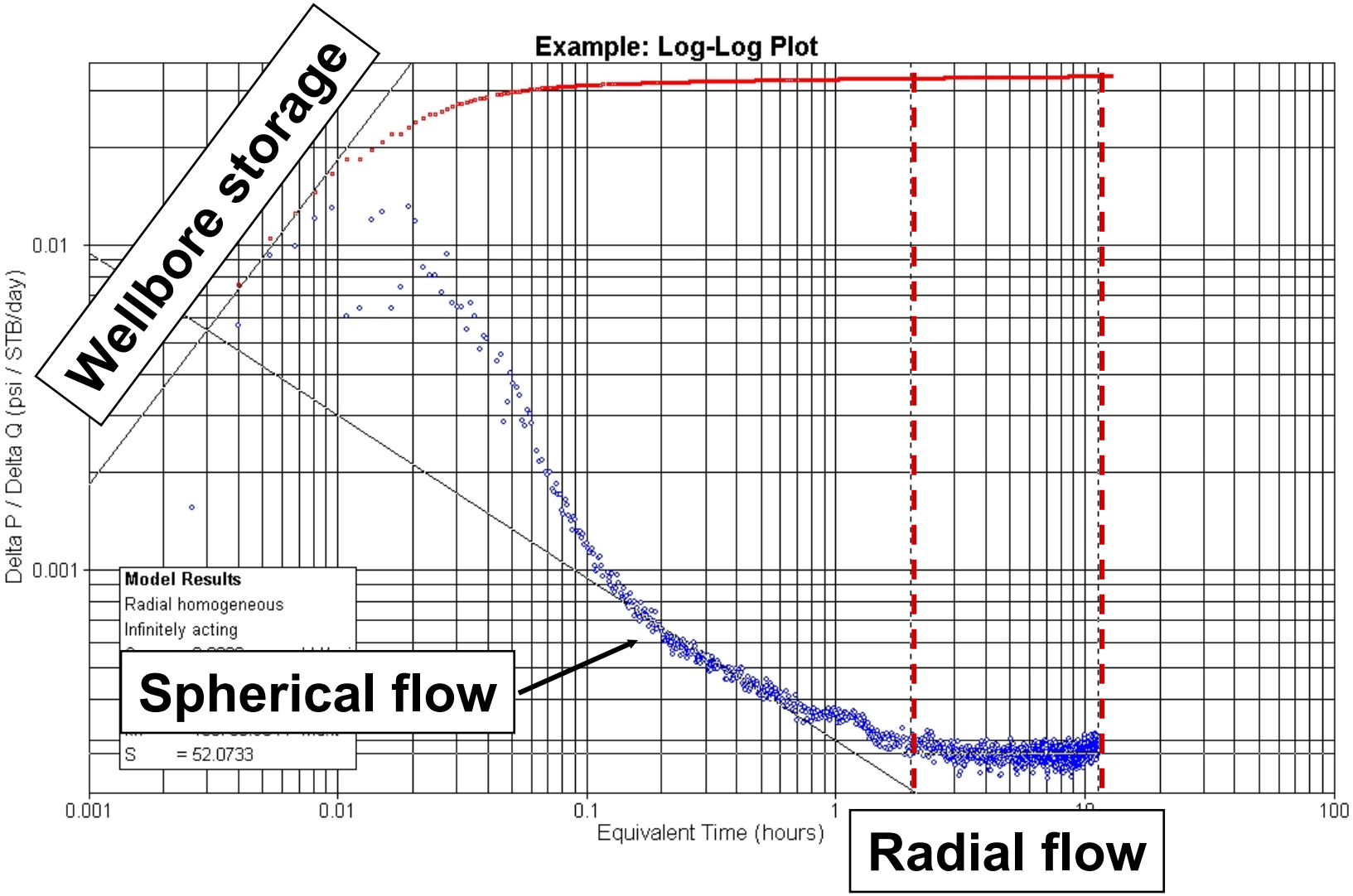
Example (cont.)

- **Reservoir Parameters:**
  - **Reservoir thickness, h: 200'**
  - **Average porosity, Φ: 28%**
  - **Total compressibility, c_t: $5.7e^{-6}$ psi^{-1}**
- **Formation Fluid Properties**
  - **Viscosity, μ_f: 0.6 cp**

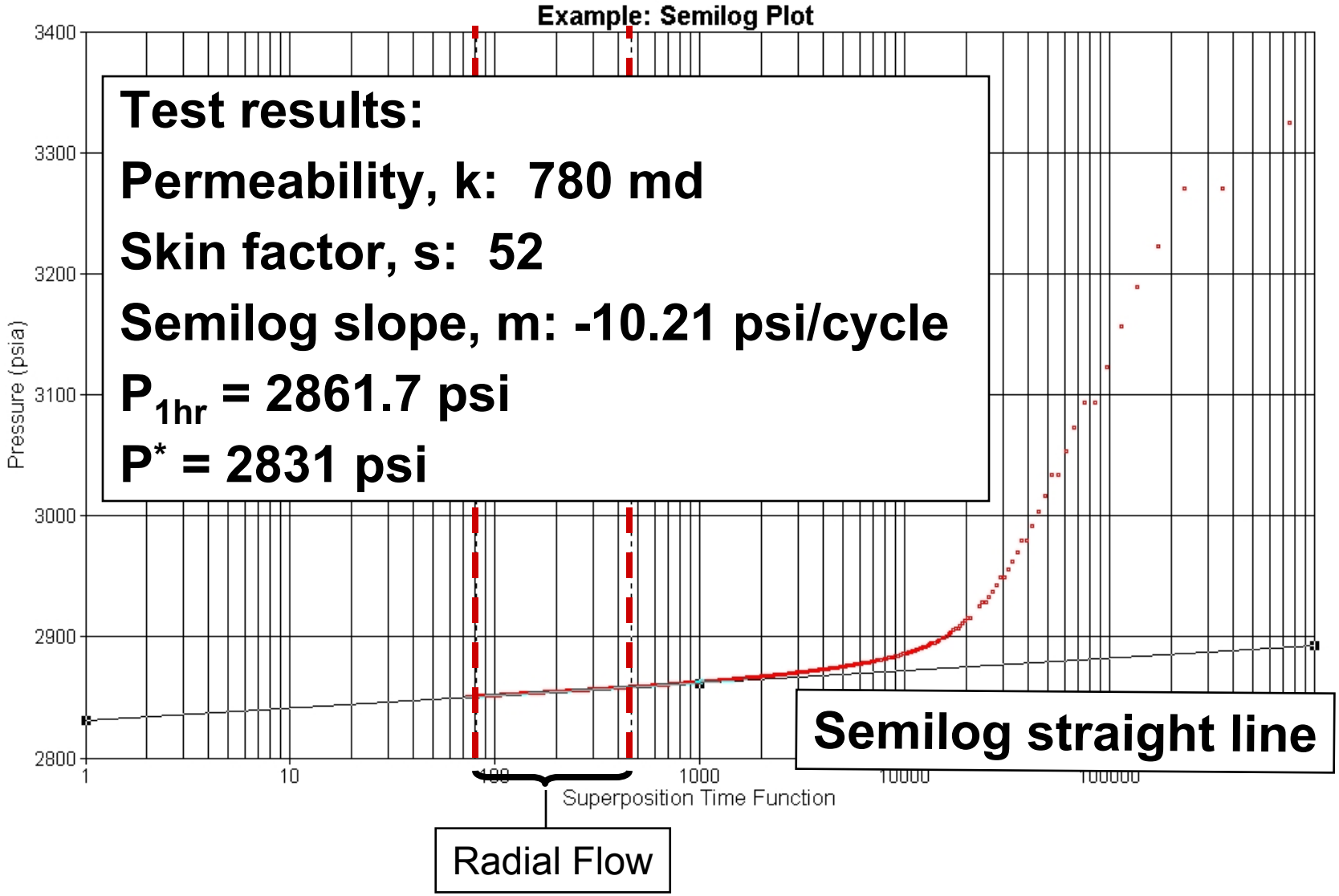
Example (cont.)



Log-log Plot


Example: Log-Log Plot
Wellbore storage
Delta P / Delta Q (psi / STB/day)
0.01
0.001
Model Results
Radial homogeneous
Infinitely acting
S = 52.0733
Spherical flow
0.001
0.01
0.1
1
100
Equivalent Time (hours)
Radial flow

Semilog Plot



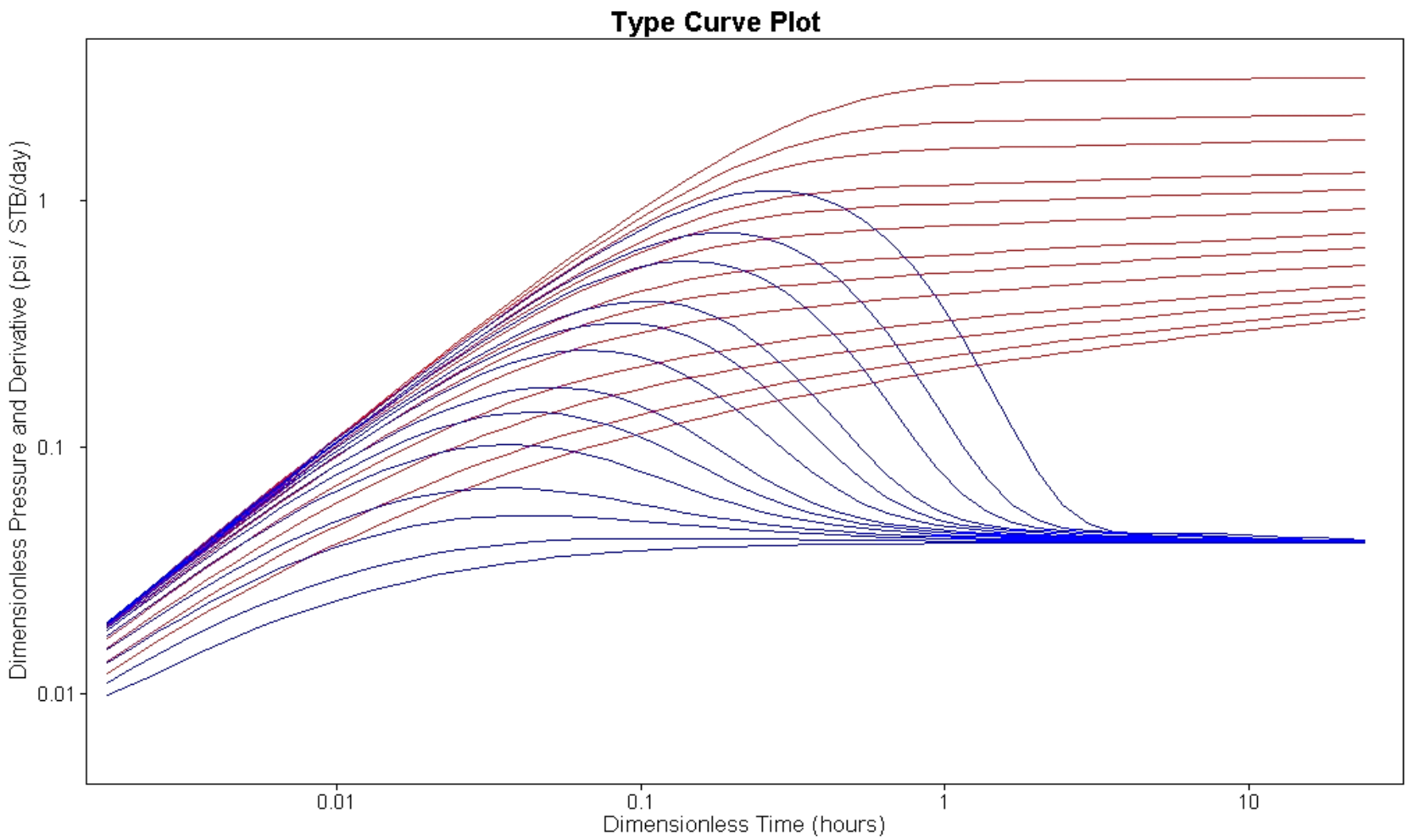
Type Curves

- Graphs of P_d vs. t_d for various solutions to the PDE
- Provide a "picture" of the PDE for a certain set of boundary conditions
- Work when the specialized plots do not readily identify flow regimes

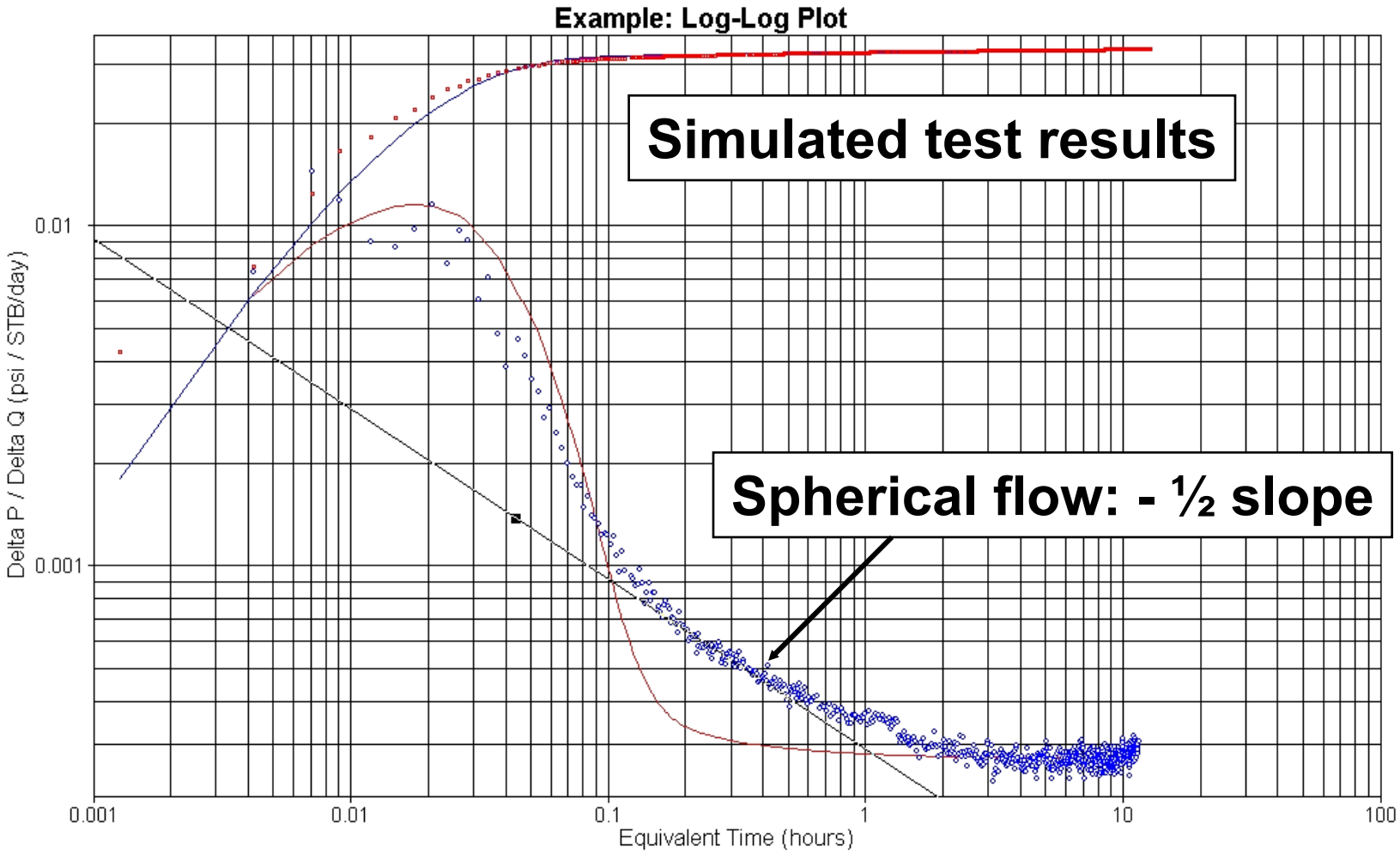
Type Curves

- Applied to field data analysis by a process called “type curve matching”
- Generally based on drawdowns/injectivity
- May require plotting test data with specialized time functions to use correctly

Example: Homogeneous Reservoir Type Curves



Type Curve Match

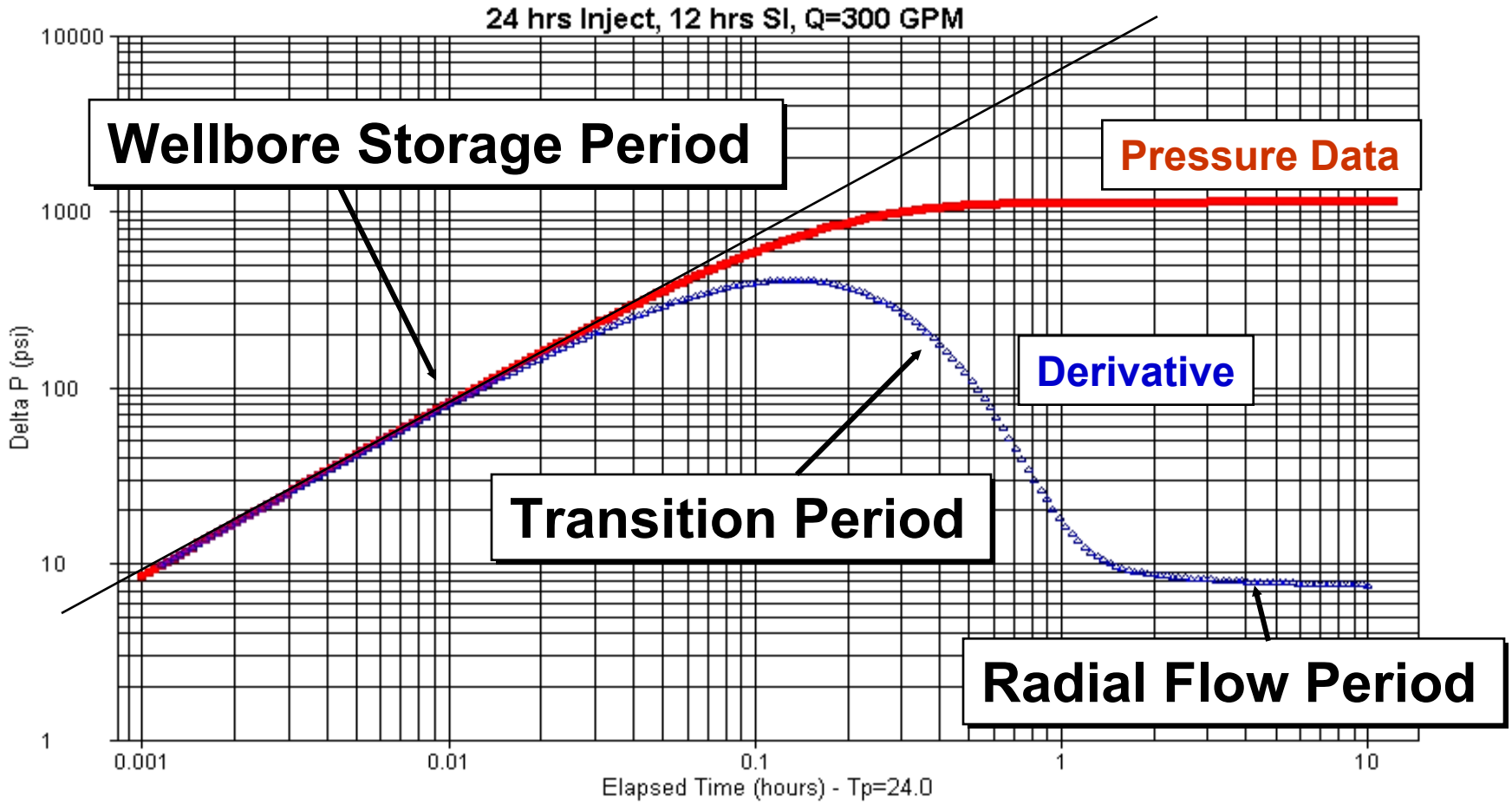


Effects of Key Falloff Variables

Key Falloff Variables

- Length of injection time
- Injection rate
- Length of shut-in (falloff) period
- Wellbore skin
- Wellbore storage coefficient

Log-Log Plot


24 hrs Inject, 12 hrs SI, Q=300 GPM
Wellbore Storage Period
Pressure Data
Derivative
Transition Period
Radial Flow Period
Delta P (psi)
10000
1000
100
10
1
0.001
0.01
0.1
1
10
Elapsed Time (hours) - Tp=24.0

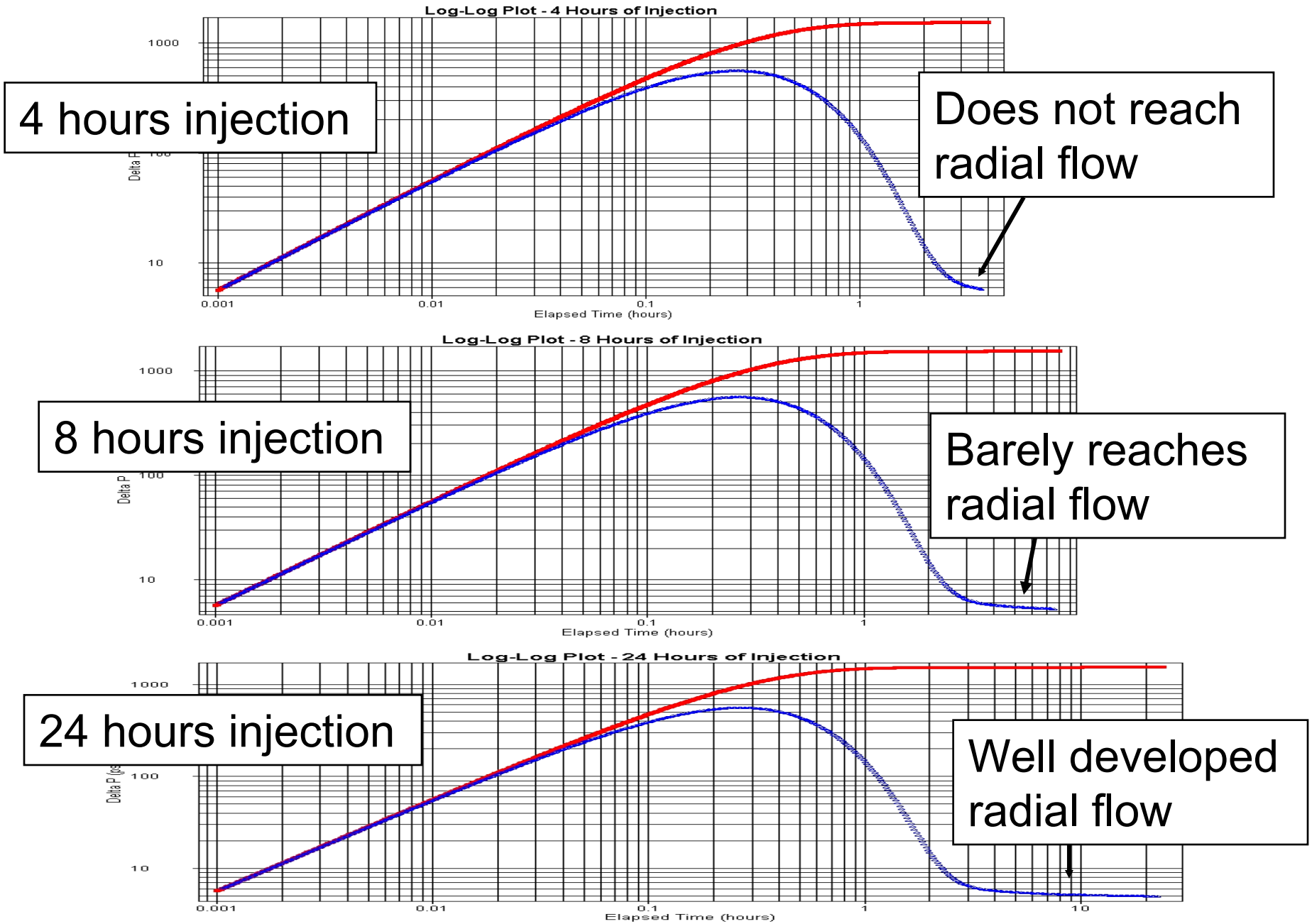
Effect of Injection Time

- Length of injection period controls the radius of investigation of the falloff test
- Falloff is a “replay” of the preceding injection period
- Falloff period cannot see any further out into the reservoir than the injection period did
- Injection period should be long enough to establish radial flow

Injection Time

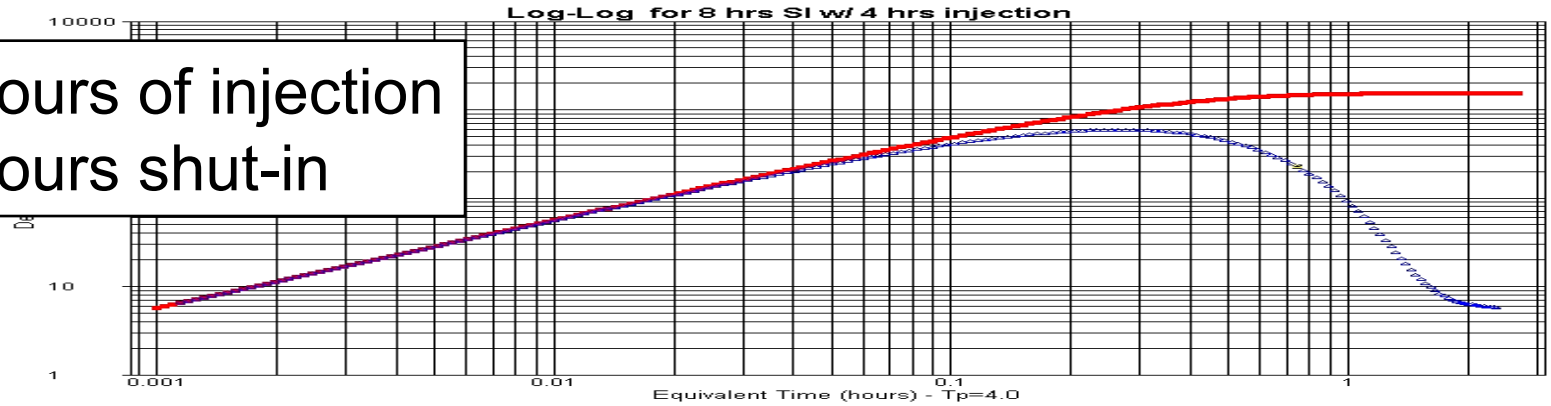
- Increase injection time to observe presence of faults or boundary effects
- Calculate minimum time needed to reach a certain distance away from the injection well

Simulated Injection Periods - Same Properties, Varying Duration

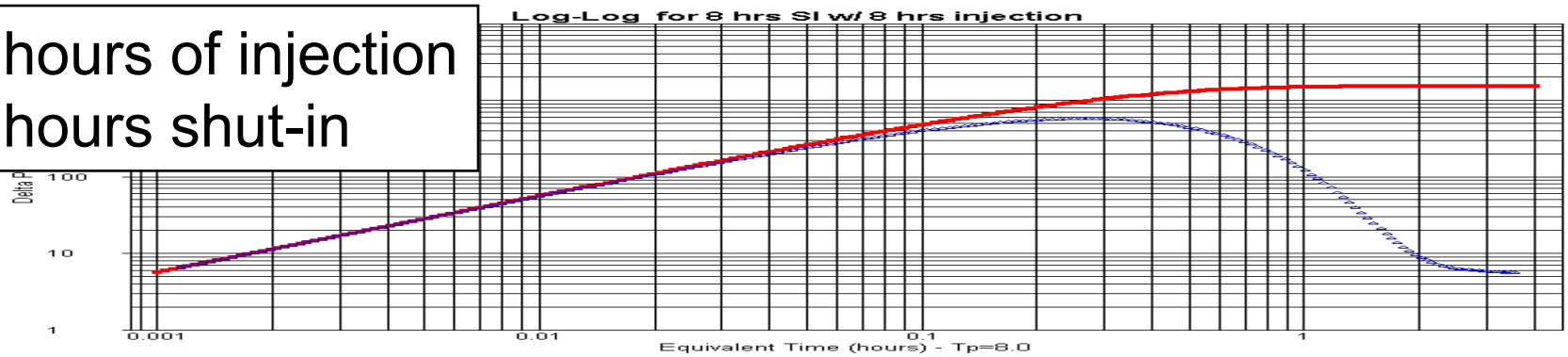


Log-log Plots for Injection Periods of Varying Length

4 hours of injection
8 hours shut-in



8 hours of injection
8 hours shut-in



24 hours of injection
8 hours shut-in

Summary of Injection Time Effects

- When injection time is shorter than the falloff, it compresses the falloff response on log-log plot
- Longer injection time extends the falloff response
- When injection time is very long relative to the falloff time, it has little effect on the falloff response

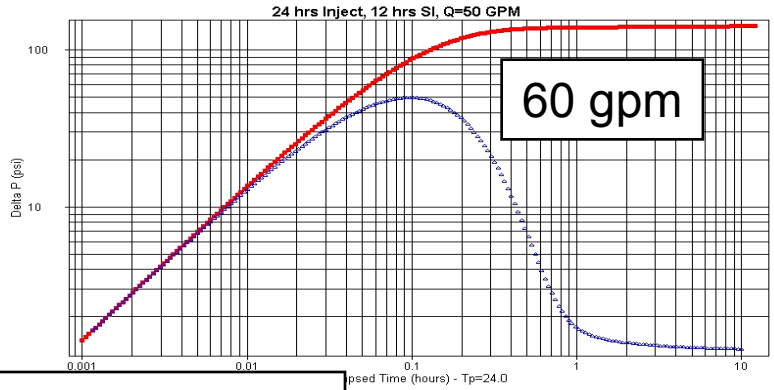
Effects of Injection Rate

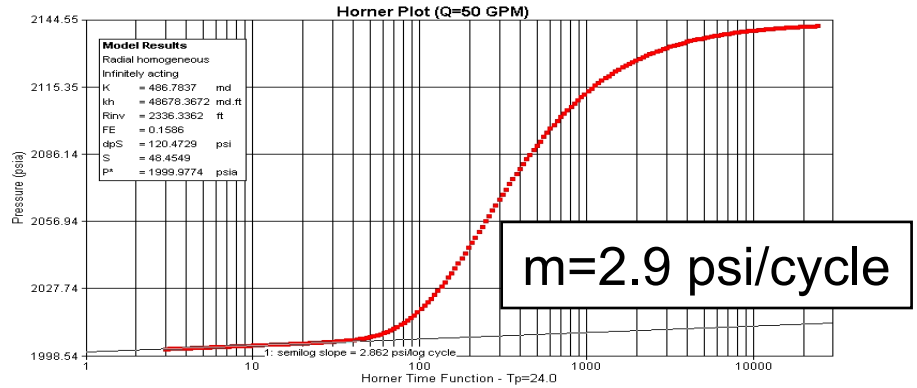
- Rate determines the magnitude of pressure rise during the injection period and the amount of pressure falloff during shut-in period
- Too small a rate can minimize the degree of pressure change measured during a falloff test
- Rate limit during a test may be constrained by permit limits, formation transmissibility, skin factor, or waste storage capacity

Injection Rate Effects

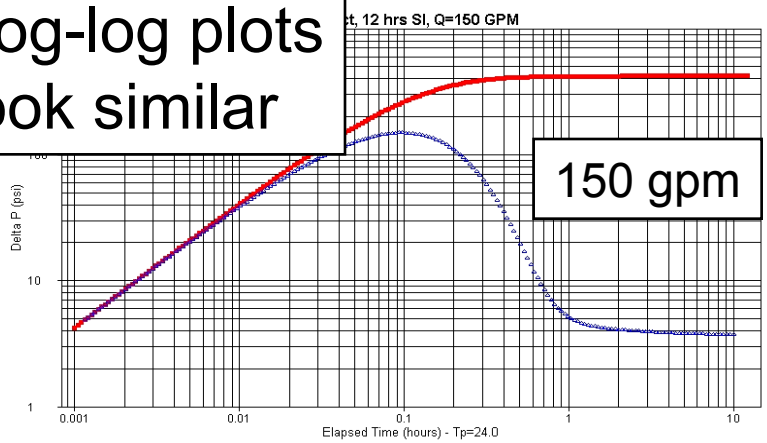
- Injection rate preceding the test may be limited by the UIC permit and no migration petition requirements or operational considerations including:
  - available injectate capacity
  - pumping capacity
  - surface pressure or rate limitations

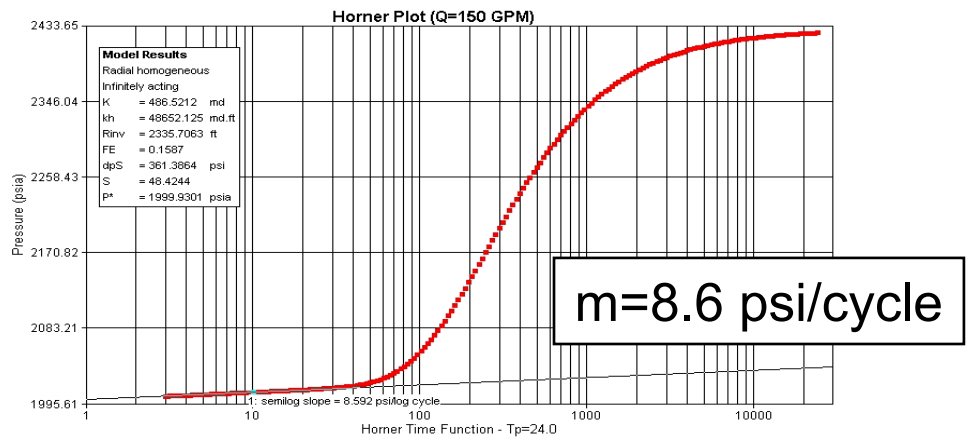
Effect of Increasing Rate on Falloff Test Response

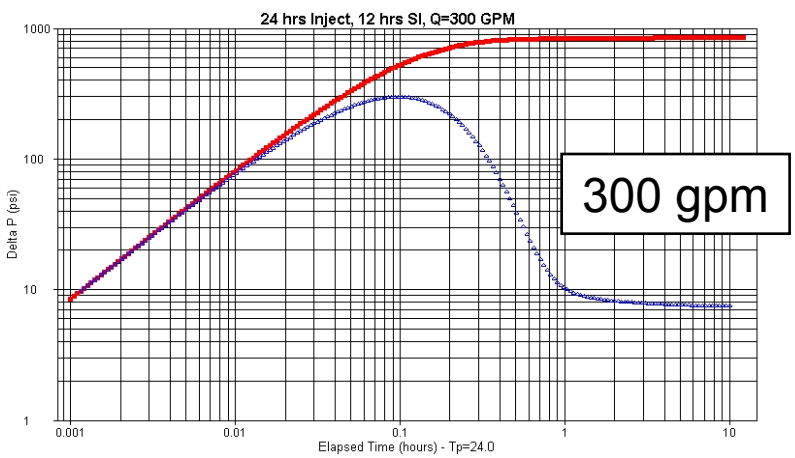


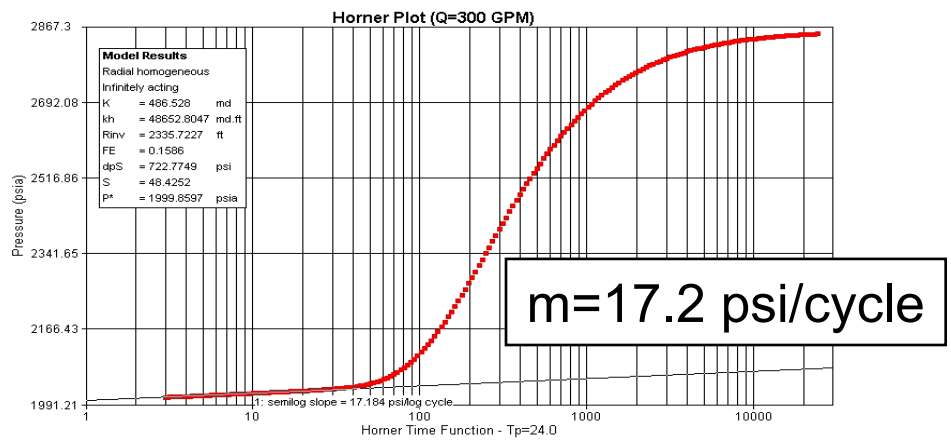


Log-log plots look similar









Summary of Injection Rate Effects

- **Higher rate increases the amount of pressure buildup during injection resulting in:**
  - **Greater total falloff pressure change**
  - **Larger slope of the semilog plot during radial flow**
  - **Increased semilog slope enables a more reliable measurement of radial flow**

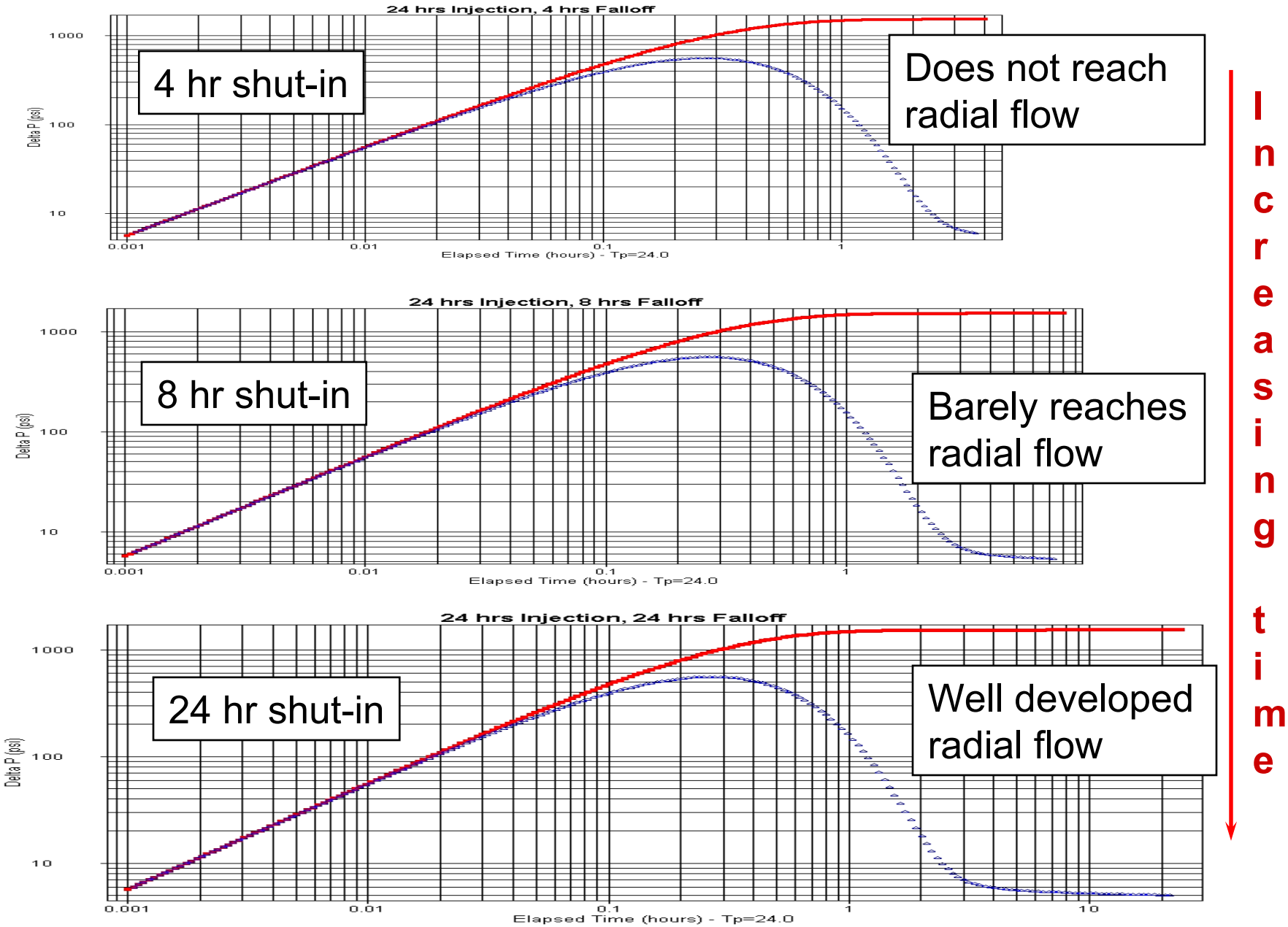
Effect of Shut-in Time

- **Too little shut-in time prevents the falloff from reaching radial flow, making it unanalyzable**
- **Shut-in time exceeding the injection period length is compressed when plotted with the proper time function on the log-log plot**

Shut-in Time

- Falloff data should be plotted with an appropriate time function on a log-log plot to account for the effects of the injection period on the shut-in time
- Increase falloff time to observe presence of faults and boundary effects if preceding injection period was long enough to encounter them

Comparison of Shut-in Times for Identical Injection Conditions



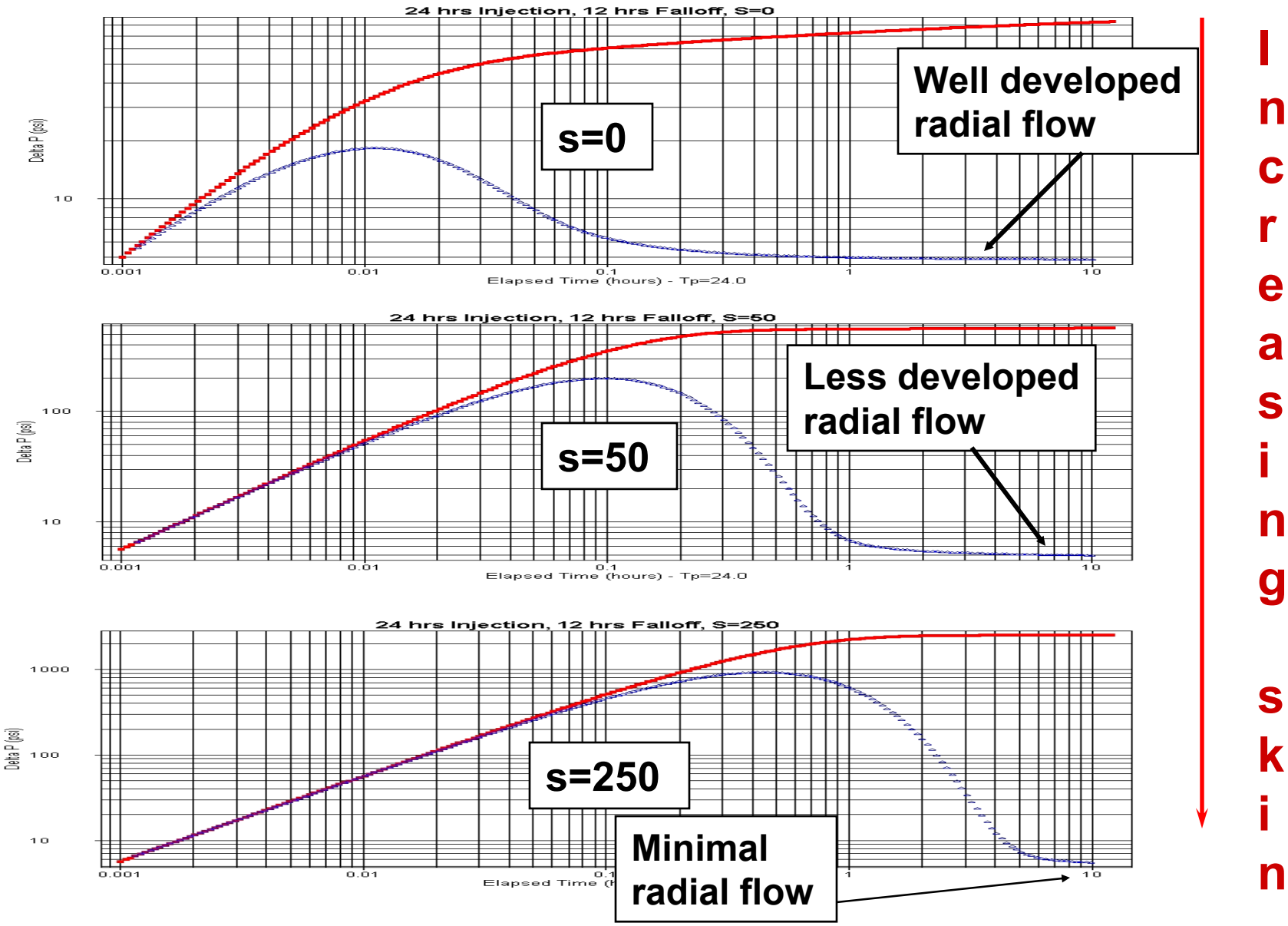
Summary of Shut-in Time Effects

- Too short a shut-in time results in no radial flow
- Shut-in time may be dictated by the preceding injection time
  - Falloff is a replay of the injection
- Wellbore storage, skin, and need to observe a boundary may increase the required shut-in time

Effects of Wellbore Storage and Skin Factor

- A positive skin factor increases the time to reach radial flow
- A negative skin reduces the time to reach radial flow
- Large wellbore storage coefficient increases time to reach radial flow
  - Caused by well going on a vacuum, formation vugs, presence of fracture or large wellbore tubular dimensions

Comparison of Skin Effect for Identical Falloff Conditions



Boundary Effects

What Can I Learn About Boundaries from a Falloff Test?

- Derivative response indicates the type and number of boundaries
- If radial flow develops before the boundary effects, then the distance to the boundary can be calculated

How Long Does It Take To See A Boundary?

- **Time to reach a boundary can be calculated from the radius of investigation equation:**

$$t_{boundary} = \frac{948 \cdot \phi \cdot \mu \cdot c_t \cdot L_{boundary}}{k}$$

  - **Where $L_{boundary}$ is the distance in feet to the boundary**
  - **$t_{boundary}$ is in hours**

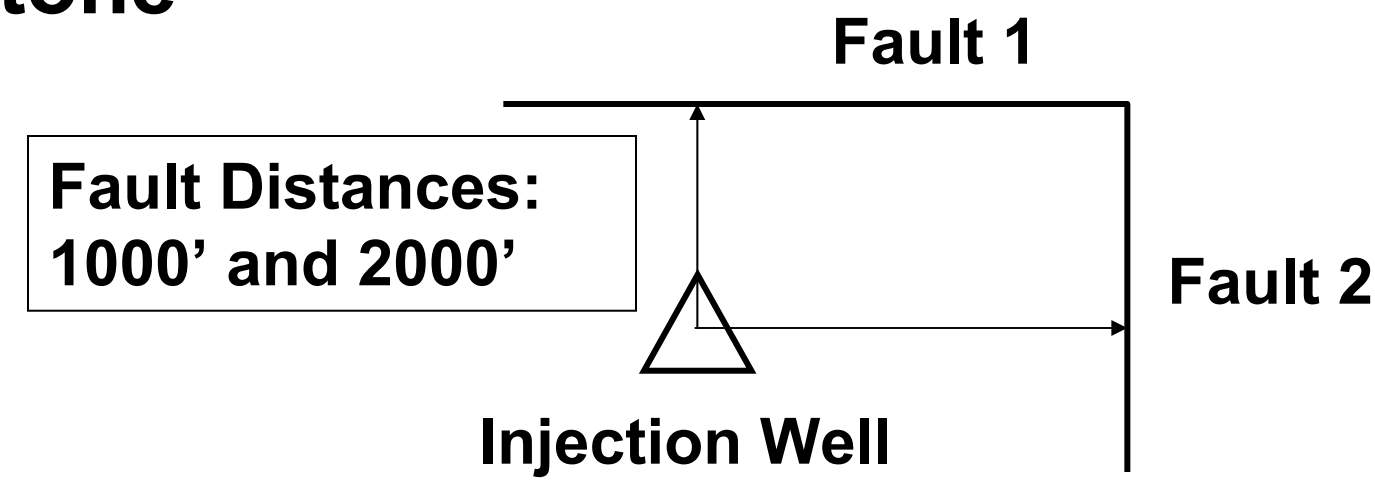
How Long Does It Take To See A Boundary?

- For a boundary to show up on a falloff, it must first be encountered during the injection period
- Additional falloff time is required to observe a fully developed boundary on the test past the time needed to just reach the boundary

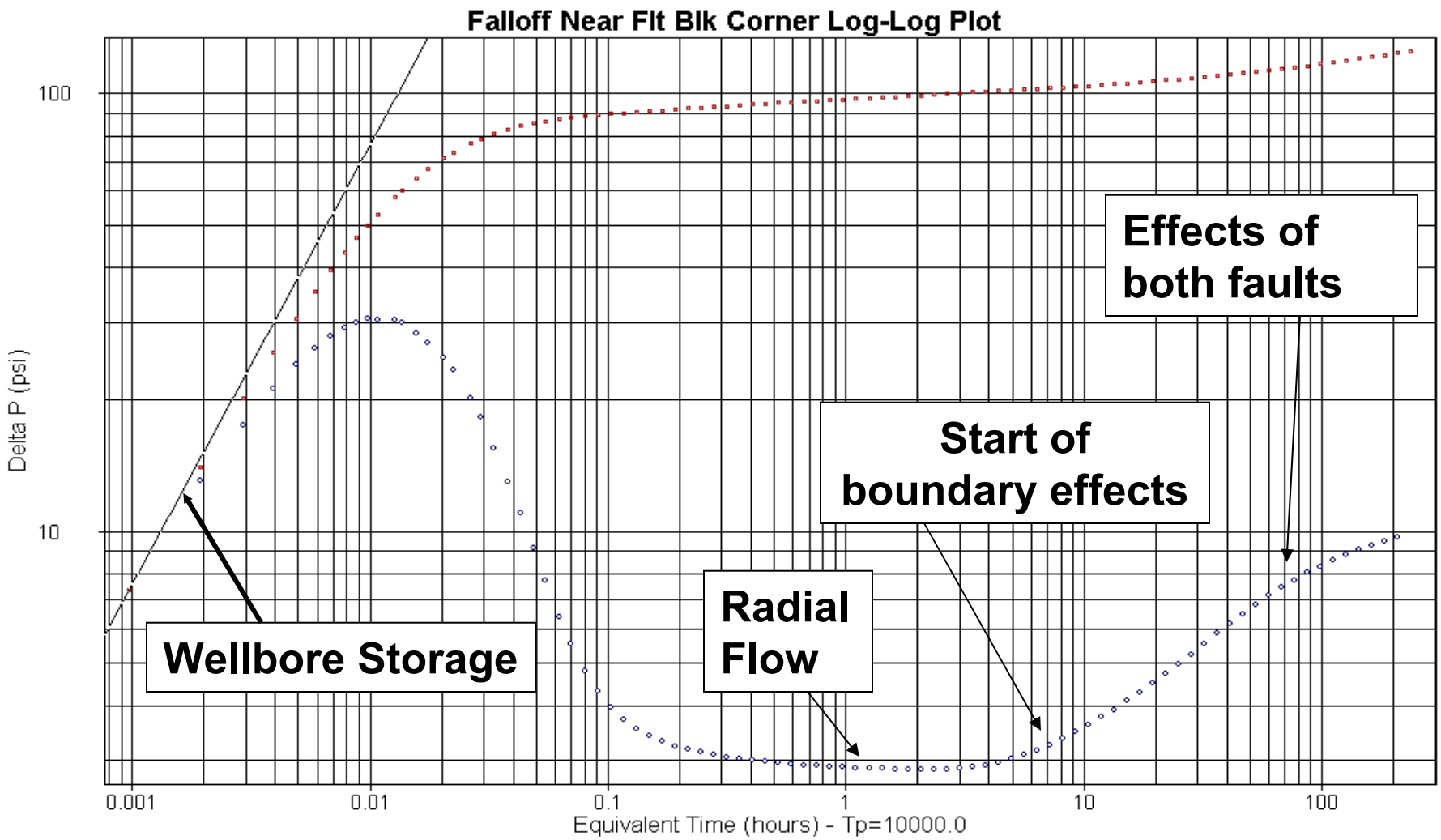
Rule of thumb: Allow at least 5 times the length of time it took to see the boundary to see it fully developed on a log-log plot

Example: Well Located Near 2 Faults

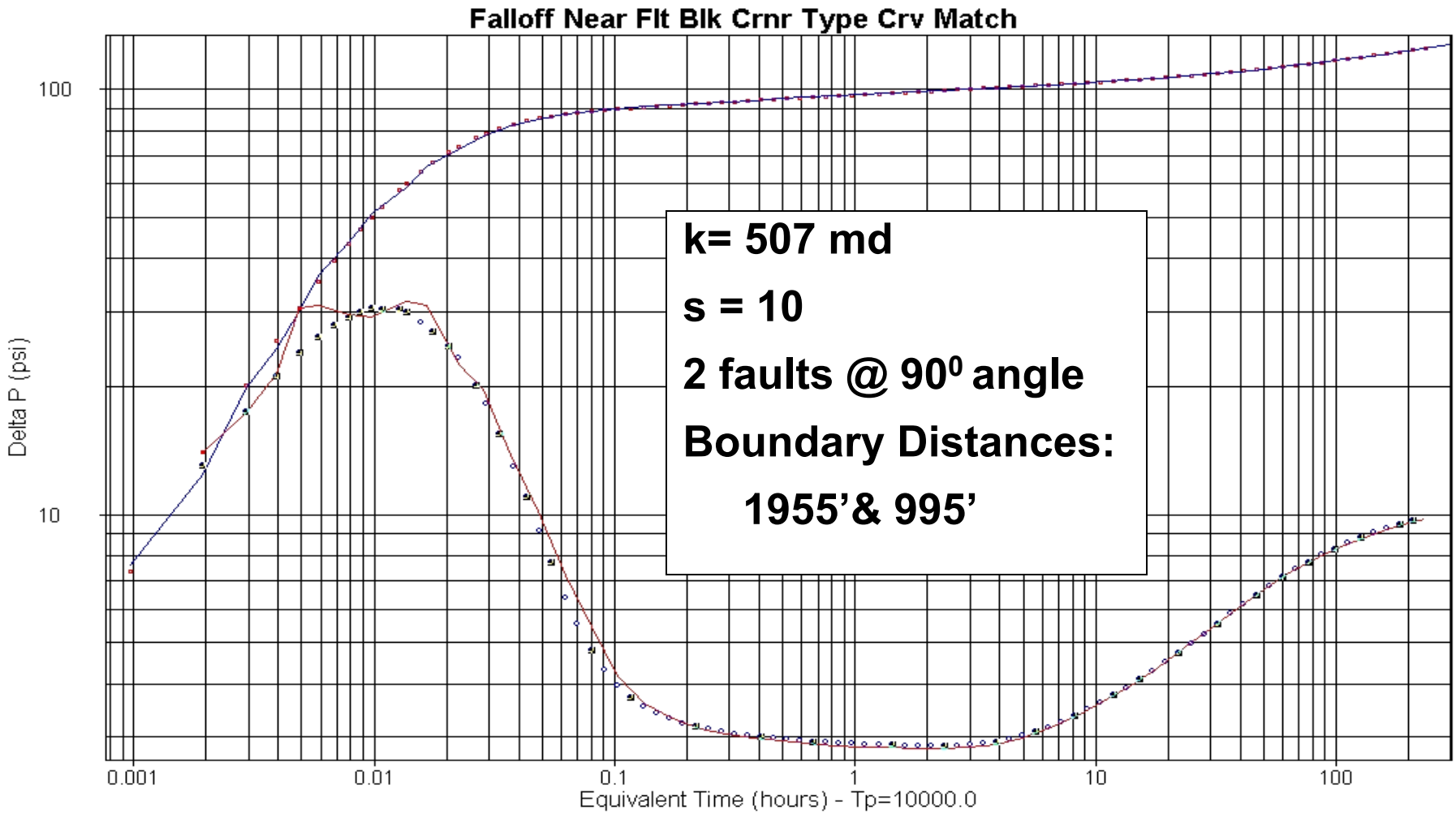
- An injection well injects at 2000 bpd for 10,000 hours and then is shut-in for 240 hours
- The well is located in the corner of a fault block
- The reservoir is a high permeability sandstone



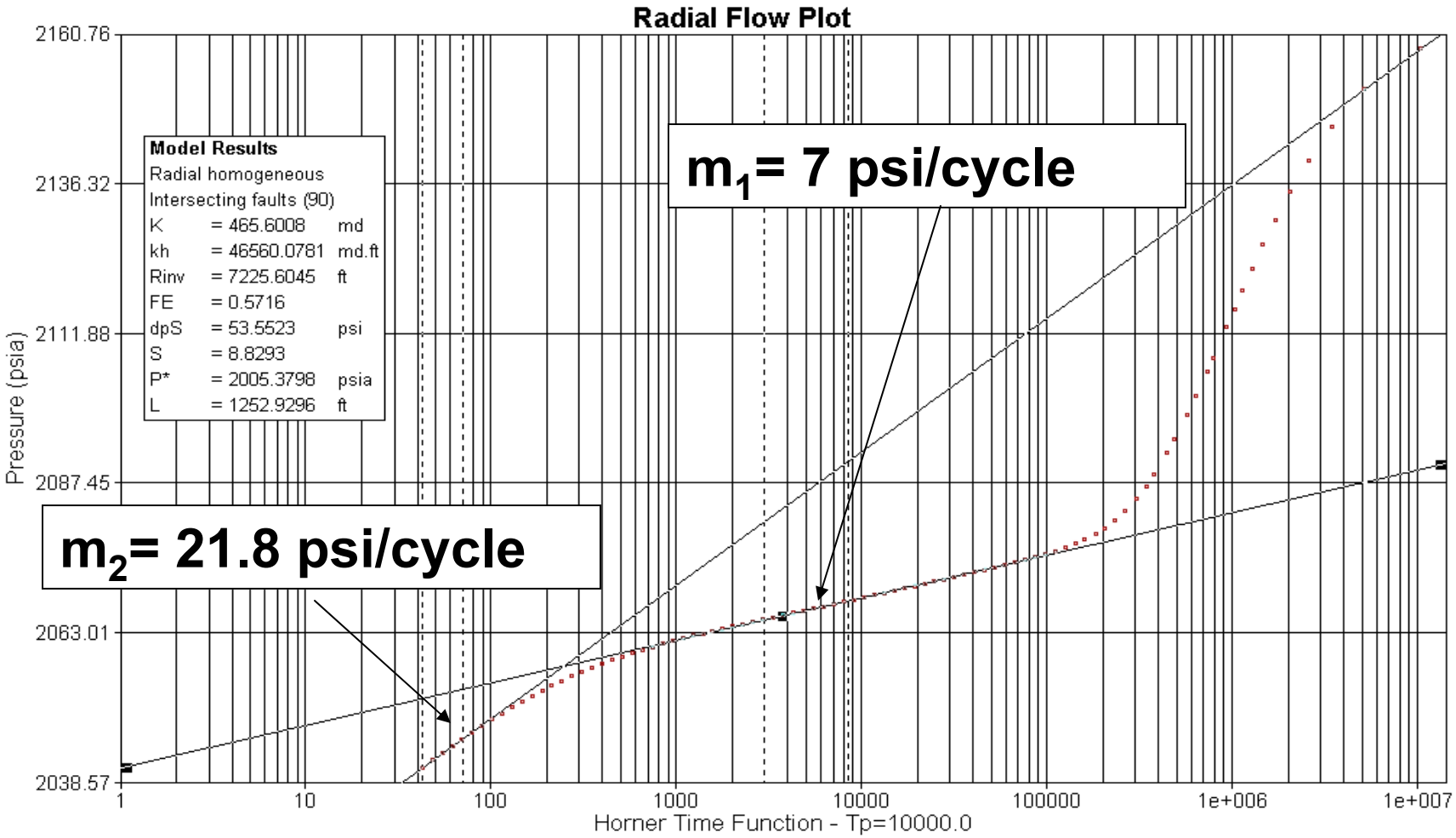
What Does the Falloff Look Like with Boundary Effects?



Type Curve Analysis of Falloff with Boundary Effects



Falloff with Boundary Effects Semilog Plot



m_2 indicates more than 1 boundary

Summary of Boundary Effects on a Falloff Test

- Use the log-log plot as “master test picture” to see response patterns
- Look for slope changes in pressure and pressure derivative trends
- Inner boundary conditions such as wellbore storage, partial penetration, and hydraulic fractures typically observed first
- Outer boundary effects show up after radial flow occurs if you’re lucky!

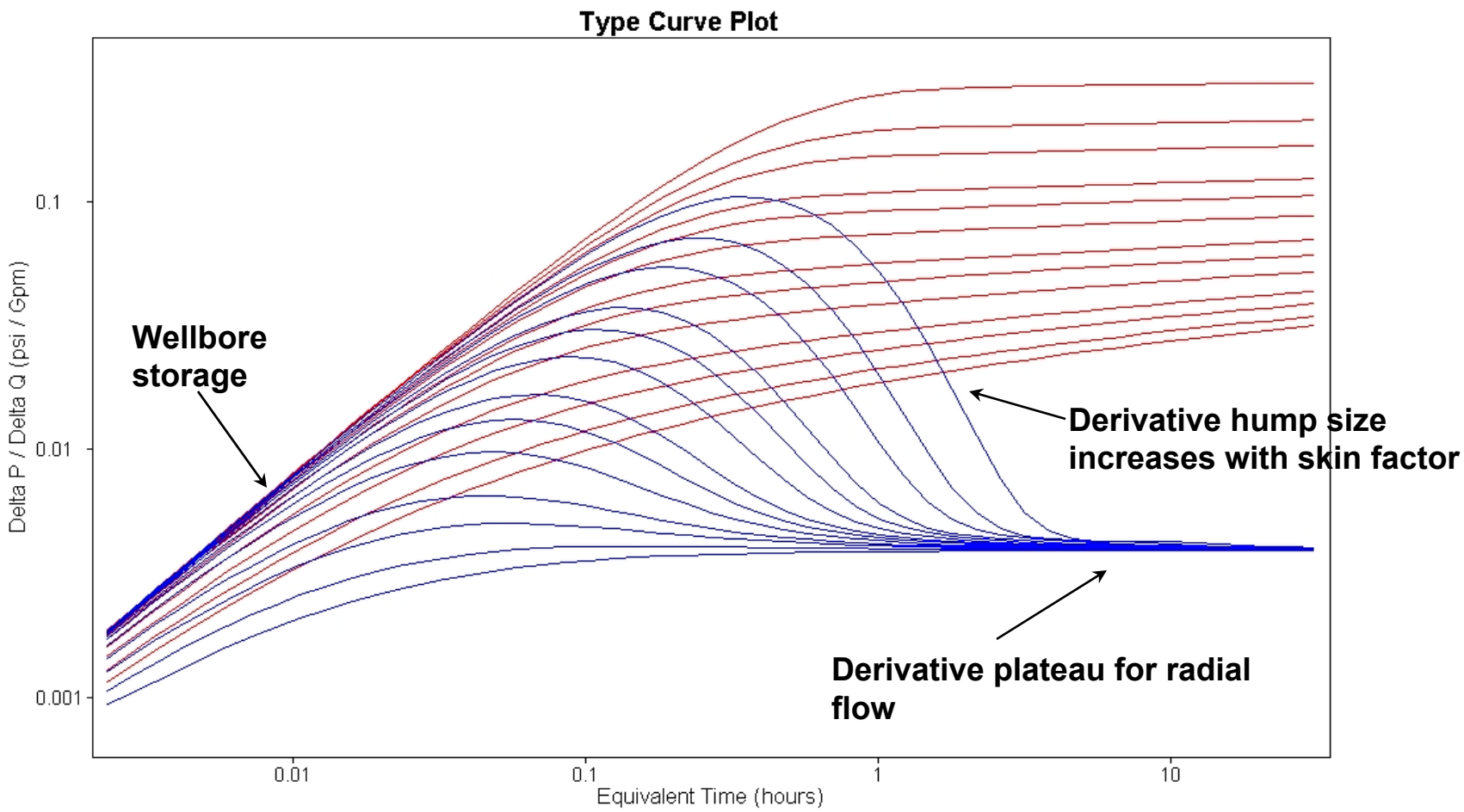
Typical Outer Boundary Patterns

- **Infinite acting**
  - No outer boundary
  - Only radial flow is observed on log-log plot
- **Composite reservoir**
  - Derivative can swing up or down and re-plateau
- **Constant pressure boundary**
  - Derivative plunges sharply

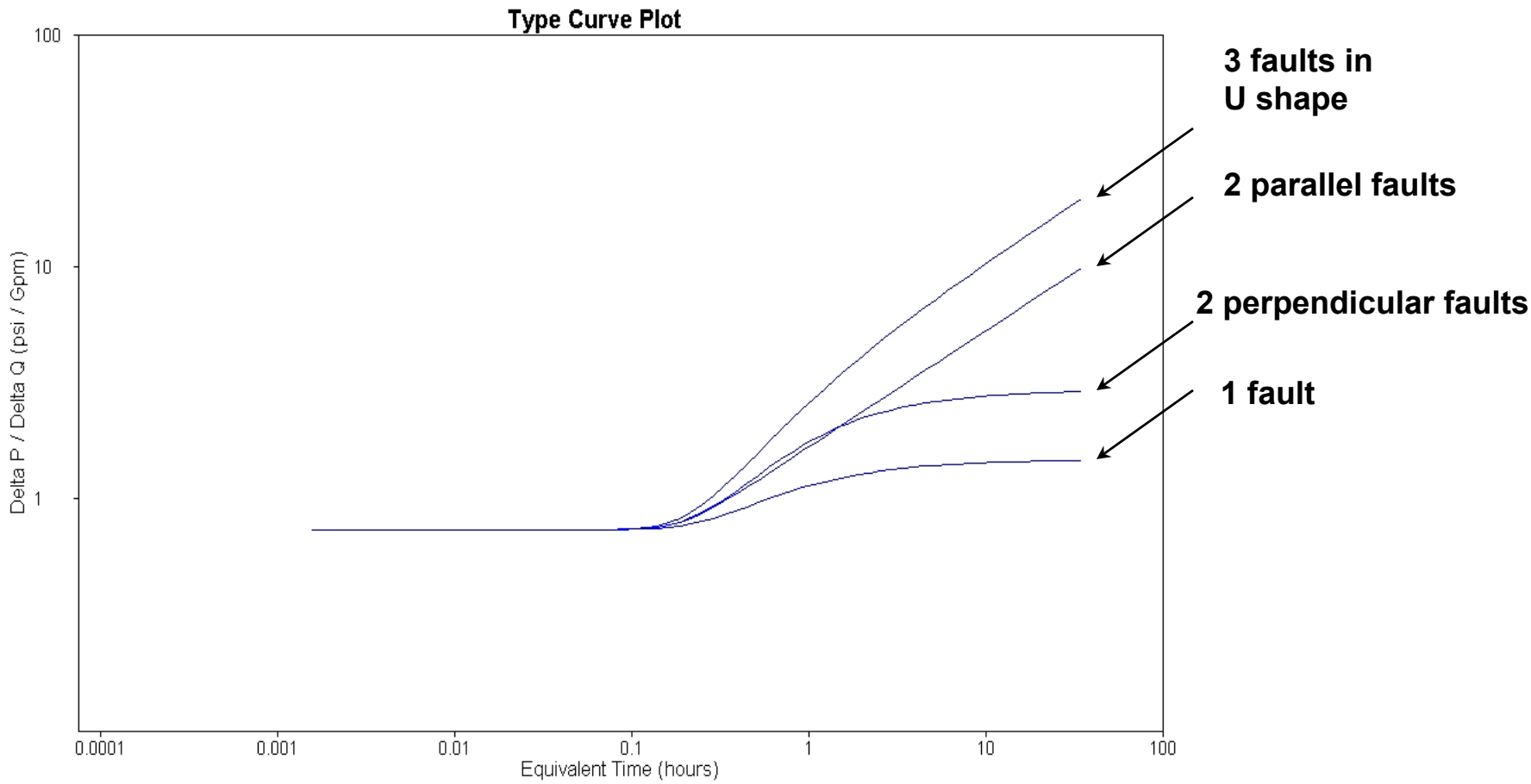
Typical Outer Boundary Patterns

- **No flow boundaries**
  - Derivative upswing followed by a plateau
  - Multiple boundaries additional degrees of the upswing
- **Pseudo-steady state**
  - all boundaries reached
  - closed reservoir
  - derivative swings up to a unit slope

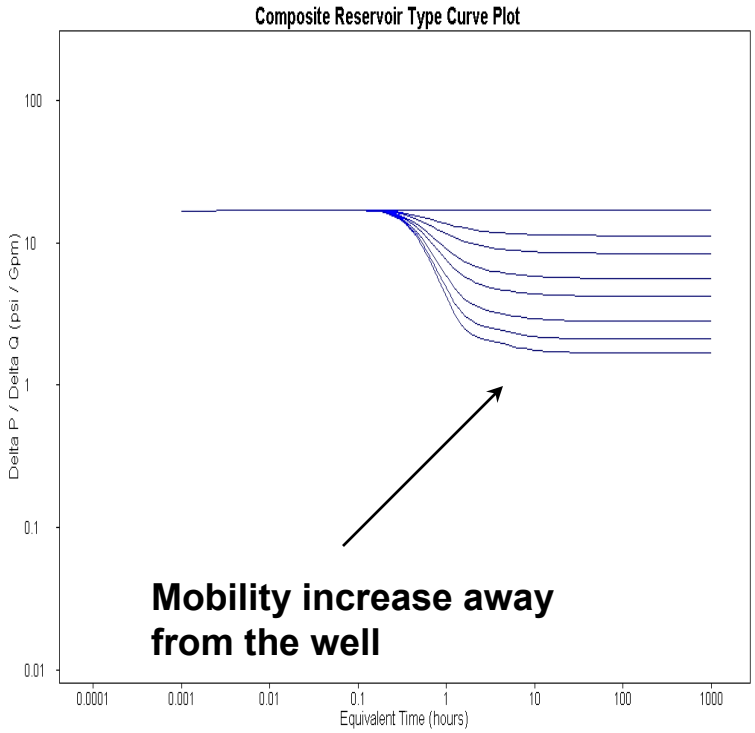
Infinite Acting Reservoir – No Boundary

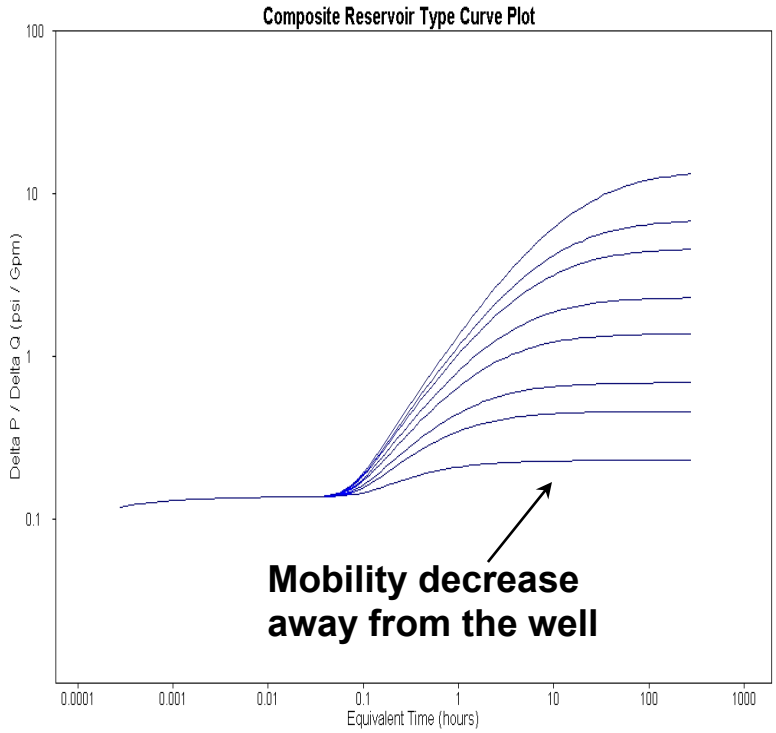


Boundary Effects from Sealing Faults – Derivative Patterns



Boundary Effects from a Composite Reservoir – Derivative Patterns

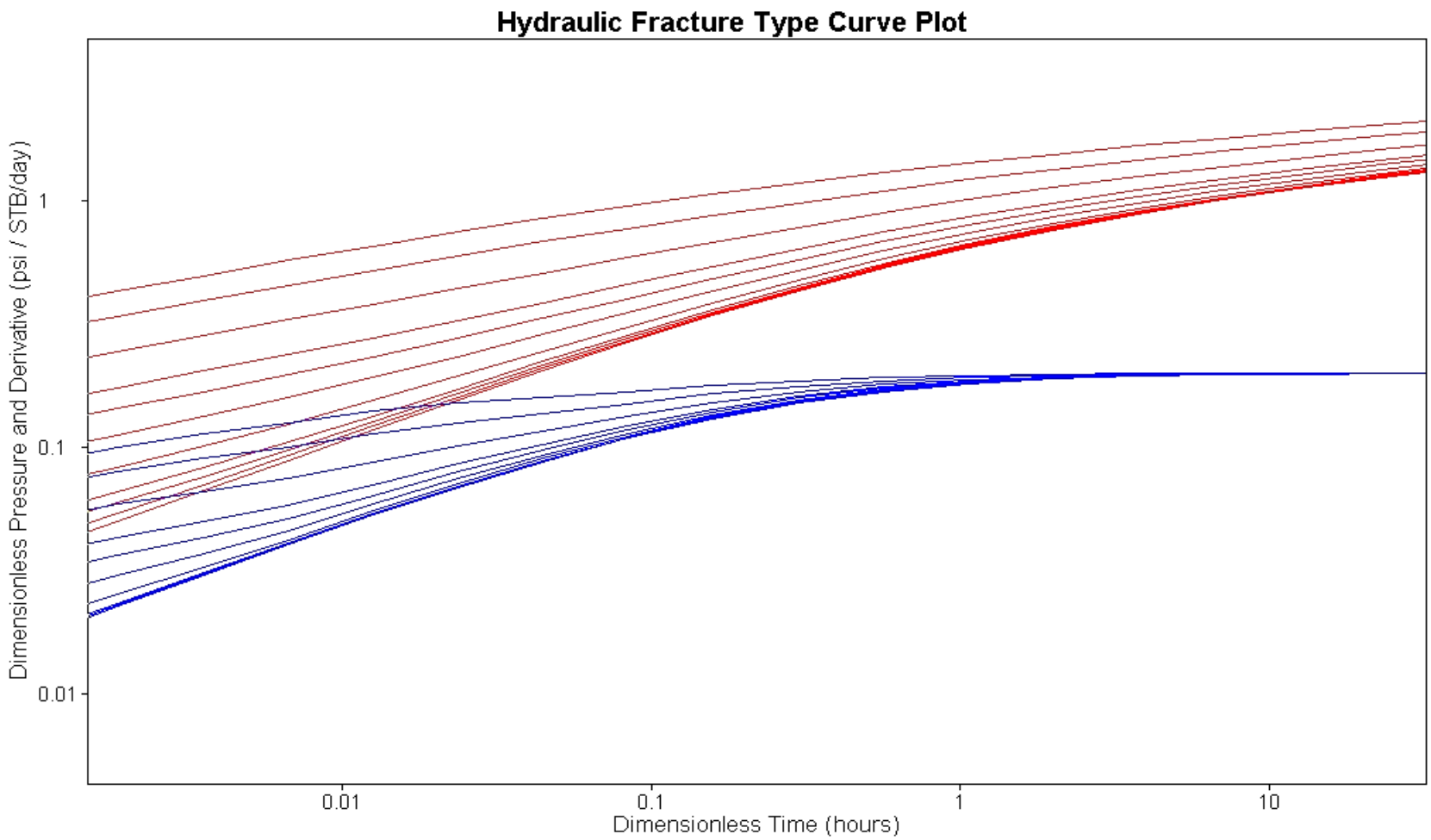




Is It a Real Boundary?

- Check area geology
- Type of injectate
- Both the injection and falloff have to last long enough to encounter it
- Most pressure transient tests are too short to see boundaries

Example: Hydraulic Fracture Type Curves

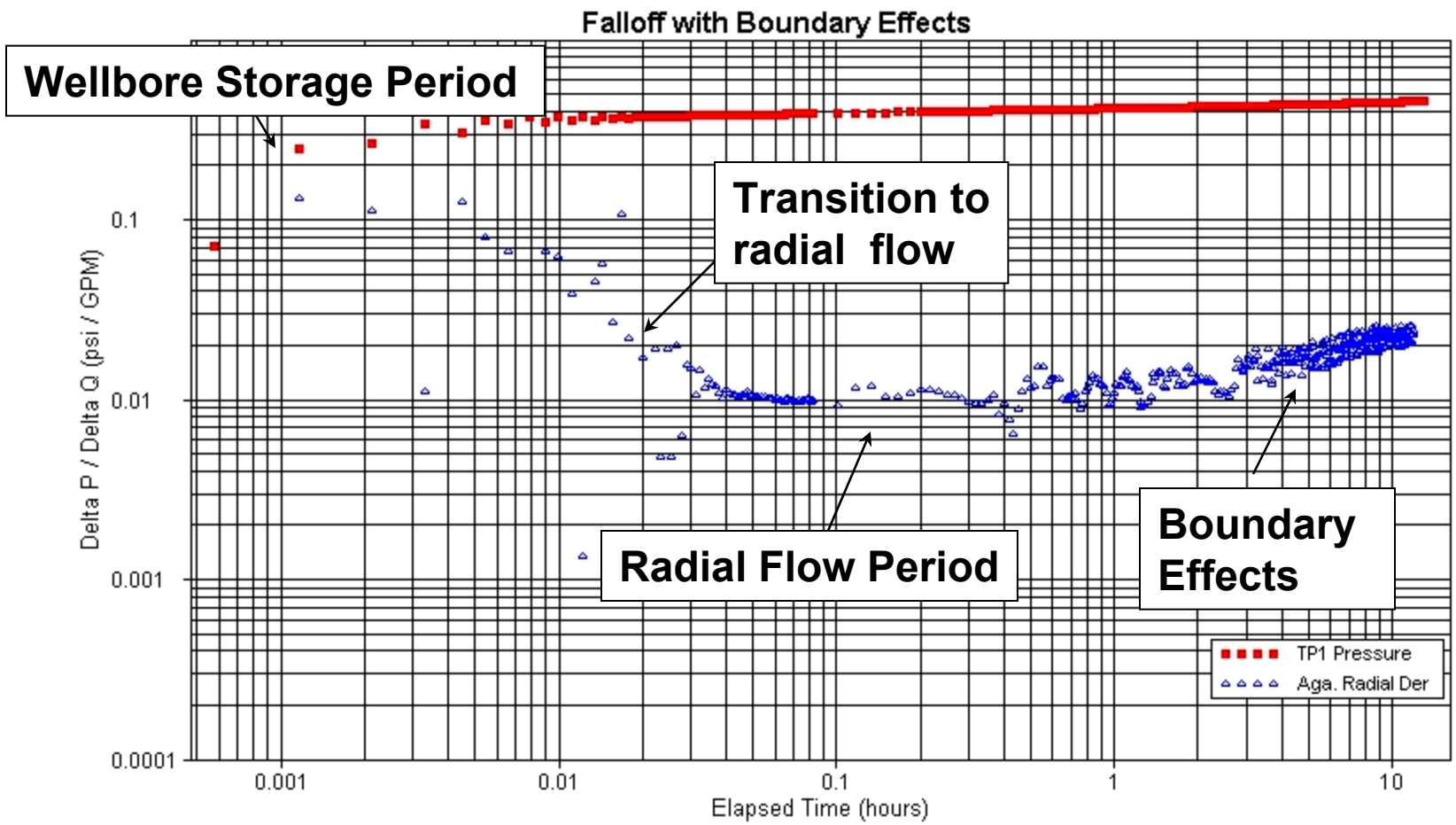


Log-log Plot Examples

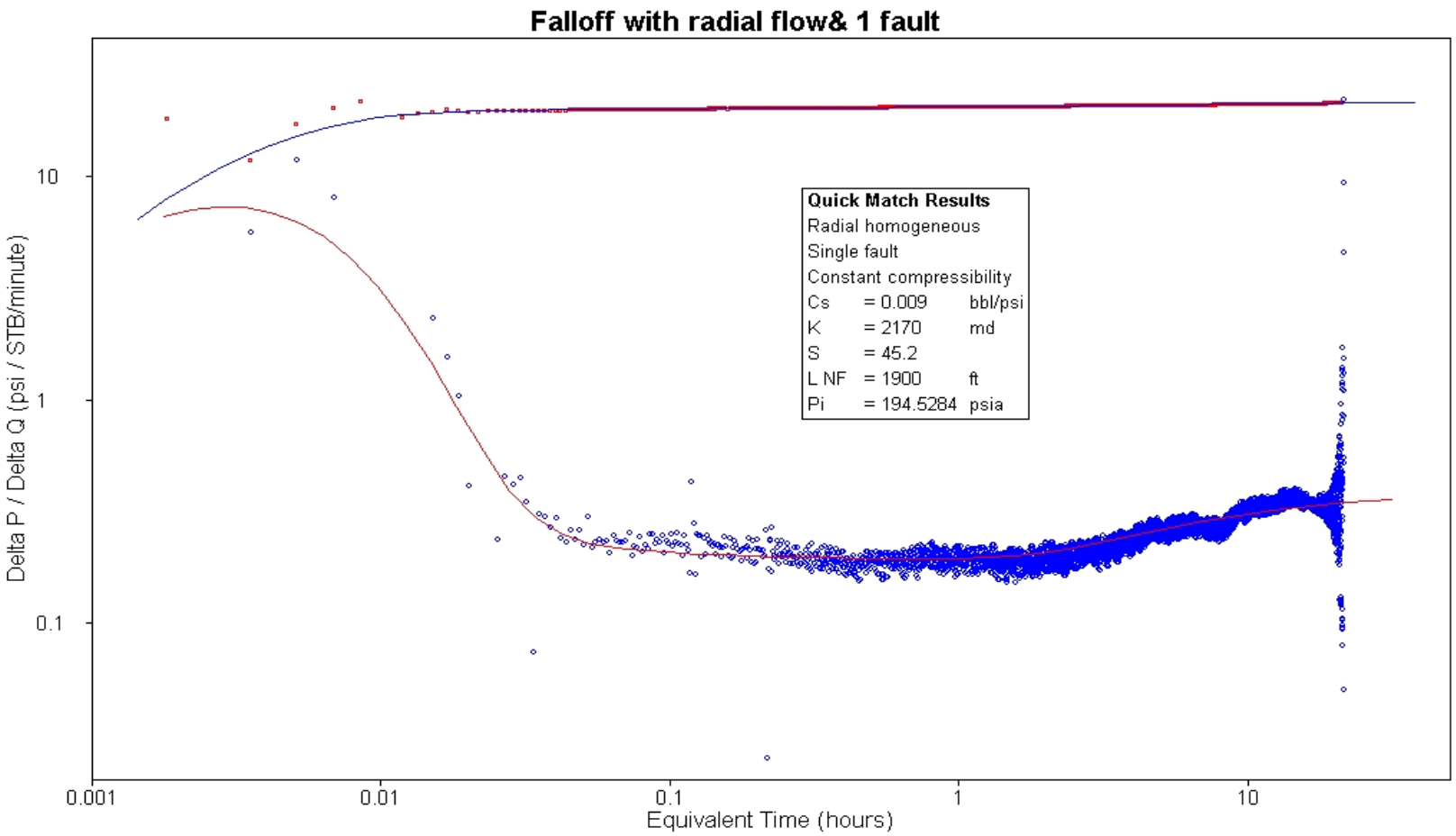
A Gallery of Falloff Log-log Plots

- Radial flow with boundary effects
- Falloff with a single fault
- Falloff in a hydraulically fractured well
- Falloff in a composite reservoir
- Falloff with skin damage
- Falloff after stimulation
- Falloff with spherical flow
- Simulated pseudosteady state effects

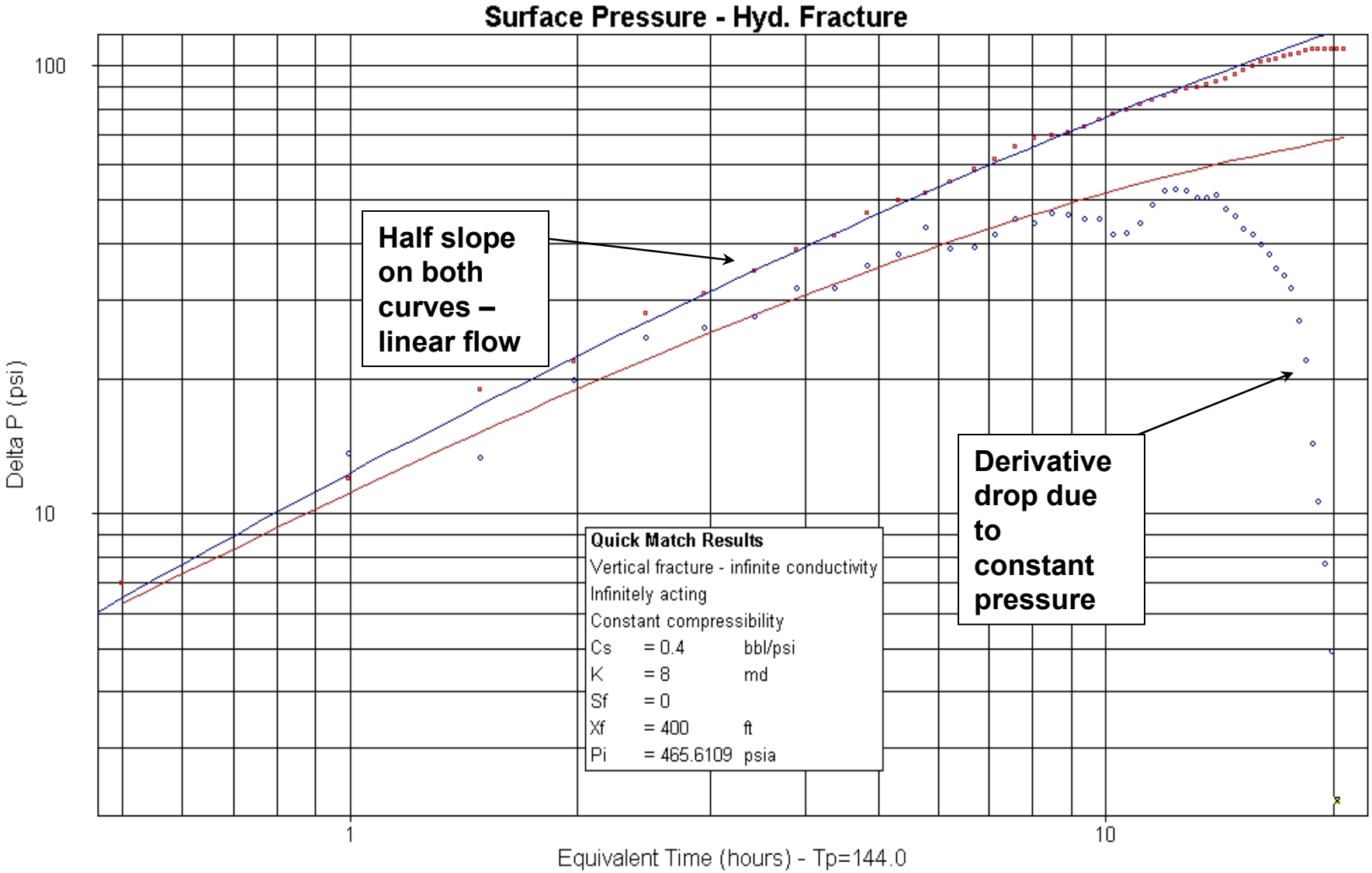
Radial Flow Followed by Boundary Effects



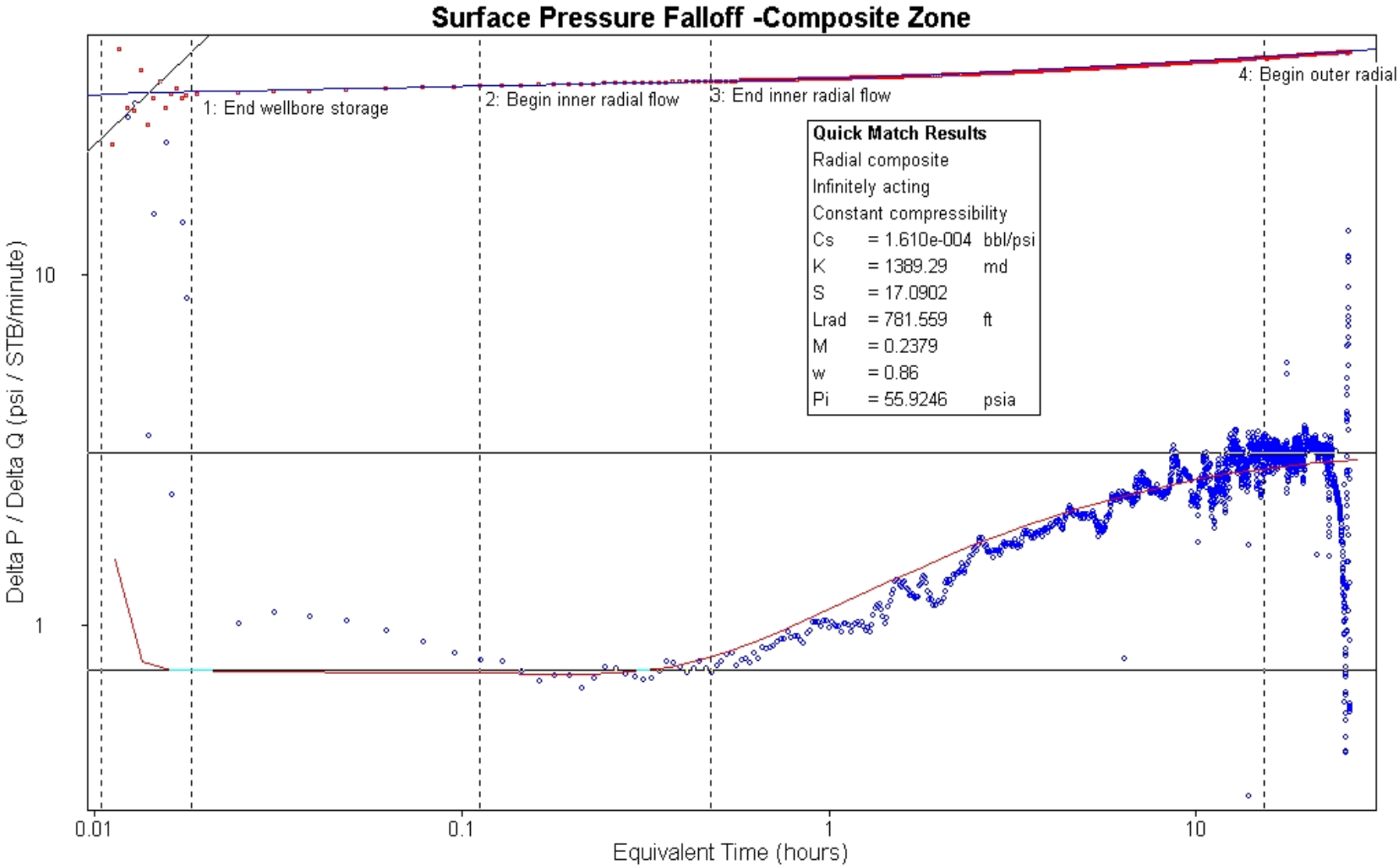
Falloff with a Single Fault



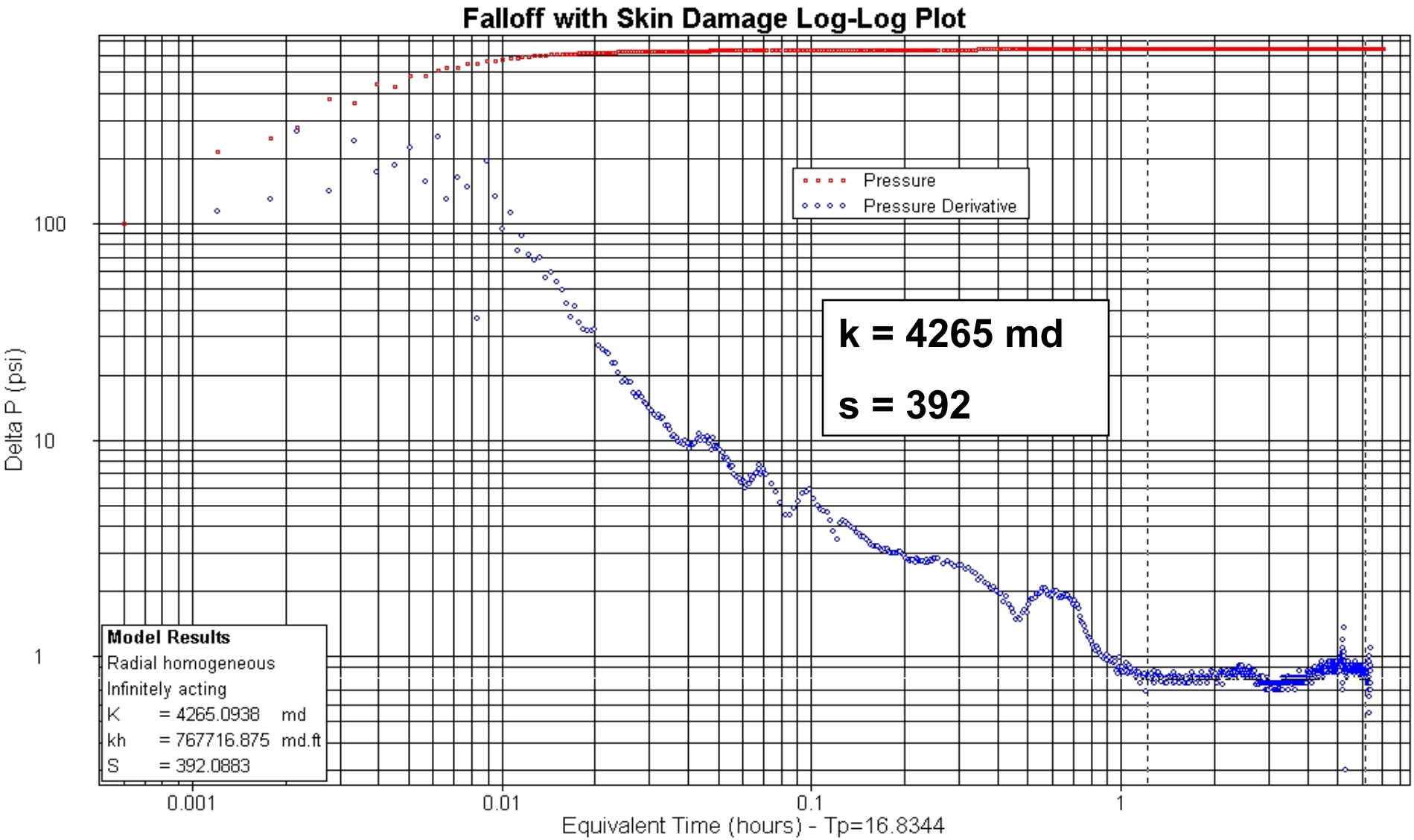
Falloff with a Hydraulic Fracture



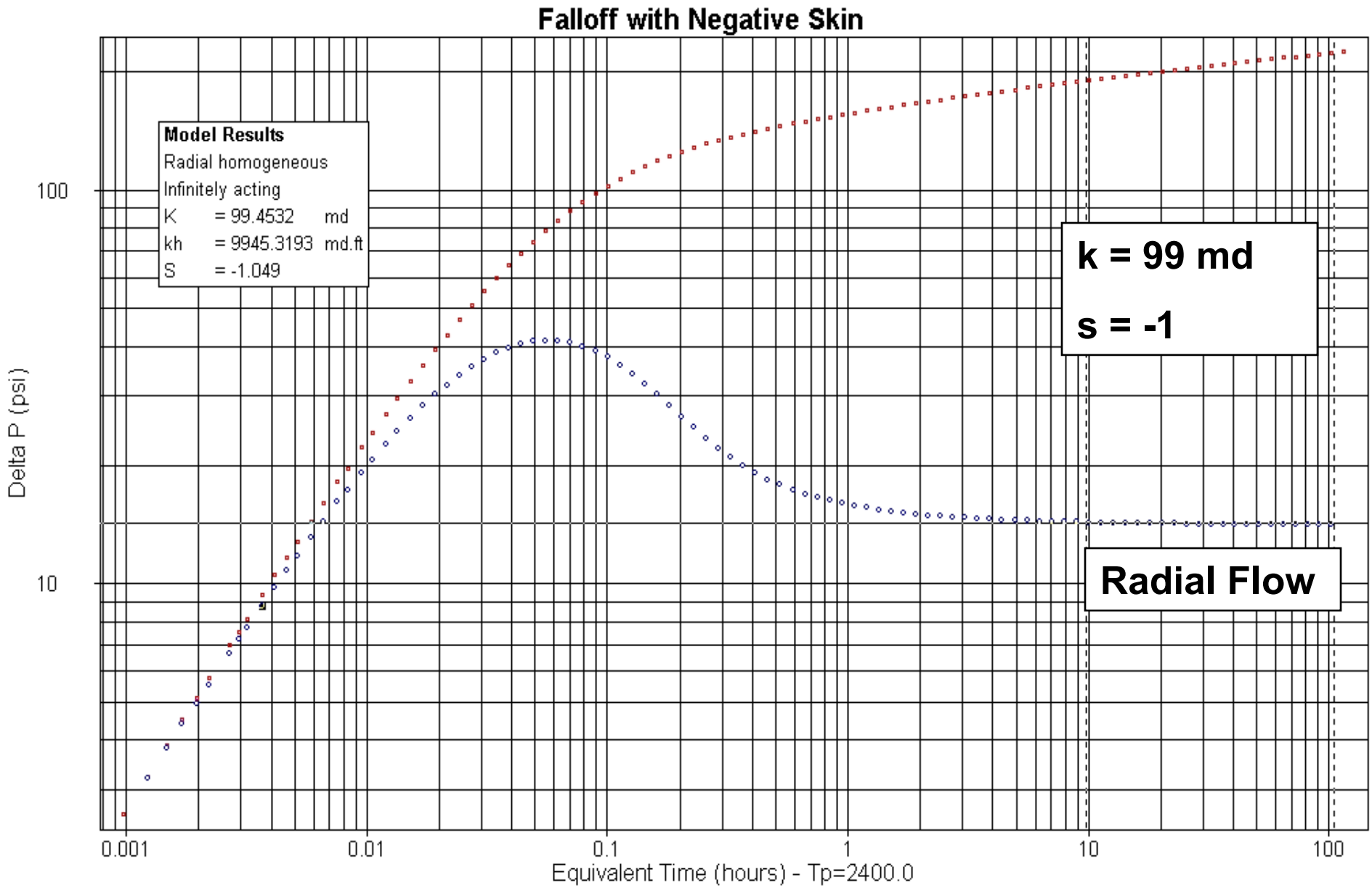
Falloff in a Composite Reservoir



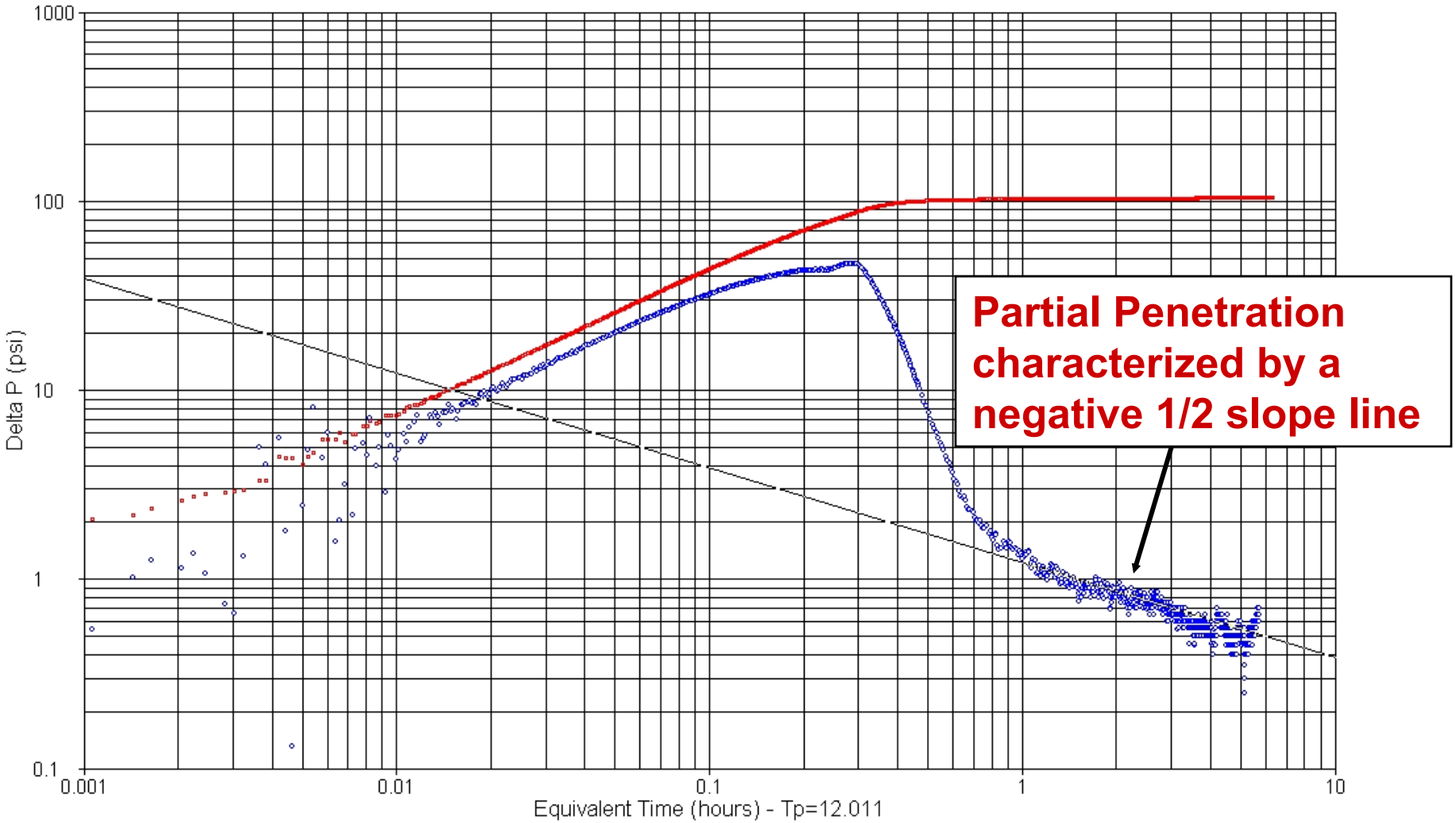
Falloff with Skin Damage



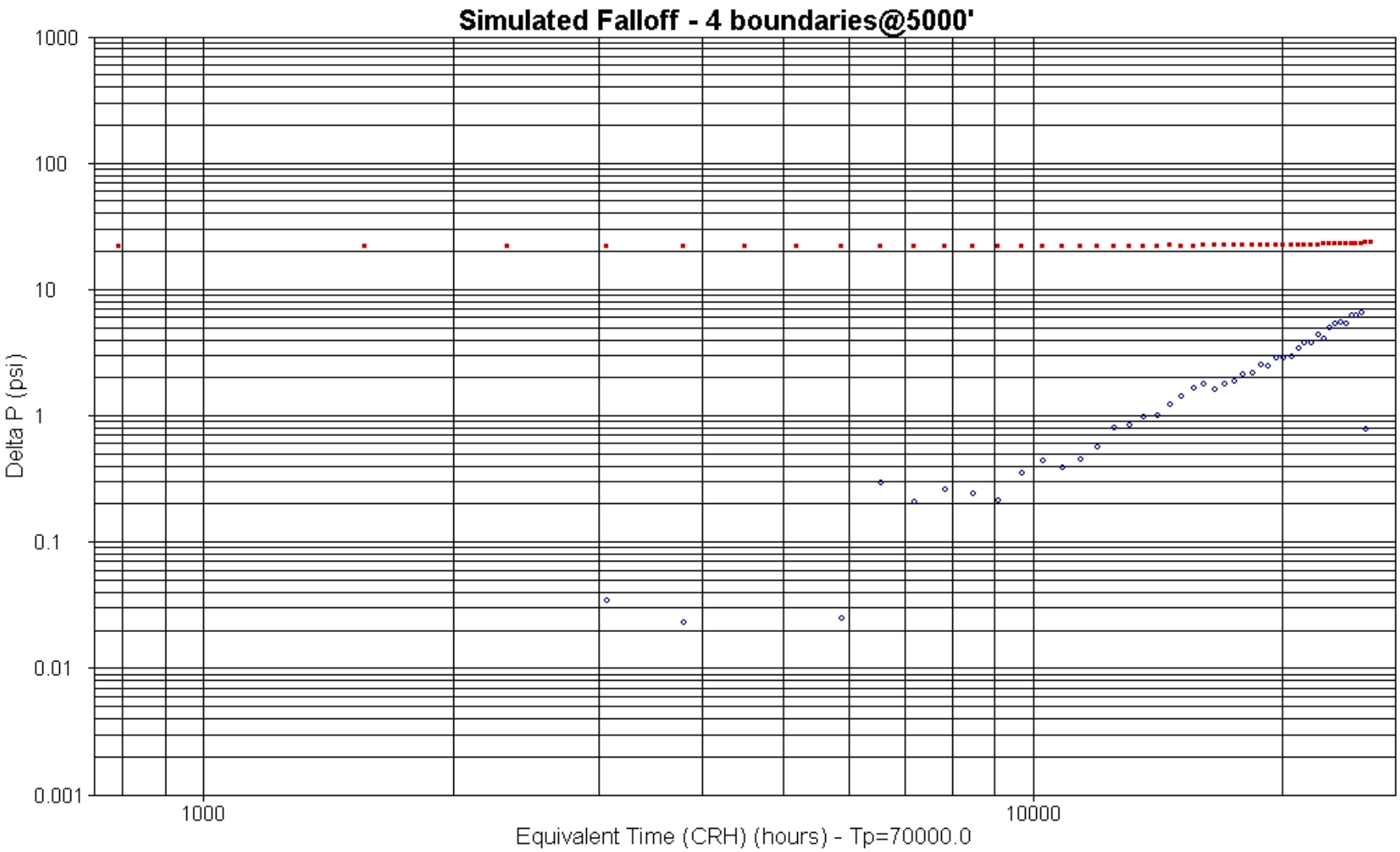
Falloff with Negative Skin



Falloff Dominated by Spherical Flow



Simulated Falloff with Pseudo-steady State Effects



Other Types of Pressure Transient Tests

Other Types of Pressure Transient Tests

- Injectivity Test
  - Record pressure, time, and rate data from the start of an injection period following a stabilization period
  - Pros
    - Don’t have to shut in well
    - Generally maintain surface pressure so less wellbore storage
    - Less impact from skin

Other Types of Tests

- Cons
  - Noisy data due to fluid velocity by pressure gauge
  - Rate may fluctuate so an accurate history is important

Other Types of Tests

- **Multi-rate Injection Test**
  - **Record pressure, time, and rate data through at least two injection periods**
  - **Pros**
    - **Can be run with either a decrease or an increase in injection rate**
    - **Minimizes wellbore storage especially with a rate increase**
    - **Provides two sets of time, pressure, and rate data for analysis**
    - **Decreasing the rate provides a partial falloff without shutting in the well**

Other Types of Tests

- Cons
  - Noisy data due to fluid velocity by gauge
  - 1st rate period needs to reach radial flow

Other Types of Tests

- **Interference Test**
  - **Use two wells: signal and observer**
  - **Signal well undergoes a rate change which causes pressure change at the observer**
  - **Measure the pressure change over time at the observer well and analyze with an Ei type curve or, if radial flow is reached, a semilog plot**

Other Types of Tests

- Pros
  - Yields transmissibility and porosity-compressibility product between wells
  - May give analyzable results when falloff doesn't work
- Cons
  - Generally involves a small pressure change of 5 psi or less so accurate surface or bottomhole gauges are needed
  - Observable pressure change decreases as the distance between the two wells increases

Other Types of Tests

- Cons (cont.)
  - Complex analysis if more than two injectors are active
  - Need knowledge of pressure trend at the observer well
  - Test rate should be constant at the signal well

Other Types of Tests

- Pulse Test
  - Similar to interference except rate changes at observer well are repeated several times
  - Pros
    - Multiple data sets to analyze
    - Verify communication between wells more than one time
  - Cons
    - Difficult to analyze without welltest software – Monograph 5 methodology
    - Requires more time and planning and careful control of the signal well rate

Designing an Interference Test

- For both interference and pulse tests, the best design approach is to use a well test simulator
- Interference tests can designed using the Ei type curve
- Design information needed:
  - Distance between signal and observer wells
  - Desired pressure change to measure
  - Desired injection rate
  - Estimates of c_t, Φ, μ, k, h, r_w

Interference Test Design Example

- Two injection wells are located 500' apart. Both wells have been shut in over 1 month
- An interference test is planned with an injection rate of 3000 bpd (87.5 gpm)
- $k = 50$ md, $h = 100'$, $\Phi = 20\%$, $\mu_f = 1$ cp, $c_t = 6 \times 10^{-6}$ psi^{-1}, $r_w = 0.3$ ft
- How long will the test need to run to see a 3 psi change at the observer?

Interference Design Example

Ei Type Curve: from Figure C.2 in SPE Monograph 5

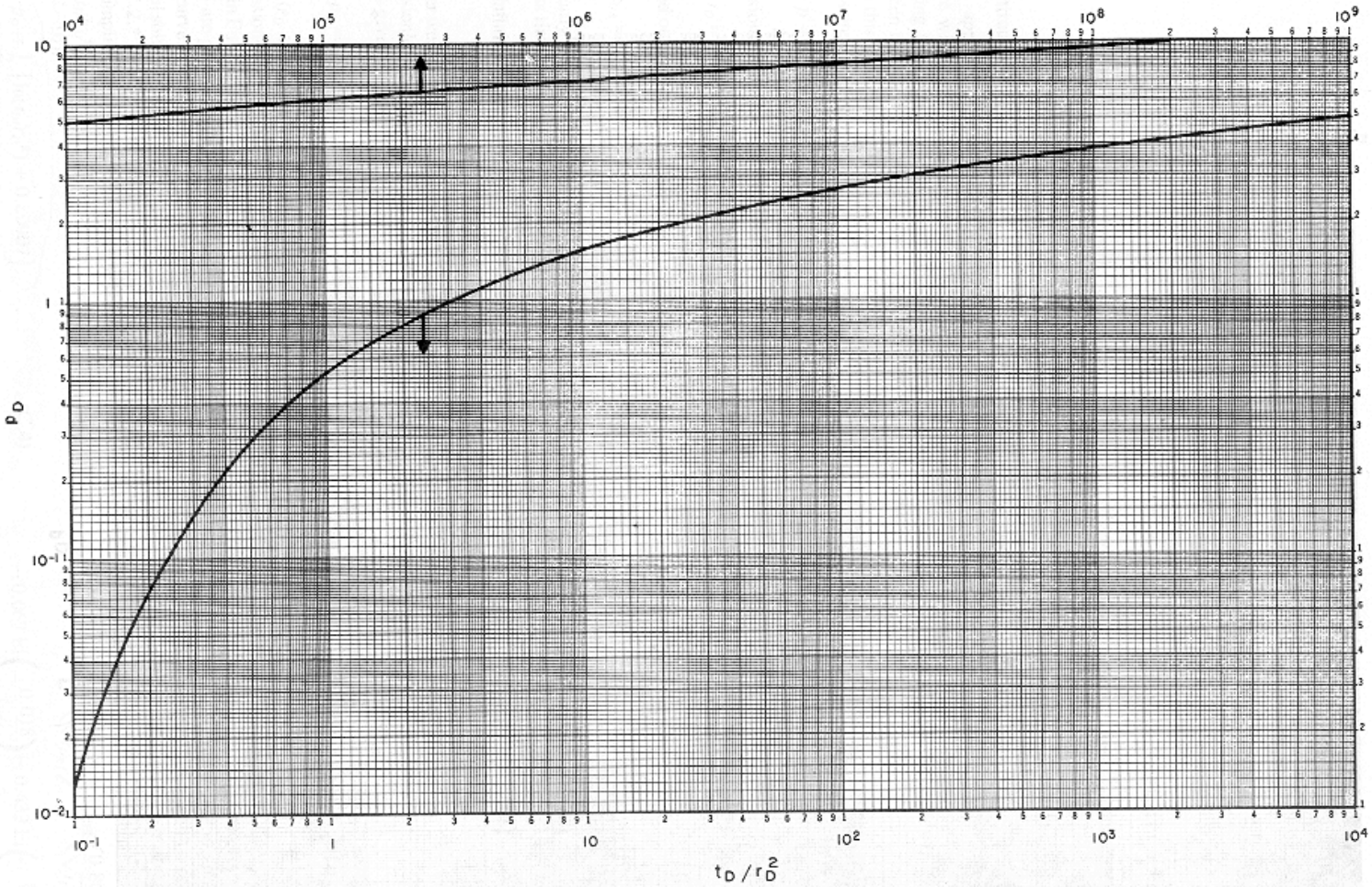


Fig. C.2 Dimensionless pressure for a single well in an infinite system, no wellbore storage, no skin. Exponential-integral solution.

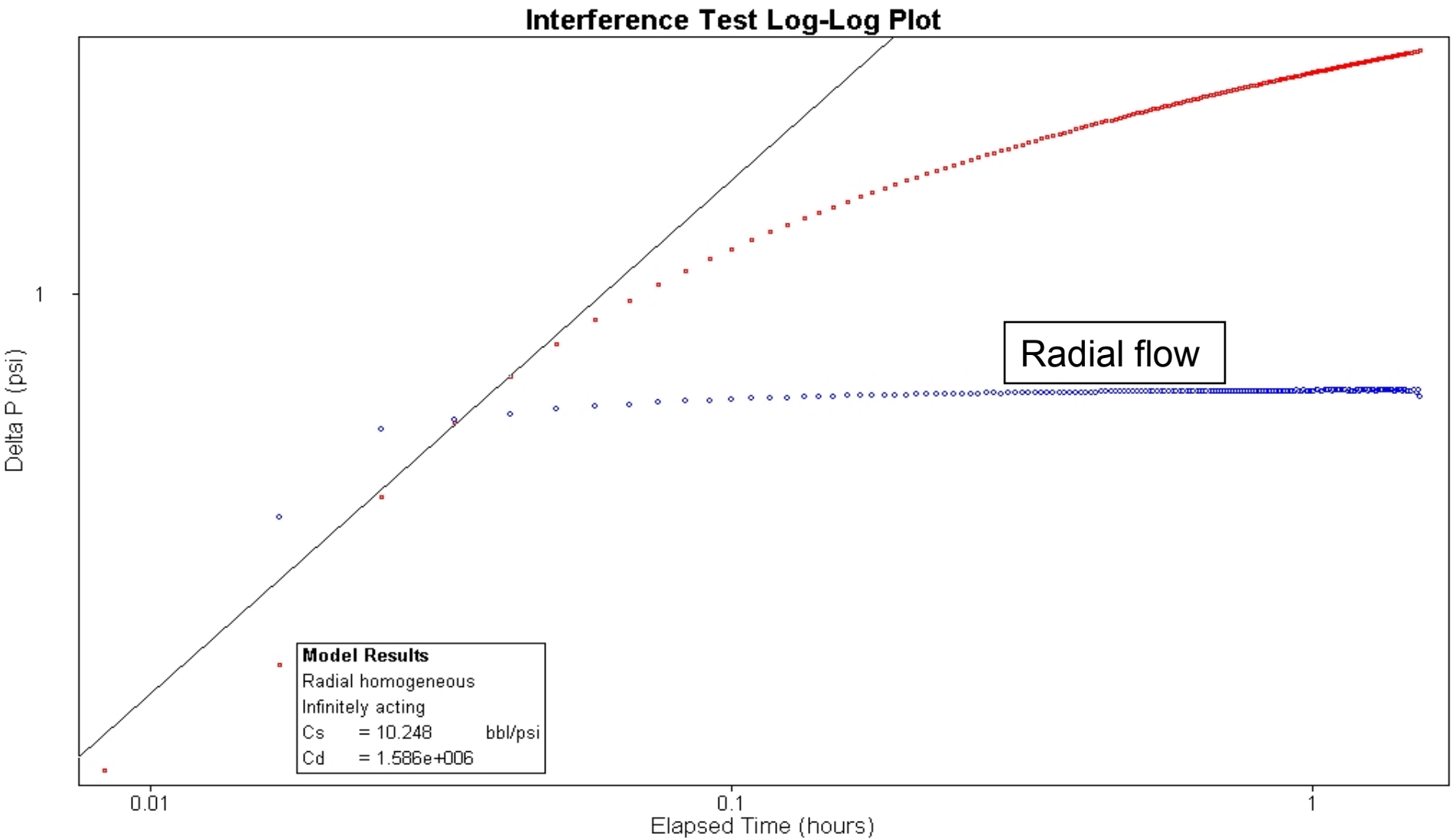
Interference Design Example

- Calculate P_D and r_D from equations listed in PDE discussion
- Find t_D/r_D^2 from corresponding P_D value on Ei type curve
- Calculate t_D and solve for $t_{interference}$
- Results:
  - P_D= 0.0354, r_D= 1666.7
  - t_D/r_D^2 = 0.15
  - t_D= 416,666.7
  - $t_{interference}$= 3.4 hours

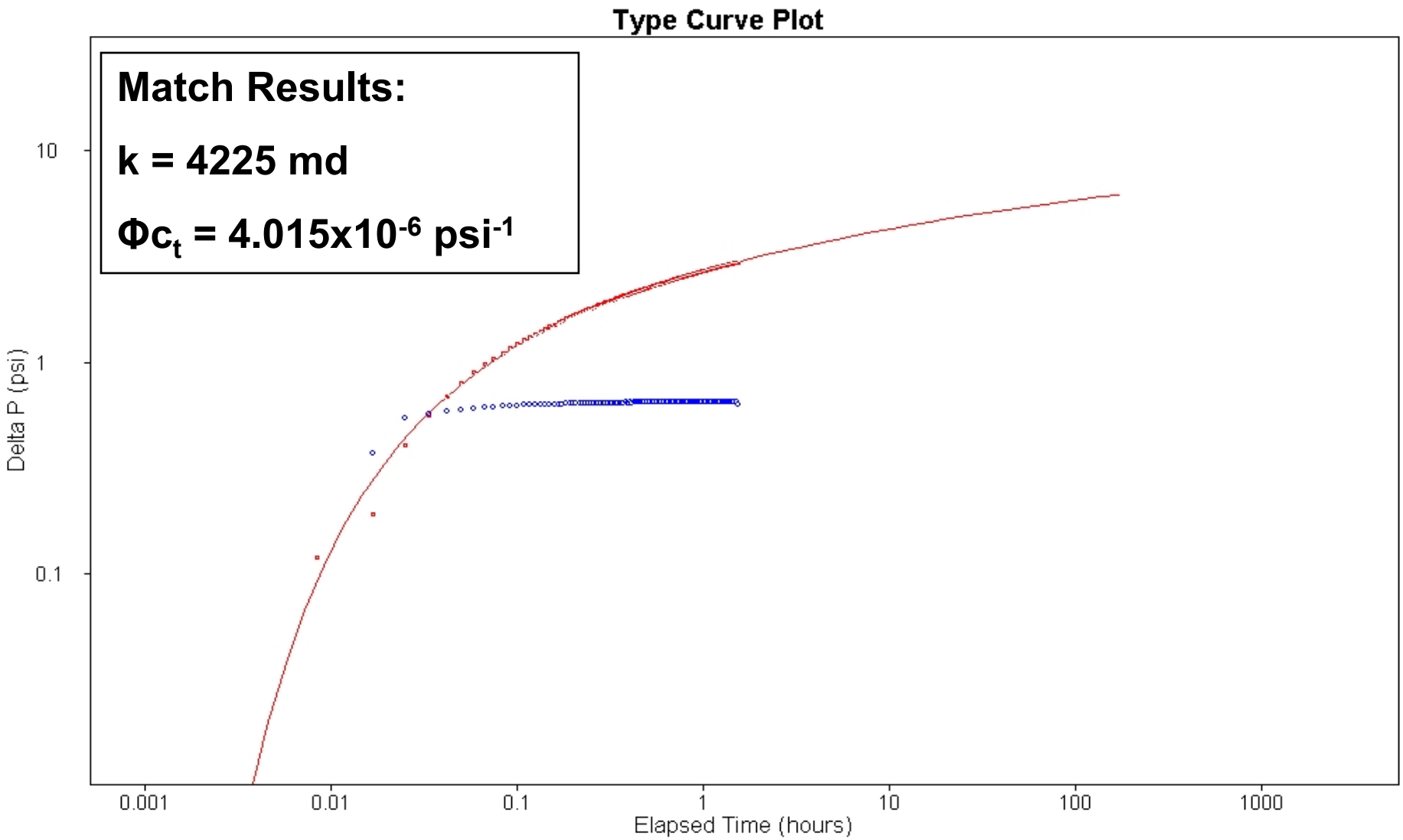
Interference Test Example

- An interference test is conducted between two injection wells at a Gulf Coast area facility.
- Reservoir conditions:
  - h=55’, Φ=28%, c_t=6x10^{-6} psi^{-1}, r_w=0.25 ft
- Well Data:
  - q = 120 gpm
  - wells are 150’ apart

Interference Test Example: Log-log Plot at Observer Well



"Real World" Interference Type Curve Match



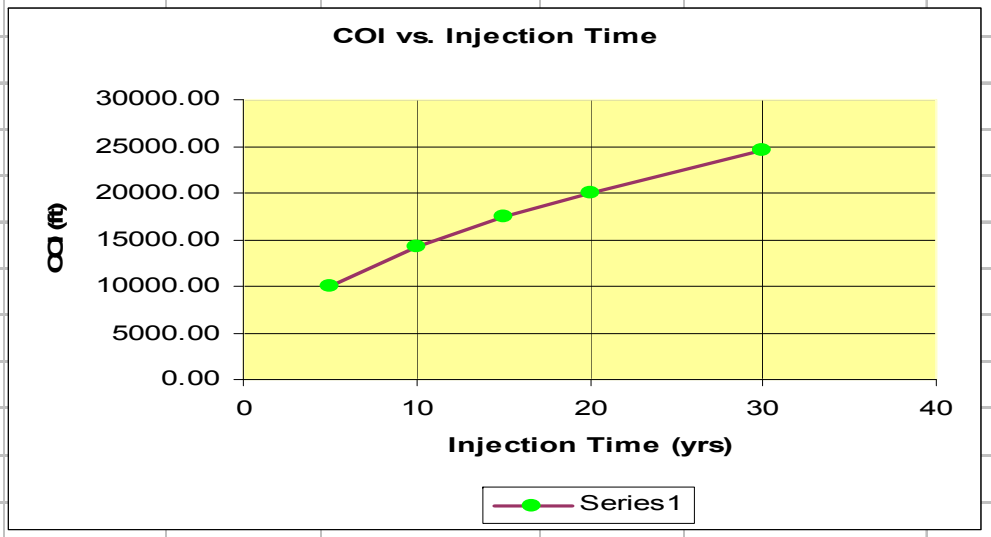
How Do Falloff Results Impact Area of Review

- The transmissibility obtained from the falloff and the solution from the PDE can be used to project the pressure increase due to injection
- The PDE solution can also be used to estimate the cone of influence location
- Both the pressure projection and cone of influence location estimate can be set up in a spreadsheet

Example Cone of Influence Estimate

Input Parameters	
Facility:	Example
Pi (initial resv. pressure in psia):	1200
h (ft):	50
porosity:	0.2
rw (ft):	0.3
ct (1/psi):	8.00E-06
viscosity (cp):	1.00
Depth to USDW base (ft):	300
Depth to Groundwater (ft):	10
Reservoir fluid SG:	1.040
Min. aband. well diameter (in.)	9.000
Min. aband. well mud wt. (lb/gal):	8.90
Top of injection interval (ft):	3000

Critical Pressure Calculations	
Critical pressure rise- brine filled borehole (psi):	141.43
Critical pressure rise - mud filled borehole (psi):	362.34
Critical pressure rise basis (enter mud or brine):	brine



COI Calculations		Falloff	Injection	Injection	Dimensionless	Critical	Dimensionless	Dimensionless	Total Pressure Increase	COI
Inj. Rate	Inj. Rate	k	Time	Time	Time	Pressure	Pressure	Radius	at Injection Well	Radius
(bpd)	(gpm)	(md)	(hrs)	(yrs)		(psi)			(psi)	(ft)
1714.29	50	20	43800	5	1.6042E+09	141.43	0.58	33462.23	2663.23	10038.67
1714.29	50	20	87600	10	3.2084E+09	141.43	0.58	47322.74	2747.12	14196.82
1714.29	50	20	131400	15	4.8125E+09	141.43	0.58	57958.29	2796.19	17387.49
1714.29	50	20	175200	20	6.4167E+09	141.43	0.58	66924.46	2831.01	20077.34
1714.29	50	20	262800	30	9.6251E+09	141.43	0.58	81965.39	2880.08	24589.62

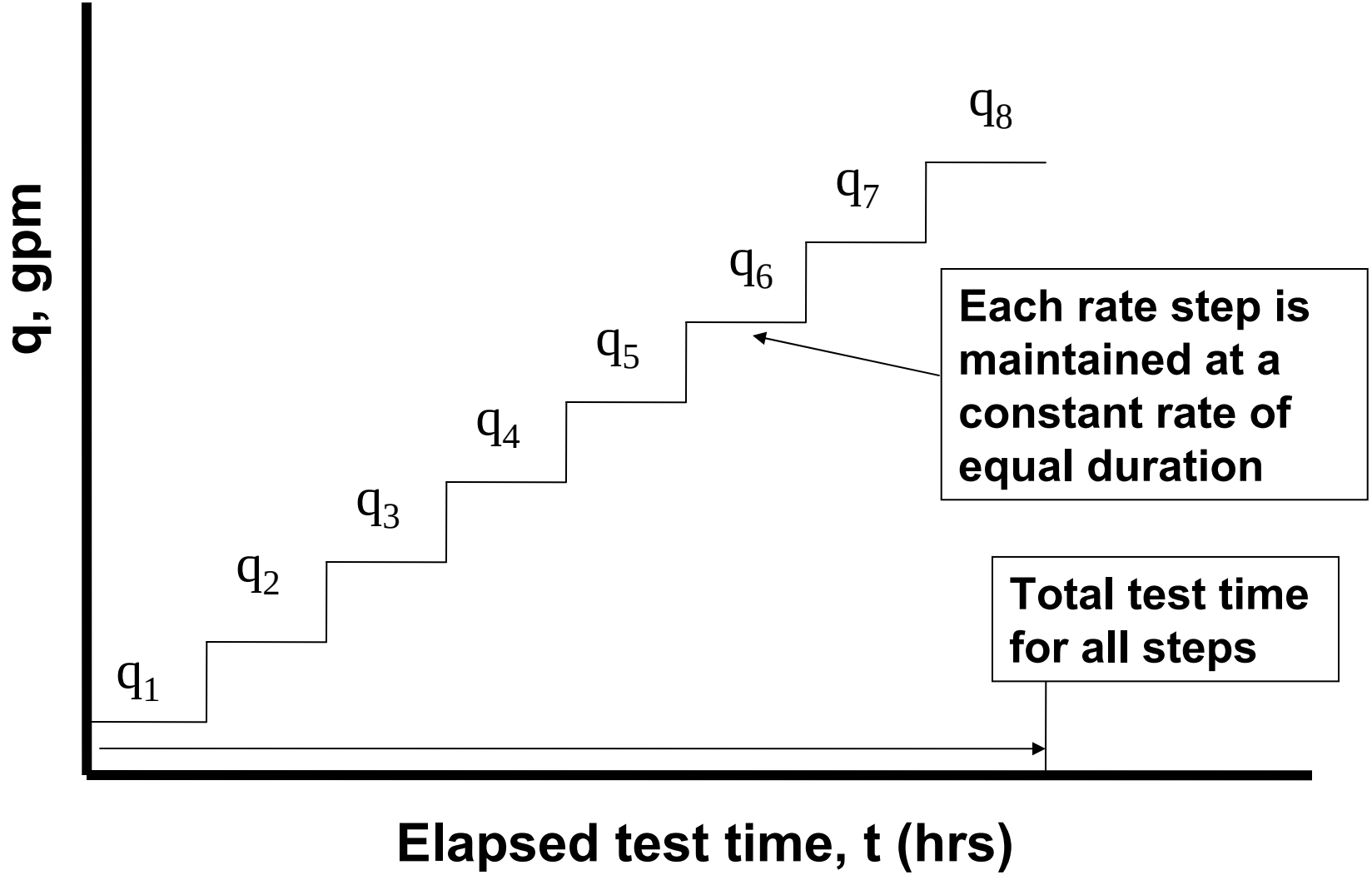
How is Fracture Pressure Determined?

- Fracture pressure is typically estimated from fracture gradient correlations (e.g. Hubbert and Willis, Eaton)
- Varies with depth, lithology, and geographical region
- Can be determined from a step-rate test

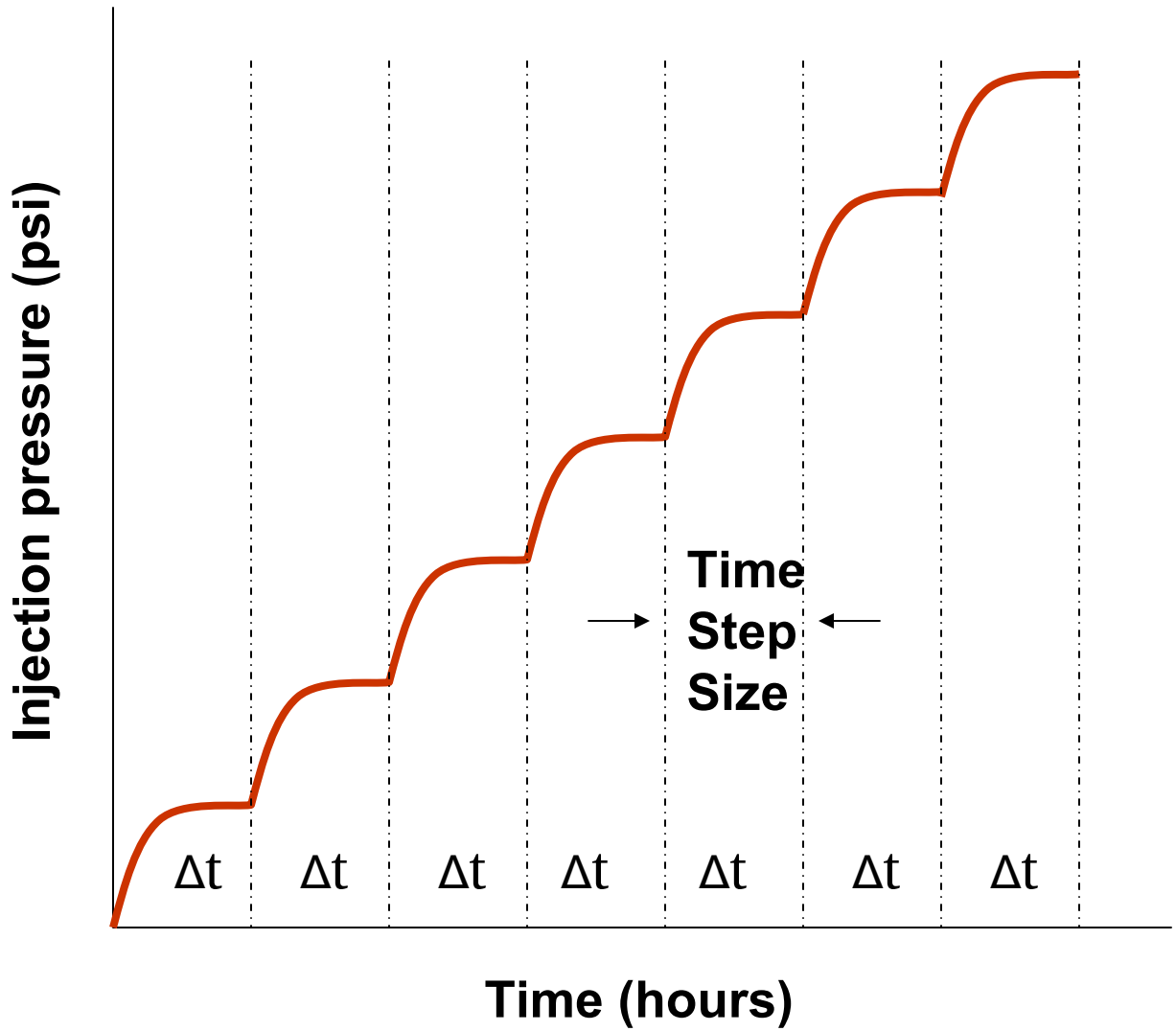
What is a Step-Rate Test?

- Series of constant rate injection steps of equal time duration
- Each step can be analyzed as a pressure transient test (injectivity test)

Step-Rate Test Rate Sequencing



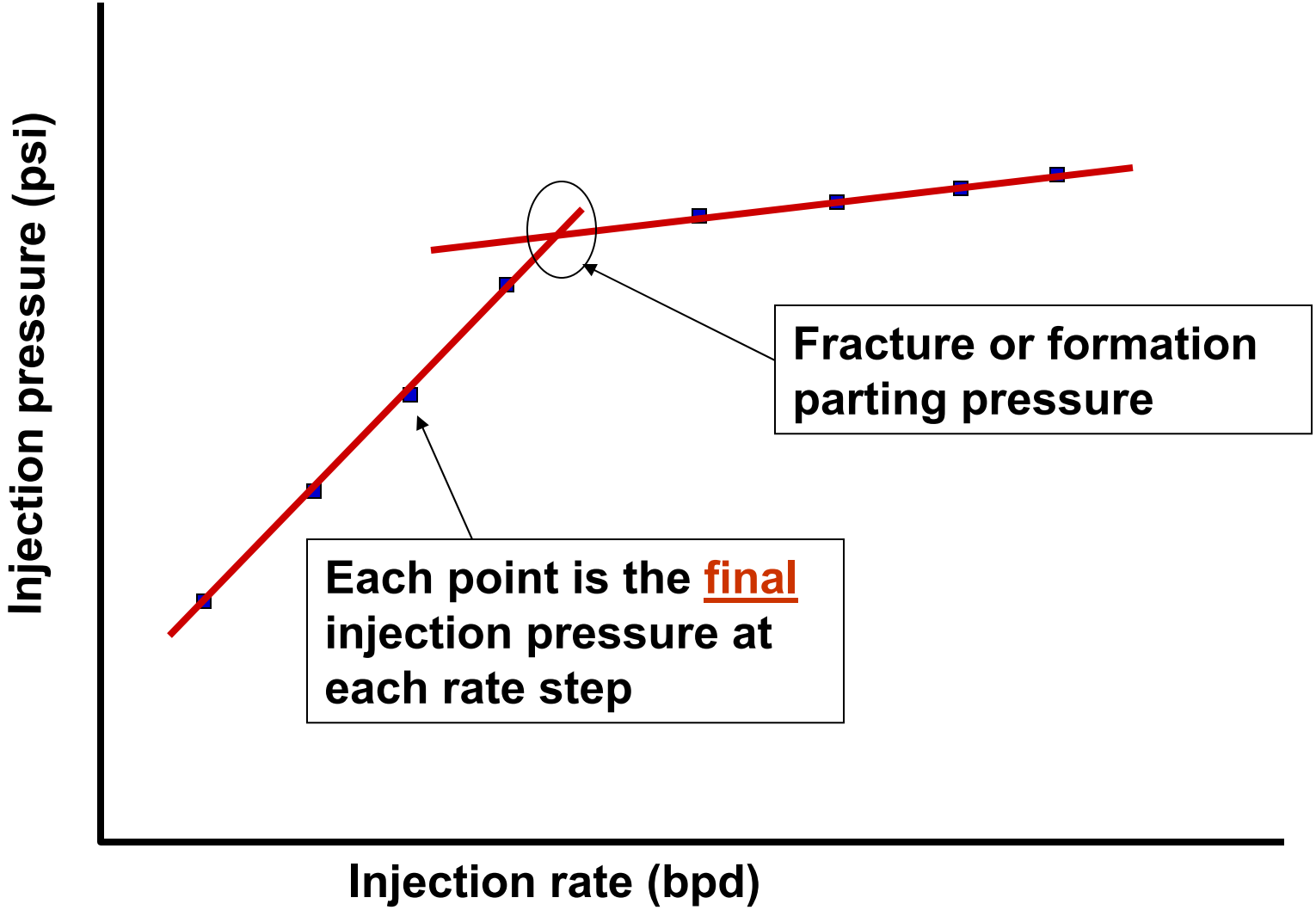
Step-Rate Test Pressure Behavior



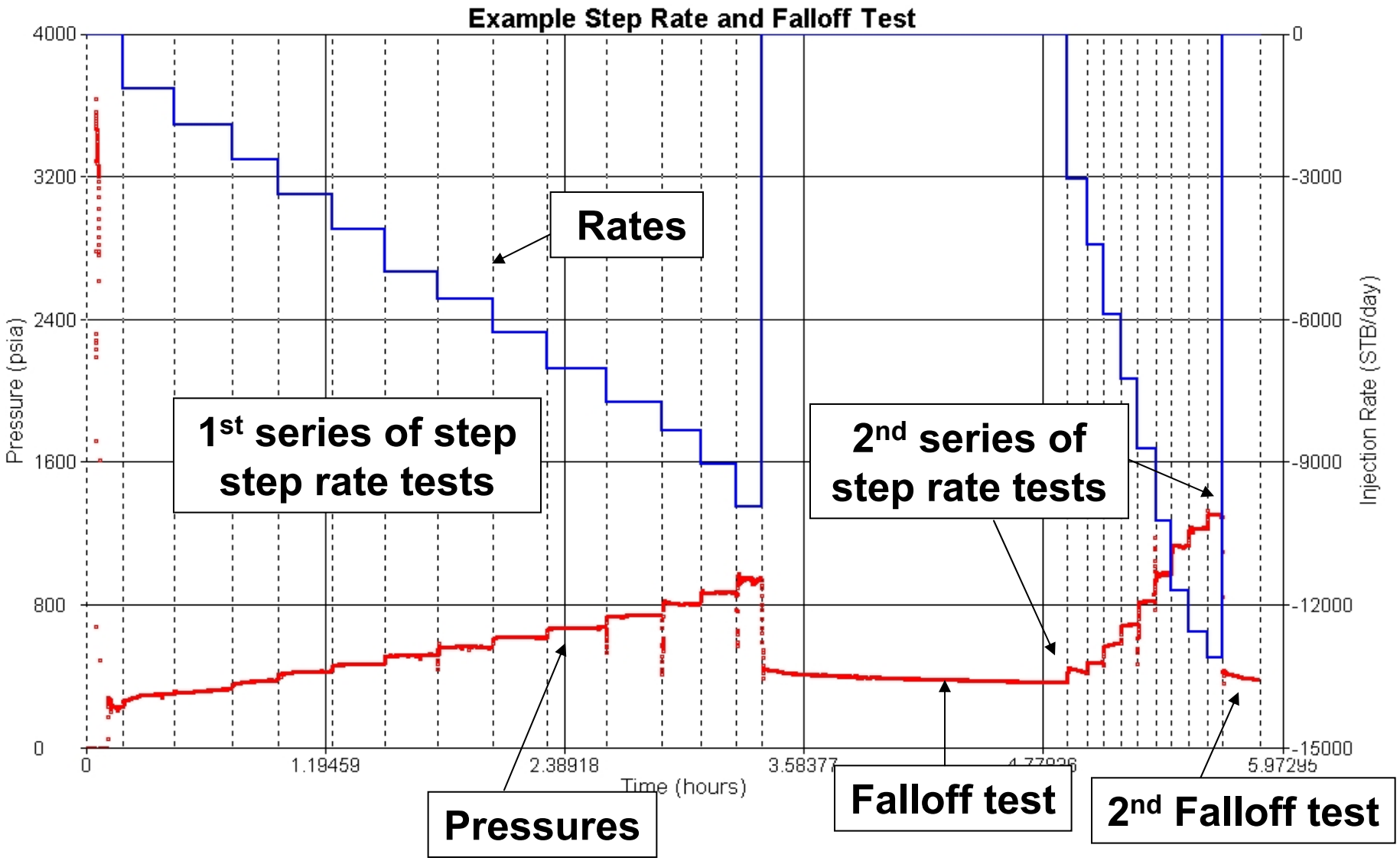
Step Rate Tests Analysis

- Data is analyzed using log-log and linear plots
- Use the linear plot to estimate fracture pressure (also called the formation parting pressure)
- Use the log-log plot to verify that fracturing occurs and estimate kh/u and skin

Step Rate Test Analysis: Linear Plot

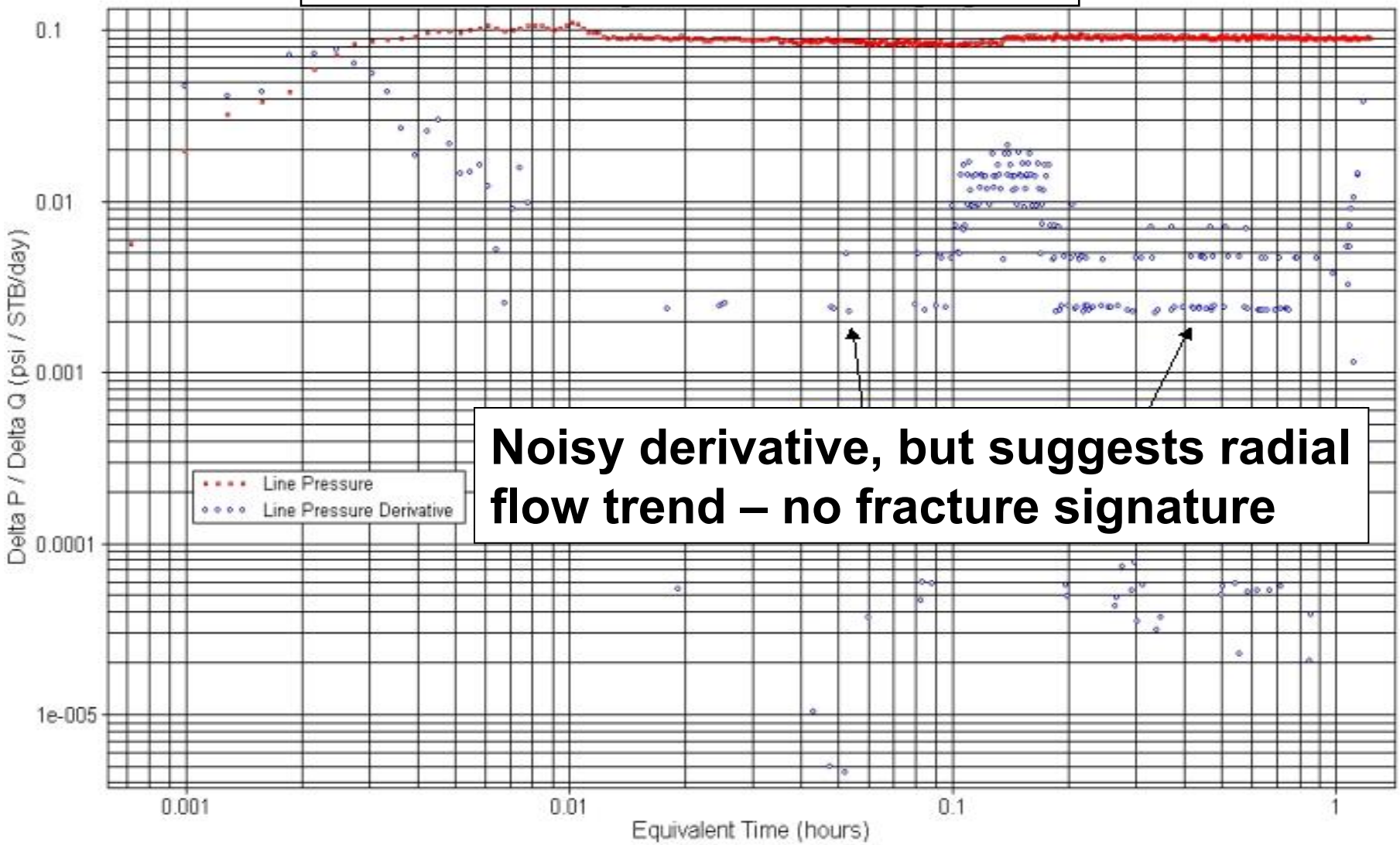


Example Step Rate Test



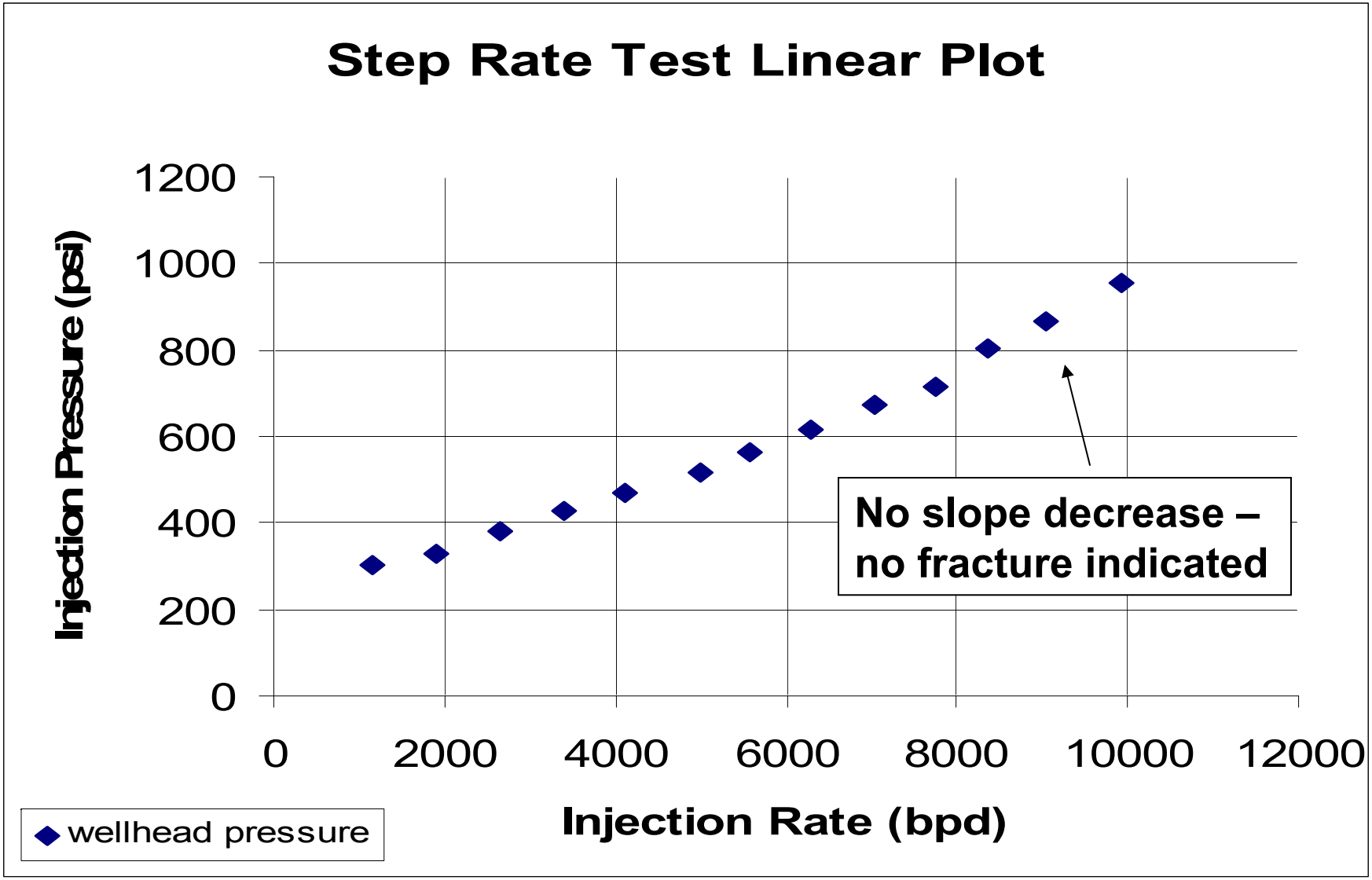
Log-Log Plot of a Rate Step

Analysis of 12th Step in 1st Rate Series



Noisy derivative, but suggests radial flow trend – no fracture signature

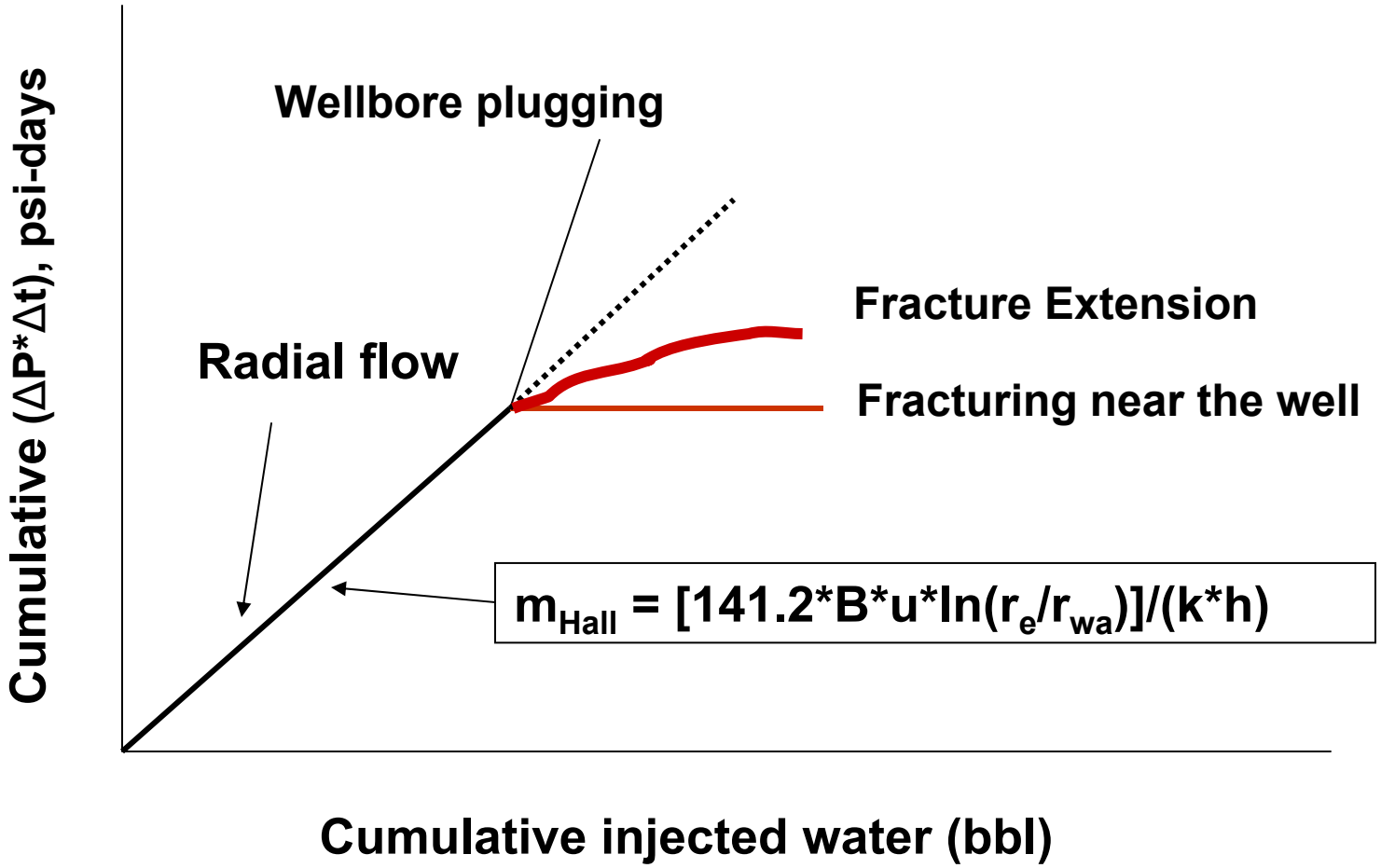
Example Step Rate Linear Plot



Other Uses of Injection Rate and Pressure Data

- Monitor injection well behavior
- Data readily available in Class I wells
- Hall plot
  - Linear plot
    - x-axis: cumulative injected water, bbls
    - y-axis: $\Sigma(\Delta BHP * \Delta t)$, psi-day
  - Can be used to identify fractures

Hall Plot


Wellbore plugging
Fracture Extension
Radial flow
Fracturing near the well
$m_{Hall} = [141.2*B*u*\ln(r_e/r_{wa})]/(k*h)$
Cumulative ($\Delta P*\Delta t$), psi-days
Cumulative injected water (bbl)

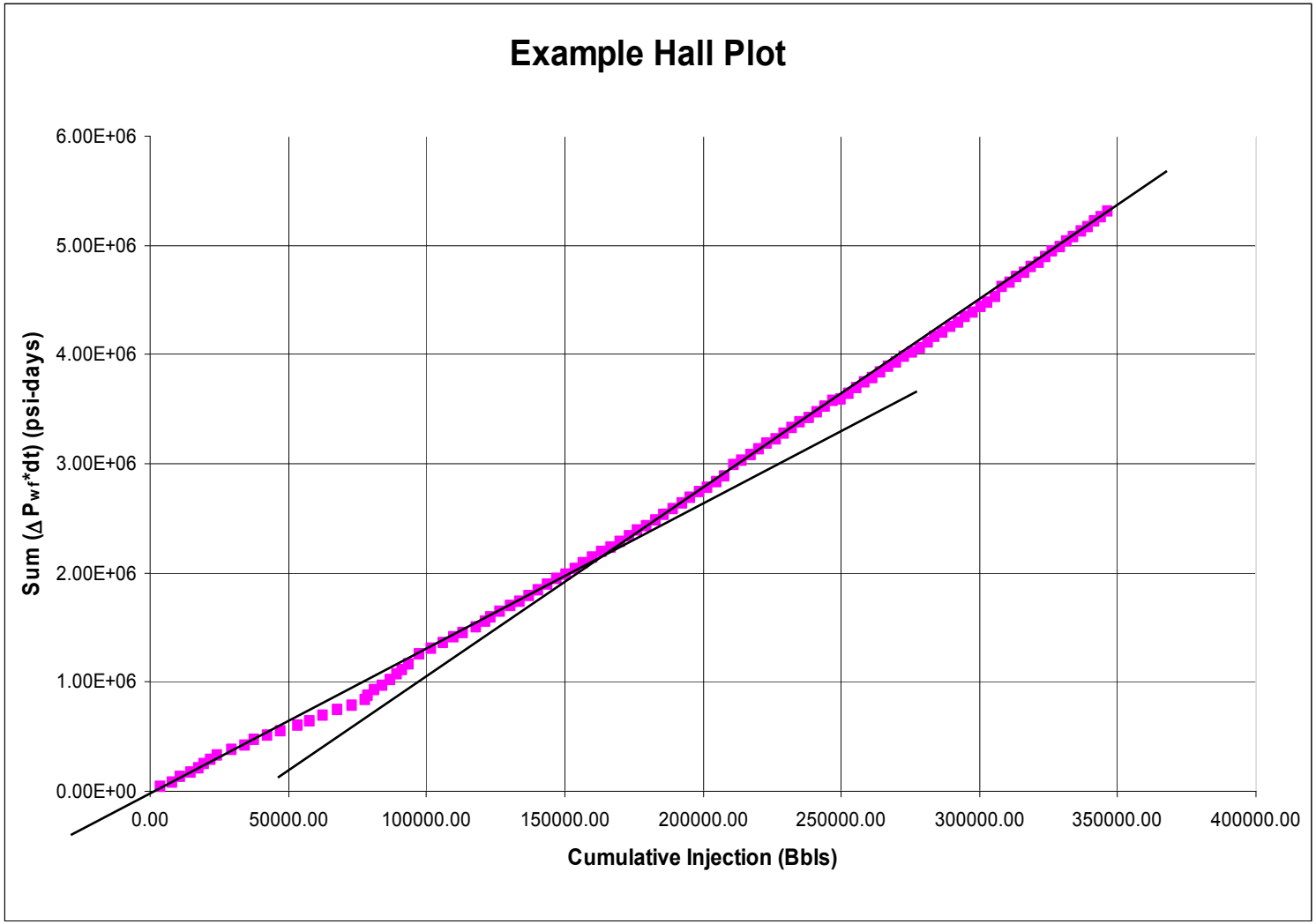
Hall Plot Analysis

- **Straight-line slope gives transmissibility:**

$$m_{Hall} = \frac{141.2\, B\, \mu \ln(r_e / r_{wa})}{k\, h}$$

- **Slope changes indicate well conditions**
  - **Decrease in slope indicates fracturing (skin decrease)**
  - **Increase in slope indicates well plugging (skin increase)**
  - **Straight line indicates radial flow**

Hall Plot Example



Hall Plot Limitations

- Type of pressure function used impacts the slope of the data plotted
- Cannot determine kh/μ and s independently from a single slope
- Pressure data is dependent on gauge quality and can be noisy