Practical Fundamentals of DFIT Execution and Interpretation

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Discussion Outline

- Background theory
  - What does a DFIT represent and what is the theory behind it?
  - Common misconceptions and misinterpretations of the theory, or theory versus practice
- Properly conducting a DFIT (in brief)
- Steps to interpret a DFIT
  - ISIP determination, and what does ISIP mean and represent
  - Step-down and blowdown analysis
  - G-function analysis
  - After-closure analysis
- Some common mistakes
A DFIT is a Diagnostic Fracture Injection Test.

- A DFIT is NOT:
  - A diagnostic formation injection test
  - A reservoir transient falloff test or “Mini-Falloff” (MFO)
  - A fluid efficiency test (FET)
  - A micro-frac
  - A mini-frac
  - A “data-frac”
  - A pressure rebound test
  - A reservoir limits test
  - A pump-in flowback test (but the analysis techniques may apply)

- The purpose is to determine properties affecting fracture initiation and extension, treating pressures, leakoff, screen-out risk, calibration of the in-situ earth stress tensor, and secondarily post-frac production
DFIT Execution – Brief Overview

▪ Inject water or clean fluid above the stable frac extension pressure
▪ Create a stable frac geometry then step-down and/or shut down
▪ Watch pressure decay to evaluate the leakoff mechanism and find fracture closure
  ▪ Closure time is proportional to leakoff rate and formation flow capacity
  ▪ Closure is driven by the difference between fracture and pore pressures
  ▪ Closure stress gives minimum principal stress
▪ Evaluate after-closure pressure decline using appropriate reservoir transient solution
  ▪ To obtain reservoir pore pressure and flow capacity

Conventional injection/falloff pressure diagnostic analysis provides information on frac extension pressure, closure stress, and leakoff rate and mechanism. These data are needed to calibrate log-derived stress profile and determine net extension pressure above the in-situ earth stress (process-zone stress in the model). After the frac closes, the pressure decay is controlled by reservoir transient flow. These data can be analyzed using solutions of the diffusivity equation appropriate to the transient flow regime identified during the falloff. Results can give reservoir pressure and transmissibility.
The procedure for a properly executed DFIT is simple but requires an understanding of the goals and attention to detail. Record all rate and pressure data with a well calibrated and accurate gauge at one sample per second throughout the test. The hole must be loaded with the test fluid, which should be a clean completion brine or oil. Pump at low rate until a breakdown event is observed. This is time zero for all dimensionless time normalization, and the beginning of the test. After breakdown, increase rate to the maximum allowed by wellhead pressure and available horsepower. Hold rate for the designed test time. Step down to 75%, 50%, and optionally 30% of maximum rate. Each step down can be as short as 10 seconds. Shut-in the well and isolate the gauge from surface leaks and upsets. Record the falloff pressure for the necessary time to identify closure and possible reservoir transients. The time elapsed from breakdown to shut-in is the pumping time (tp). Average rate and integrated volume over this time will be used in some analyses and must be known.
Ambiguous Closure Using Sqrt(t) of G(t) Analysis: K. Nolte warned that many people pick “bumps and wiggles” on the P-f(t) curve, without understanding the physics behind the response.

The problem with any analysis technique is that the signature for closure has not been rigorously defined, or if it has, it has not been universally accepted. At the 2007 SPE Hydraulic Fracturing Conference in College Station, Texas, Ken Nolte showed a similar figure to illustrate the various “closure” points used by different practitioners in the industry. There is only one correct closure pressure and time. Unfortunately, there are many possible incorrect results that can, and are, frequently used. For normal constant-fracture-area, matrix-dominated leakoff the inflection point (3) is the correct closure. Use of the first derivative of pressure wrt. Sqrt(t) is helpful in locating the inflection point; but this method does not provide the correct closure in all cases, as will be shown. The same ambiguities can exist with any diagnostic plot for closure determination. A consistent method, using all diagnostic methods in concert, is needed to determine the correct closure point without ambiguity.
Background Theory

- Nolte developed the theory for a PKN fracture model
  - Constant fracture height
  - Linear-elastic rock
  - Elliptical fracture cross-section
  - Isotropic, homogeneous reservoir
  - Constant permeability for leakoff
  - Single-phase flow for leakoff
  - Based on material balance and elasticity
  - G-function derived to yield a straight line

- Reality
  - No real fracture fits any of these assumptions
  - Model provides limited parameters to explain non-linear pressure decay
  - Analysis of real data means we need to understand the reasons for deviation from Nolte’s theory

- Exceed closure stress:
  - Opens initial fracture aperture

- Exceed extension pressure:
  - Extend fracture length and height
  - Develop stable fracture width
  - Increase surrounding pore pressure
  - Alter stress tensor
  - Induce shear in surrounding rock
    - Microseisms, perm change, and plastic yield

- Shut-in and Leakoff:
  - Quasi-elastic rebound pushes fluid out of fracture
  - Fracture width decreases
  - Unloading modulus differs from loading modulus

- “Closure”:
  - Fluid pressure equals earth stress
  - Pressure decays only by reservoir transient flow
  - Fracture is NOT mechanically closed
  - Residual aperture remains until closed by drawdown
Assumed DFIT Process

- Open and extend a fracture to contact reservoir.
  - A pressure transient is established normal to the fracture face, into the surrounding reservoir
  - Each element of length starts a transient at different time, as the fracture extends
  - Leakoff rate (arrow width) from each element varies with √Time since opening (arrow length)
  - Final, overall leakoff rate and closure time depends on **pumping time, nothing else!**
- Establish representative fracture geometry and stress field by pumping fast enough.
  - Must pump at high enough rate to get to the characteristic extension pressure (stable PZS)
  - This establishes a relatively constant surface to volume ratio, and representative fracture height
- Observe elastic rebound of rock during closure.
  - Strain energy or (frac pressure–pore pressure) drives leakoff to closure
  - “Closure” is a zero net-pressure acting on the fracture face, NOT zero aperture!
- Analyze transient pressure dissipation after closure.
  - Controlled by reservoir compressibility and transmissibility driven by (frac fluid pressure - pore pressure)

A DFIT is a fracture diagnostic test. The first requirement is that a stable fracture geometry be established. The test will not be useful as a fracture diagnostic unless the injection rate is high enough to create a stable extension pressure with representative fracture width and height. Through experience this requires about 10 bpm (slightly more than 1 m3/m) rate. Rates less than 5-6 bpm (0.5 m3/m) may give ambiguous results. A properly designed and executed test provides information about rock failure modes, fracture extension pressure, closure stress, and reservoir properties.
Special Considerations for Overall DFIT Planning

- The pressure decline analysis theory assumes a single pulse injection (short pump time, long falloff) into a constant pressure (iso-potential) reservoir
- Multiple injections, or starts and stops, destroy the validity of the assumption and invalidate results
- Multiple injection pulses super-impose multiple pressure transients in the system that the theory cannot handle
- Once fracture initiation occurs, after start of injection, the test is committed.
  - If injection ends prematurely, analyze the falloff from that time
  - Do not re-start injection
- Do not conduct the multi-step pre-frac tests commonly recommended (especially internationally)
  - These tests consist of multiple injections for breakdown, step-up, short low-viscosity injection, gelled “mini-frac” with extended falloff, and often more injection/falloff cycles
  - These tests are not analyzable and provide no useful information
- Step-down tests are not transient tests
  - They can be conducted at any time, regardless of prior injection
  - Multiple step-downs can be run in a frac treatment (pre-pad, pad, after scour, post-job)
No need for step-up test: Apparent extension pressure is often masked by perforation breakdown and inefficiency (~6 bpm often reported)

- Rate necessary to initiate and extend a fracture at various reservoir permeabilities (absolute and undamaged).
- Assumes a reservoir depth of 7000 ft, fracture gradient of 0.8 psi/ft, normal hydrostatic pore gradient, formation thickness of 20 ft, 40-acre drainage area, and a water injection system.

Where,

\[
q_{i,\text{max}} = \frac{4.917 \times 10^3 k h (F G \times D) - \Delta p_{\text{safe}} - p}{\mu \beta (\ln r_e + s)}
\]

- \(q_{i,\text{max}}\) = injection rate in bbl/min
- \(k\) = permeability of undamaged formation, md
- \(h\) = net thickness, ft
- \(F G\) = fracture gradient, psi/ft
- \(D\) = depth, ft
- \(\Delta p_{\text{safe}}\) = safety margin, psi
- \(p\) = reservoir pressure, psi
- \(\mu\) = viscosity of injected fluid, cp
- \(\beta\) = formation volume factor
- \(r_e\) = drainage radius, ft
- \(r_w\) = wellbore radius, ft
- \(s\) = skin
Most people consider a short-duration fracture injection test to be too small to effectively evaluate enough reservoir volume to be applicable for post-frac production. Figure 13 shows the estimated fracture half that would be generated for a 30 foot fracture height, with a fracture width of 0.1 inches, given 100% fluid efficiency. These may seem to be arbitrary input assumptions, but are reasonable for water injection in “typical” rocks of 3-4 million psi Young’s Modulus with a net pressure of 1000 psi and very low system permeability. The estimated fracture length can be directly multiplied by fluid efficiency to correct for leakoff in higher permeability systems, and corrected by the ratio of created to assumed fracture height, if it is known.

Note that for the recommended rate of 10 bpm, a pumping time of 5 minutes generates a fracture half-length of more than 600 feet, when leakoff during the 5-minute injection period is negligible. This is very likely the case in a shale or ultra-tight sand or carbonate reservoirs. Extending the pumping time to 10 minutes increases the created length to almost 1200 feet and increases the time to closure by increasing the average exposure time of all fracture face elements. Clearly, in tight rocks, these are not “small” fractures and the formation surface area exposed is statistically significant. For the 5-minute, 10 bpm injection case, the surface area of one of the four fracture wing faces exposed is 18,000 square feet.
DFIT Design Constraints:

- Plan for enough HP to reach about 10 bpm (1.5 m³/m) at treating pressure
- Time to reach closure is approximately Pump Time / 3*Estimated Perm (md)
  - Five minutes in 0.001 md rock = 1500 min (25 hours)
  - Five minutes in 0.01 md rock = 150 min (2.5 hours)
- Time to establish analyzable reservoir transient is roughly 3 times the closure time or pump time/perm
  - Longer created fractures will take longer to transition from pseudo-linear to pseudo-radial reservoir flow
- Gel filtercake or severe face plugging affects the development of the far-field pressure transient and will delay closure and invalidate after-closure analysis

Longer pumping times allow more time for penetration of the induced pressure transient. Given a stable fracture geometry, the time required to close the fracture by leaking off a fixed volume to surface-area ratio of fluid in the fracture can be related to the system permeability. A good approximation for time to closure is given below:
The plot shows the time, in hours, to reach closure for a range of system permeabilities. Each line represents a different pumping time, in minutes. The chart is a useful reference for design of DFITs. Recall that it will take roughly three times the closure time to establish a valid reservoir transient for after-closure analysis.
Once a stable fracture geometry is achieved, meaning the injection rate is fast enough to reach a stable net pressure, height, and width, the volume of fluid in the fracture that must leak off to closure will be the same. The total fracture volume can vary but in a uniform permeability system (assumed in the theory) the closure time will be the same, if pump time is the same. The figure shows the link between pump time and closure time. During pumping, pressure transients are established as fluid leaks out of the fracture. The longer an element of fracture face is exposed, the slower the leakoff rate becomes, as the transient depth of invasion increases. After a long pump time, the final integrated leakoff rate will be much lower than for a short pump time, and closure will be delayed. For a short pump time, at high rate, a more linear pressure field is developed. That means it ill take longer to reach pseudo-radial flow after closure. The time to establish a radial flow regime is dependent on the length of the fracture created and the permeability of the system.
Days to Reach Pseudo-Radial Flow for a Single Planar Fracture

Time to reach pseudo-radial transient flow for a single planar bi-wing fracture (days) in an infinite-acting reservoir is usually assumed to occur at dimensionless time (TDXF) of 3.

These results assume TD XF=1.

Red circle (0.01 md, 600-ft $x_f$) indicates about 60 years for a gas reservoir.

Transient will hit BDF in 3 years for 20-acre 4:1 aspect ratio.

$$t_{pr} = \frac{\phi \mu C_t x_f^2 t_{Dxf}}{0.0002637k}$$

If we follow the assumptions for the PKN fracture geometry, and assume that linear transient flow governs fracture leakoff flow up until closure, then the time required for the induced pressure transient to establish a pseudo-radial flow regime can be computed from the definition of tDxf. For pseudo-radial flow, a value of tD xf = 1.0 (at least) must be reached in the falloff period. Equation 4 gives the time, in hours, to reach pseudo-radial flow (tpr) as a function of reservoir storativity, permeability, and fracture length.

Where,  
$t_{pr}$= time to reach pseudo-radial flow, hours  
$\phi$= porosity, fraction  
$\mu$=fluid viscosity, cp  
$C_t$=total reservoir compressibility, 1/psi  
$x_f$=fracture half-length, ft  
$k$= permeability of leakoff system, md

Equation 4 has been solved for tDxf=1 for a gas reservoir case with viscosity of 0.02 cp, porosity of 8%, and total reservoir compressibility of 3.0e-5/psi. The time, in days, required to reach the fully developed pseudo-radial flow period, according to these assumptions, is shown here. Daltaban and Wall (1998) suggest that pseudo-radial flow may not be identified until tDxf=2 for an infinite conductivity fracture, or tDxf=3 for a uniform flux fracture. The assumptions
used in the figure are, therefore, somewhat optimistic.
Why do Apparent Radial Flow Regimes Appear?

- Most fractures are not simple bi-wing planar geometry
- Leakoff occurs through each fracture face
- Pressure fields superpose to form an apparent radial flow condition
- Any flow capacity computed from this composite does not fit the assumptions for the solution of the diffusivity equation in pseudo-radial flow
- KH/μ estimates from this geometry will be high, possibly by 10-100 times

In many cases an apparent radial flow period occurs in the data much faster than predicted by the previous chart. A probably cause if the early radial flow is generation of a complex, non-planar fracture set. Leakoff transients from this fracture system will resolve into what appears to be a radial flow pattern much faster than a single linear crack. The flow regime may look normal but the time to establishment of the flow pattern is not consistent with any of the assumptions made in the theory used to derive reservoir transmissibility. The result will be a KH estimate that is orders of magnitude too high, in many cases. When this occurs, the permeability estimate from the closure time is usually more appropriate for production forecasts.
DFITs in Vertical and Horizontal Wells

▪ What’s the same?
  ▪ Any DFIT, when conducted correctly, should generate a vertical fracture, dominantly in the azimuth of maximum stress and orthogonal to minimum stress
  ▪ The measured closure stress should be the minimum stress, regardless of well orientation

▪ What’s Different?
  ▪ Fractures initiated in vertical wells are usually co-axial with the well, and oriented with the dominant stress tensor
  ▪ Near-well friction and tortuosity are usually minor
  ▪ In horizontal wells, the tangential stress concentration around the borehole practically guarantees initiation of a co-axial (longitudinal) fracture, unless drilling through existing open fractures
    » Transverse fractures initiate through shear and reorientation, likely from the longitudinal frac face
  ▪ Tortuosity and near-well restrictions are typically much more severe
  ▪ Near-well complexity and longitudinal fractures almost always generate a variable storage signature, which is much less common in vertical tests
    » Tests in the same reservoir, including vertical and horizontal wells, show the same (correctly determined) closure pressure but virtually all horizontal tests show variable storage, while only about 15-20% of verticals do.
Step-Rate Analysis

- Hold each rate step for 10-15 seconds
- Make the steps consistent length
- Make sudden rate changes and do NOT “search” for a specific rate
- Extrapolate ISIP from linear pressure decline on log(time) scale
- Solve simultaneous equations for frictional components:
  - Pipe friction (rate squared, SPE 122917)
  - Perforation pressure drop (rate squared)
  - Tortuosity (square-root of rate)

Rather than analyzing the entire injection test second-by-second, a more common technique uses only the points when rate and pressure are held constant at each step-down. The analysis is currently conducted in GOHFER® and other commercial fracturing software.

Good "water-hammer" indicates efficient communication to fracture and low near-well friction
Step-Rate Analysis Results

- SRT is not a transient analysis
- Tests can be conducted any time during a job
  - Pre-pad
  - Pad
  - After scour or acid
  - During flush
  - EOJ step-down
- Provides useful information about changes in tortuosity and perf entry conditions
- Results are dependent on inputs for pipe ID, fluid, perf EHD, and CD

Automatic regression to minimize errors between observed and calculated frictional components gives a solution describing the number of holes open and the tortuosity factor. These results depend entirely on the description of the perforations (EHD, CD), pipe and fluid properties and are not otherwise unique.
Where is ISIP? What is the Correct Frac Gradient?

- ISIP is NOT instantaneous
- ISIP, at BH conditions, should represent the fracture extension pressure
- This is ALWAYS greater than closure pressure
- Correct extension pressure minus closure pressure gives PZS estimate
- When measured inside pipe, the pressure may be affected by friction
- Surface shut-in does not make the perforation rate go to zero instantly

In many pressure-activated toe sleeve DFITs, the near-well pressure drop caused by tortuosity and complex breakdown can obscure the ISIP. It is necessary to understand the physical processes controlling the pressure decline after the end of injection in these cases, and to have a method to get the right actual fracture extension pressure, fracture gradient, and process-zone stress.
Some people attempt to construct arbitrary tangents to the pressure falloff, and extrapolate to an apparent ISIP. This method generates arbitrary and random results. In the case shown, the fracture extension gradient may vary between 1.22 psi/ft and 0.97 psi/ft. Only one of these actually represents the fracture extension pressure,
High Tortuosity and Near-Well Pressure Drop + Wellbore Storage

Measure compressive wellbore storage during initial injection.

Compute wellbore discharge or blowdown rate, assuming constant tortuosity (psi/√bpm) and variable DP.

If all the rate-pressure data are recorded from the start of pumping into the well, the correct ISIP, and the cause of the pressure decay can be explained from simple physical processes. At the start of injection, the wellbore fluid is compressed by injection at 4 bpm (in this case) for about 2 minutes. The slope of this initial compression curve determines the wellbore storage, or compression, in psi/bbl. At the end of injection, this wellbore storage must be expanded through the near-well restriction caused by the breakdown geometry. By extrapolating from an apparent straight-line on the pressure vs. log(time) plot, an estimate of ISIP can be found. This trial ISIP, and the pressure at the end of pumping, gives a total frictional pressure difference at the final injection rate. Pressure drop divided by the square-root of rate gives a tortuosity coefficient. The (assumed constant) tortuosity, and the differential pressure between the wellbore and fracture, determine the instantaneous injection rate. As the wellbore pressure declines, the loss-rate from the well to the fracture declines. With each element of volume removed from the well, the wellbore pressure drops according to the measured compressibility. In the plot, the thin dashed red line shows the theoretical rate of decompression (blowdown) of the stored compressible energy in the wellbore. When it matches the observed pressure decay, the ISIP and wellbore storage are correct.
The extended wellbore decompression affects the interpretation of the DFIT semi-log derivative. While the pressure is falling abnormally fast, a large hump forms in the derivative. This cannot be interpreted as pressure dependent leakoff or system permeability, as it is caused by wellbore storage. The end of the hump must be carefully analyzed to determine if it is caused by the wellbore affect or actual reservoir response. In extreme cases, wellbore blowdown can extend all the way to fracture closure.
Observed Wellbore Compressibility

Lines indicate theoretical compressibility for water-filled pipe of 4" or 5" ID.

Field data from actual tests suggests that many wells have some trapped gas or other reason for higher compressibility.

This stored energy must be dissipated at shut-in before fracture leakoff commences.

The wellbore compressive storage can be computed assuming water compressibility and pipe stretch. The lines in the plot show the theoretical compression that should occur in water-filled 4" and 5" ID pipe, as a function of total pipe length. The points show a sample of field cases with measured wellbore compression. In many cases, there is significantly more energy stored in the wellbore than can be accounted for by water-filled volume.
Algebraic Definition of the G-Function

- G-function is a dimensionless function of shut-in time normalized to pumping time:
  \[ G(\Delta t_D) = \frac{4}{\pi} \left( g(\Delta t_D) - g_0 \right) \]
  \[ \Delta t_D = \left( t - t_p \right) / t_p \]

- Originally Nolte provided a range of \( g(\Delta t_D) \) functions for different fluid efficiencies (\( \eta \)) to account for superposition of multiple transients launched at different pumping times.
  - \( \eta = G_c/(2+G_c) \) (only valid for linear \( G(t) \) semi-log derivative)
  - He stated that for short pump times and high rate, these are unnecessary, as all leakoff transients start at approximately the same time.
  - \( G \approx 2\sqrt{\Delta t_D} \) for very low perm systems and short pump times

Pressure decline analysis after fracturing has traditionally been accomplished through some shut-in time-function. The G-function is a dimensionless time function relating shut-in time (t) to total pumping time (tp) (at an assumed constant rate).
Typical Derivative Shapes in G-function Analysis

Classical Nolte Analysis:
Find the “correct” straight line on the pressure-G-time plot.

Deviation from the end of the straight line indicates closure (1979).

Castillo suggested plotting 1st derivative to define the “correct” straight line (1987).

Barree added semi-log derivative to reduce ambiguity and define leakoff “type-curves” (1996).

1. Enhanced or accelerated leakoff
2. Normal “matrix dominated” leakoff
3. Delayed leakoff or variable storage
Biggest Current Misconception: Variable Compliance

- Nolte defined fracture compliance, for a PKN fracture, as H/E (L/E for KGD)
- Compliance represents the inverse of stiffness of the fracture
- Compliance, in his model, controls the rate of pressure decline
- For a single planar fracture, with all his other limiting assumptions, the only way he had to change the rate of pressure decline was to assume that “compliance” was changing
- With rock modulus, E, constant that leaves H as the only variable
- This led to the concept of fracture “height recession”
  - Initial slow pressure decline > high compliance
  - Transitions to faster decline > decreasing compliance
- The same concept of “variable compliance” can be applied to “length recession”
- Both theories must assume that the fracture
  - Closes from the tip back to the center (height or length)
  - Closure of the tip changes frac length or height and compliance
  - That means the rock grows back together
- Fundamentally, this NEVER happens!
Illustration of Fracture Compliance: Flat Spring Analog to PKN and KGD Models

\[ \delta = \frac{UL^4}{6.4Eb h^3} \]

\[ \delta \approx CPL/E \]

\( \delta \) = deflection  
\( U \) = applied load (lb/in)  
\( L \) = spring length (in)  
\( E \) = Young’s Mod (psi)  
\( b \) = spring width (in)  
\( h \) = spring thickness (in)  
\( P \) = \( U/b \) (psi)

\( U = 30 \text{ lb/in} \)  
\( E = 1.8e6 \text{ psi} \)  
\( b = 4" \)  
\( h = 0.5" \)

\( L=10"; \delta = 0.05" \)  
\( L=20"; \delta = 0.83" \)  
\( L=30"; \delta = 4.22" \)

PKN: \( W=2(1-\nu^2)H^*P/E \)  
KGD: \( W=4(1-\nu^2)L^*P/E \)

\( W=2\delta=CPH/E \)  
\( L=H/2; W=C^*PL/E \)

Compliance is \( H/E \) for PKN, \( L/E \) for KGD.

As the fracture extends, \( H \) and/or \( L \) grows.

\( E \) represents stiffness of the material.

Smaller \( H \) or \( L \) takes more stress (net \( P \)) to generate aperture (width).

What happens as the “fracture” closes and the net pressure decreases?

\( H \) and \( L \) do NOT change, so compliance remains constant.

Width decreases uniformly over the fracture surface.
Imaginary balloon analogy for closing fracture: This may confuse some people who think “closure” means zero fracture width. Closure represents a neutral stress state, or zero “net pressure” in the fracture.

Initially, the fluid-filled “balloon” may extend to the fracture tips. Pressures from the fluid inside acts on the fracture walls of the elastic solid to develop fracture aperture.

During closure, the balloon may recede from the fracture tips, but still exerts pressure on the fracture walls. The total created extent of the fracture (L) remains the same, as the aperture deflates.

The closure process continues, with the balloon receding further from the fracture tips. Even if the pressurized area covered by the balloon shrinks, it still exerts pressure on the fracture walls. The total created extent of the fracture (L) remains the same, as the aperture deflates.

A special case for real rocks: They are not perfectly elastic, and plastic deformation means that there is still open aperture with zero net pressure on the walls, at “closure”.
Experimental evidence of uniform fracture closure, not “height recession” or “variable compliance”

“In our experiments we observed that the crack radius remains a constant during the closure process.”


SPE 48926, 1998

Elastic Relaxation of Fluid-Driven Cracks and the Resulting Backflow

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* Not a bunch of frac-hacks
G-Function for Variable Storage Falloff, not Height Recession or Variable Compliance

Incorrect Closure  Correct Closure

Nolte “straight line” and Castillo 1st derivative plateau
Closure and Storage on Log-Log Derivative Plot

Half-slope indicating $\sqrt{t}$ linear-flow leakoff from fracture, ends at closure.

Unit slope indicating compressible fracture storage or wellbore storage, ends at critical fissure pressure.
Usual Cause of the “Belly” or Delayed Leakoff: Recharge from Variable or Transverse Storage

No recharge from storage: Hard shut-in with no return rate

With recharge from storage: Variable return rate

Recharge rate from transverse fractures
For a normal constant-area fracture, the time required to reach closure through normal leakoff is proportional to the volume of fluid stored in the fracture at shut-down and the surface area open to leakoff, adjusted for fracture compliance. In the case of variable storage, there is a much larger volume of fluid in the fracture at shut-in than would be the case for a constant-height planar fracture. For this reason, the time required to reach closure is delayed in proportion to the excess fluid storage ratio. A correction factor \( r_p \) must be applied to correct the observed closure time to the appropriate closure time for a planar constant height geometry fracture. Nolte describes \( r_p \) as the net-to-gross ratio of the fracture to the leakoff zone for the height recession case. For general variable storage (recession or transverse fractures) \( r_p \) is here called simply the variable storage correction factor. It can be approximated by the ratio of the area under the semi-log derivative of the G-function up until closure, to the area under the right triangle formed by the tangent line to the semi-log derivative and passing through the origin. The equation in the inset mathematically defines the area ratio. For the example, the ratio is approximately 0.85.
One more thought about fracture compliance:

What if the rock is not fully elastically coupled?
What if there are shear fractures, bedding planes, weak joints, and natural fractures?
What if each element of the fracture surface is displaced independently by local stress balance, with shear-slippage between elements?
What if this happens in both vertical and horizontal sections?

In that case, fracture compliance becomes a meaningless academic theory that does not apply to real-world hydraulic fractures in heterogeneous media. The fracture can close irregularly, with some high-stress or high-modulus layers closing quickly and forming “pinch points”.

Every “cell” on the fracture surface moves independently in a “shear-decoupled” system, not together like a spring or bow.
G-Function Example for Constant-Rate Flowback (2011): Get to closure quickly but lose reservoir property information. Must maintain constant flowback rate.
Example of PDL (pressure or stress dependent permeability) causing accelerated leakoff

- Total leakoff coefficient is proportional to the magnitude of the 1st derivative.
- Constant derivative plateau defines the pressure invariant system leakoff.
- Induced fissures are still present, enhancing system perm, but not changing with pressure.
- If plateau value of dP/dG is used for C_L, the actual leakoff while pumping, above ISIP, may be more than 6x higher.

\[ C_L = \frac{2h}{\pi r_p E} \sqrt{t_p} \frac{dP}{dG} \]
Estimation of PDL Coefficient from Falloff Data

- Leakoff ratio of 0 occurs at critical fissure opening pressure (CFOP).
- $C_{dp}$ or PDL coefficient is defined by the slope of the best straight-line of the leakoff ratio vs. BHP extending from CFOP or leakoff ratio = 0.
- This is the rate of change of leakoff coefficient, not total leakoff.
- Accelerated leakoff has positive slope
- Variable storage coefficient has a negative slope.

During the pressure-dependent leakoff phase of closure, the observed magnitude of the pressure derivative ($dP/dG$) is an indication of the relationship between leakoff coefficient and pressure. Once the fissure opening pressure ($P_{fo}$) is determined from the end of pressure-dependent behavior, a plot of effective leakoff coefficient at any pressure ($C_p$) divided by stabilized constant leakoff after fissure closure ($C_o$) can be made as a function of pressure or pressure differential above $P_{fo}$. If the data are plotted as $\ln(C_p/C_o)$ vs $dP$ the slope of the line gives the coefficient for pressure dependent leakoff ($C_{dp}$).
Tip-Extension G-Function Analysis: Semi-log derivative stays on positive slope. No fracture closure during the test

The data show the expected signature for fracture extension after shut-in. Note that there appears to be a late-time straight-line with what will be shown is a pressure dependent leakoff signature. Using the G-function and its derivatives alone can lead to errors in interpretation of the correct closure mechanism. The vertical dashed line [1] is positioned at the end of the data but there is no actual closure in this test.

The fracture tip-extension behavior implies fairly low permeability (or at least, low leakoff). Note that the dP/dG curve never becomes a horizontal line, indicating that the apparent leakoff continues to change throughout closure, as seen in the hypothetical example.
The log-log plot provides the most definitive indication of tip-extension. Because the pressure transient along the length of the fracture continues to dominate the pressure decline, while some leakoff to the formation may occur, the tip-extension phenomenon exhibits a ¼ slope of the pressure derivative on the log-log plot. The pressure difference curve follows a parallel ¼ slope offset by 4x from the derivative. If the derivative is still rising, the fracture has not yet closed. Obviously, no after-closure analysis can be performed.
The log-log plot of the change in pressure with change in time after shut-in for the normal leakoff case is shown. This plot is extremely powerful in that it can be used to determine fracture closure, leakoff mechanism and transient flow regime, and after-closure transient flow regimes in the reservoir. The fracture closure from the previous G-function and Sqrt(t) plots is shown by [1]. Note that the pressure derivative and pressure difference curves are parallel and approximately ½ slope up until closure. This corresponds to the formation linear flow period and is consistent with the typical model of fracture fluid leakoff under one-dimensional linear flow with constant pressure boundary conditions. The reservoir pseudo-linear flow regime (not present in this test) is shown after closure by a -1/2 slope of the derivative. The reservoir pseudo-radial flow regime is indicated by a -1 slope of the derivative.
ACA: After Closure Analysis

- Based on reservoir transient flow theory for a stable pseudo-radial reservoir pressure transient
- Theory is based on time to establishment of the pseudo-radial flow transient
- Theory only applies in two cases:
  - Single planar symmetric bi-wing fracture in an infinite, homogeneous, isotropic, constant permeability reservoir
  - Reservoir matrix permeability is high enough that flow capacity of secondary, natural, and shear-induced fractures is negligible (k>0.1 md)
- Single planar fracture requires G-function semi-log derivative to be a straight line up to closure (no non-linear behavior)
- At best, ACA gives total transmissibility (kh/μ)
  - Net h contacted by the test is generally unknown
  - μ is far-field reservoir mobile fluid effective viscosity
Approximate Transient Radius of Investigation and Depth of Fluid Invasion by Leakoff

ACA $\frac{kh}{\mu}$ uses far-field reservoir fluid viscosity. Pressure transient is 10s of feet from fracture face.

G-function perm estimate uses injected fluid viscosity. Leakoff mobility is dominated by the frac fluid, with invasion depth of inches.
The log-log plot of pressure minus assumed reservoir pressure, versus the square of the linear flow time function can be used to identify the after-closure flow regimes. The analysis depends on an accurate closure pick. The pressure difference curve is completely dependent on the value of reservoir pore pressure used, but the pressure derivative is insensitive to the pressure estimate. For this reason the method is iterative and the pressure derivative should be used for all initial analyses.

On the plot the linear flow period is identified by a ½ slope of the pressure derivative. If the correct pore pressure is used then the pressure difference curve will also fall on a ½ slope and be 2x higher in magnitude than the derivative. During the radial flow period, both curves will lie on the same unit slope line if the pressure estimate used for the pressure difference function is correct. In this example, there is no reservoir pseudo-linear flow regime and the system transitions from closure directly to radial flow.
Once the radial flow regime has been identified, the Cartesian plot of pressure versus the radial flow time function can be constructed. A straight line through the appropriate data in the radial flow period is constructed. The intercept gives pore pressure. The slope is related to transmissibility as shown previously. In this case, the pore pressure is 7475 psi and \( \frac{kh}{\mu} = 300 \text{ md-ft/cp} \). Note that the far-field transient is dominated by the reservoir fluid viscosity as the radial-flow regime is far outside the area invaded by the injected fluid. Knowing net pay height and reservoir fluid viscosity, the permeability can be determined.
Horner Analysis: Only Valid in Pseudo-Radial Flow

If a pseudo-radial flow regime is identified on either the Talley-Nolte plot or the log-log pressure derivative plot, then the Horner analysis can be used directly to obtain **pore pressure and transmissibility**. In the figure, the Horner slope through the radial flow data is 14411 psi. Using an average pump rate of 18.4 bpm, $kh/m = 298 \text{ md-ft/cp}$. For the assumed gas viscosity $kh=7.9 \text{ md-ft}$. Using the same assumed net gives $k=0.097 \text{ md}$. This result is consistent with the ACA results.

The conventional Horner analysis uses a Cartesian plot of observed pressure versus Horner time, $(tp + Dt)/Dt$, with all times in consistent units. The fracture propagation time is $tp$ and the elapsed shut-in time is $Dt$. As shut-in time approaches infinity the Horner time function approaches 1. A straight-line extrapolation of the Horner plot to the intercept at a Horner time of 1.0 gives an estimate of reservoir pressure. The slope of the correct straight-line extrapolation, $m_H$, can be used to estimate reservoir transmissibility: The flow rate in the equation is assumed to be in barrels per minute and is the average rate for the time the fracture was extending. The viscosity is the far-field mobile fluid viscosity. The propagation of the transient in pseudoradial flow occurs at a great distance from the fracture and is not affected by the injected fluid viscosity.

The major problem with the Horner analysis is that the results are **only valid if the data used to extrapolate the apparent straight line are actually in fully developed pseudoradial flow**. There is no way to determine the validity of the Horner analysis or to determine the flow regime within the Horner plot itself.
After-Closure Flow Regime Plot: Linear flow with gas entry

The linear flow period is apparent on the ACA log-log plot. When segregation begins, the pressure difference curve deviated upward and the derivative drops precipitously. Any late-time trend is essentially meaningless.
On the ACA Linear Flow Plot the pressure trend reverses at the start of phase segregation. Obviously, any extrapolation of this trend is meaningless. Even the start of gas entry causes the slope of the pressure curve to deviate upward, leading to an erroneously high estimate of reservoir pressure.
An apparent linear trend is seen on the Radial Flow Plot, but no pseudo-radial flow period was identified in any of the flow regime analysis (log-log) plots. Even though this looks like a straight line, the extrapolation is NOT valid and the much higher pore pressure is not correct. Also, the slope of the constructed line is far too low for a true radial flow period, so the calculated reservoir flow capacity from this construction will be too high by several multiples (up to 10 times).
Permeability Estimation from G at Closure ($G_c$)

✓ Good estimate when after-closure radial-flow data not available or unreliable

\[
k = \frac{0.004 \mu \sqrt{0.01 P_z}}{\phi c_t \left( G_c E r_p Ln \left( \frac{P_{close} - P_{pore}}{1000} \right) \right)^{1.8}}
\]

Where:
- $k$ = effective perm, md
- $\mu$ = viscosity, cp
- $P_z$ = process zone stress or net pressure
- $\phi$ = porosity, fraction
- $c_t$ = total compressibility, 1/psi
- $E$ = Young’s Modulus, MMpsi
- $r_p$ = leakoff height to gross frac height ratio

If a relationship between G-function and flow rate exists, then it is reasonable to expect a correlation between permeability and G-function. The equation shown was developed empirically but has been tested in many cases and gives a good estimate of permeability when after-closure radial-flow data are not available. Note that formation height and frac length do not appear in the equation. The dimensionless time to closure is a function of the volumetric efficiency of the fluid and the volume to surface area ratio of the created frac. The surface area can be a large $H$ and small $X_f$ or the inverse and the closure results will be the same. Things that change the rate of fracture surface-area growth, like process-zone stress, modulus, and net-to-gross ratio are important. The value returned from the relation is $k$ and not $kh$. 
Using the data from the example, the permeability is estimated to be 0.097 md. This is in close agreement with the more direct measurements. Note that the viscosity used in this analysis is an approximation of the injected fluid viscosity corrected for relative permeability effects in the invaded region around the fracture. Leakoff up until closure is dominated by the mobility of the injected fluid more than the far-field reservoir properties. The reservoir effects are handled through the compressive storage term made up of porosity and total reservoir compressibility ($C_t$). The reservoir compressibility includes pore volume compressibility and all fluids, adjusted for their saturations. The variable $P_z$ is defined as the process-zone stress or net fracture extension pressure. It is obtained from the observed ISIP minus the closure pressure for the fracture. Higher values of $P_z$ imply increased resistance to fracture extension and greater width with less surface area generated per volume of fluid injected. This leads to more stored fluid in the fracture at shut-in and less permeable area available for leakoff. The result is that closure time is longer than for the same permeability reservoir and injected fluid volume with a lower $P_z$ value.
Accelerated Leakoff from Permeability Change (PDL): Measured system perm is not matrix or core perm!

Under parallel flow conditions, addition of open (shear) fractures can increase system permeability above the matrix value by 2-3 magnitudes for very small fracture porosity.
Some Common DFIT Mistakes

- Injecting at a rate too low to get a stable fracture geometry
- Cutting the falloff short before confirming closure
- Using gelled or wall-building fluids
- Multiple perf intervals or too many holes to know what was tested
- Unknown fluids in the well or injection
- Worrying about injected fluid volume: Time is the critical parameter
- Pumping into an un-filled well or phase segregation
- Wells that go on vacuum
- Casing coupling or wellhead leaks
- Improper analysis or flow regime identification
Common Analysis Mistakes

- Phase segregation and gas entry

\[ P_2 = P_1 = \frac{zNRT}{V} \]

\[ P_1 = P_{head} = \frac{zNRT}{V} \]

End of useful data
Common Analysis Mistakes

- Loss of hydrostatic head, with bottomhole gauge and sealed wellhead

Valid data for analysis ends when BHP = hydrostatic head (WHP=0)

- Fixes:
  - Bottomhole shut-in tool (that seals), with gauge below isolation
  - BH gauge, no BH shut-in, vent wellhead to prevent formation of partial vacuum
  - Casing or wellhead leaks give a similar log-log derivative response
Effects of wellhead temperature fluctuations (Tompkins, et al, JPT Sept 2014)

- Both surface and BH pressures are affected by surface temperature changes

- Insulating the wellhead reduces pressure fluctuations and allows for smoother derivative calculation
Common Analysis Mistakes: Details Matter

- After-closure analysis (ACA)
  - Example is horizontal well, perforated, toe section, BH pressure gauge
  - Closure time and pressure are consistent

\[ G_c = 19.87 \]
\[ P_c = 22.46 \]

\[ G_c = 21.53 \]
\[ P_c = 22.42 \]
Common Analysis Mistakes: Flow Regime Identification

- After-closure analysis (ACA)
  - Log-log pressure change with semi-log derivative slope = -1/2
  - Identified correctly as pseudo-linear flow
Common Analysis Mistakes: Applying correct constructions

- After-closure analysis (ACA)
  - Pressure versus linear and radial time functions
  - Linear flow extrapolation (left), $P^* = 17.55$ MPA (correct)
  - Radial flow extrapolation (right), $P^* = 18.03$ MPA (incorrect)
Common Analysis Mistakes: Honor the Data

- After-closure analysis (ACA)
  - Log-log of well pressure minus static reservoir pressure versus square of the linear flow time function
  - Left: Shows linear flow period not fully established (0.002 mD estimate)
  - Right: Data incorrectly forced to false radial flow (0.1 mD estimate)
Application of DFIT Results and Calibration of Stress Models

▪ Step-down tests
  ▪ Effective number of perforations open
    » Requires a good guess at effective diameter, coefficient of discharge, and knowledge of pipe geometry and fluid friction when using wellhead gauges
    » Should be considered a relative indication of perforation efficiency, never absolute
    » Perf geometry will change when injecting slurry, higher viscosity gels, or at higher pump rates
  ▪ Tortuosity
    » Pressure drop outside the pipe, not related to perforation orifice losses
    » Can occur even is uncemented liner, open-hole completions
    » Related to complex and shear fractures with small apertures in the wellbore sandface
    » Can change during sand injection, either erode or get worse

▪ Blowdown analysis
  ▪ With no step-down, allows estimation of tortuosity and cross-check for ISIP
Application of DFIT Results and Calibration of Stress Models

- Pore pressure
  - From correct extrapolation of after-closure linear or pseudo-radial pressure transient to infinite time, using the appropriate flow-time function
  - Foundation of all stress models and determines net stress, internal friction, and shear failure risk in the formation
  - Abnormally high pore pressure presents added risks of rock fabric dominated fracture growth and severe stress dependent permeability

- Closure stress
  - From correct analysis of G-function derivatives
  - Allows determination of minimum stress only
  - Allows calibration of tectonic stress and strain boundary conditions to match total minimum stress
  - Stresses and pore pressure CANNOT be determined from any log data
Application of DFIT Results and Calibration of Stress Models

- Critical fissure opening pressure (CFOP)
  - From identification of the end of non-linear leakoff behavior on G-function semi-log derivative
  - May indicate secondary fractures/fissures which contribute to stress (pressure) dependent system permeability or a network with substantial storage volume
  - CFOP represents the pressure required, above closure stress, to dilate some secondary fracture or joint set at unknown azimuth relative to the primary HF
  - Difference between fissure opening and closure stress is a minimum estimate of stress anisotropy in the system

- Fracture extension pressure (corrected ISIP)
  - Difference between extension and closure pressures determines the effective “net pressure” or “process zone stress (PZS)”
  - This controls fracture aperture and the maximum mass/area proppant concentration that can be placed (conductivity)
Application of DFIT Results and Calibration of Stress Models

- Permeability or reservoir transmissibility
  - From After Closure Analysis (transmissibility)
    » Only valid in confirmed stable pseudo-radial flow transient period
    » Only valid for single planar bi-wing fracture
      ▪ No G-function non-linear behavior before closure
    » Usually gives incorrect over-estimate of flow capacity in unconventional reservoirs
    » Only gives $kh/\mu$, leaving user to guess at $h$ and $\mu$
  - From G-closure time (permeability)
    » Material balance for expulsion of fracture volume through created surface area, driven by pressure differential between closure pressure and pore pressure
    » Estimate corrected to effective permeability based on mobility of injected fluid in the invaded zone
    » Measures the stimulated system permeability of the failed rock around the fracture, not core perm or absolute perm
Fracture Pumping Diagnostics

- Design and execute the test correctly to get usable results
  - High enough rate
  - Short pump time
  - Clean, simple fluid
- Identify the correct flow regimes for analysis and apply the appropriate methods, plots, and equations
- Be honest about the results and don’t force interpretations that are not supported by the data
- Don’t fall for “new” “advanced” unproven or fallacious interpretation methods
- Ken Nolte said: “If you don’t do this, and do it right, don’t even think of using a numerical simulator for frac design.”

Another technology borrowed from conventional reservoirs is the pre-frac diagnostic injection test. Correct analysis of the test relies on identifying an established reservoir transient flow regime. If the induced pressure transient does not propagate in the porous medium, the analysis may be invalid or can give misleading results.
THANK YOU