SPE Gulf Coast Section Completions & Production Study Group Luncheon

# Reexamining DFIT Interpretation Methods


Presented by

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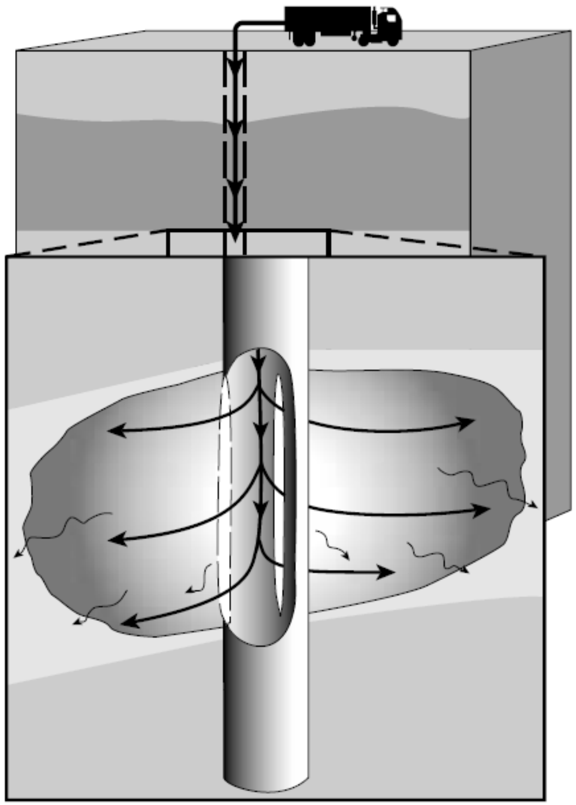
October 28, 2015

# Agenda

- Discuss hydraulic fracture closure mechanics and methods of identification.
- Study two diagnostic fracture injection test (DFIT) field examples.
- Evaluate the ramifications of interpreting fracture closure pressure incorrectly.
- Review key messages.

# Diagnostic Fracture Injection Test (DFIT)



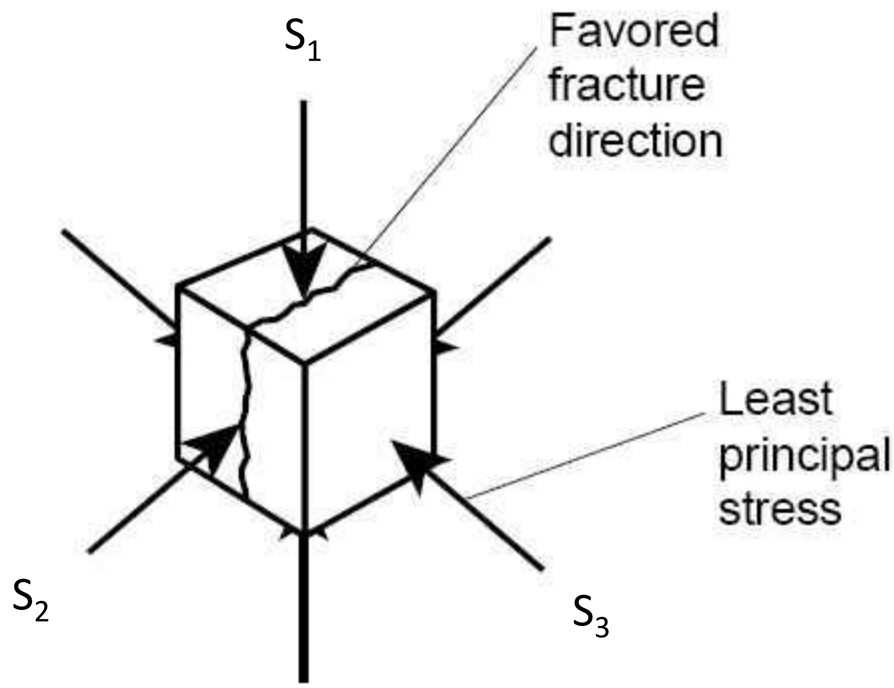
Main objectives – to acquire:

1) minimum in-situ stress (fracture closure)
2) transmissibility ($kh/\mu$)
3) pore pressure ($p_i$)

*The process starts with the creation of a small hydraulic fracture, typically requiring 1 to 10 barrels of water for a shale interval. The fracturing event induces a pressure disturbance that is analyzed <u>using established well testing methods</u> based on diffusivity solutions in order to derive critical information for reservoir characterization and modeling .*

# How Does the Formation Fracture?

Hydraulic Fractures Open Normal to the Least Principal Stress

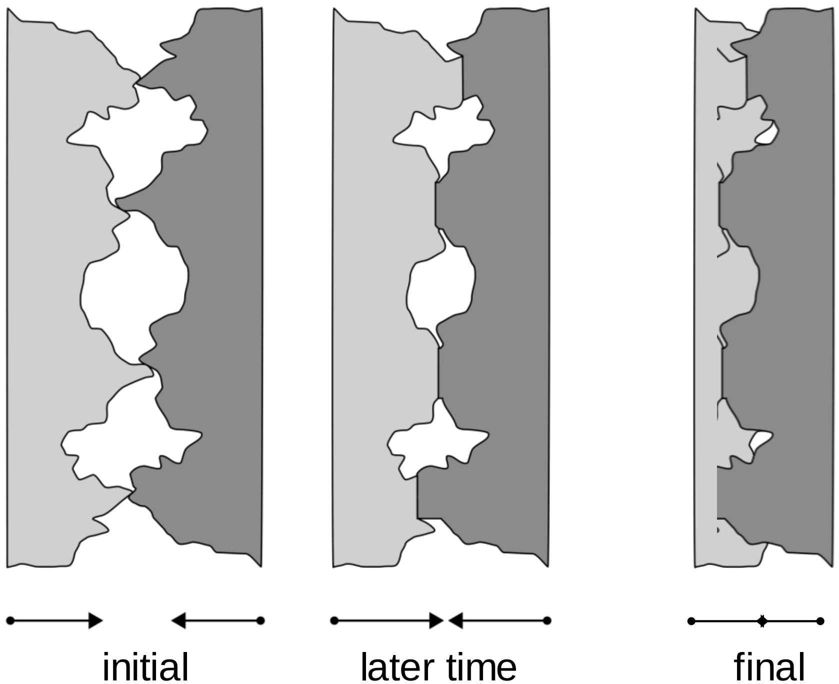



*Normally, $S_3$ is the minimum horizontal stress, designated $\sigma_h$*

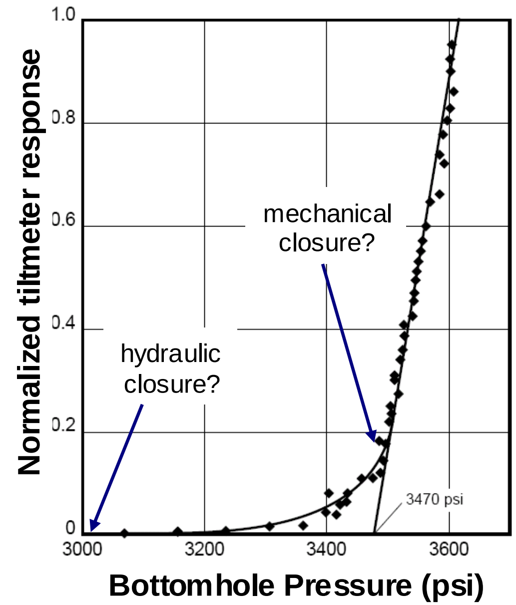
*Primary hydraulic fractures open normal to the least principal stress, propagating in the direction of maximum horizontal stress ($\sigma_H$). Since the least principal stress (i.e., $\sigma_h$) acts to close the primary fracture, identifying the fracture closure pressure yields $S_3$ or $\sigma_h$.*

# Fracture closure is a progressive process

**Mechanical closure** **Hydraulic closure**



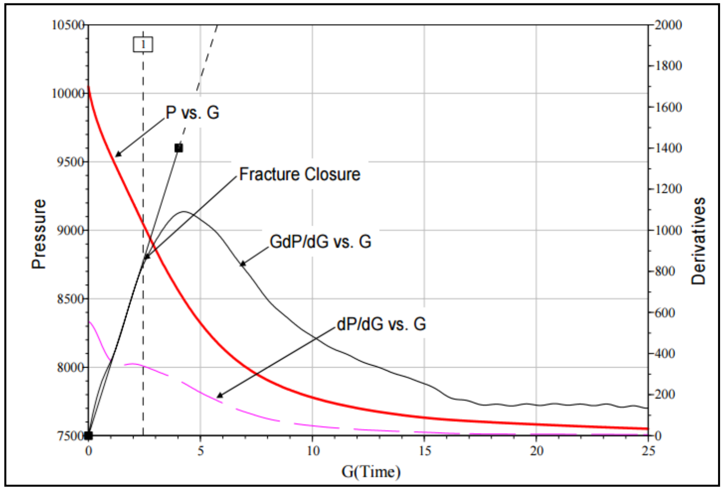

**Frac Width vs Pressure**



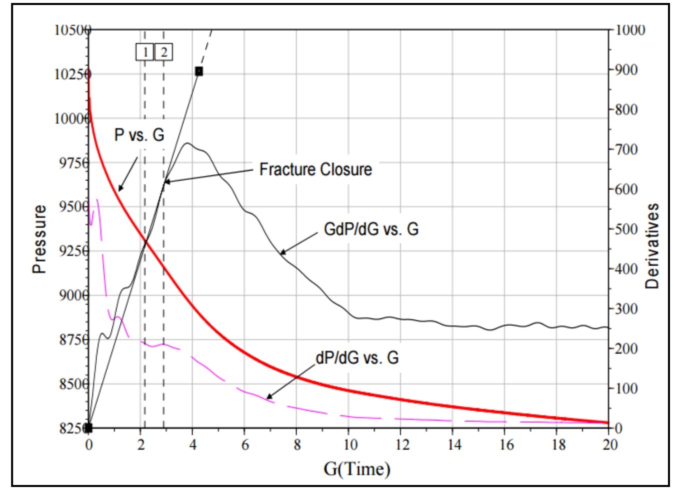

Proportional to normalized fracture width
MWX Test Site Project

- *Asperities on opposing fracture faces touch in the initial stages of fracture closure.*
- *Interconnected voids between the asperities impart residual fracture conductivity.*
- *Typically, dimensionless fracture conductivity, i.e., $(k_f \times w_f) \div (k_r \times x_f)$, is initially very high, especially in low permeability reservoirs (where $k_f$ = fracture permeability, $w_f$ = effective fracture width, $k_r$ = reservoir permeability, $x_f$ = fracture half length).*
- *In low permeability reservoirs, hydraulic (complete) fracture closure can result in isolation of the closed portion of the fracture from the wellbore pressure response.*

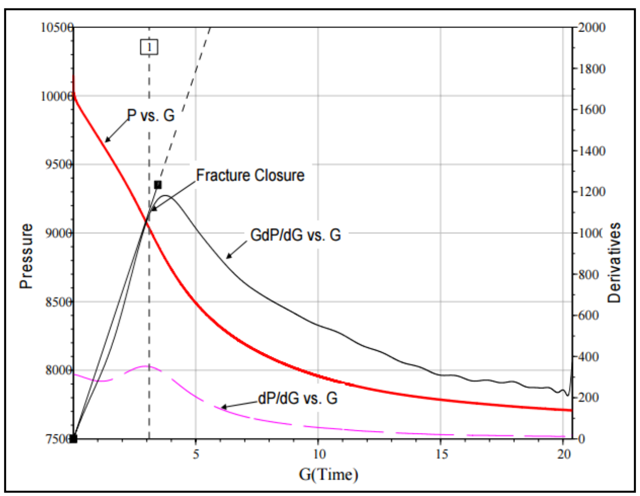
# Fracture Closure Identification: Holistic Method



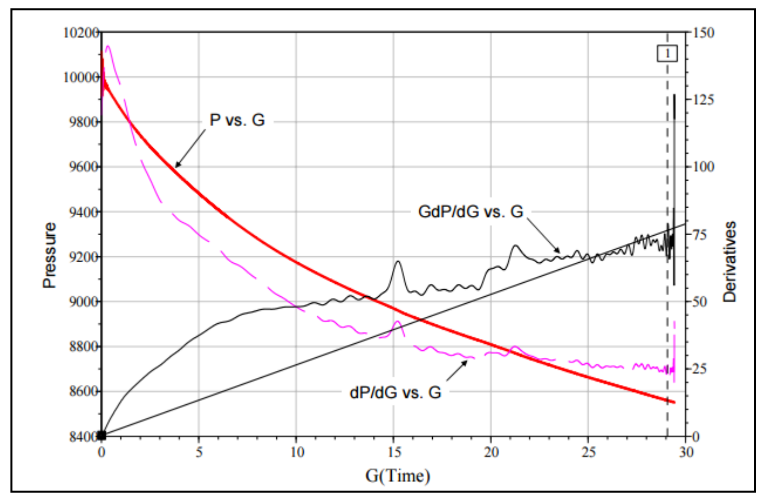

**Normal Leakoff**




**Pressure Dependent Leakoff (PDL)**




**Transverse Fracture Storage**




**Fracture Tip Extension**

*In guidance provided in "Holistic Fracture Diagnostics" (SPE 107877), fracture closure is indicated near the crest of the G dP/dG hump. Recently, this guidance and associated hypotheses have been questioned, especially for DFIT's in low leak-off intervals.*

# Evaluation of Fracture Closure Using a Numerical Simulator (CFRAC)

- Developed by Dr. Mark McClure and the petroleum engineering departments of Stanford and University of Texas at Austin.
- Allows fractures to retain aperture after mechanical closure.
- After the onset of mechanical closure, an empirical, non-linear joint closure law is used to relate fracture aperture and stiffness to the effective normal stress.
- Fracture closure results in a significant decrease in fracture compliance, which causes an <u>increase in the pressure derivative</u> in low permeability formations as the fluid leak off rate changes only slightly due to initially high dimensionless fracture conductivity, i.e., $(k_f \times w_f) \div (k_r \times x_f)$ .
- The corresponding fracture closure signature (i.e., Fracture Compliance (FC) method) is at the <u>base</u> of the G dp/dG hump, which is contrary to the Holistic method of determining fracture closure.

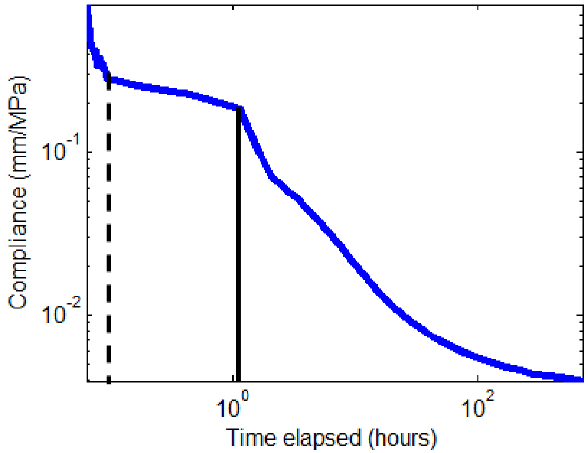
# Pressure Change During the DFIT Shut in Period

Fracture compliance term　　　　Fluid loss term

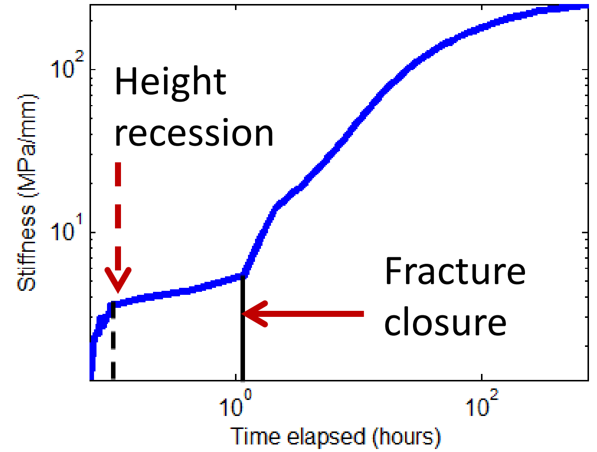
$$\frac{dp}{dt} = \frac{dp}{dV} \times \frac{dV}{dt}$$

where V = volume of fracture, p = average pressure in the fracture and t = time

$\frac{dV}{dp}$



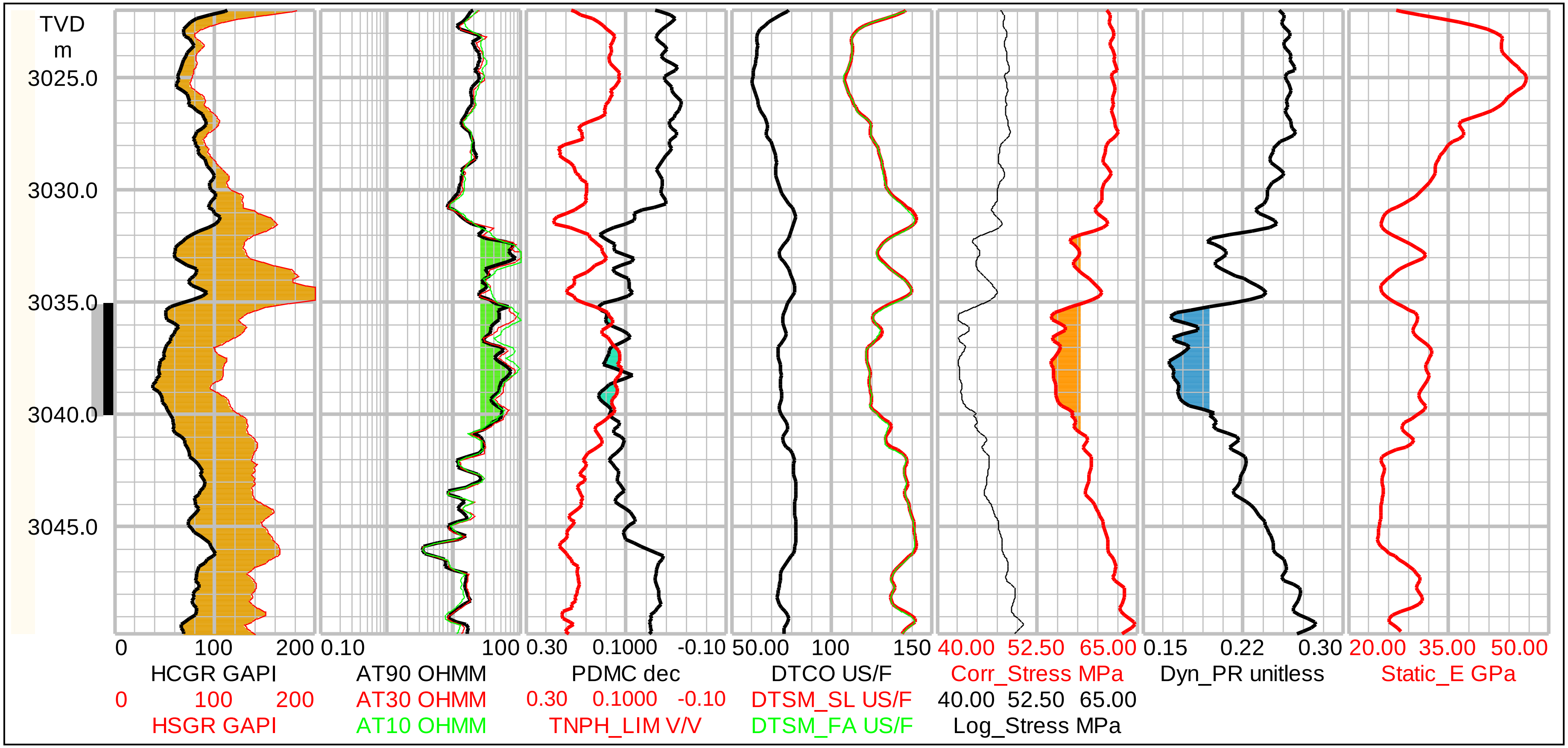

$\frac{dp}{dV}$




**CFRAC output from Ordovician Shale validation case**

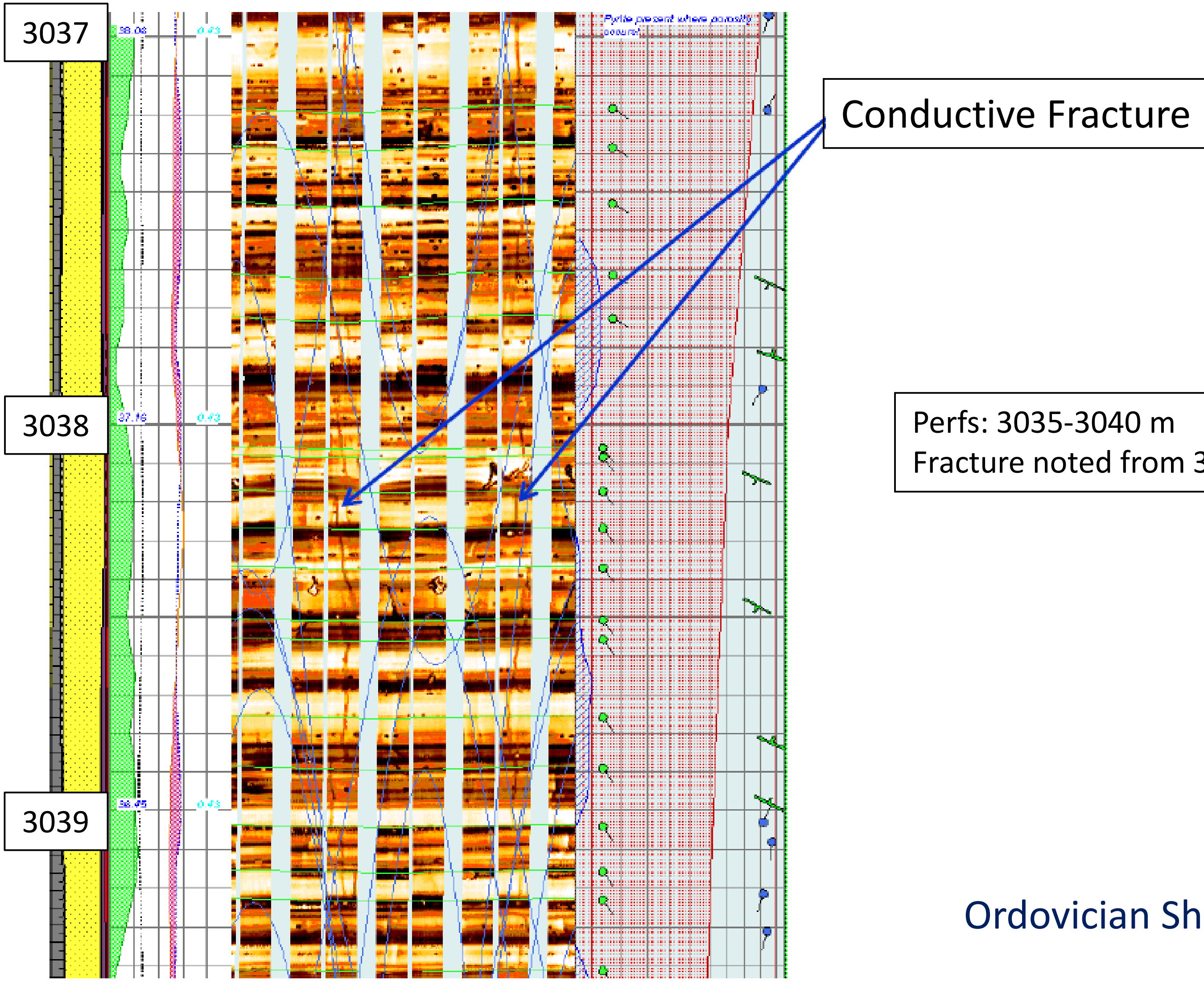
*The rate of pressure falloff following a DFIT injection is a function of the reciprocal of fracture compliance (dp/dV) and fluid loss from the fracture (dV/dt). Fracture closure results in a sharp decrease in fracture compliance <u>and</u> corresponding upward spike in the pressure derivatives, e.g., dp/dt, dp/dG, G dp/dG, as fluid loss is typically not as strongly affected.*

# Field Validation: Ordovician Shale Interval




*Target interval is 5 - 7 meters (16.5 - 23 ft) thick. The stress contrast with bounding intervals ranges from 3.75 – 5 MPa (550 – 725 psi).*

# Vertical Fracture Trace Observed in Image Log

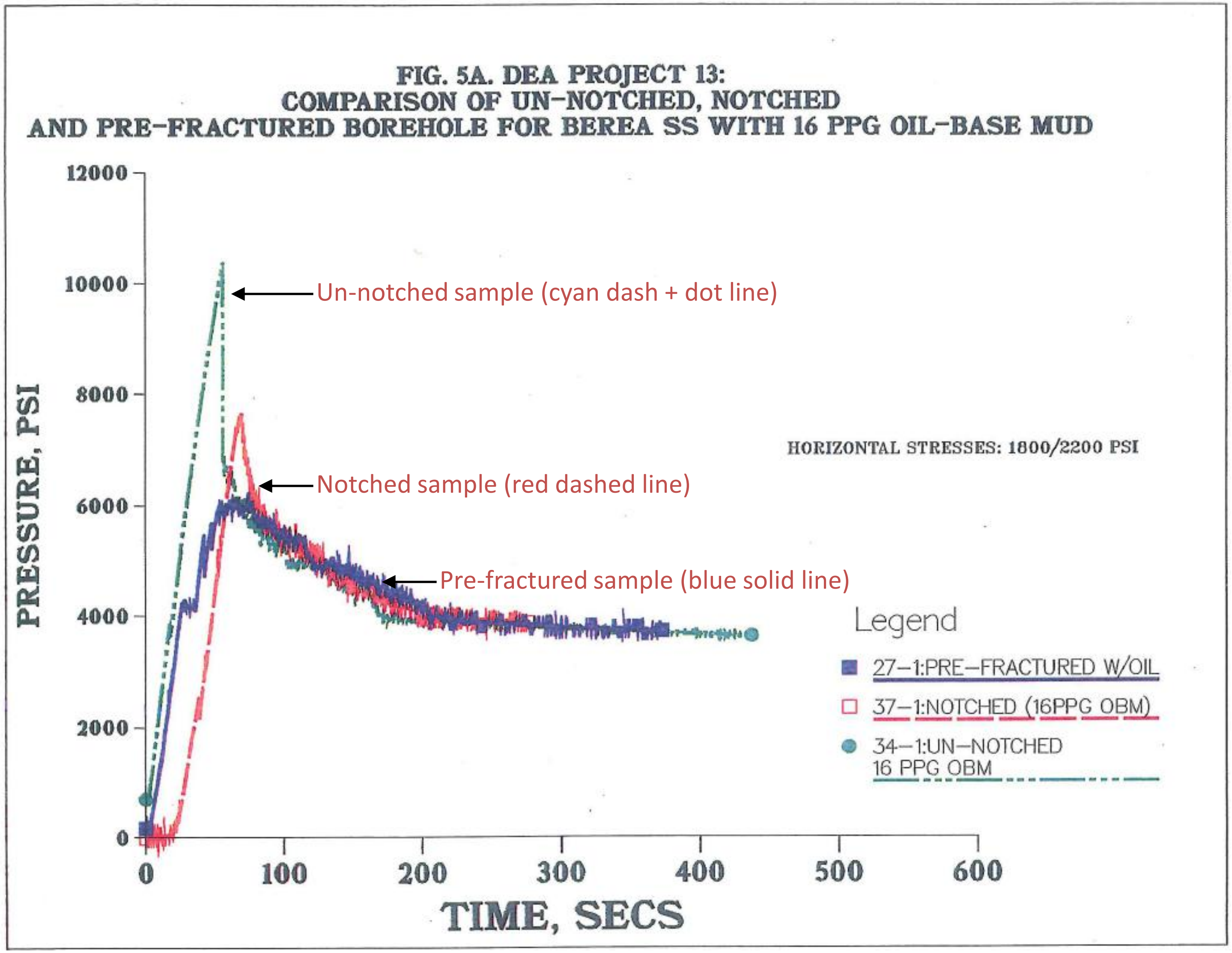



Perfs: 3035-3040 m
Fracture noted from 3037 – 3039 m

Ordovician Shale DFIT interval

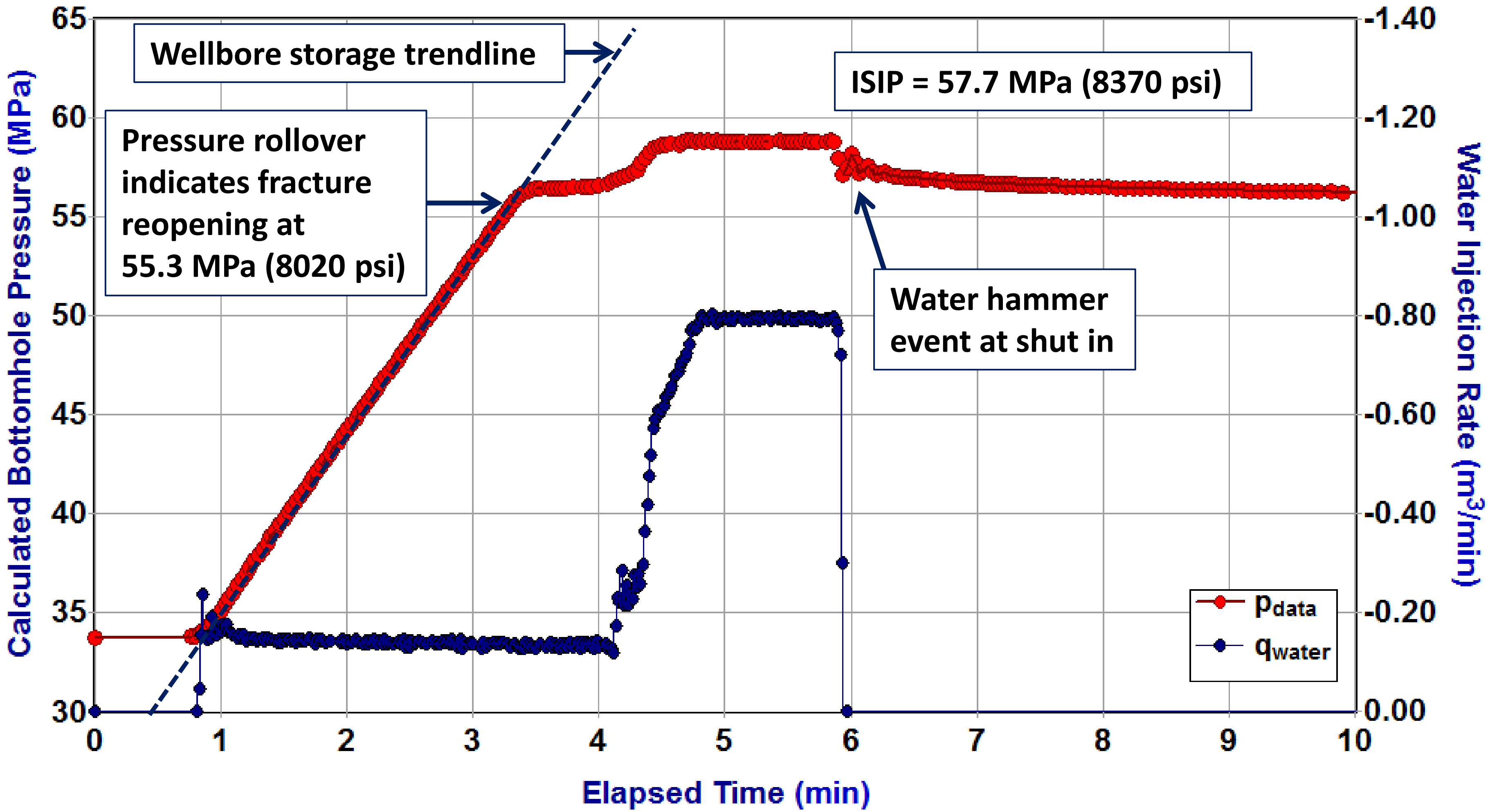
*Open drilling-induced fractures are typically aligned with the far-field hydraulic fracture azimuth and facilitate fracture initiation by circumventing the wellbore hoop-stress zone.*

# Fracture propagation tests



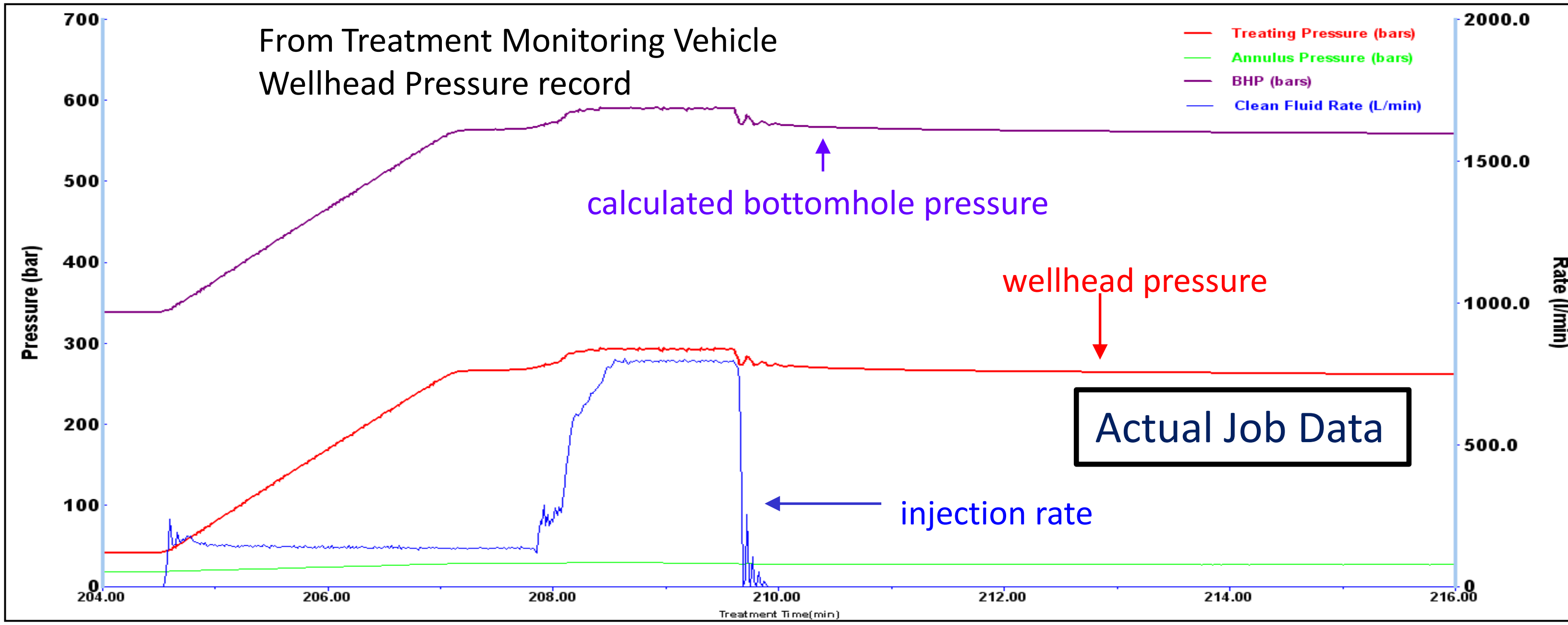

*Pre-fractured samples exhibit relatively low fracture initiation pressure (Onyia, SPE 22581)*

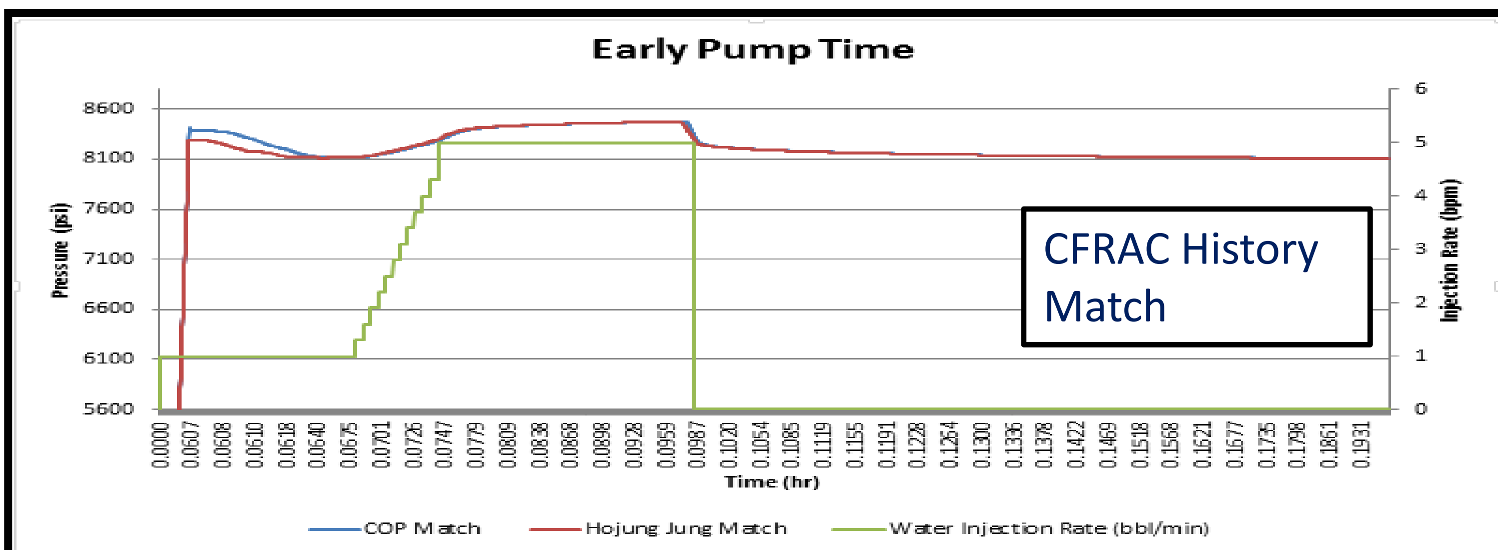
# Fracture Reopening Event Indicated during DFIT



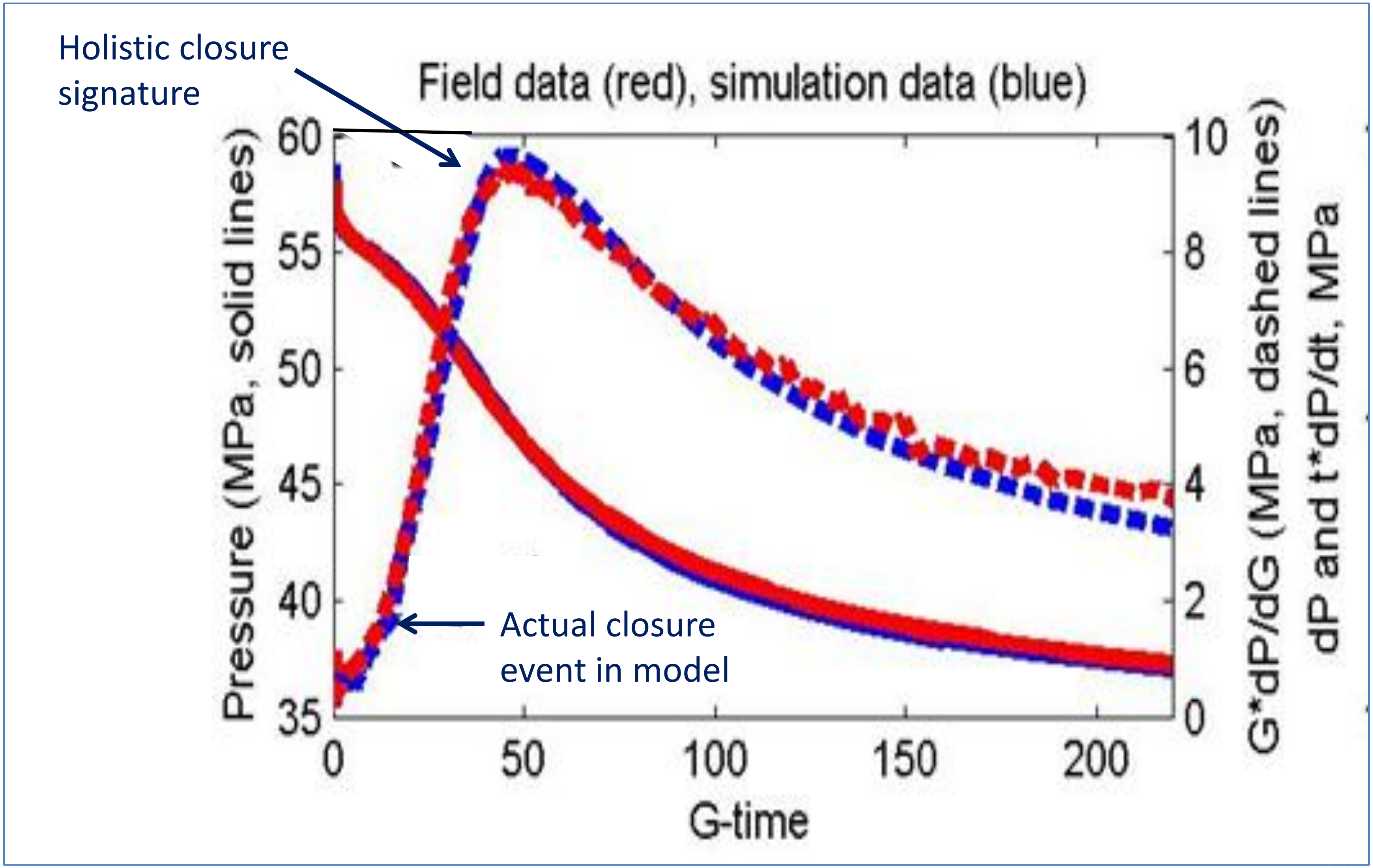

*Injection event and early shut in period for the Ordovician Shale case.*

# CFRAC History Match: Ordovician Shale DFIT



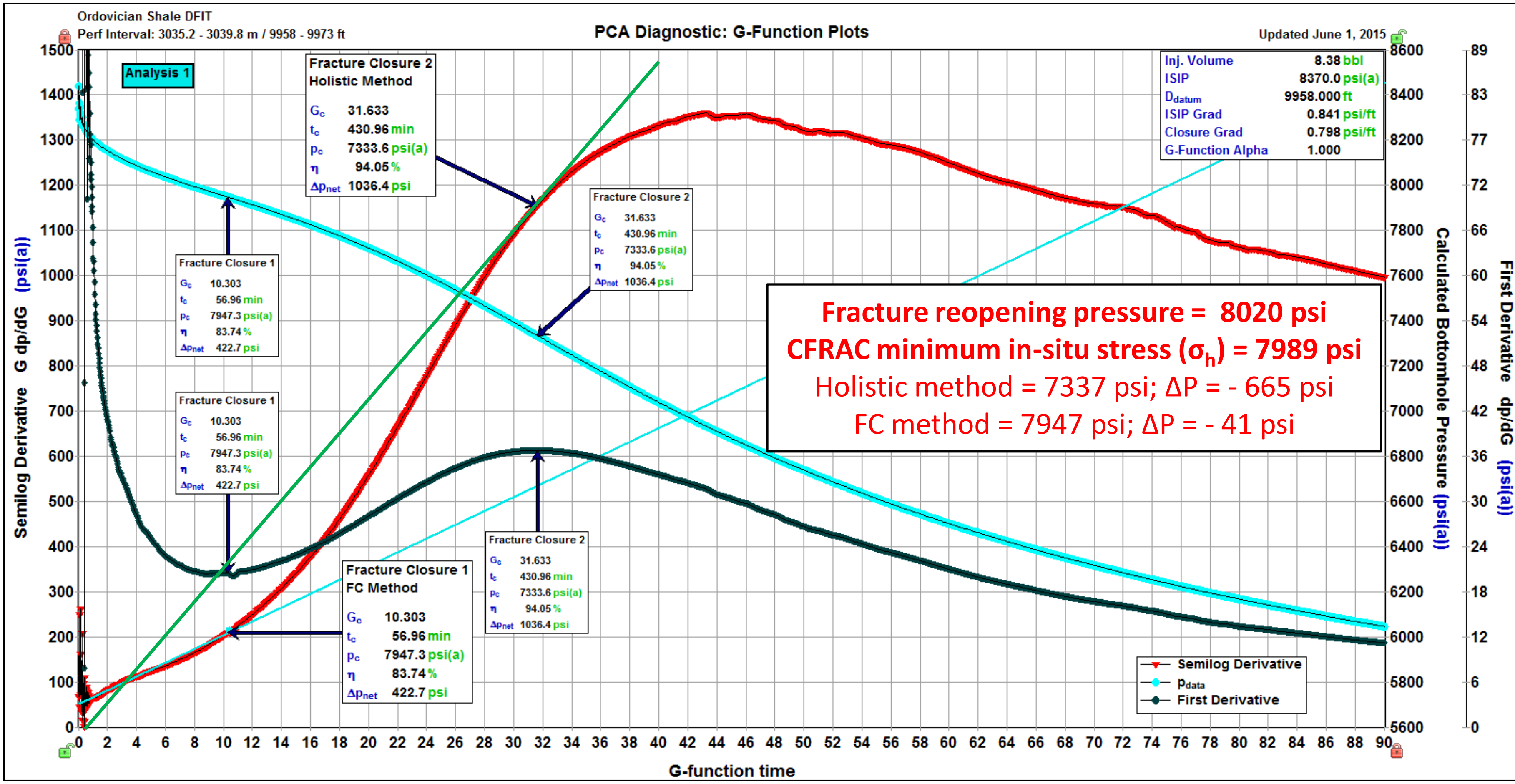
# Ordovician Shale DFIT, G-Function Plot:
## Long-term History Match, CFRAC-Simulated vs Actual



# Parameters Associated with CFRAC Match-Run for the Ordovician Shale DFIT

- Fracture Height = 7 m (23 ft)
- Shear Modulus = 15 GPa (2,170,000 psi)
- Young's Modulus = 37.5 GPa (5,439,000 psi)
- 90% Closure Stress = 45 MPa (6526 psi)
- Fracture toughness = 2 MPa-m$^{0.5}$ (1820 psi-in$^{0.5}$)
- Poisson's Ratio = 0.25
- Permeability = 50.6 nanodarcies
- Reservoir Pressure = 33.7 MPa (4886 psi)
- **Minimum Principal Stress ($\sigma_h$) = 55.1 MPa (7989 psi)**

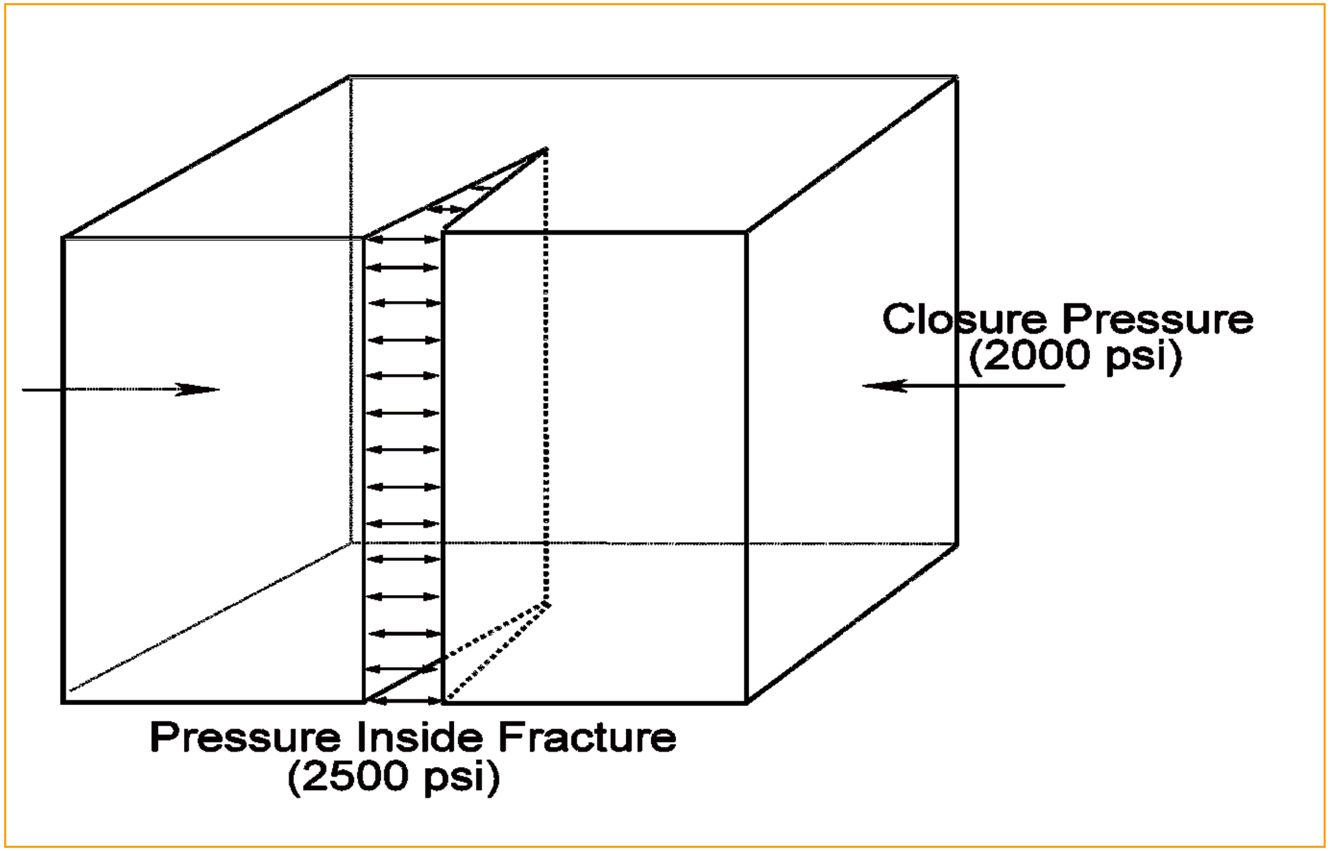
# Diagnostic DFIT G Function Plots




*In the Fracture Compliance (FC) method, fracture closure is picked at the upward inflection in the G*dp/dG curve, as it departs from an initial linear trend. The result is very close to the CFRAC-modeled $\sigma_h$ and the observed fracture reopening pressure.*

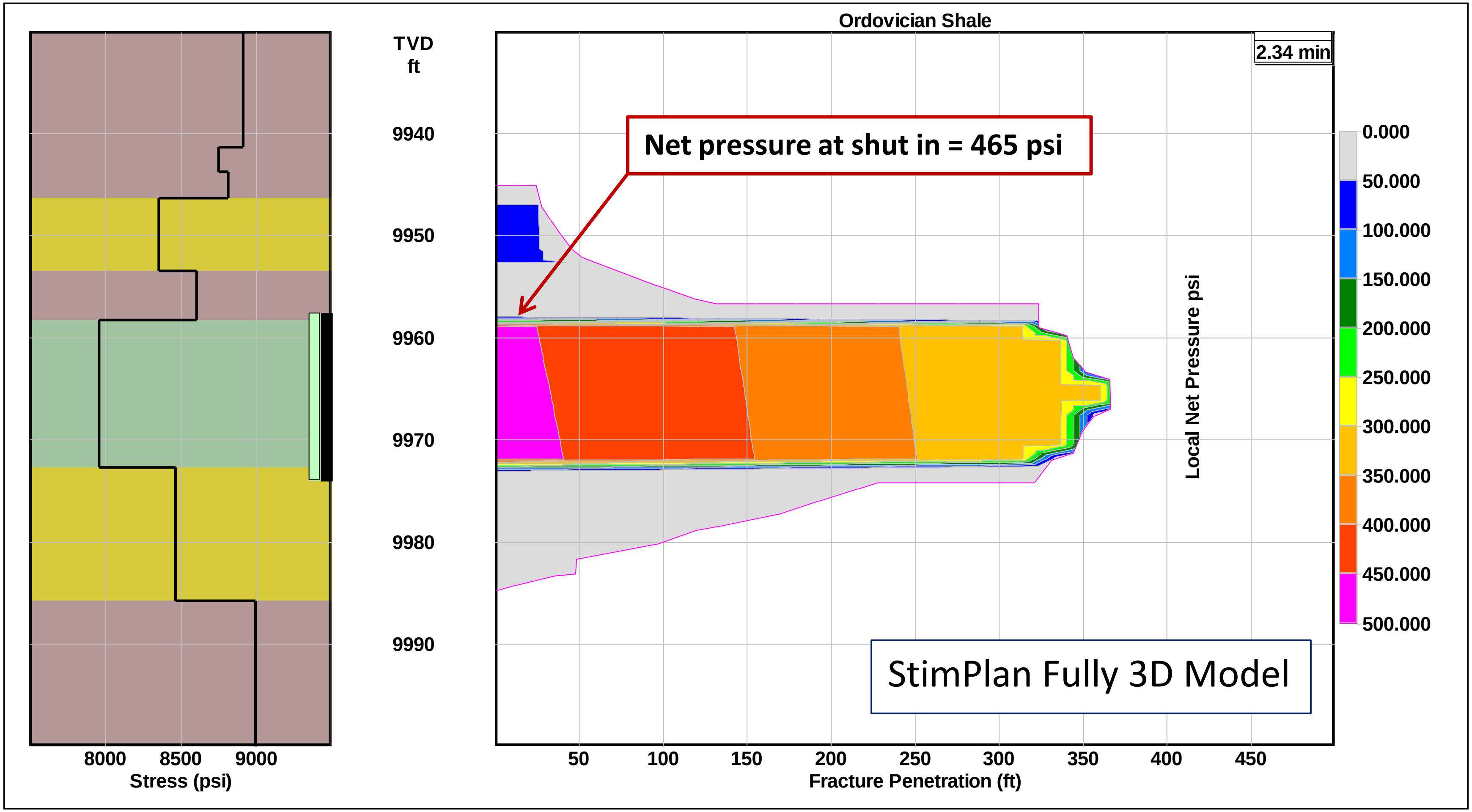
# Net Pressure

Net Pressure = Pressure Inside the Fracture - Closure Pressure
In the example below, net pressure = 2,500 psi - 2,000 psi = 500 psi



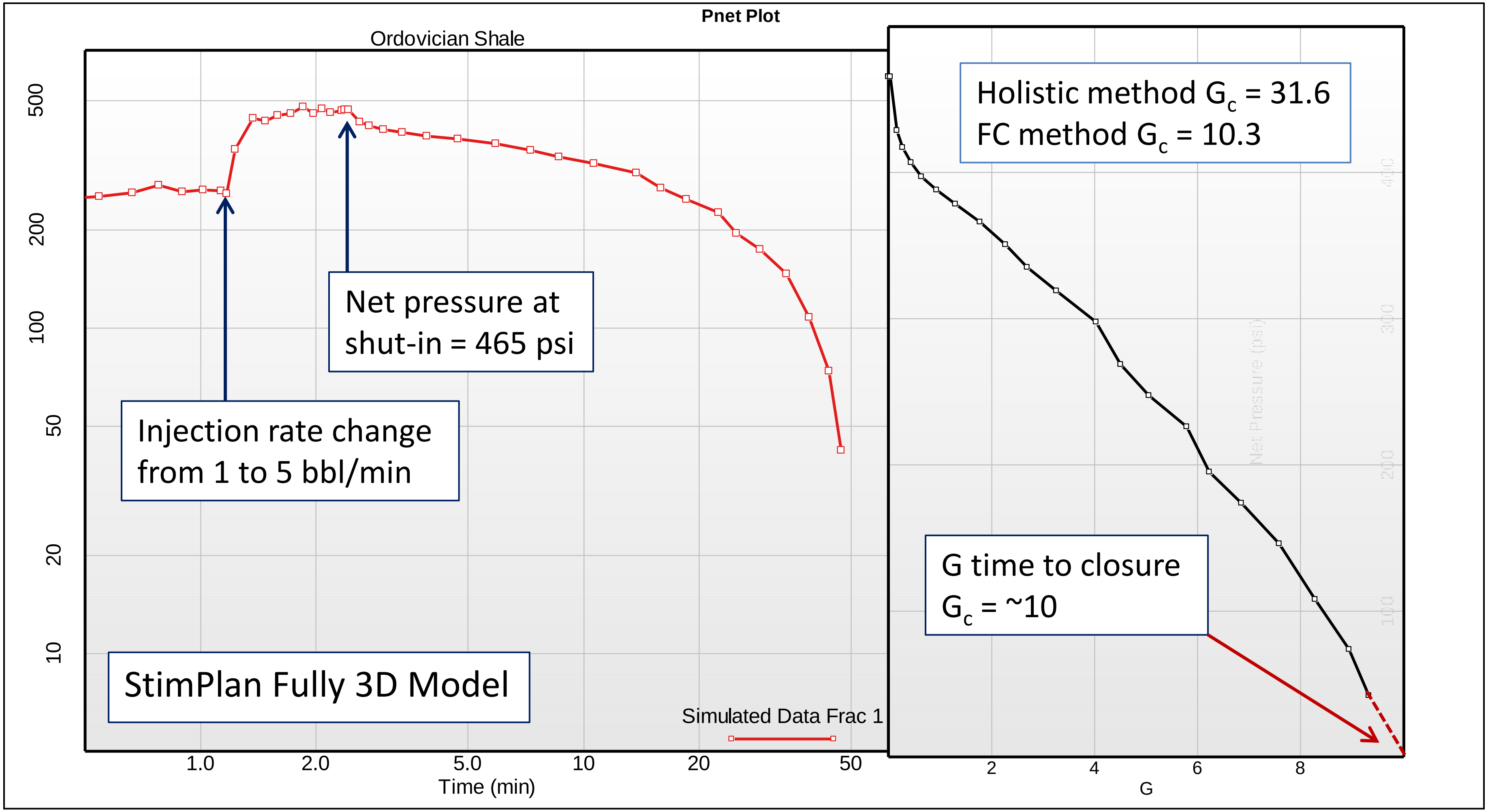

*Net pressure is the driving force in hydraulic fracture propagation*

# DFIT Modelling Using Commercial Hydraulic Fracturing Software: Net Pressure vs Frac Half-Length




*The FC closure selection method yielded net pressure that is compatible with the modelled result; i.e., 423 psi. The Holistic method yielded a net pressure of 1036 psi.*

# DFIT Modelling Using Commercial Hydraulic Fracturing Software: Net Pressure & Closure Time




*The modelled responses compare favorably to the fracture closure event indicated by the FC method, i.e., net pressure at shut in = 423 psi, $P_c$ = 10.3.*

# Field Validation: Summary of Key Points

1. Cement integrity was excellent, as evidenced by the cement bond log, assuring adequate interzonal isolation throughout the injection and falloff periods.
2. The test interval was mechanically strong (low clay content) and sufficiently thick (7 m) for establishing a dominant vertical hydraulic fracture.
3. The stress contrast to higher-stress bounding rock layers is sufficient for containing a DFIT-scale fracture to the test interval.
4. A conductive drilling induced tensile fracture was exhibited in the center of the test interval by an open-hole image log. This preexisting fracture facilitated non-complex, planar fracture initiation and propagation.
5. The vertical orientation of the wellbore assures that the axial starter fracture will be in line with the plane normal to the minimum principal/horizontal stress, further reducing the potential for fracture complexity.
6. The pressure rollover event that was observed near the beginning of injection and at a relatively low bottomhole pressure is a strong indication that the preexisting fracture was reopened during the DFIT. Reopening of an existing fracture assures that the influence of wellbore hoop stress zone was mitigated or eliminated.

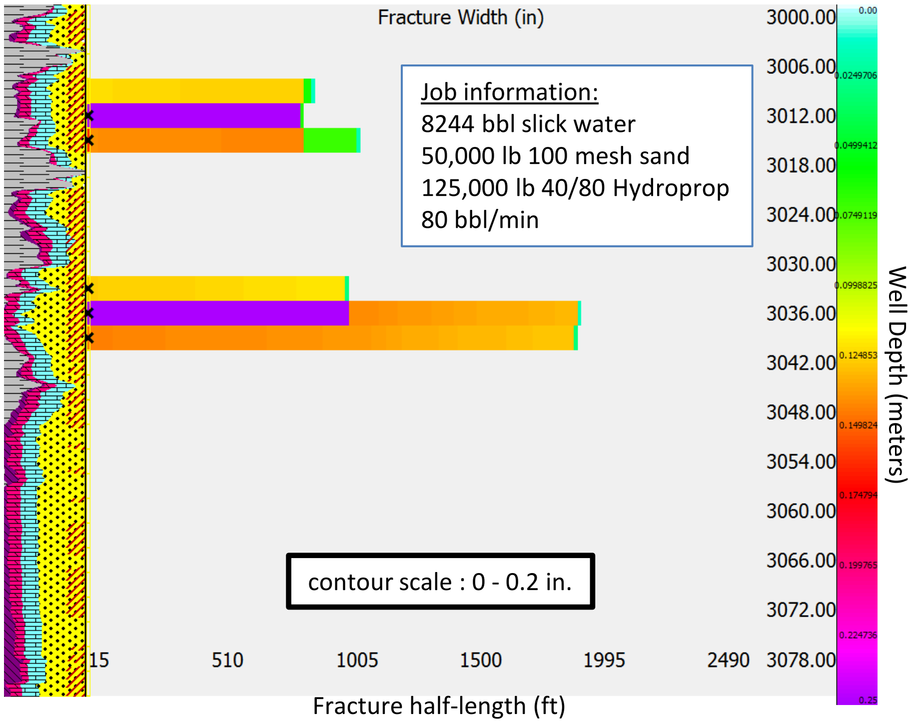
# Field Validation: Summary of Key Points

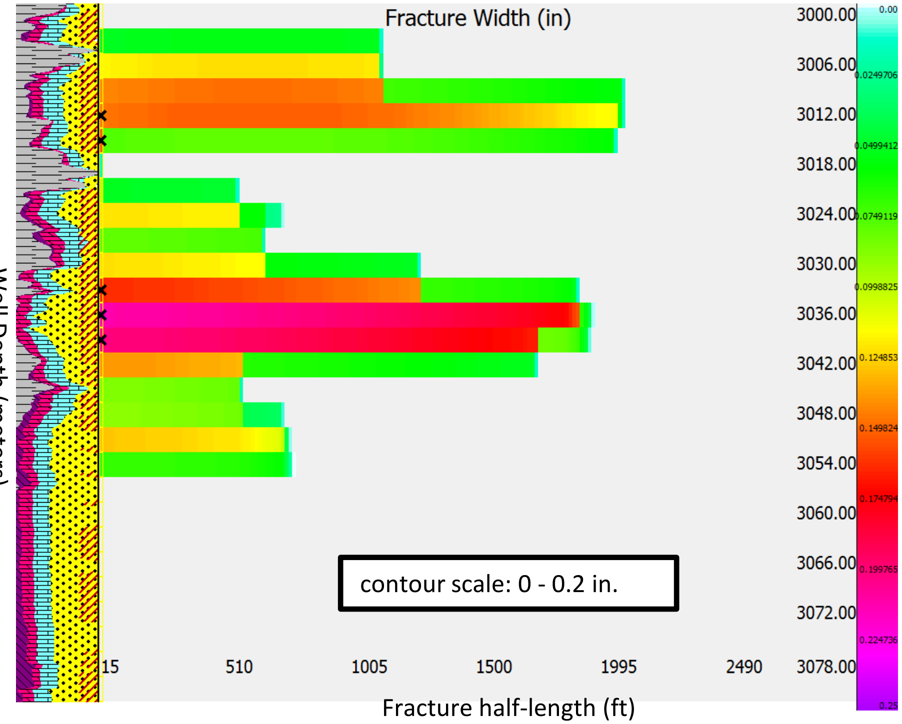
7. The onset of the pressure rollover event, in which the pressure plot departs from the wellbore storage trend line (at 8020 psi), is in effect the fracture reopening pressure. This fracture reopening pressure was slightly above the indicated fracture closure pressure (at 7989 psi).
8. There was a water hammer event at the end of injection, indicating that an excellent connection existed between the wellbore and primary, far-field fracture. This is assurance that there was no distortion of the shut-in pressure response due to near-wellbore fracture complexity or tortuousity.
9. Borehole breakout analysis of adjacent intervals indicated the existence of a large difference between minimum and maximum horizontal stresses. Consequently, the probability of a primary hydraulic fracture interacting with and reopening crossed natural fractures is very low; transverse fracture storage is extremely unlikely.
10. Permeability in the tested interval is very low, in the range of 20 - 100 nanodarcies. Consequently, dimensionless fracture conductivity should be very high following mechanical fracture closure, resulting in a stable fluid leak-off rate during closure. Thus, the change in fracture compliance/stiffness due to fracture closure should dominate the pressure falloff response when fracture closure occurs.

# The Implications of Fracture Closure Selection for Treatment Design and Interpretation

# Main Treatment Design – Hydraulic Fracture Width

## Ordovician Shale Case




<u>Treatment Pressure-Match Simulation (GOHFER)</u>

**Closure derived from Holistic DFIT method**

DFIT net pressure = 1056 psi

End-of-injection net pressure = 1107 psi

Process zone stress = 150% of default

Stress shift = 900 psi

<u>Treatment Pressure-Match Simulation (GOHFER)</u>

**Closure derived from FC DFIT method**

DFIT net pressure = 424 psi

End-of-injection net pressure = 560 psi

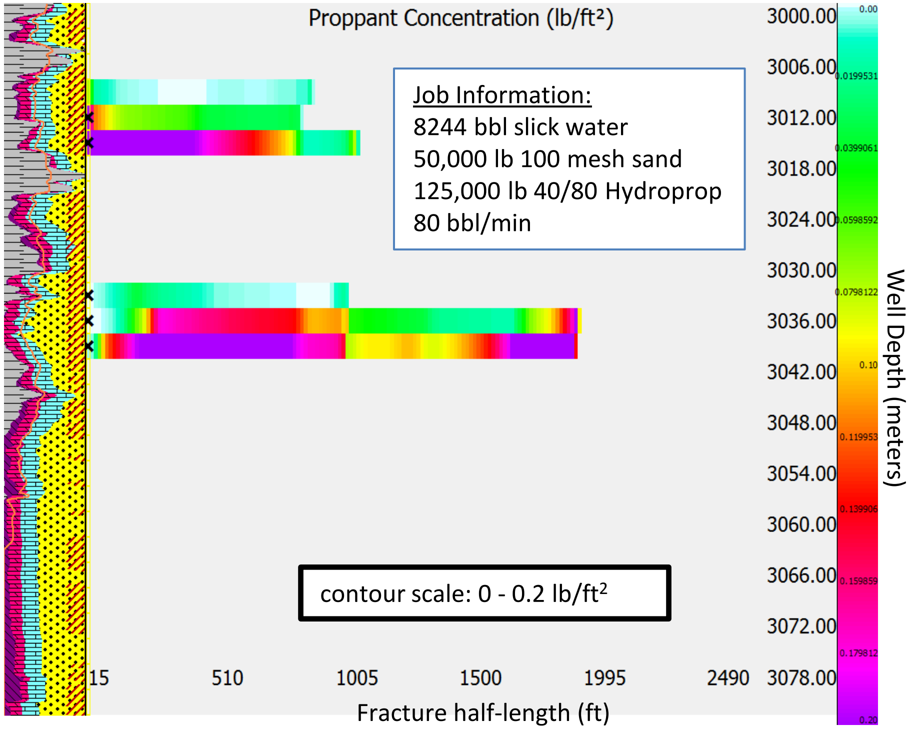
Process zone stress = 50% of default

Stress shift = 1500 psi

*Fracture closure pressure determines the calculated net pressure, which is the basis for pressure-history calibration of fracture models. For the Ordovician Shale case, fracture geometry varies significantly as a function of the DFIT fracture closure selection method.*

# Main Treatment Design – Proppant Concentration

## Ordovician Shale Case

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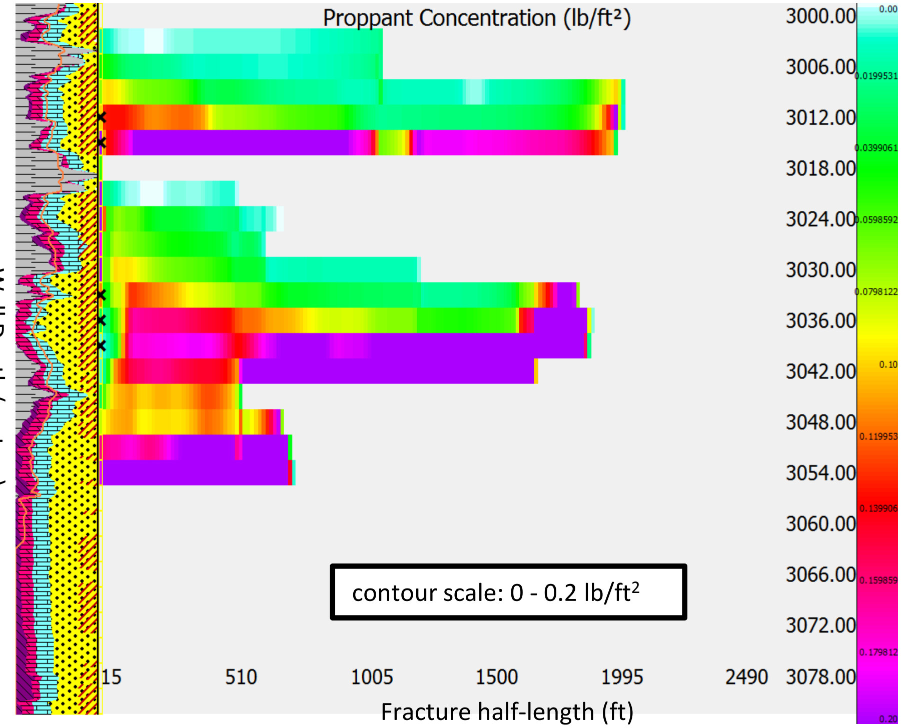


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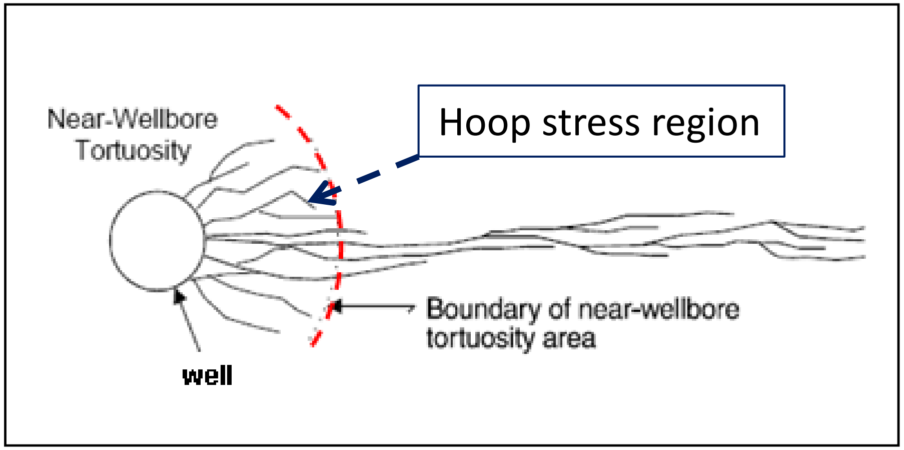
*Fracture closure pressure determines the calculated net pressure, which is the basis for pressure-history calibration of fracture models. For the Ordovician Shale case, proppant distribution varies significantly as a function of DFIT fracture closure selection method.*

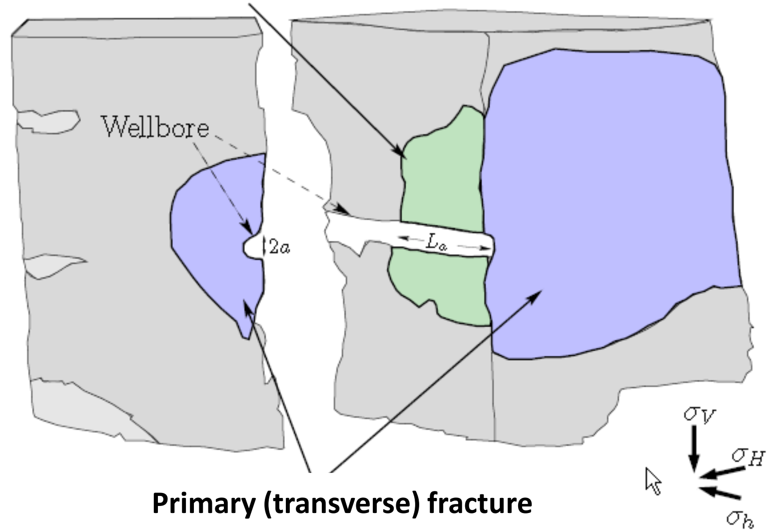
# Considerations for DFIT in Horizontal Wells

# Observations of Complex Fracture Initiation from Horizontal Wellbore




Cipolla (2008)

Starter (axial) fracture




Primary (transverse) fracture

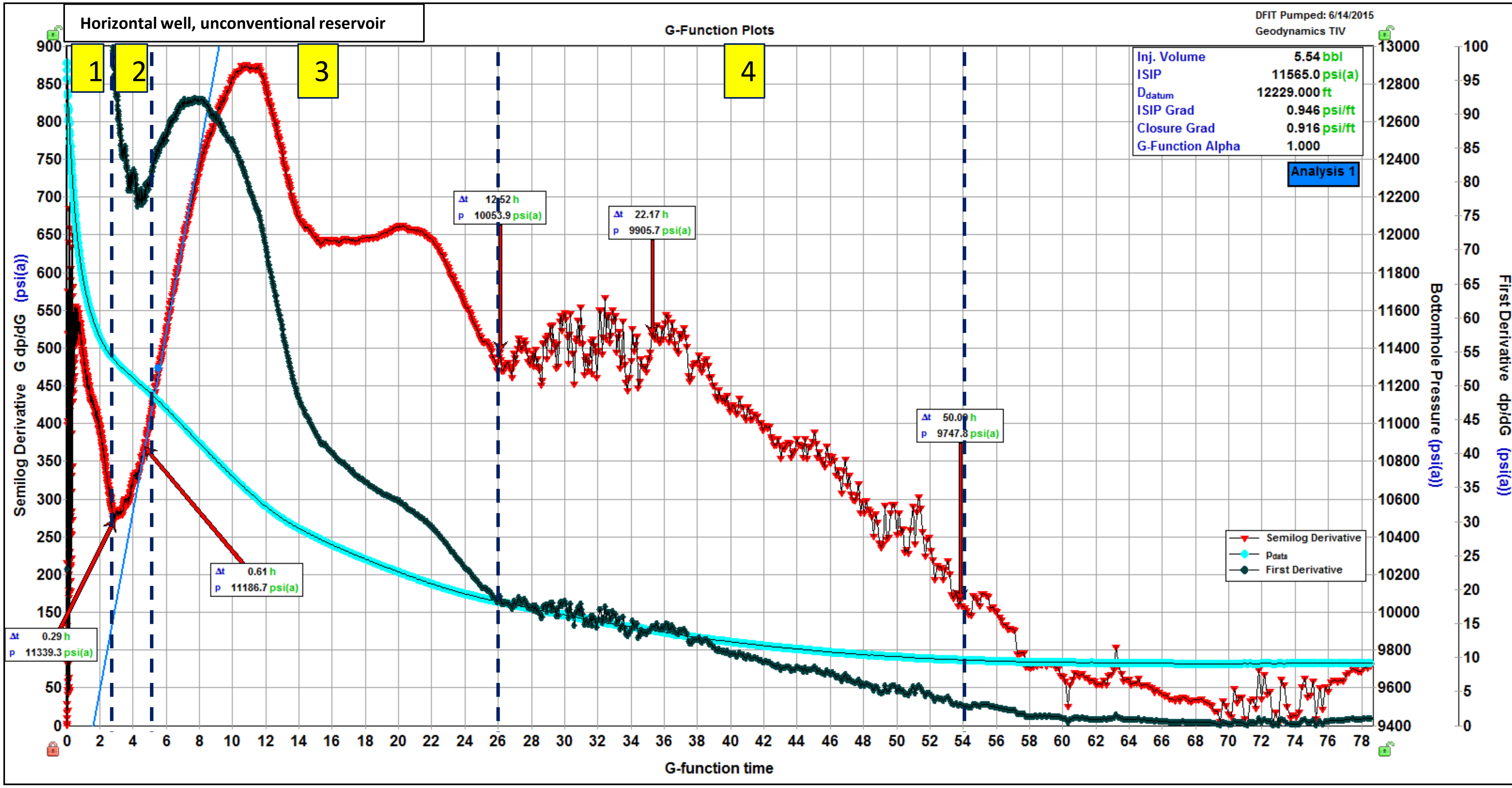
Weijers (1994)

*Near-wellbore fracture complexity is influenced by wellbore azimuth, orientation & exposure. It can result in significantly elevated pressure during DFIT injection and early shut in period.*

*If properly designed, most of the injected DFIT volume contributes to a primary (transverse) hydraulic fracture propagating normal to the minimum principal stress.*

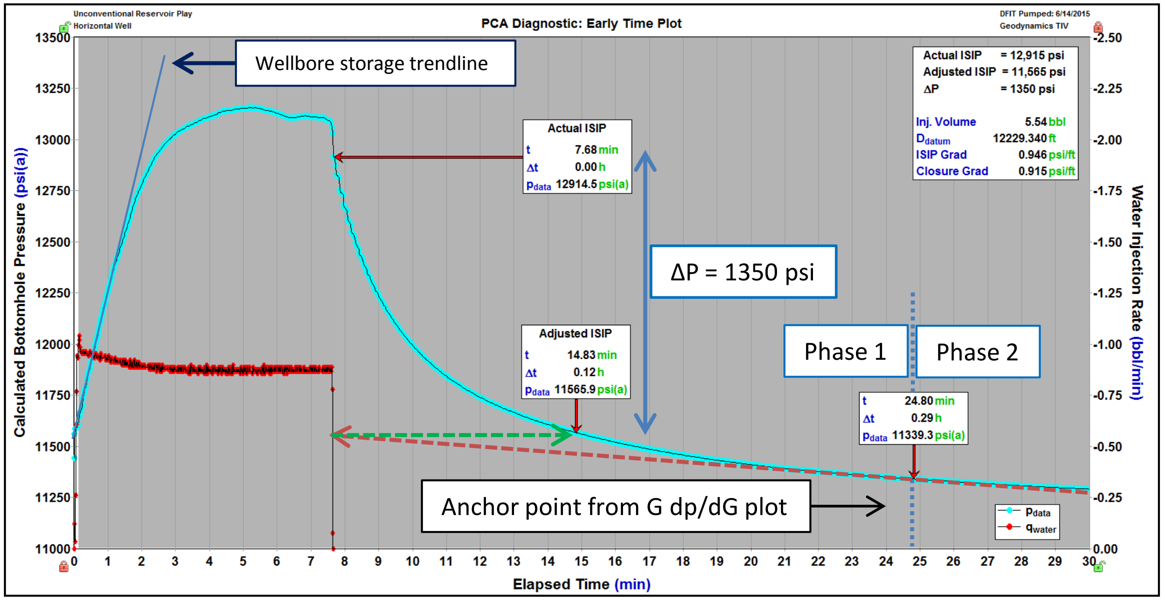
# The Four Phases of a Typical DFIT Shut-in

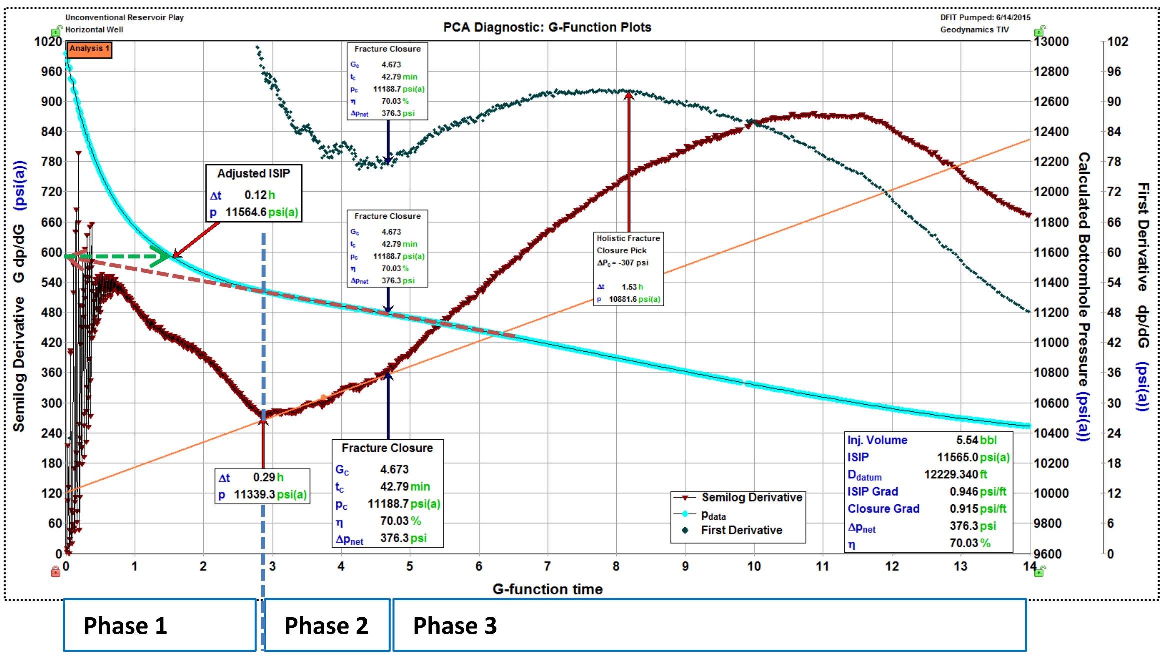
## Cased and Cemented Horizontal Well




*Phase 1: dissipation of excess pressure; Phase 2: far-field fracture closure response; Phase 3: mechanical closure/reduction of residual aperture; Phase 4: reservoir response*

# ISIP Adjustment for Computing Net Pressure




*Excess treating pressure occurs as a result of near-wellbore fracture complexity and tortuosity, and must dissipate via fluid leak-off and fracture tip extension during the initial phase of the DFIT shut in period.*

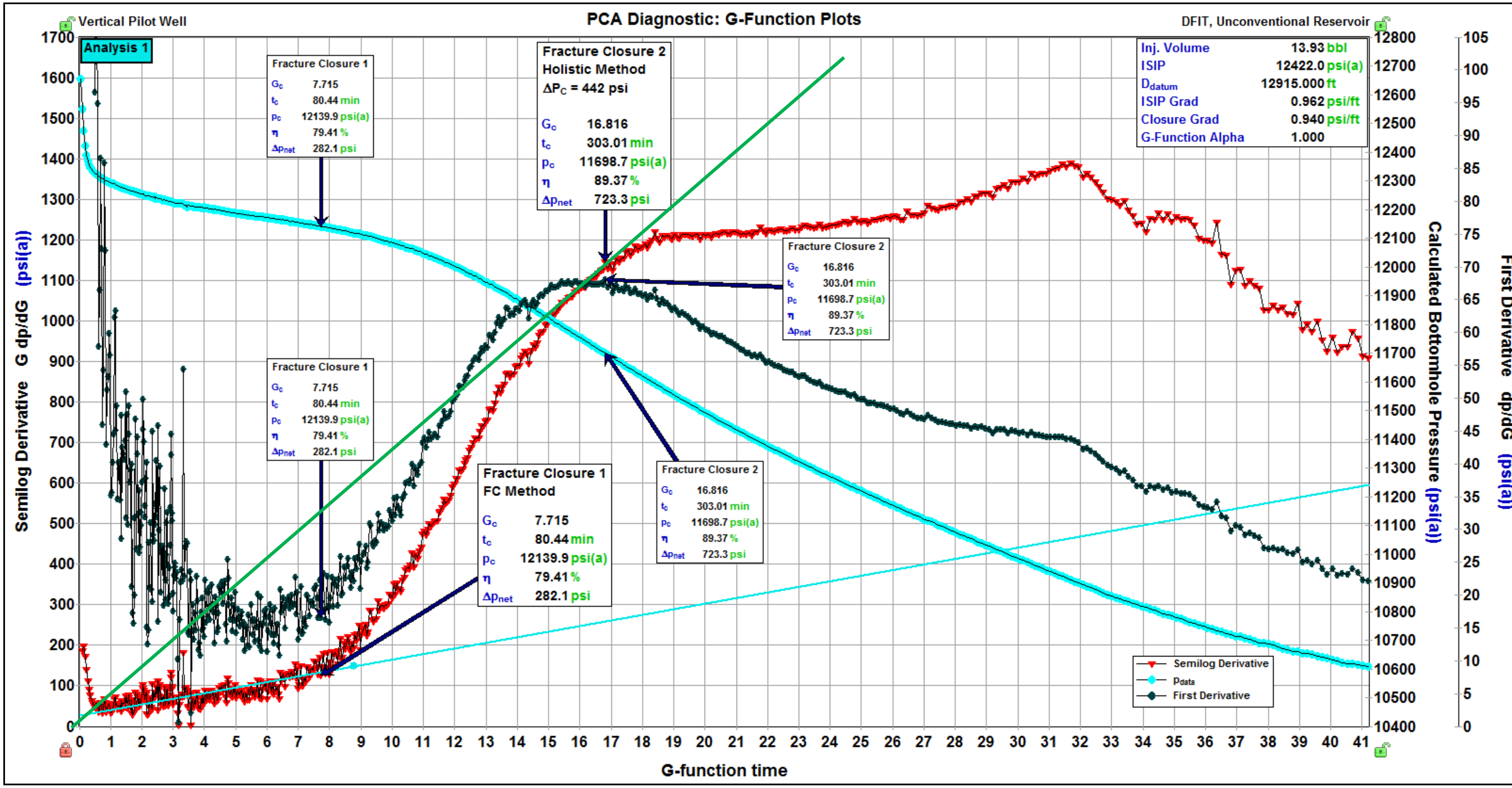
*The actual ISIP is not representative of conditions associated with the primary far-field fracture because of this over-pressure event.*

*The ISIP associated with the far-field primary fracture can be estimated or adjusted by using the Phase 2 trend line to extrapolate to the Y-axis intercept. In this way, the actual net pressure at shut in can be approximated.*

*This ISIP adjustment technique does not account for equilibrium and tip extension processes that occur right after shut in and thus tends to slightly underestimate the far-field ISIP.*

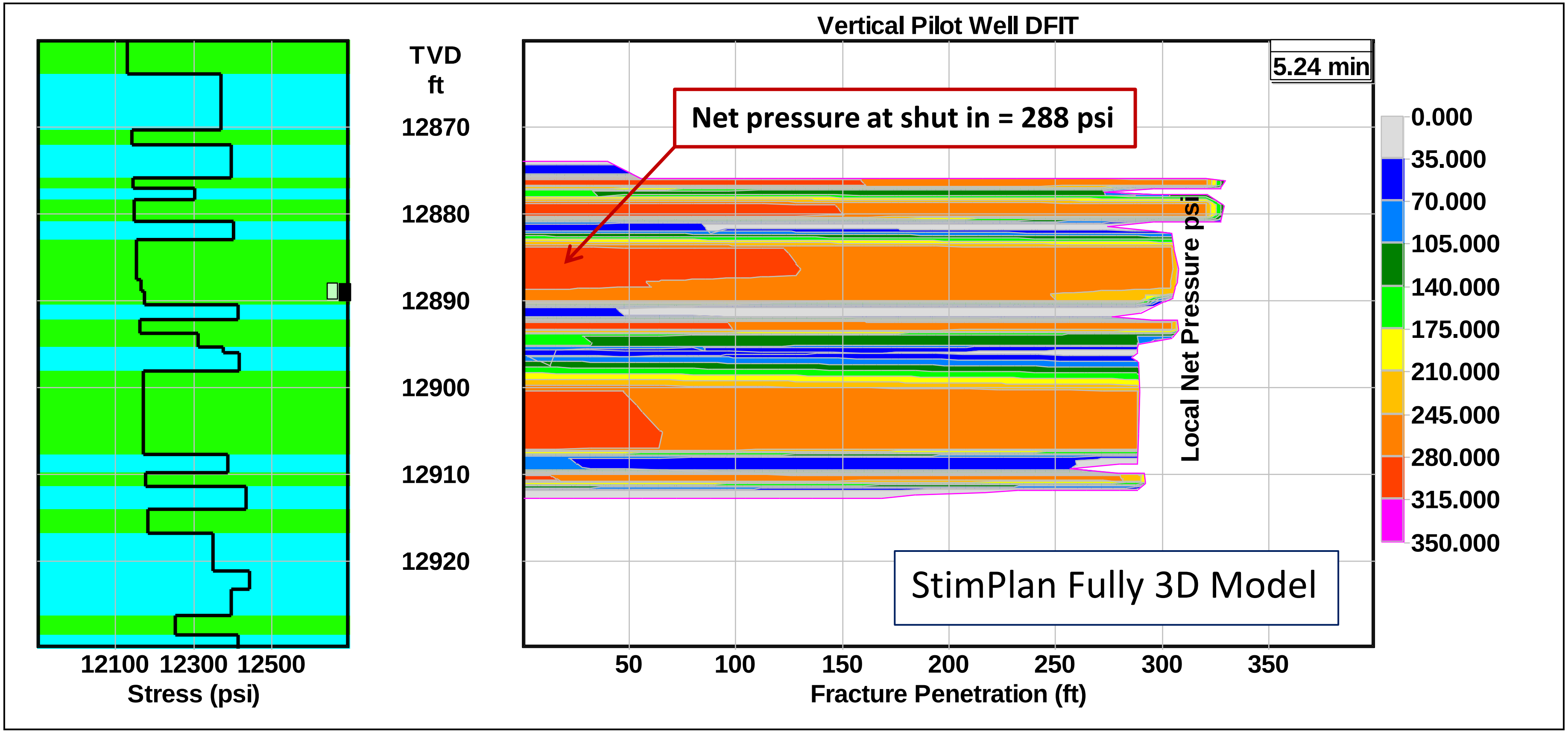
# Reevaluating Previous DFIT Interpretations in an Unconventional Play

# Diagnostic DFIT G Function Plots



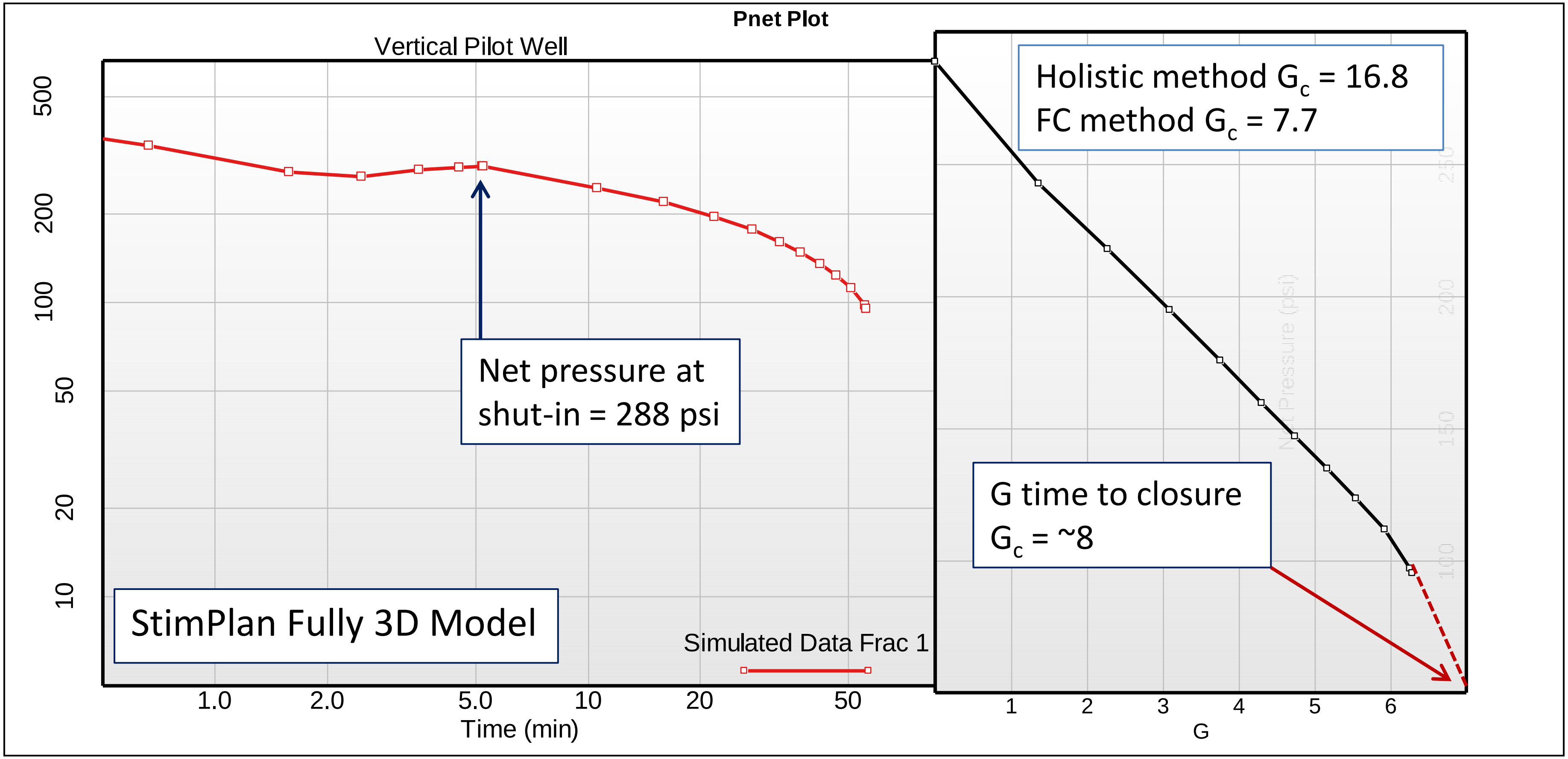

*The first DFIT in the unconventional play was conducted in a vertical pilot well. Derivative signatures are similar to the previous Ordovician shale case.*

# DFIT Modelling Using Commercial Hydraulic Fracturing Software: Net Pressure vs Frac Half-Length




*The Fracture Compliance (FC) closure selection method yielded net pressure that is compatible with the modelled result; i.e., 282 psi. The Holistic method yielded a net pressure of 723 psi.*

# DFIT Modelling Using Commercial Hydraulic Fracturing Software: Net Pressure & Closure Time



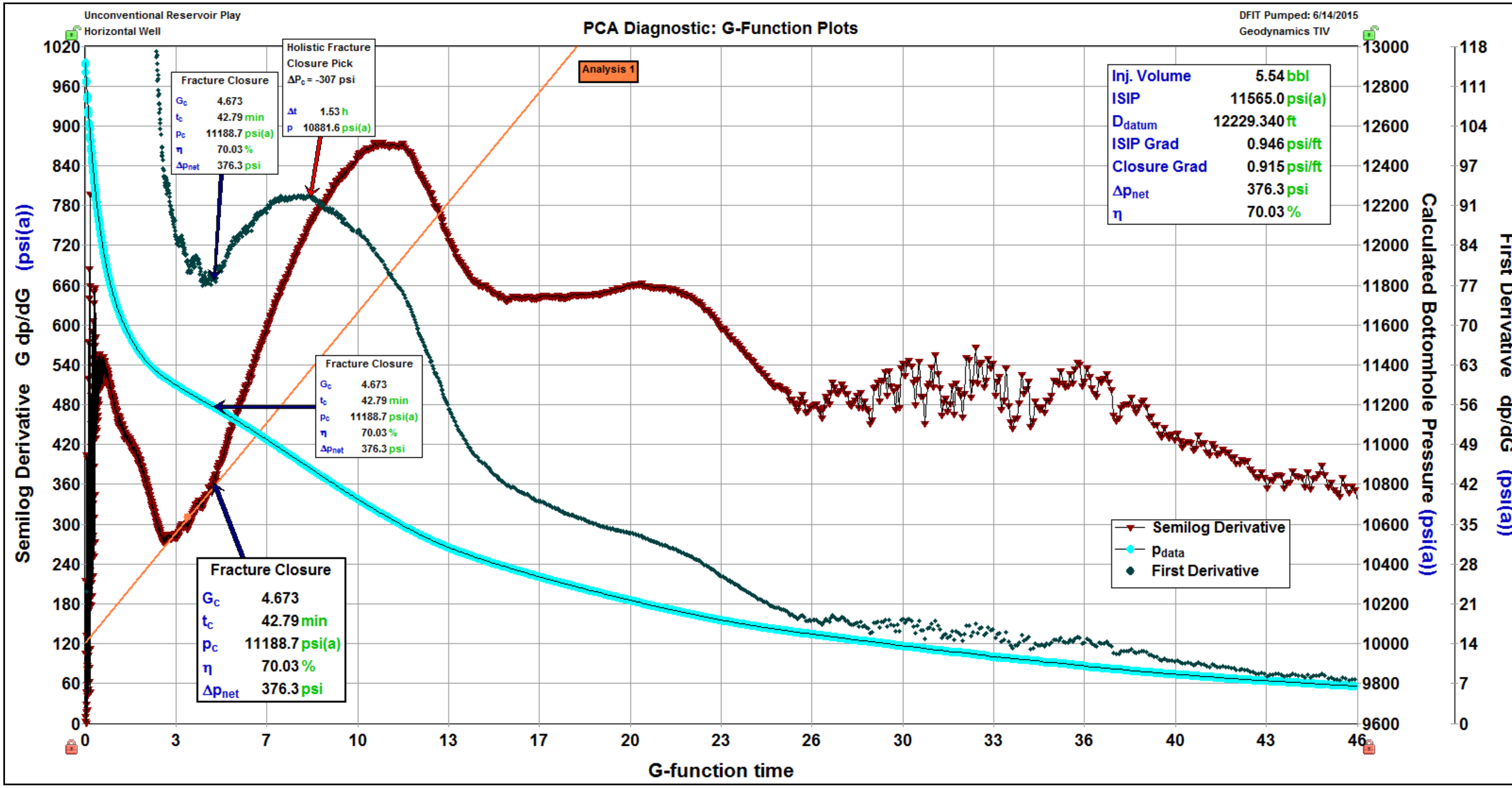

*The modeled responses compare favorably to the fracture closure event indicated by the Fracture Compliance (FC) method, i.e., net pressure at shut in = 282 psi, $P_c$ = 7.7.*

# DFIT Reexamination: Quality Criteria

- Characteristic derivative signatures (based on the Fracture Compliance (FC) method)
  - Increasing change in slope from the initial G dp/dG straight-line trend
  - Departure from minima in dp/dG plot
- Smoothly changing pressure and derivative responses
- Compatibility with fracture model projections
  - Net pressure: 200 – 400 psi
  - Time to fracture closure: 20-150 minutes

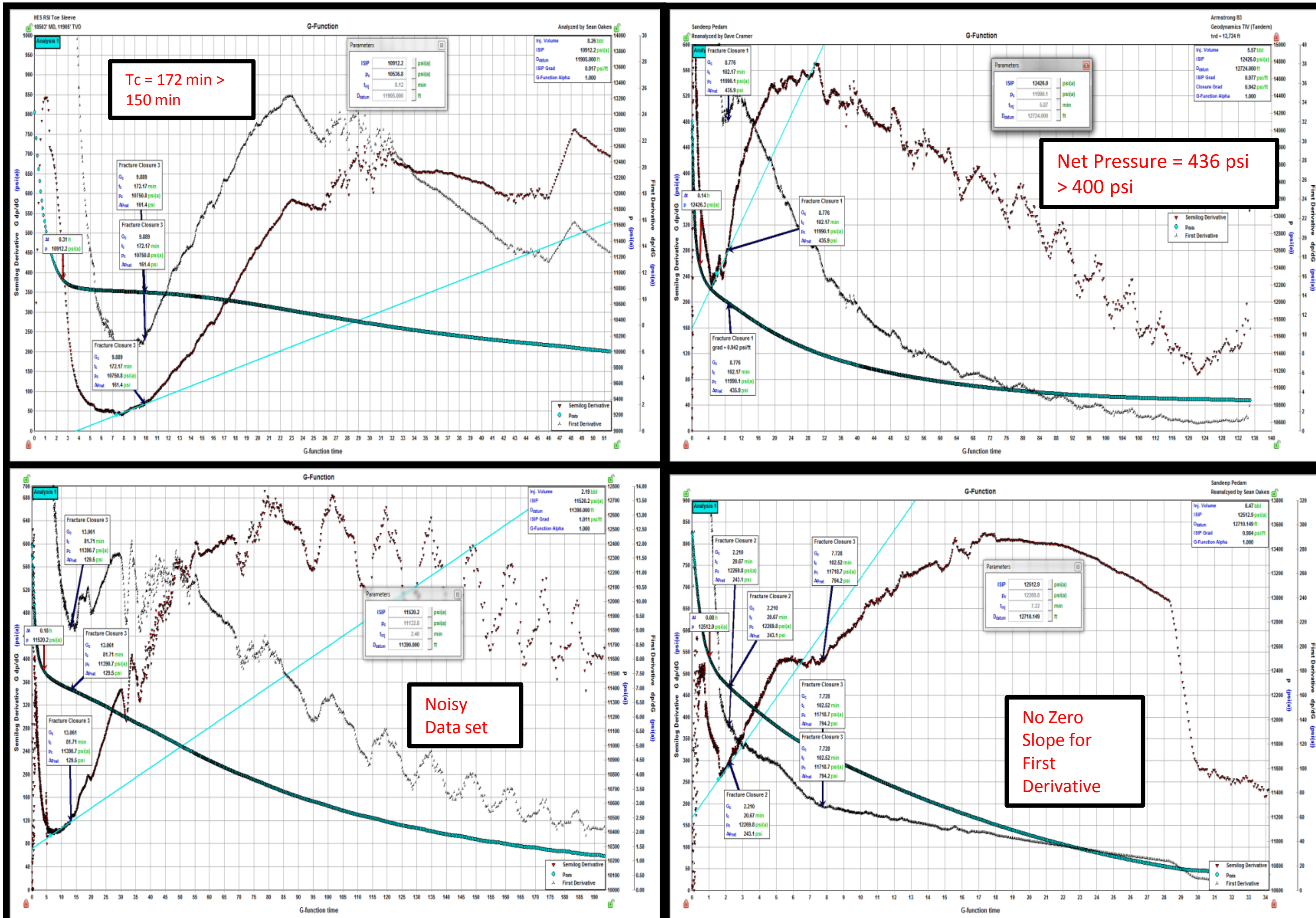
# Highly Reliable Interpretation

## All quality criteria were satisfied (acceptable)



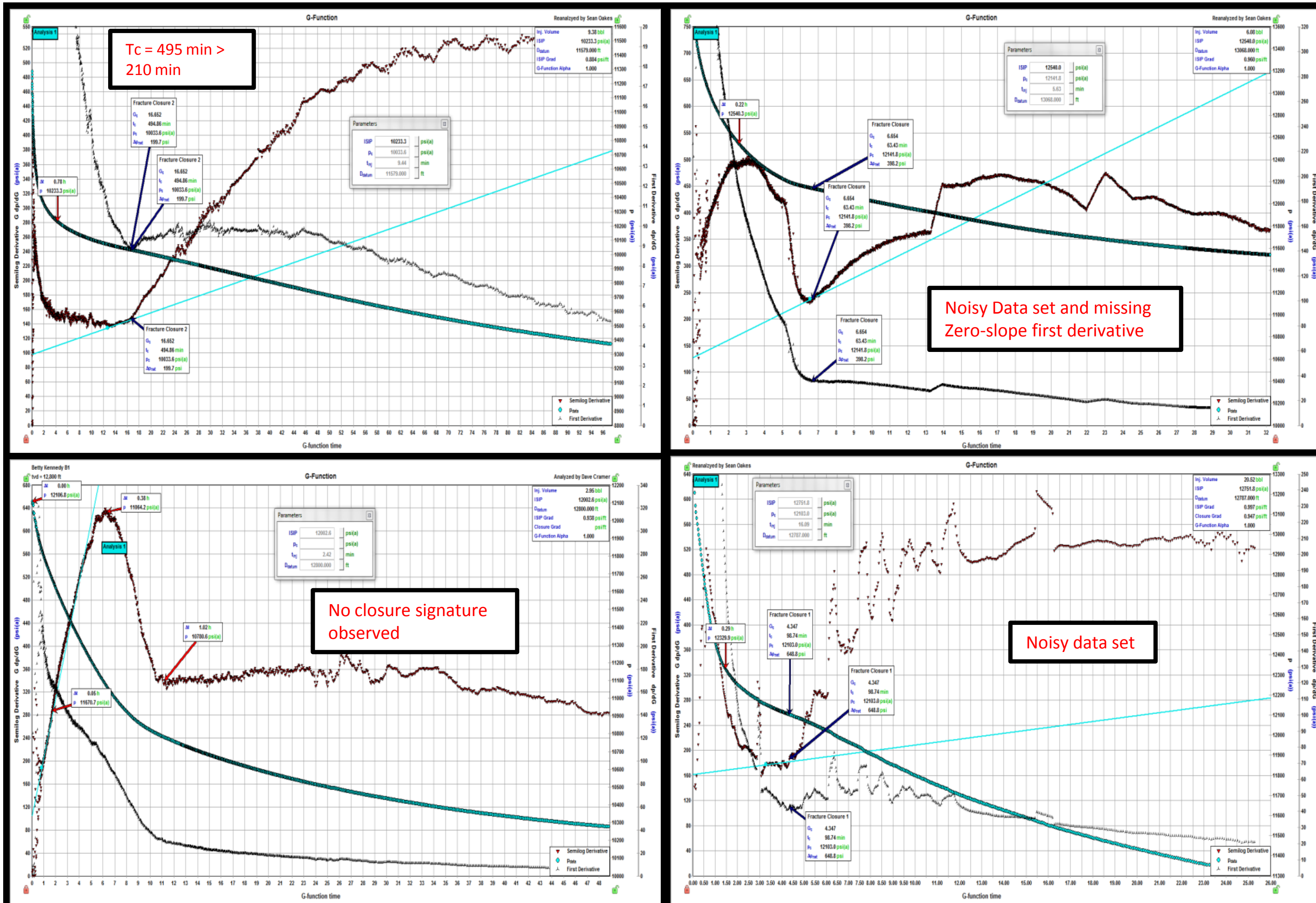
# Moderately Reliable Interpretation

## All but one of the quality criteria were satisfied (acceptable)



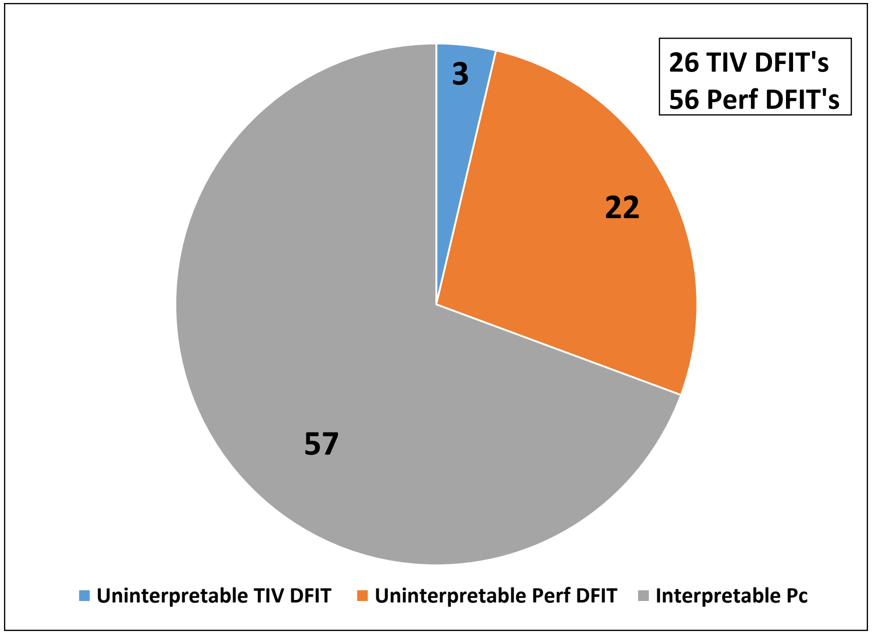
# Unreliable Interpretation

## Multiple quality criteria were not satisfied (unacceptable)

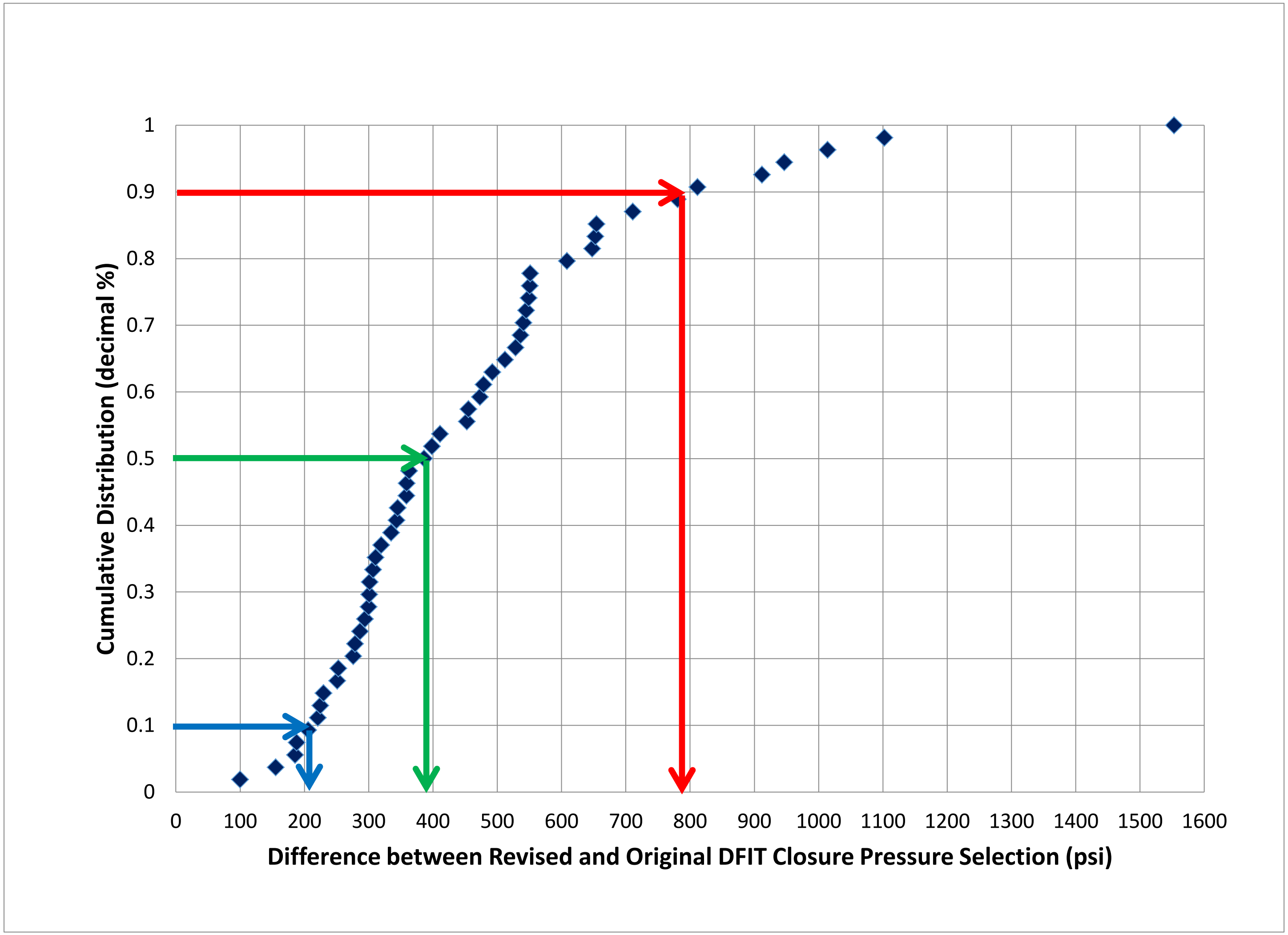


# DFIT Reexamination Findings

- Conducted by Sean Oakes, ConocoPhillips
- 82 DFIT’s were reexamined using the Fracture Compliance (FC) method.
- Previous DFIT evaluation criteria was based on the Holistic method.
- 26 DFIT’s done via TIV (toe initiator valve)
- 56 DFIT’s done via Frac Stage 1 perf clusters
- 57 or 69% of all DFIT’s were deemed reliable for fracture closure selection.
- Best pressure responses were achieved using delayed-action, pressure-actuated TIV’s as compared to other methods, e.g., multiple perforation clusters. This is believed to be the result of providing a relatively good connection of the wellbore with a single primary fracture.

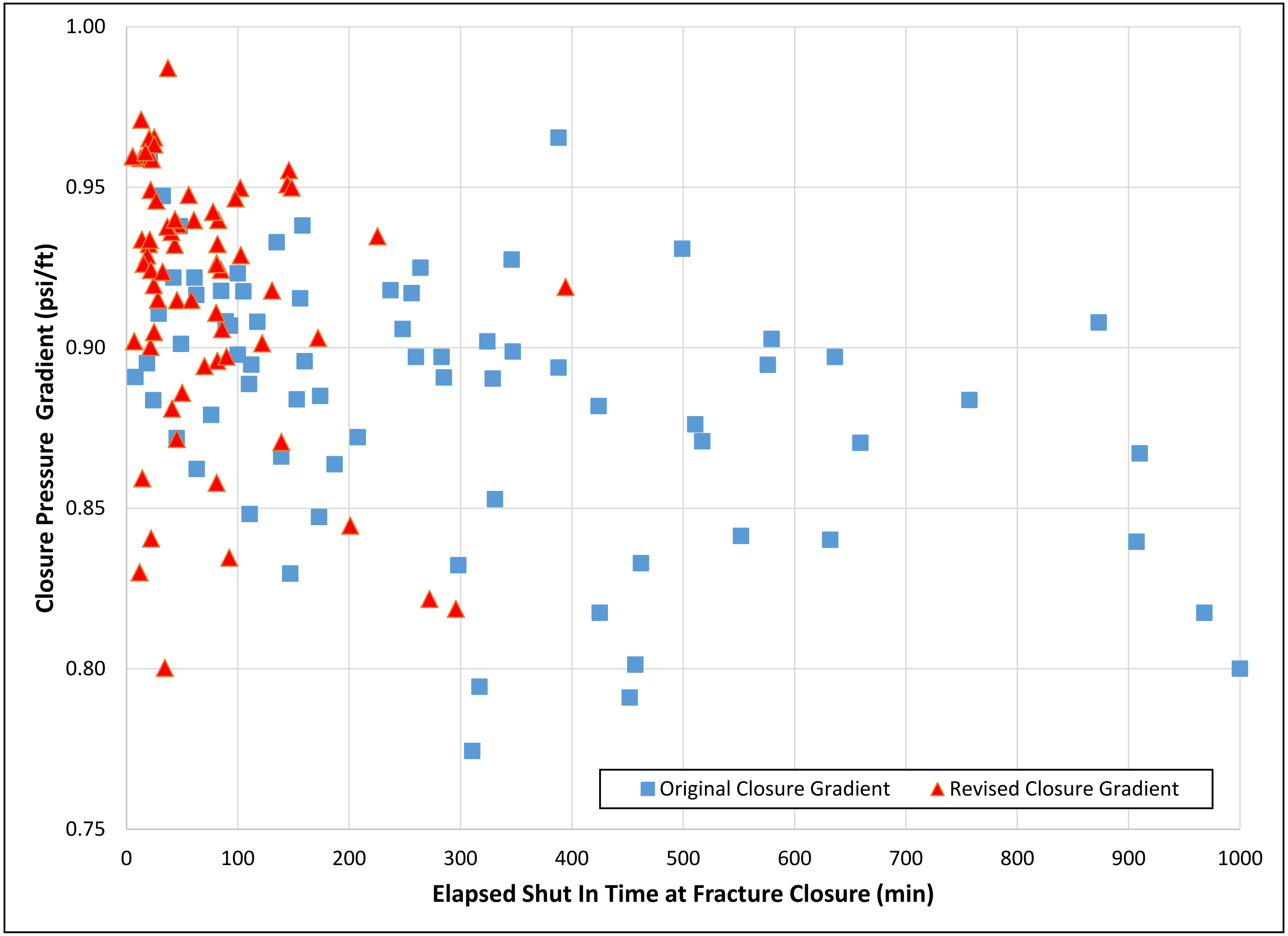


# Magnitude of Change in Closure Pressure



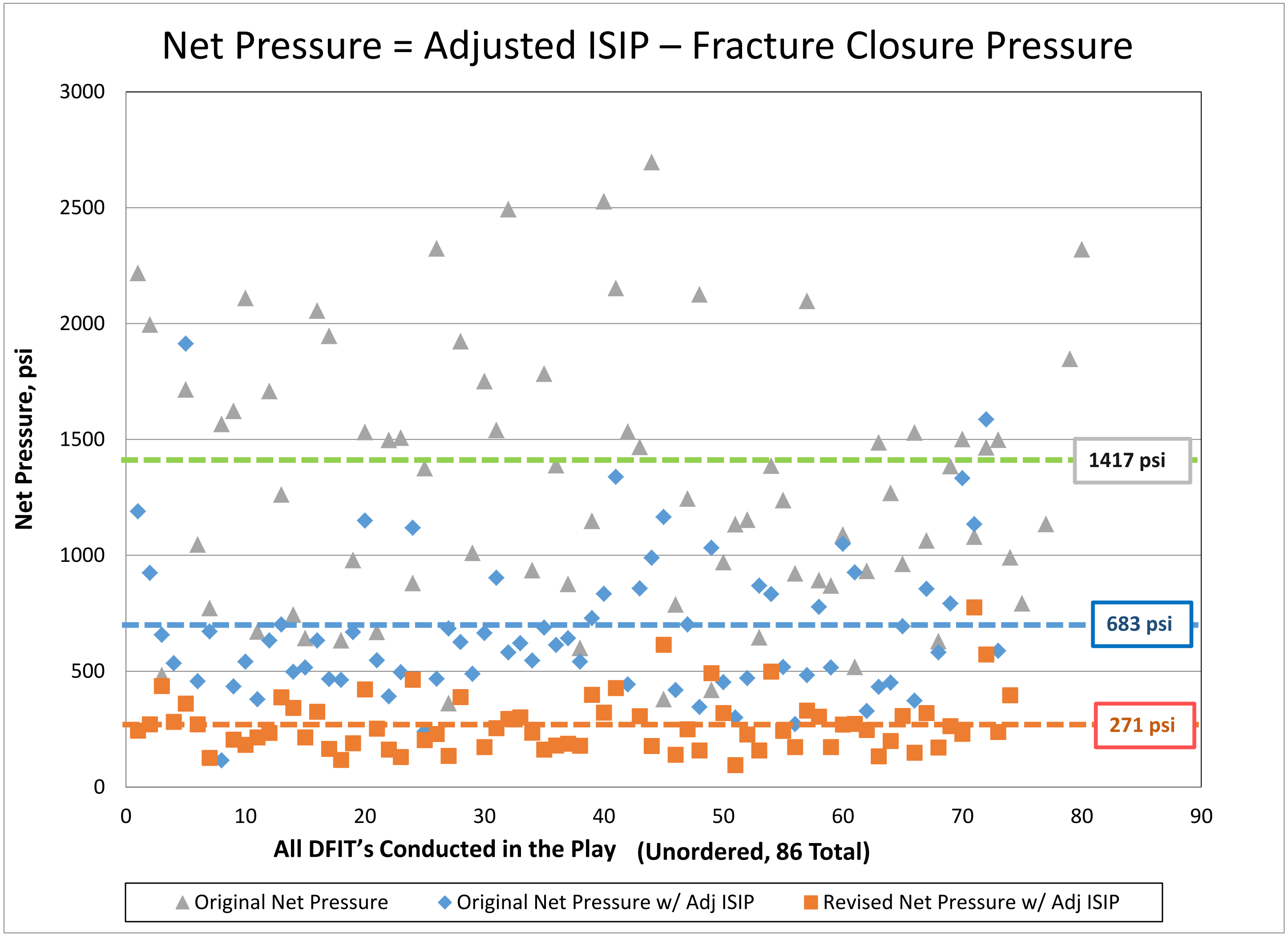

*50 % of reliable DFIT's had an upward revision in closure pressure of 385 psi or greater as compared to the previous interpretation based on the Holistic method.*

# Closure Pressure vs Time to Closure




*Fracture closure using the Fracture Compliance (FC) selection method occurred much sooner and were more in agreement with fracture simulator results than the previously utilized Holistic selection method.*

# Net Pressure at Shut in

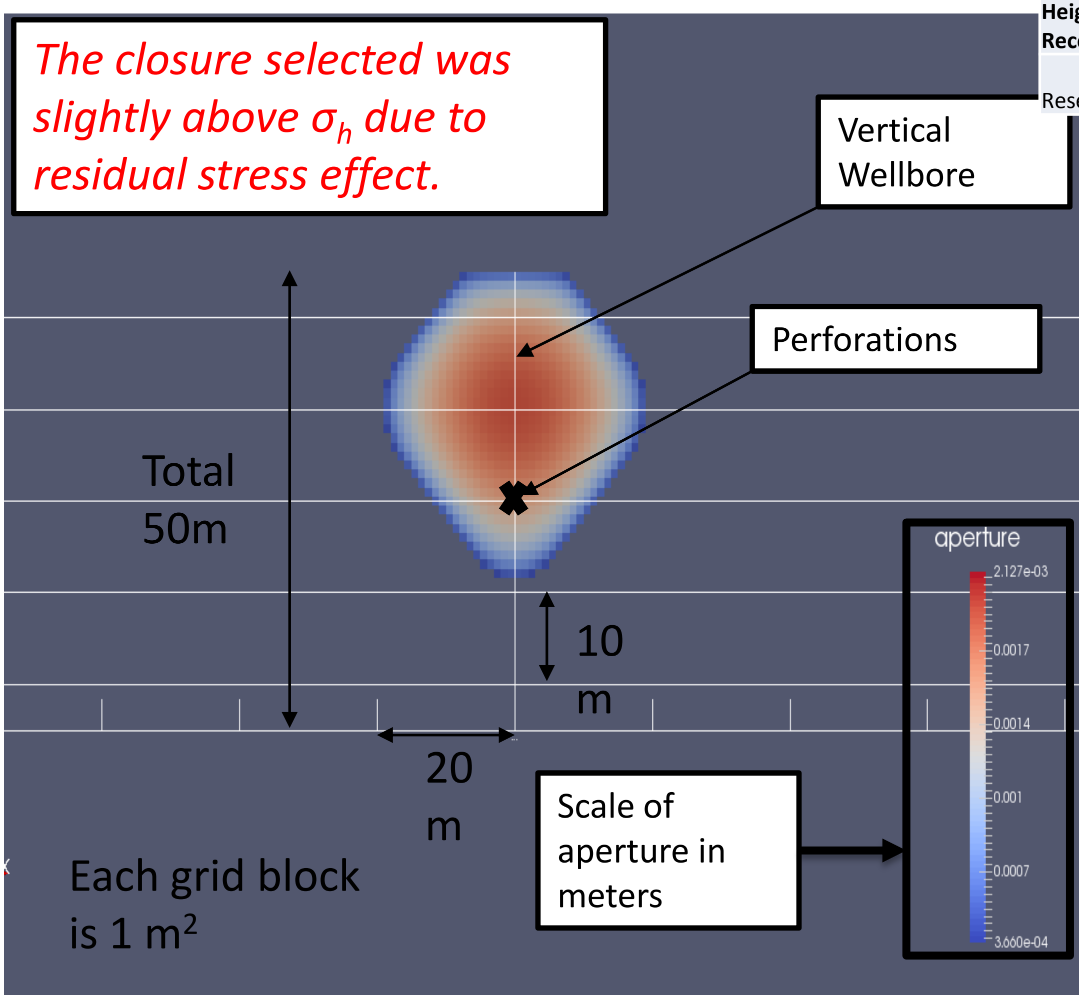


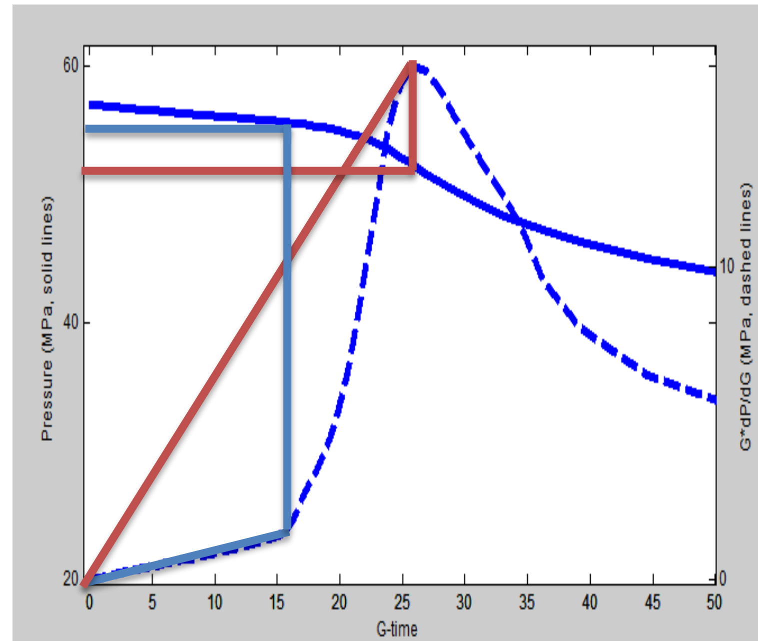

*Revised net pressure, derived from closure based on the Fracture Compliance (FC) selection method, was in better agreement with fracture simulator results than the previously-utilized Holistic selection method.*

# Multi-layer Evaluation

# Single-Layer CFRAC Simulation – Base Case

| Height Recession Case 1 | Perm | Height | Min Principal (Mpa) | McClure Method | Holistic Method |
|---|---|---|---|---|---|
| Reservoir Perm | 506.325 nD | 50 m | 55.1 | 55.7 Mpa | 51.64 Mpa |



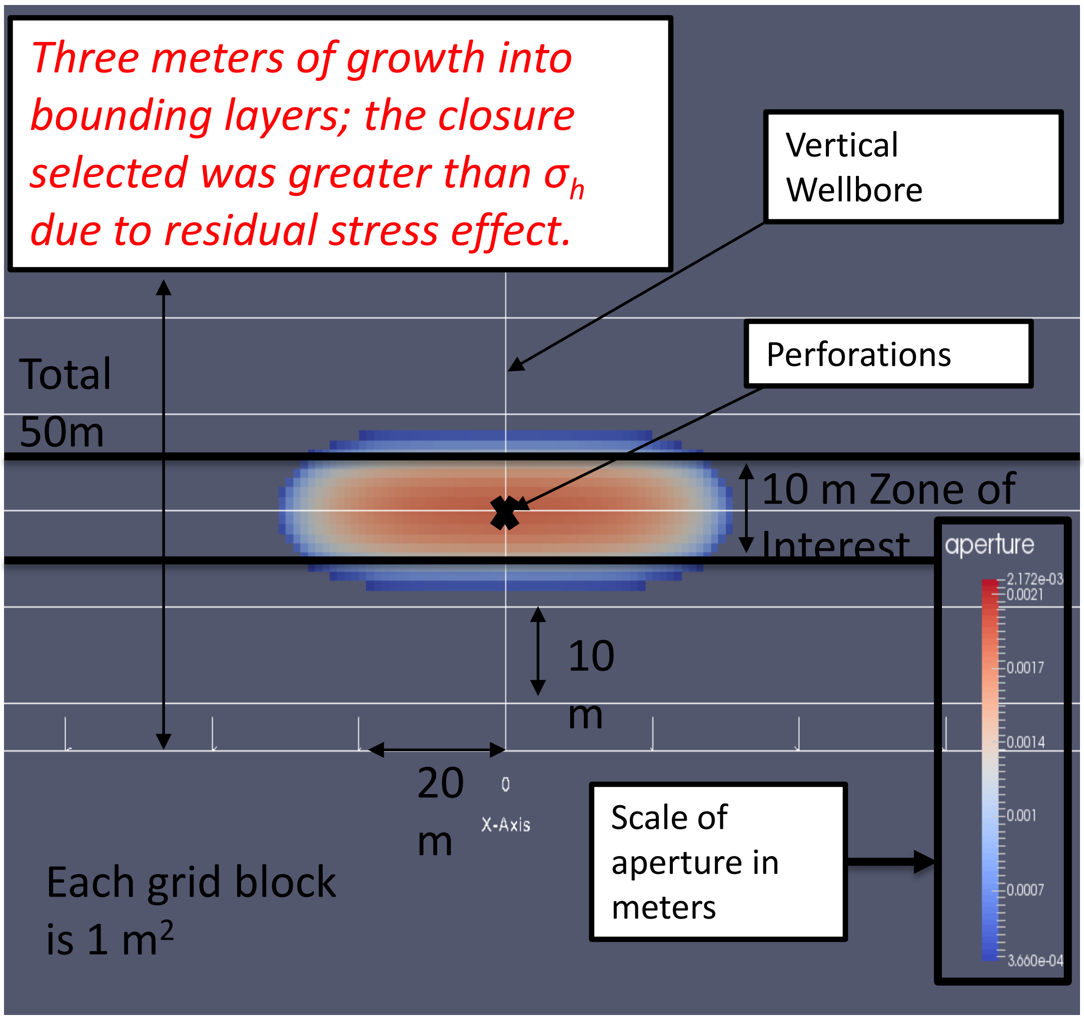

$P_c$ underestimated by 500 psi when using the Holistic method.

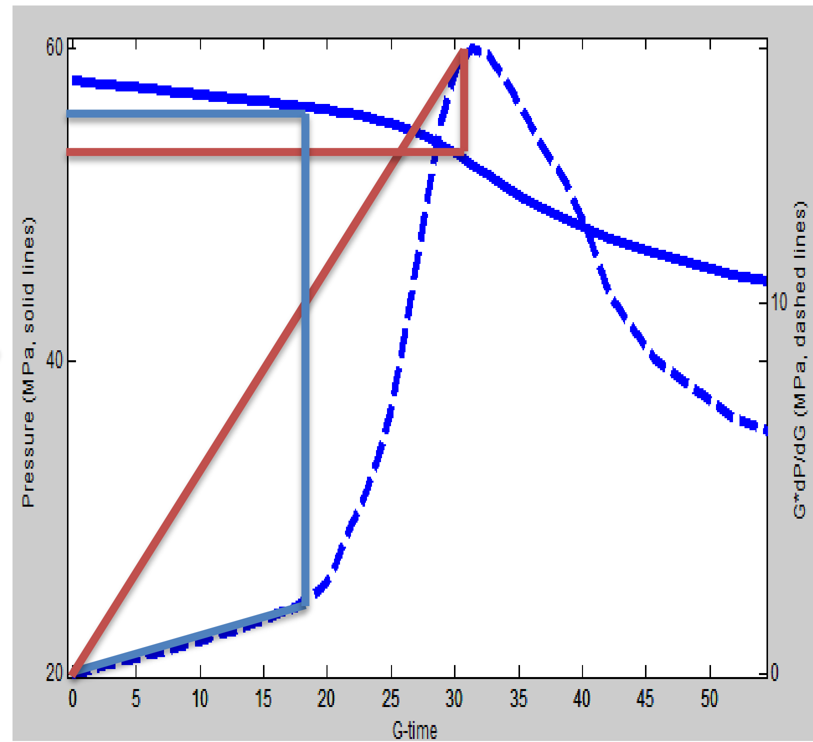
*Performed by Sean Oakes and using previously-reviewed Ordovician Shale DFIT validation field case as a starting point.*

# Zone of Interest with Bounding Layers

## Moderately thick target interval (10 meters)

| Height Recession Case 2 | Perm | Height | Min Principal (Mpa) | McClure Method | Holistic Method |
|---|---|---|---|---|---|
| Reservoir Perm | 506.325 nD | 10 m | 55.1 | 56. 08 Mpa | 52.59 Mpa |
| Upper Layer | 50.662 nD | 20 m | 57.1 | | |
| Bottom Layer | 50.662 nD | 20 m | 57.1 | | |



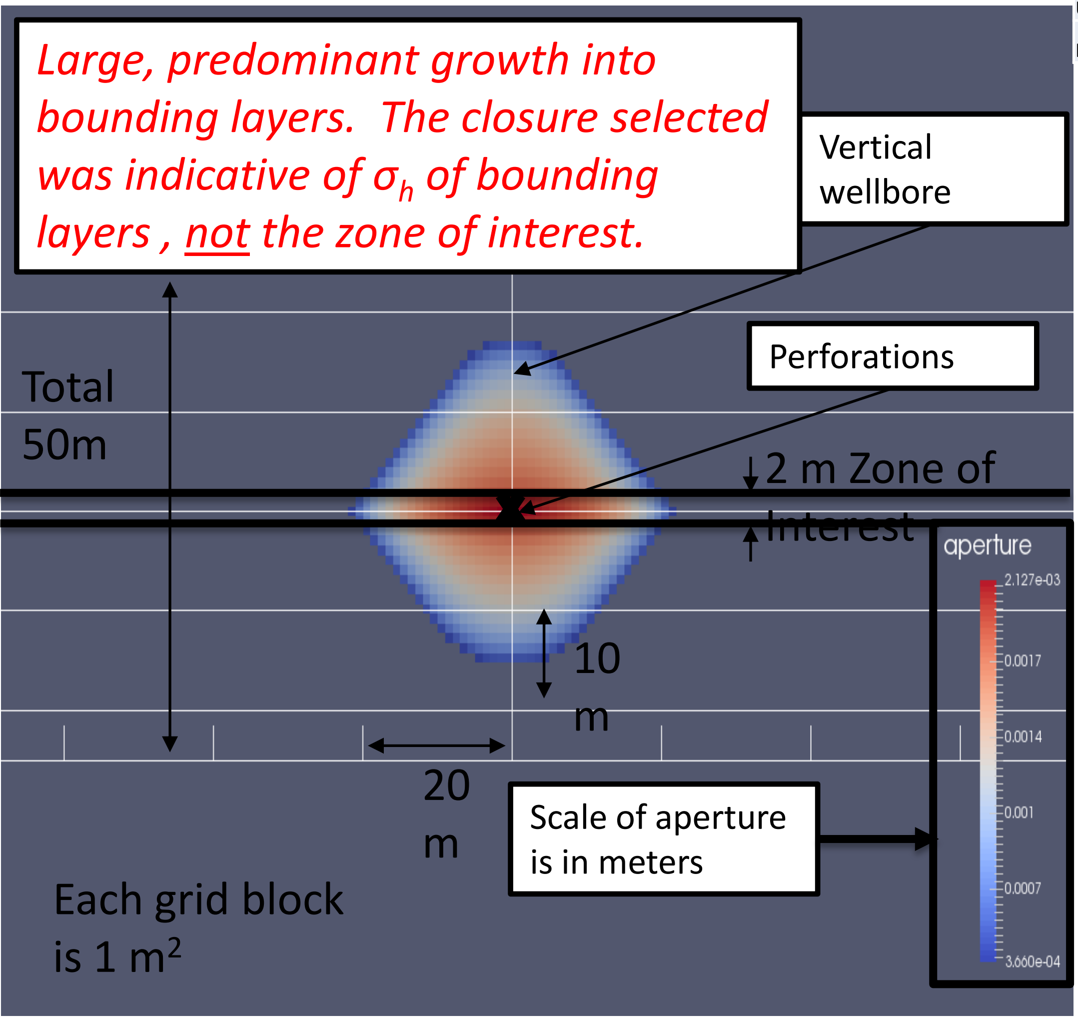



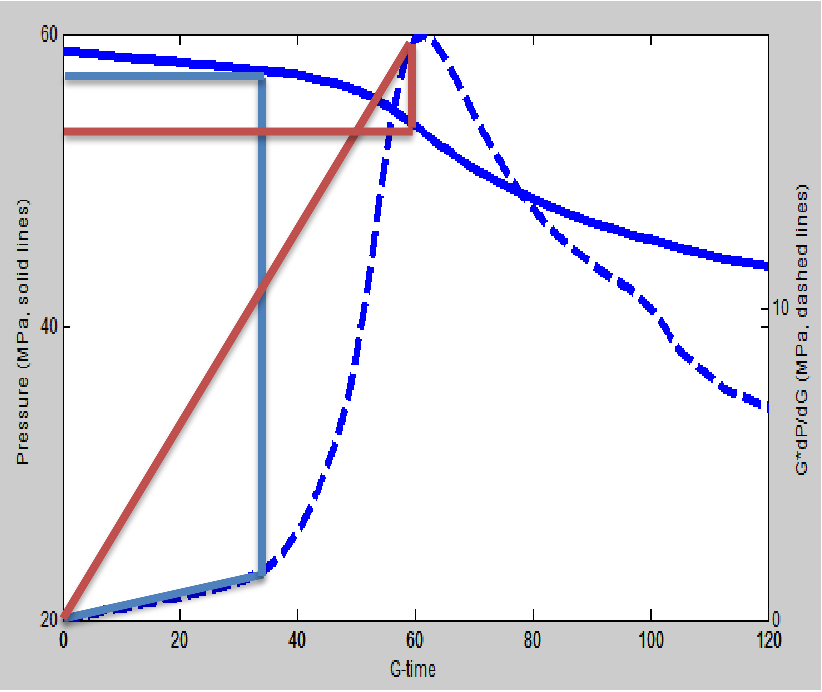

$P_c$ underestimated by 365 psi when using the Holistic method.

# Thin Zone of Interest with Bounding Layers

## Target zone is 2 meters thick

| Height Recession Case 3 | Perm | Height | Min Principal (Mpa) | McClure Method | Holistic Method |
|---|---|---|---|---|---|
| Reservoir Perm | 506.325 nD | 2 m | 55.1 | 57.5 Mpa | 53.6 Mpa |
| Upper Layer | 50.662 nD | 25 m | 57.1 | | |
| Bottom Layer | 50.662 nD | 25 m | 57.1 | | |



# Key Messages

- Fracture mechanics
  - Shut-in pressure behavior is dictated by the interplay between fracture compliance and fluid leak off from the fracture.
  - The change in fracture compliance at fracture closure typically dominates the pressure response in low leak-off scenarios, resulting in an increasing slope for the derivative plots.
  - Fracture closure is a process, not an instantaneous event.
- The Fracture Compliance (FC) method of DFIT fracture closure selection is suitable for most low permeability and unconventional reservoirs.
- DFIT Tactics
  - The delayed-action TIV (toe initiator valve) is optimal for connecting the wellbore to a primary DFIT fracture in horizontal wells.
  - Smaller is better in regard to DFIT injection rate and volume. Large or high-rate injections increase the risk of significant fracture propagation into bounding intervals with mechanical properties that differ from the target DFIT interval.

# Acknowledgements & Associated Publications

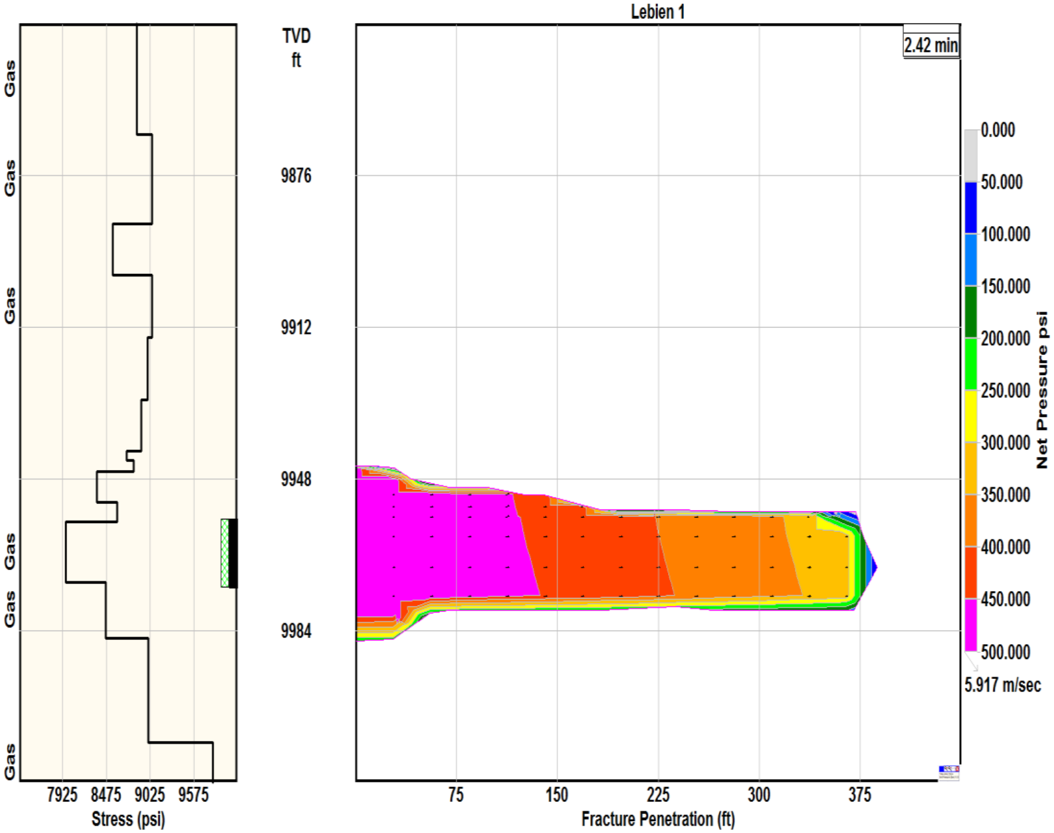

- Dr. Mark McClure, Hojung Jung and Dr. Mukul Sharma - University of Texas at Austin
- Sean Oakes, Tim Post, Steve McRaith, Keith Lynch, Eric Davis, Dung Nguyen – ConocoPhillips



- Mark McClure, Hojung Jung, Dave Cramer, Mukul Sharma “A critical reexamination of methods for picking closure pressure from diagnostic injection tests” Report# 2015HFSC00001, Hydraulic Fracturing & Sand Control Joint Industry Project, The University of Texas at Austin.
- Hojung Jung, Mukul Sharma, Dave Cramer, Sean Oakes and Mark McClure “Computational reinvestigation of nonideal behavior during diagnostic fracture injection tests” in draft mode.

# Extra Slides

# DFIT Modelling Results Using Commercial Hydraulic Fracturing Software: Net Pressure vs Fracture Half Length

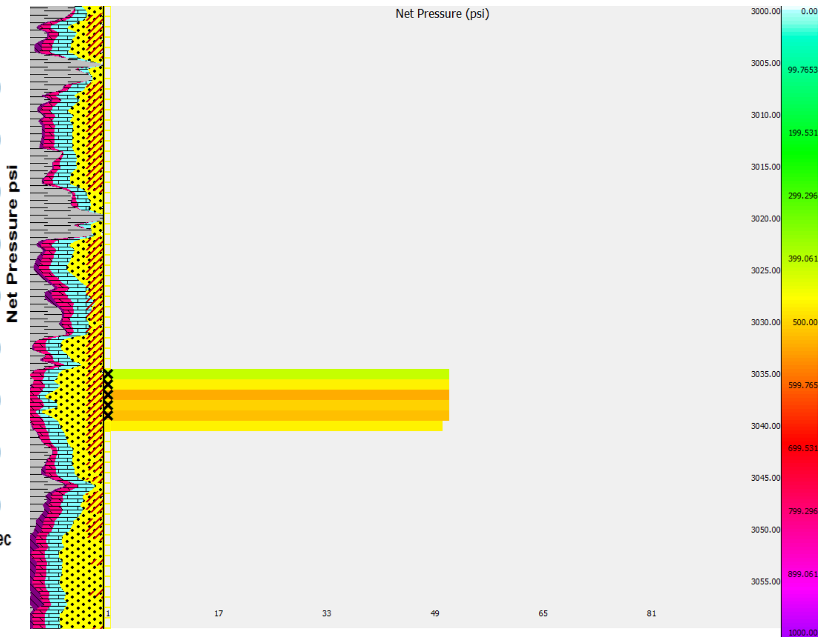



StimPlan Fully 3D Model

Net pressure = 465 psi

Fracture Height = 39 ft

Fracture Half-Length = 373 ft




Gohfer with StimPlan Stress Profile

Net Pressure = 486 psi

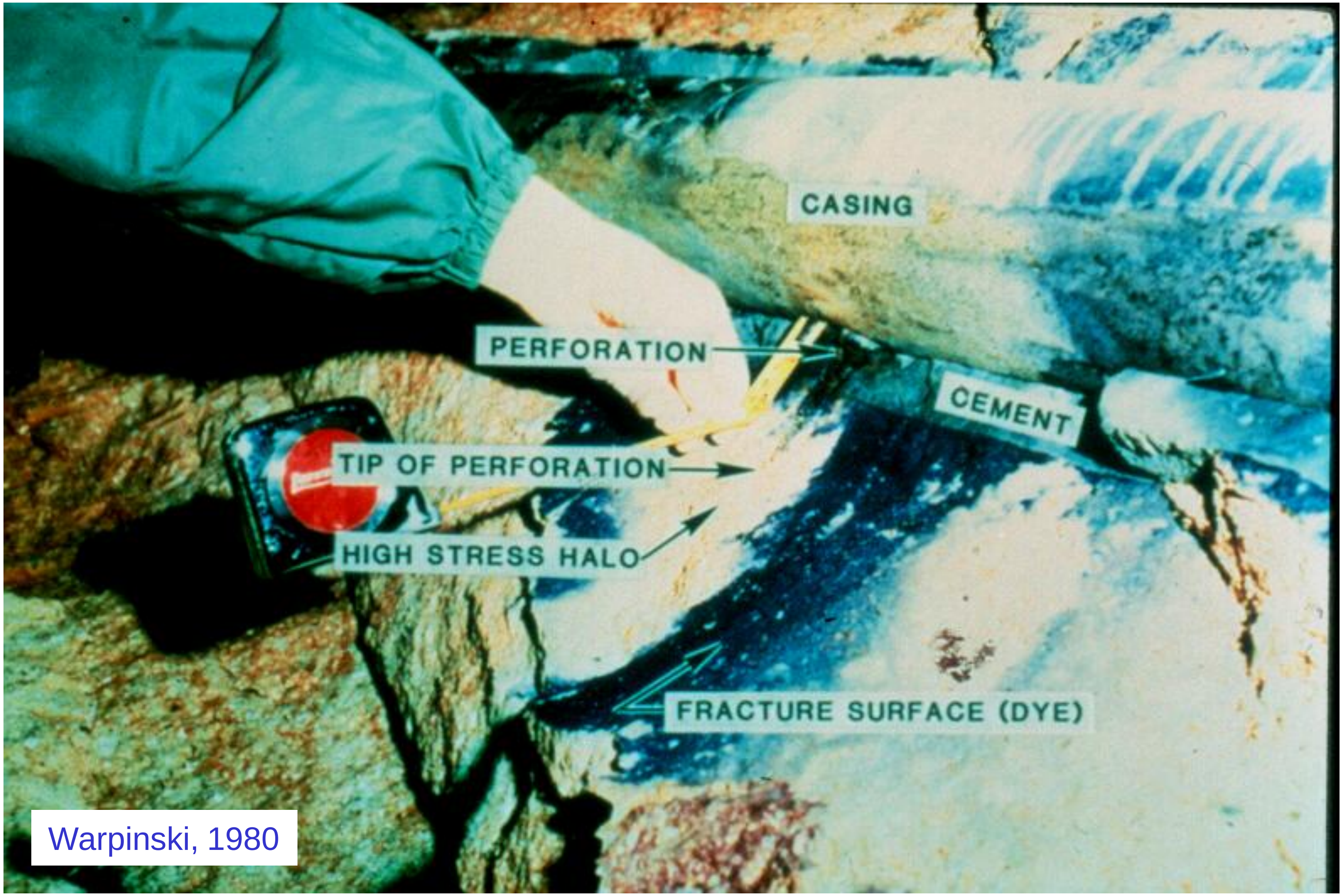
Fracture Height = 20 ft

Fracture Half-Length = 167 ft

Process zone stress (PZS) = 0

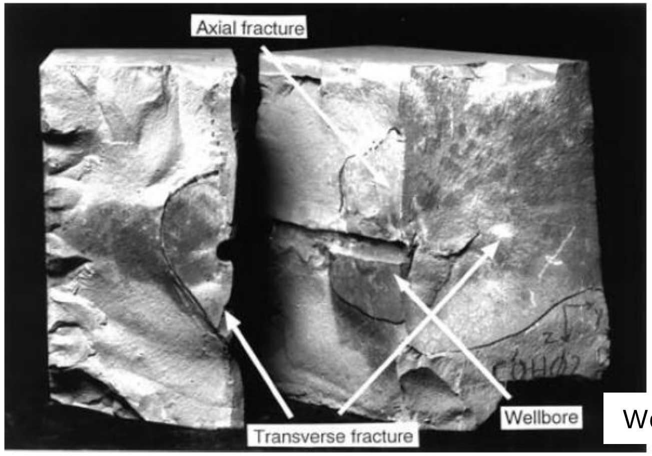
Biot's constant = 0.8

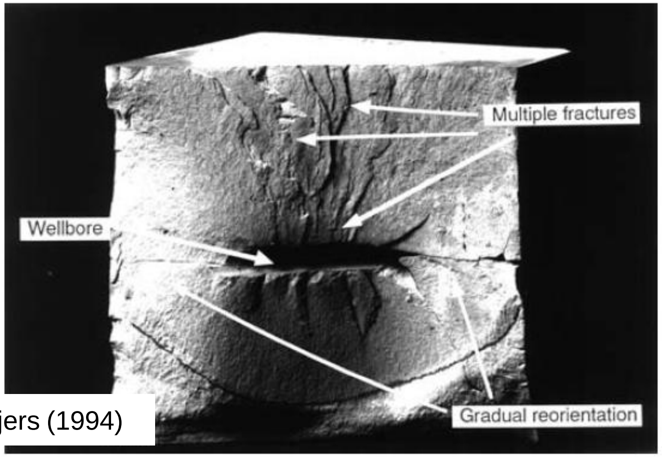
# In-Situ Study of Wellbore-to-Fracture Connection




*Mineback observations indicated that hydraulic fractures tended to avoid the high stress region associated with shaped charge produced perforation tunnels*

# Observations of Fracture Complexity

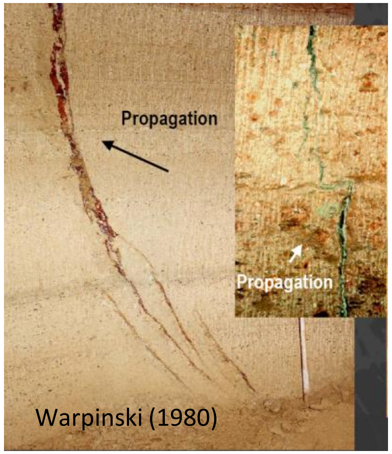


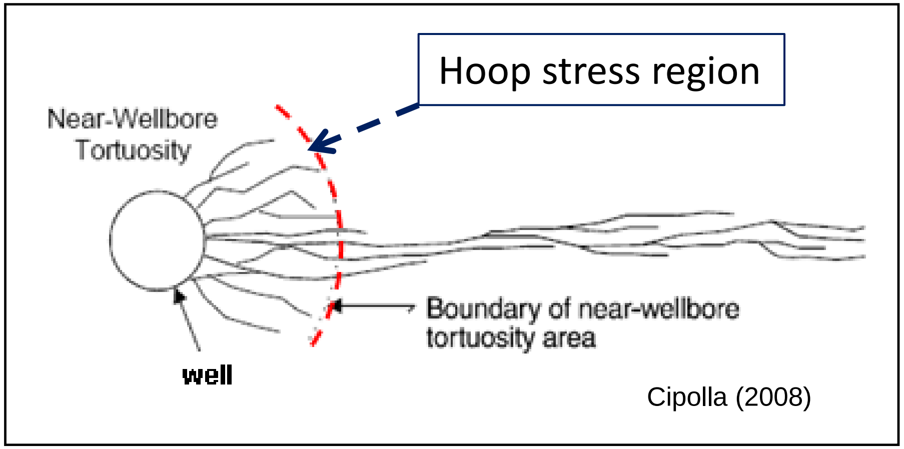




Weijers (1994)

Wellbore 90° to σH

Wellbore 45° to σH




*Near-wellbore fracture complexity is influenced by wellbore azimuth, orientation and exposure. It can result in significantly elevated pressure during DFIT injection and the early part of the DFIT shut in period.*