FRACTURE EXTENSION PRESSURE TESTING AND ANALYSIS GUIDELINES

Theory and Practice

Prepared for: BC OGRIS

Prepared by: Pressure Diagnostics Ltd.

Edition 1

Report Date: 26-Dec-2025

Forward

Pressure Diagnostics Ltd. was engaged by BC OGRIS, to review and propose appropriate updates to fracture pressure testing guidelines for safe and sustainable disposal and injection well pressures. This includes wastewater disposal, storage and pressure maintenance injection and, with safety factor adjustments, carbon capture and storage (CCS) operations in British Columbia.

Through the course of this project, we investigated multiple Step Rate Tests (SRTs) and a few Diagnostic Fracture Injection Tests (DFITs) to determine errors in past submissions and to recommend appropriate fracture and reservoir testing methods going forward. We document procedures for determining the breaking point of the rock, enabling safe injection pressure limits to be quantified. We also address issues regarding long term injection capacity of the disposal reservoirs.

This report is provided as guidance for conducting fracture gradient testing and analysis. It does not replace regulation, qualified expert design, and review of sight-specific applications.

FRACTURE EXTENSION PRESSURE TESTING AND ANALYSIS GUIDELINES

1. Initial Well Test Requirements - Step-Rate Test (SRT) and Pressure Fall-off

In BC, the Regulator requires submission of a fracture pressure test and analysis, as well as a reservoir pressure test and analysis for every disposal or injection well application. Step Rate Tests (SRT) are considered the most consistent and reliable method to determine the necessary pressures, as will be shown in this study. The purpose of the test is to set a Maximum Wellhead Injection Pressure (MWHIP) that establishes a safe threshold for pressure during disposal (or injection) operations to avoid hydraulic fracturing.

Testing is normally performed with surface gauges on the wellhead, but down-hole gauges may be necessary. If surface gauges are used, 'at depth' pressures must also be calculated using appropriate fluid density and rate-dependent pipe friction.

A subsequent pressure fall-off test is critical to establish a baseline for annual testing and for determining Farfield Fracture Extension Pressure (FFEP), fracture closure pressure (Pc), and the associated pressure gradients. Prior to the initial SRT, the well may be acidized but should not be hydraulically fractured with proppant. The BCER, as a part of the disposal approval process, requires an engineering report with a full analysis. After testing the well may be hydraulically fracture stimulated with proppant, at the operator's discretion.

Considerations for Step Rate Tests (SRT):

1) Operators should ensure that enough fluid is on site to perform the necessary rate steps to distinguish both matrix injection and post-fracture flow trends.
    a. Fill the well with fluid (if possible) and initially inject at a low rate. Stabilize pressure for a minimum of 10min.
    b. SRT's should have a minimum of 7-steps with a minimum of 3 before fracturing occurs. Test methods to be followed are outlined in SPE 16798 and [AER Directive 065 Appendix O].
    c. Each step should be performed for long enough such that the surface injection pressure is stable (defined as <10% difference between the starting and ending pressure of any 10-minute portion of that rate in the test).
    d. Increase first 3 to 4 rates at small increments (0.05 m3/min) to achieve representative matrix inflow pressure and rate readings.

2) Even under ideal conditions, experience shows that a significant number of SRT's do not exhibit behavior that can clearly differentiate between matrix and fracture behavior. This makes identifying fracture opening pressure uncertain. Ambiguity in the interpretation will be considered a null result. This document covers what to do under this scenario. All tests, even those having ambiguous results must be submitted to the regulator.

3) After the final injection period of the SRT portion of the test, shut down the pump and shut-in the well immediately (hard-shut-down) for a **minimum** of 24 hours. Monitor pressures for 24 hrs after shut-down and report both surface pressure, and pressure gradient to formation depth (surface pressure + hydrostatic fluid column to depth, the total divided by formation depth). These values will be called P24 and P24-Grad, respectively. It requires no complex analysis and should be a representative value for current reservoir pressure in a reasonably permeable reservoir. Pressure should continue to be recorded for long enough to stabilize so pressure change is <2kPa/hr. This allows a Pressure Transient Analysis (PTA) procedure on the fall-off to determine fracture related properties such as Far-field Fracture Extension Pressure (FFEP), closure pressure (Pc) and current reservoir pressure.

4) If the surface pressure on the well drops to zero-gauge pressure (vacuum) in less than 24 hours, another means of determining reservoir pressure is required. A 2-week shut-in with downhole gauges is recommended, though a static gradient may suffice if the pressure is proven to be stable.

5) A Null Result for a Step-Rate-Test can occur under the following conditions:

   a) Difficulty in identifying a clear break in the pressure vs rate plot. This may occur with an insufficient number of discreet injection rates or a curving of the data that does not identify a clear breakpoint. In **Figure 1** the data is ambiguous and may be interpreted as having a breakpoint or interpreted as having a continuous curve with no breakpoint.
   b) Without distinct straight lines with 3 or more points before and after break, the test is ambiguous.
   c) Well on vacuum (surface pressure drops to zero pressure) any time prior to closure.

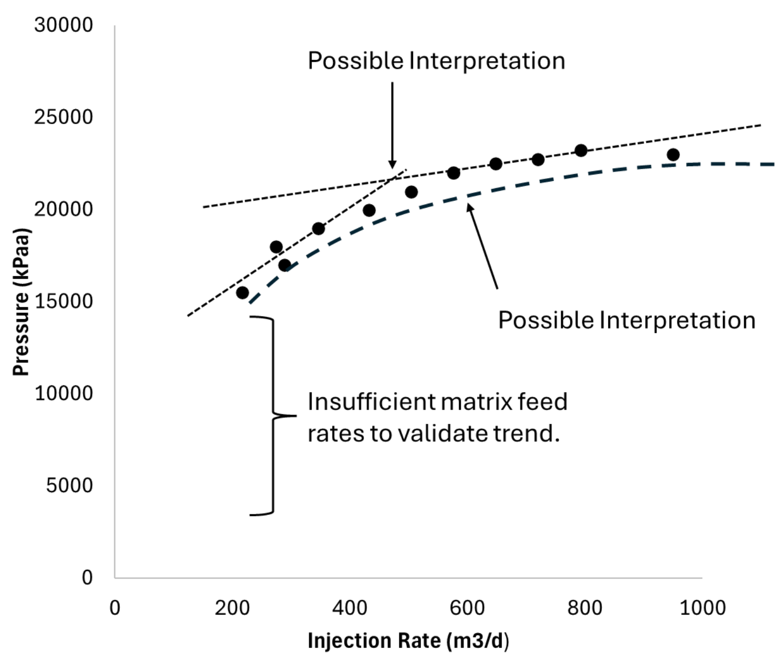

Figure 1: Step Rate Tests Showing Examples Leading to 'Null Results'

6) All SRT rates and pressures data, interpretations, including null results, must be reported to the BCER.

7) A single successful test result is acceptable and can be used for application purposes.

NOTE: Step Down SRT's at the end of the injection period are not recommended before the fall-off portion of the test. There is a risk closure will occur rapidly during the step-down process due to high system permeability eliminating much of the interpretation potential of the fall-off portion of the test.

NOTE: Diagnostic Fracture Injection Tests (DFITs) are not an acceptable method to determine MWHIP during initial disposal well testing. DFITs are typically low-rate, low-volume, tests conducted in low permeability formations. Disposal wells in general are high permeability formations, where low rate and volume tests typically result in null results. See **Appendix A** for more information.

2. SRT Analysis Submission Expectations

Have a qualified professional analyze the results with submission of analyses and reports to include the following:

1) **Raw Data** Cartesian plot of raw data (rate and pressure vs time) including measured pressures and injection rates for all steps (**Figure 2**) and for a minimum of 24 hours after final shut-down.

2) **BH Pressure cartesian plot** calculated of at the top of the True-Vertical-Depth (TVD) of the injection interval vs. time for all steps (**Figure 2**).

3) Water analysis of test injection fluid and project fluid analysis used for injection (they can be different). Specific requirements are density and salinity/**TDS** (total dissolved solids).

4) **Fracture Extension Pressure (FEP)** Interpretation cartesian plot (pressure vs rate) of the SRT showing BOTH surface and BH pressures at the TVD of the top of the injection interval, the Calculated Lithostatic Pressure and the Interpreted (Maximum Wellhead Injection Pressure-Test) **$MWHIP_T$**. See **Figures 3, 5 & 6**.

5) A table reporting measured **P24, P24-Grad, bottom-hole Fracture Extension Pressure (FEP, Fracture Propagation Pressure (FPP) and reservoir pressure** values.

6) **Calculated value for the** (Maximum Wellhead Injection Pressure-License) **$MWHIP_L$**. This corrects for the density difference between the test fluid and the project injection fluid.

7) **Log-Log Diagnostic** plot showing Bourdet and Primary-Pressure-Derivative (PPD) curves of the post SRT fall-off c/w flow regime Identification and interpretation (**Figure 7 and Appendix A**),

8) **Specialized** plots used to identify flow regimes and key pressures from Log-Log Diagnostics plot (**Figure 7**), pore pressure extrapolations (e.g. Semilog-**Figure 8**), or G-Function fracture closure pressure interpretation (**see Appendix A)**

9) Comprehensive discussion and interpretation of results, including a level of confidence in the results and rationale.

3. SRT Examples - Fracture Extension Pressure Determination

Maximum Wellhead Injection Pressure (MWHIP) will be determined from an SRT depending upon the available data and whether the Bottom Hole (BH) pressure is measured or calculated to exceed the Lithostatic Pressure, P_{Litho}. The default value P_{Litho} = 24 kPa/m. Three examples are summarized in **Table 1** to demonstrate methods for determining $MWHIP_T$ and $MWHIP_L$.

Example	Well TVD (m)	Flow Path Size (mm)	Fluid Gradient (kPa/m)	Pre- & Post-Frac Trends Present (Y/N)	BH Press. Post-Frac Trend Y-Int.	Hydrostatic & Friction Pressures Calc. or BCER Defaults
Ex-1	1171	73	9.8	Y	< Litho	Known Fluid SG, Software Calc. Friction
Ex-2	1225	89	11.5	Y	> Litho	BCER Min. Fluid SG, BCER Friction Calc.
Ex-3	1300	89	Unknown	N	Unknown	BCER Min. Fluid SG, No Friction Calc.

Table 1: Summary of SRT Example Cases

Example Ex-1: Fracture Extension Pressure less than Lithostatic

In the Ex-1 Example, the operator provided calculated BH pressure data using commercial software to determine hydrostatic and friction calculations. Inputs for the fluid specific gravity, injection tubing dimensions and True Vertical depth (TVD) are listed in Table 1. Fresh water was used in the test (hydrostatic gradient=9.822 kPa/m in software). Figure 2 shows measured surface and calculated BH pressures vs rate. Table 2 shows detailed calculations for the stabilized pressures at each rate step.

The last column of Table 2 (Effective Gradient with Friction) is an important check that the calculations are consistent. The Effective Gradient with Friction is the measured or calculated BHP including friction. Values should always be less than or equal to the hydrostatic value as friction works in the opposite direction to flow.

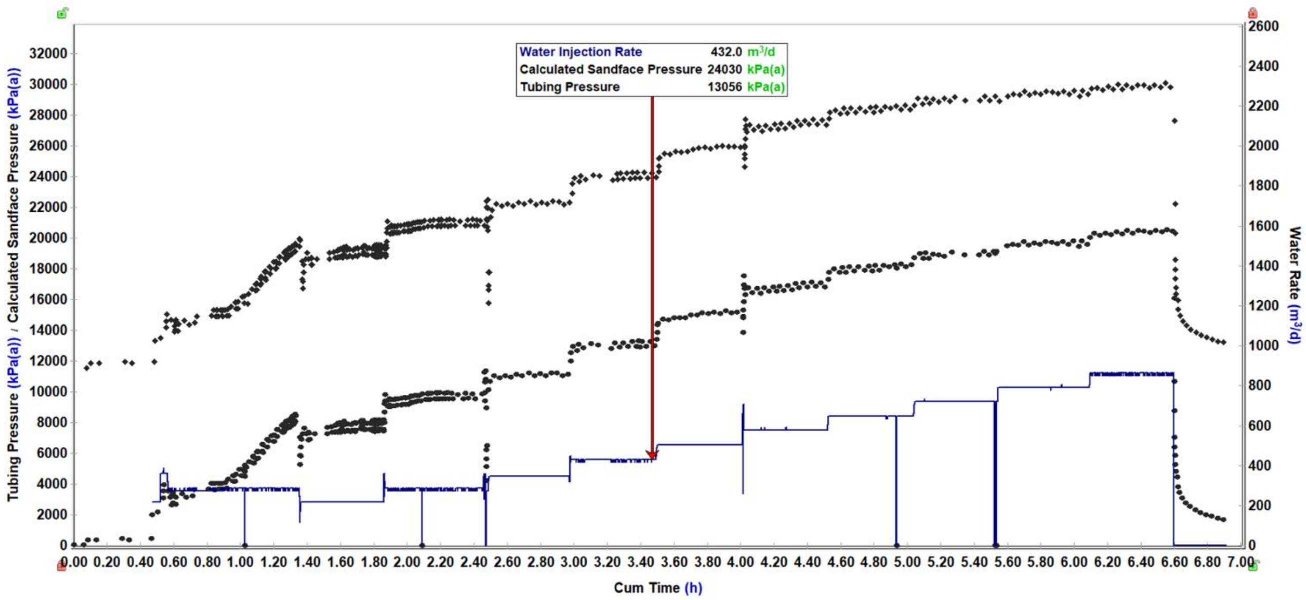

Fig 2: Example EX-1: Cartesian Plot of Raw Tubing Surface Data & Calculated BH Pressures

Injection Rate (m3/d)	Measured Surface Injection Pressure, P_WH (kPaa)	Calc. Hyd.Gradient (kPa/m)	Calc. Hydrostatic Pressure, Phyd (kPa)	Calc. BH Pressure - No Friction	Calc. BH Pressure, with Friction	Effective Gradient with Friction
0	100	9.822	11501	11601	11601	9.8
273.6	9647	9.822	11501	21148	20941	9.6
216	8159	9.822	11501	19660	19535	9.7
288	9634	9.822	11501	21135	20903	9.6
345.6	11032	9.822	11501	22533	22195	9.5
432	**13056**	**9.822**	**11501**	**24557**	**24030**	**9.4**
504	15076	9.822	11501	26577	25864	9.2
576	16726	9.822	11501	28227	27301	9.0
648	18206	9.822	11501	29707	28541	8.8
720	18896	9.822	11501	30397	28960	8.6
792	19822	9.822	11501	31323	29590	8.3
864	20496	9.822	11501	31997	29943	8.1

Table 2: Raw and Calculated BH and Friction Pressures for Example EX-1
Highlighted row corresponds to Figure 2 label (and does NOT represent the fracture pressure)

The Fracture Extension Pressure (FEP) Interpretation for Example EX-1 is shown in Figure 3. There are two plot series, the stabilized Surface Pressure versus rate and the calculated BHP versus rate. For both series, there are two groupings of several points that show distinct pre-, and post-frac pressure linear trends. The early time trend is reservoir flow and late time is post-breakdown fracture flow. This is a successful test. The intersection of the early and late time slopes for the surface pressure series is shown ($P_{surf\ Frac}$ =16726 kPaa).

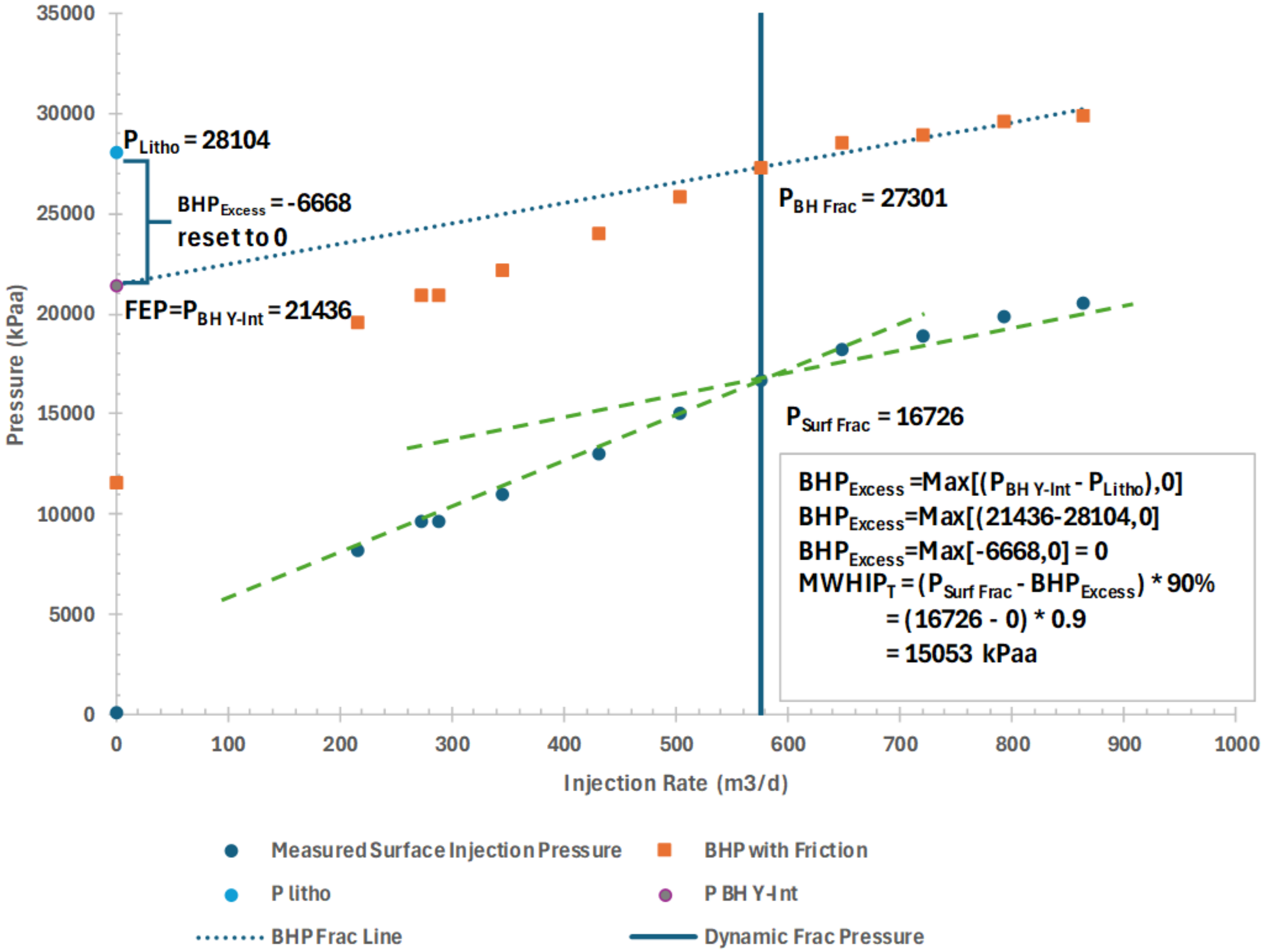

Fig 3: SRT Analysis of Example EX-1

Extrapolation of the calculated BHP (P_{BH}) series on the fracture line to zero rate is also shown. This value defined as $P_{BH\ Y\text{-}Int}$. = 21,436 kPa (Gradient = 18.3 kPa/m) is also the Fracture Extension Pressure (FEP). The FEP is determined from the y-intercept of the SRT pressure vs injection rate plot as outlined in **Appendix B.** In this example, the gradient of FEP is less than the calculated lithostatic stress gradient (24.0 kPa/m). Since FEP is below the lithostatic pressure, the Maximum Wellhead Test Injection Pressure (**MWIP$_T$**) can be determined as follows.

BHP_{Excess} = Max($P_{BH\ Y\text{-}Int}$ - P_{Litho})

BHP_{Excess} = Max(21436 - 28104,0)

BHP_{Excess} = Max(-6668,0) = 0 kPa

$MWHIP_T$ = ($P_{surf\ Frac}$ - BHP_{Excess}) * 90%

$MWHIP_T$ = (16726 - 0) * 0.9

$MWHIP_T$ = 15053 kPaa

In practice the test fluid may not be representative of the licensed disposal fluid (Project Fluid). For this case and a hydrostatic correction is applied to determine the $MWHIP_L$ The actual injection fluid SG for disposal for this example is SG_L=1.1. **g** is defined as the default freshwater pressure gradient, 9.806 kPa/m

$$MWHIP_L = MWHIP_T + (SG_T - SG_L) \times g \times TVD$$
$$MWHIP_L = 15053 + (1.0 - 1.1) \times 9.806 \times 1171$$
$$MWHIP_L = 15053 - 1030$$
$$\mathbf{MWHIP_L = 14023\ kPaa}$$

Example EX-2: Fracture Extension Pressure Greater Than Lithostatic

In Example EX-2, pressures are much higher than Example EX-1. The operator does not have access to commercial software to estimate friction and is unsure of the fluid specific gravity, SG. Therefore the operator relied upon values referenced in the BCER Water Service Wells Summary Information VERSION 3.7: December 2024 and summarized in Table 3, to calculate BH pressures. For this case the Specific Gravity (SG)=1.07 was considered the most reasonable value.

Brine Pressure Grad kPa/m	Fresh Water Pressure Grad kPa/m	SG -	Source
10.5	9.806	1.07	Page 39 Minimum Value
11.0	9.806	1.12	Page 19 Typical Example
11.7	9.806	1.19	Page 19 Extreme Example

Table 3: BCER Water Services – Recommended Published Gradients

The formula for the BH pressure calculation is:

$$\mathbf{P_{BH} = P_{Surf} + SG_T \times 9.806 \times TVD - P_{fric\_def}}$$

For this case a representative Friction Pressure (P_{fric_def}) is obtained from **Figure 4** which is available in the BCER Water Service Wells Summary. Info. App B.

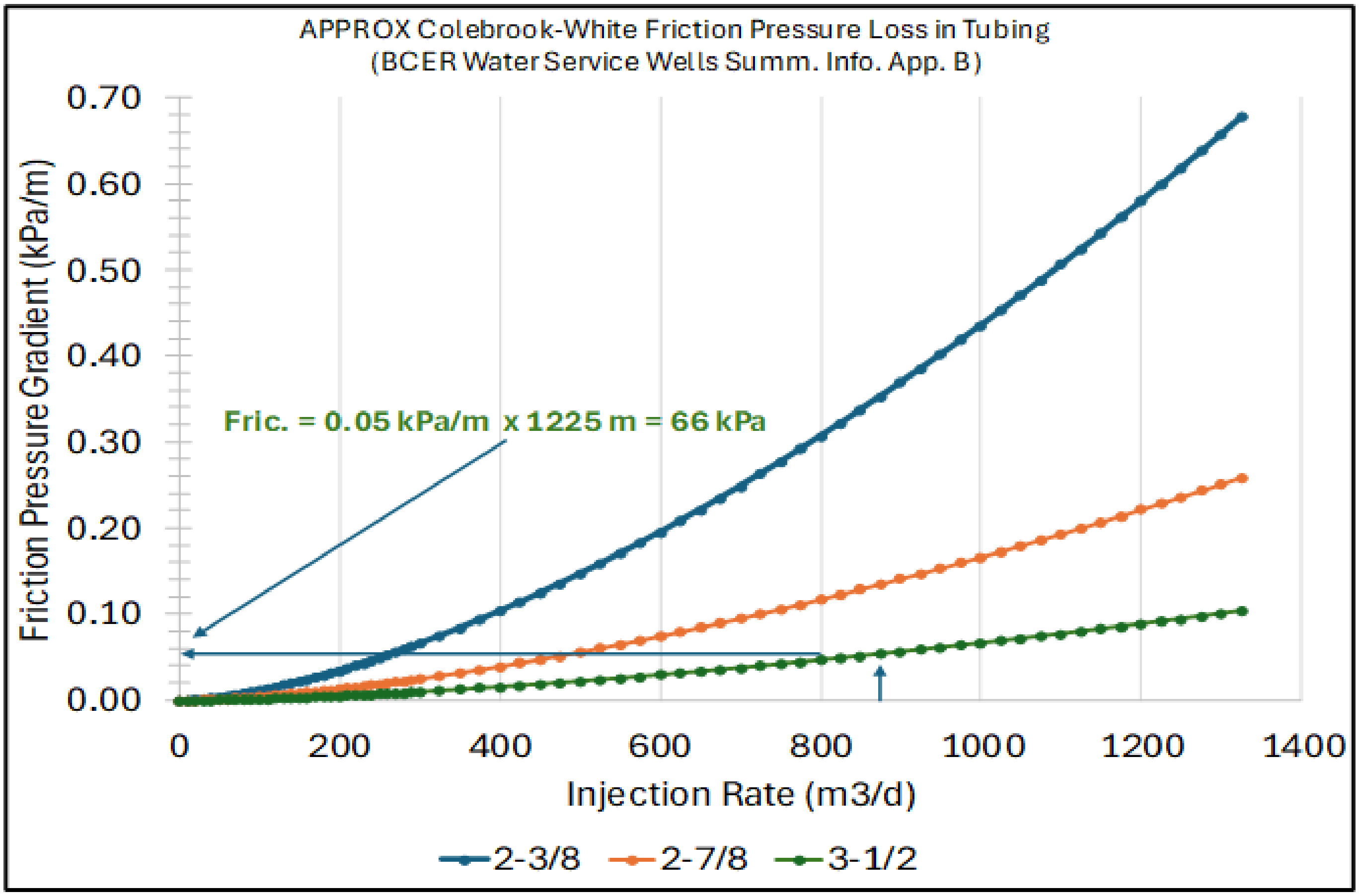

Fig 4: Friction Calculations (BCER Water Service Wells Summary. Info. App B)

At the maximum injection rate of Q=864 m3/d and a wellhead pressure of 30694 kPa, $\mathbf{P_{BH}}$ is:

$$P_{BH} = 30694 + 1.07 \times 9.806 \times 1225 - 66 \text{ kPaa}$$

$$\mathbf{P_{BH} = 43491 \text{ kPaa}}$$

Similar BH calculations are made for all measured surface pressures. In **Figure 5**, pre- and post-frac linear trends are again evident supporting the conclusion that the test is valid. However, the FEP (FEP=31673 kPaa) is **ABOVE** the Lithostatic pressure value of 29400 kPaa (TVD * 24.0 kPa/m).

This case is quite common in practice for unknown reasons. Steps are required to ensure that the BH pressure gradient is less than the lithostatic gradient which is deemed to be the maximum pressure gradient that will bound hydraulic fractures within a specific stratigraphic interval. Calculation of excess pressure is performed in the same manner as Example EX-1. In this case the excess pressure (BHP_{Excess}) is positive and $MWHIP_T$ must be corrected as follows.

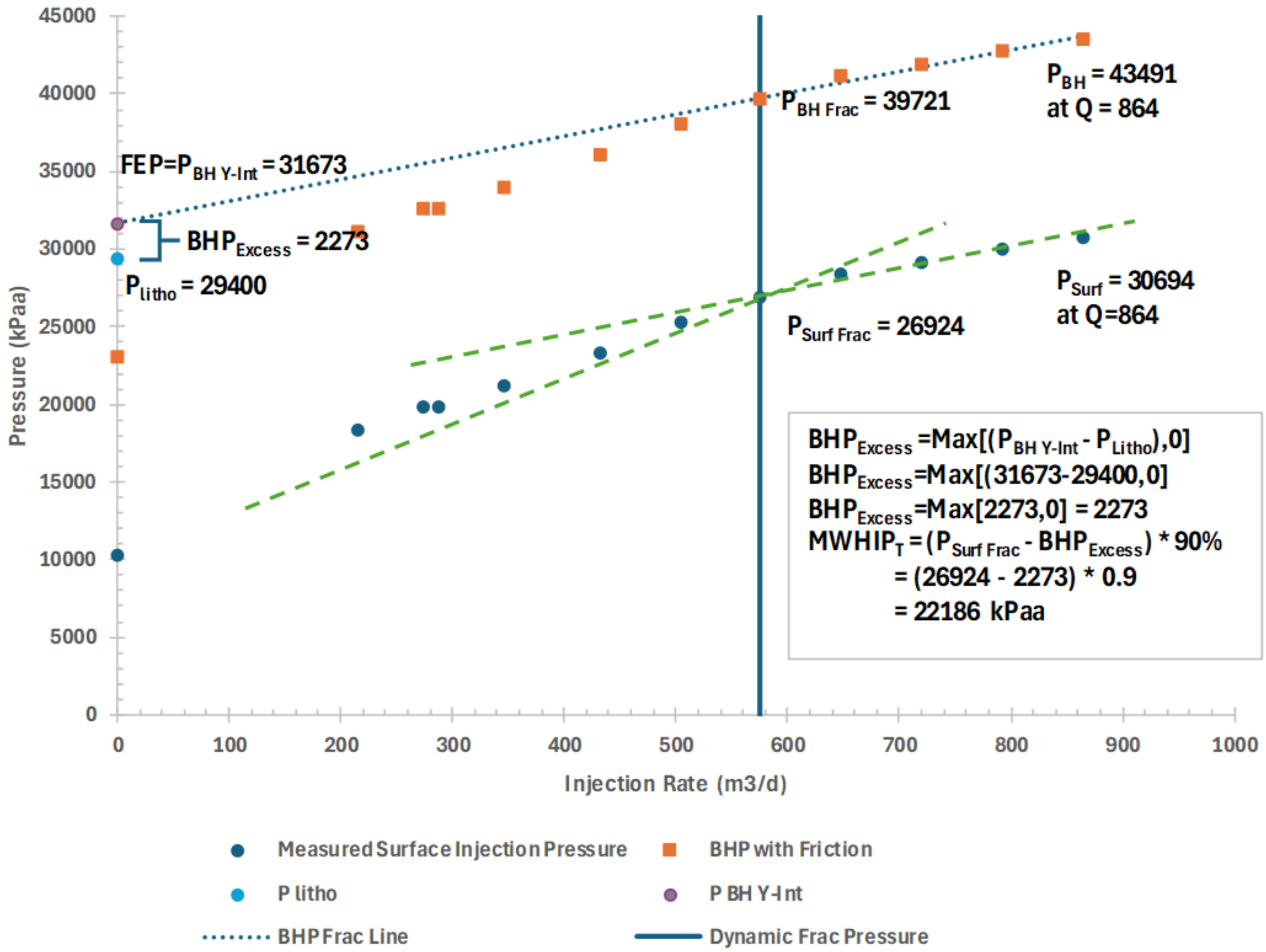

Fig 5: SRT Analysis of Example EX-2.

BHP_{Excess} = Max($P_{BH\ Y\text{-}Int}$ - P_{Litho})

BHP_{Excess} = Max(31673 - 29400,0)

BHP_{Excess} = Max(2273,0) = 2273 kPa

$MWHIP_T$ = ($P_{surf\ Frac}$ - BHP_{Excess}) x 90%

$MWHIP_T$ = (26924 - 2273) x 0.9

$MWHIP_T$ = 22186 kPaa

The actual disposal fluid SG for this example is SG_L=1.15, so the value for $MWHIP_L$ is different than $MWHIP_T$

$MWHIP_L$ = $MWHIP_T$ + (SG_T – SG_L) x TVD x 9.806

$MWHIP_L$ = 22186 + (1.07 – 1.15) x 1225

$MWHIP_L$ = 22186 – 98

$MWHIP_L$ = 22088 kPaa

Example EX-3: Invalid Test Results

In this example, the operator performs a test with little supporting data; such as the fluid gradient and friction pressure calculations. Also, the SRT interpretation is inconclusive. This result is deemed to be a null test. Figure 6 shows the SRT interpretation plot.

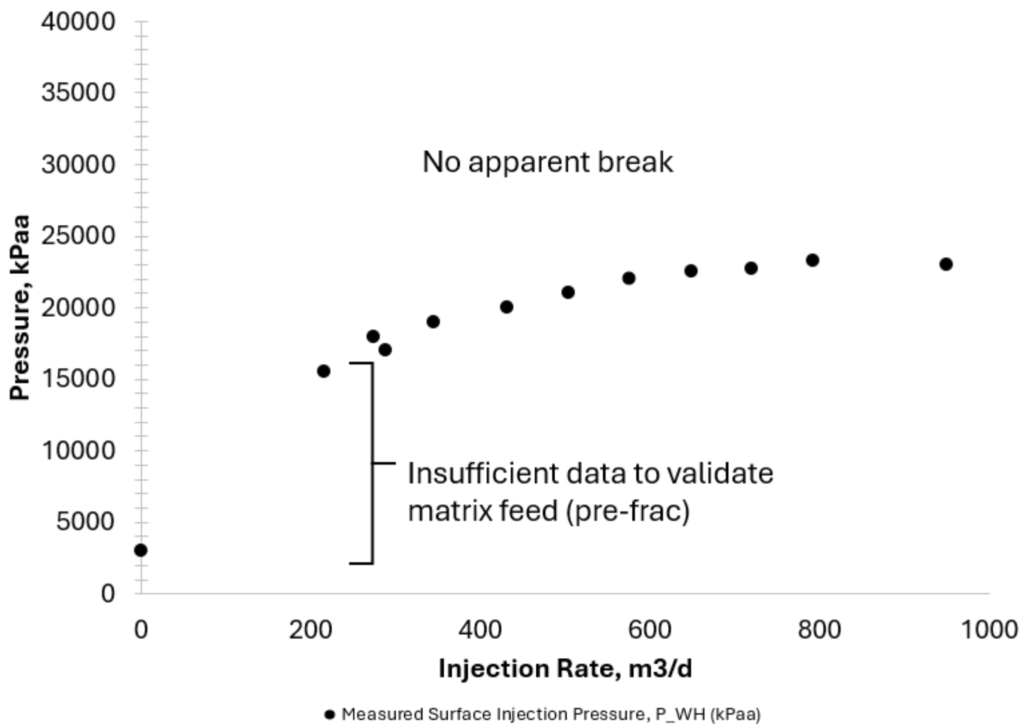

Figure 6: Step Rate Test, Surface Pressure for Example EX-3

In Example EX-3 there is no apparent fracturing and no BH pressure calculations are provided. The project fluid SG_L is 1.1. Friction factor was determined to be 200 kPa. Due to uncertainty the safety factor is more conservative than the previous cases and may be set to 0.8. The calculation of $MWHIP_L$ is:

$$MWHIP_L = (P_{Litho} – SG_L \times 9.806 \times TVD - P_{fric}) \times 0.8$$

$$MWHIP_L = (24*1300 - 1.1 \times 9.806 \times 1300 - 200) \times 0.8$$

$$\mathbf{MWHIP_L = 13582\ kPaa}$$

3. Required Supplementary Information

Figure 7 & 8 show examples of post-SRT fall-off Log-Log Diagnostic and Superposition Radial extrapolation for initial reservoir pressure, Pri. These plots are required to be submitted as outlined in B.8).

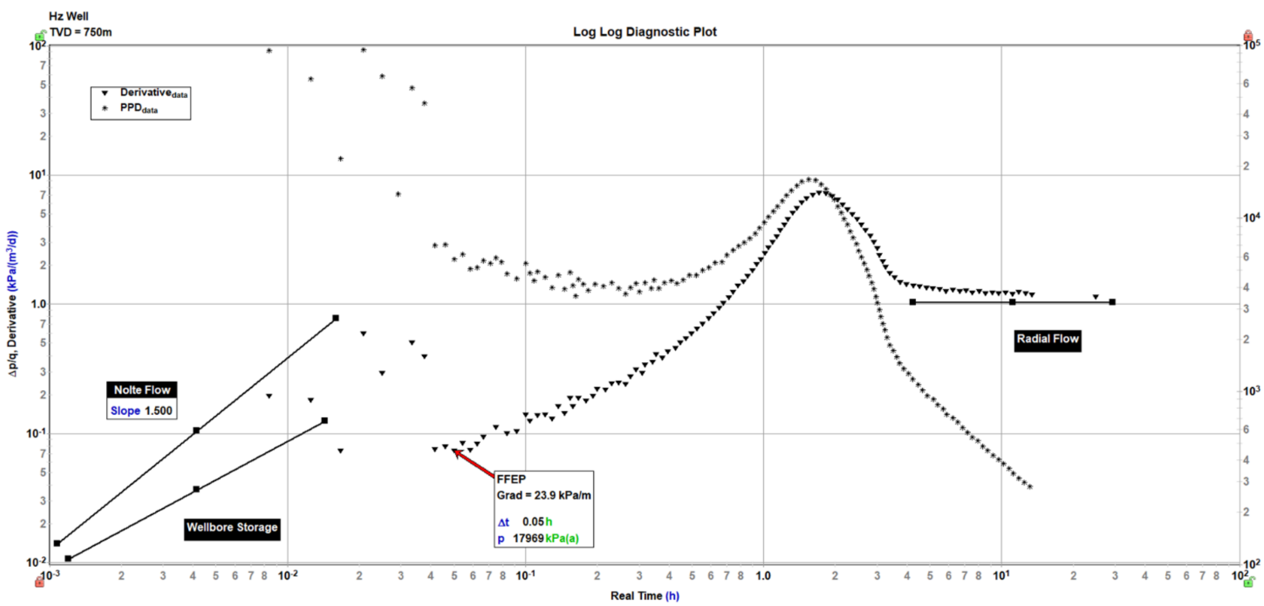

Figure 7: Post SRT Fall-off Log-Log Diagnostic Plot Showing Evidence of Hydraulic Fracturing and Closure Behavior

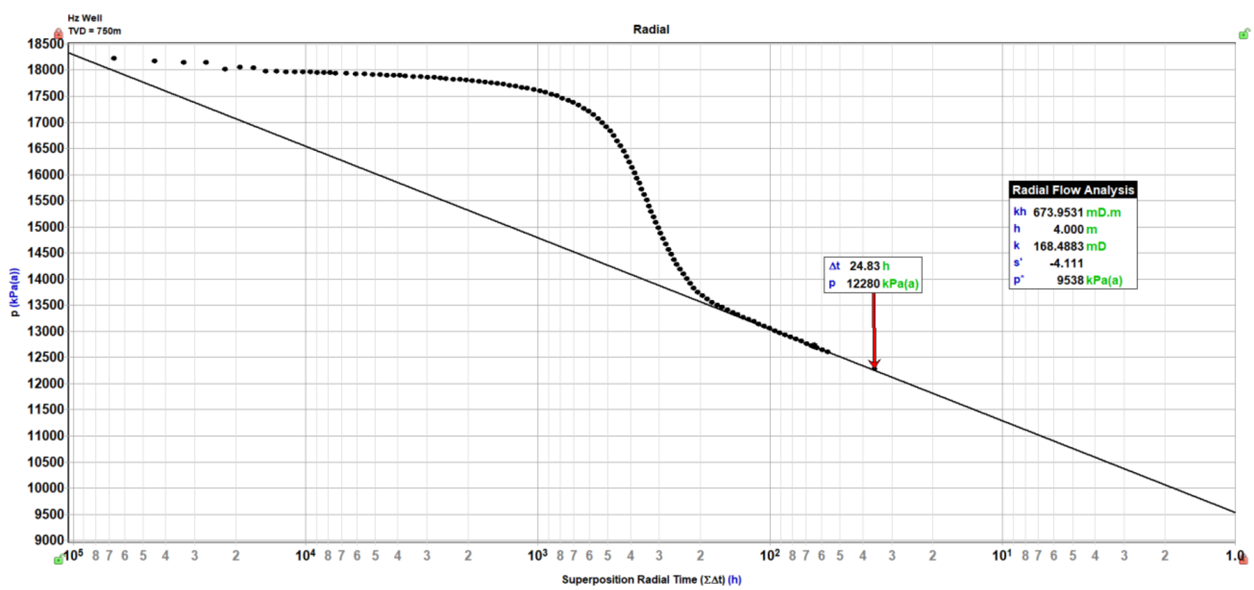

Figure 8: Radial Superposition Time Extrapolation for Pri

The possible Farfield Fracture Extension Pressure (FFEP) identified in Figure 7, at the discretion of the BCER, may be used as validation for the FEP determined from a successful SRT or as replacement for FEP determined in null tests such example EX-3.

4. Annual Testing Guidance for Approved Disposal Wells

1) Water analysis of project injection fluid. Specific requirements are density and salinity/TDS (total dissolved solids).
2) Recommend install electronic pressure gauges downhole. Shut-in well for long enough for pressure to stabilize to <2.0 kPa/hr and a minimum of 24hrs. If surface gauges are used and if the surface pressure drops to 0 gauge pressure, further testing will be required.

   Run BH gauges to a depth where fluid level will not pass below the gauges during any portion of the test. Surface electronic web-live gauges are recommended to enable real-time oversight and initial plots of the results.

   NOTE: The combination of surface and BH gauges are valuable for validating friction calculations.

3) Perform an Injection/Fall-off test with a minimum of 6hrs injection & 24hr fall-off.
4) Report the P24 fall-off pressure value at depth and corresponding pressure gradient, P24-Grad.
5) Have a qualified professional analyze the test results. Submission of analyses and reports shall include the following:
6) Cartesian plot including measured pressures and injection rates for all steps showing from (1) through (3),
7) Cartesian plot of BH Pressure calculated at the Mid-Point (MP) True-Vertical-Depth (TVD) of the injection interval vs. time for all steps from (1) to (5),
8) Log-Log Diagnostic plot showing Bourdet and Primary-Pressure-Derivative (PPD) curves of the post SRT fall-off c/w FFEP (if any), flow regime identification and interpretation (see Pressure Transient Analysis guidance - **Appendix A**),
9) Any specialized plots used to identify key pressures from Log-Log Diagnostics plot identified flow regimes (e.g. radial- or linear-superposition pore pressure extrapolations, G-Function fracture closure pressure interpretation**).** Comprehensive discussion and interpretation of results, including a level of confidence in the results and rationale.
10) Compare and confirm results from Initial Testing (MWHIP), Dietz-MBH, Other.

ABBREVIATIONS, DEFINITIONS AND TERMINOLOGY

Symbol	Description
BD	Formation Break-Down pressure; the pressure needed to initiate a hydraulic fracture (may be reported at wellhead or at BH)
BH	Bottom Hole; indicates the pressure measurement is located at the depth of the injection point into the reservoir and includes the hydrostatic pressure of the fluid between surface and that point
BH_{Excess}	Excess Bottom Hole Pressure as calculated in Examples EX-1 and EX-2
Closure Pressure	Pressure that a hydraulic fracture closes usually represents the minimum horizontal in-situ stress
DFIT	Diagnostic Fracture Injection Test
Dynamic Frac Pressure	Pressure measured at the intersection of the two straight lines on at SRT plot of pressure vs rate
FEP	Fracture Extension Pressure. A dynamic value for FEP be measured at the wellhead in a SRT or it may be represented by ISIP in a DFIT
FFEP	Far-field Fracture Extension Pressure, a value determined from Pressure Transient Analysis as described in SPE 196194
Formation Depth	True vertical depth from surface to formation
g	Default freshwater pressure gradient 9.806 kPa/m
InjFO	Injection Fall-Off Test
ISIP	Instantaneous Shut-in Pressure. The value selected after an injection test pump-shut-down (may be DFIT, SRT or InjFO) which represents the pressure needed to propagate a fracture or push the fluid into the reservoir after friction in the wellbore and perforations have dissipated
LITHO	Lithostatic Stress Gradient (default BCER value = 24.0 kPa/m)
$MWHIP_L$	Licensed Maximum Wellhead Injection Pressure; the maximum pressure that is allowed during injection during the project
$MWHIP_T$	Test Maximum Wellhead Injection Pressure; the maximum pressure that is computed from the SRT to avoid hydraulically fracturing the well
N/A	Not Applicable for this test or Not Available from test…either way it results in "I don't know"
P_c	Pressure that a hydraulic fracture closes usually represents the minimum horizontal in-situ stress
P24	Post SRT BH pressure at 24 hrs after pump shut-down
P24-Grad	P24 divided by the TVD at the top of the injection interval

P_{BH}	Calculated or measured bottom hole pressure at TVD location
$P_{BH\ Y\text{-}Int}$	a value determined from the SRT interpretation plot that is the y-intercept of the BH pressure post-frac trend line. This value is used to determine if the FEP is above the lithostatic pressure, Pl
P_{Surf}	Measured Surface pressure at a given rate
$P_{Surf\ Frac}$	Surface fracturing pressure is defined as the intersection of the reservoir line and the fracture line. See Example EX-1 and EX-2
PDL	an initialism for our company name - Pressure Diagnostics Ltd
P_{fric}	friction loss during injection; may be calculated using software or estimated using the chart in BCER Water Service Wells – Summary Information VERSION 3.7: December 2024
P_{fric_def}	The default value for friction is obtained from Figure 4
$P_{surf\ Trends\ Int.\ Pt}$	the intersection of the pre-frac and post-frac trend lines on the SRT interpretation chart. Usually interpreted to be the FEP
P_{Litho}	the calculated Lithostatic pressure (stress) of the formation using the BC average value of 24 kPa/m
Pri	Pore or Reservoir Initial Pressure
P_{WH}	Wellhead Pressure during testing at a specific rate
Q	Measured injection Rate
SG	Specific Gravity of fluid as shown in Table 3 (SG of fresh water = 1.0)
SG_L	Licensed injection fluid Specific Gravity
SG_T	Test Fluid Specific Gravity
SRT	Step-Rate-Test
TDS	Total Dissolved Solids
TVD	True Vertical Depth, taken at the top of the injection interval

REFERENCES

Bachman, R. C., Walters, D. A., Hawkes, R. A., Toussaint, F. L., & Settari, T. (2012). *Reappraisal of the G Time Concept in Mini-Frac Analysis*. Society of Petroleum Engineers. https://doi.org/10.2118/160169-MS

Bachman, R., Afsahi, B., & Walters, D. (2015). *Mini-Frac Analysis in Oilsands and their Associated Cap Rocks Using PTA Based Techniques*. Society of Petroleum Engineers. https://doi.org/10.2118/174454-MS

Barree, R. D., Barree V. L., Craig D. P. (2009). *Holistic Fracture Diagnostics: Consistent Interpretation of Prefrac Injection Tests Using Multiple Analysis Methods*. Society of Petroleum Engineers. https://doi.org/10.2118/107877-PA

Bourdet, D.P., Whittle, T.M., Douglas, A.A., and Pirard, Y.M. (1983). *A New Set of Type Curves Simplifies Well Test* Analysis, World Oil (May 1983).

Chow, V. T. (1952). *On the steady flow into a non-penetrating well*. In Proceedings of the Fifth Hydraulics Conference, University of Iowa, Iowa City, November 1952.

Fekete PTA Poster (2009). *Well Testing Fundamentals*, https://cdn.ihs.com/www/pdf/Well-Testing-Applications.pdf.

Gringarten, A.C. *From Straight lines to Deconvolution: The Evolution of the State of the art in Well Test Analysis*, Society of Petroleum Engineers. https://doi.org/10.2118/102079-PA

Hawkes, R.V., Bachman, R., Nicholson, K., Cramer, D.D. and Chipperfield, S.T. (2018). *Good Tests Cost Money, Bad Tests Cost More - A Critical Review of DFIT and Analysis Gone Wrong*, Society of Petroleum Engineers. https://doi.org/10.2118/191458-18IHFT-MS

Mattar, L., and Zaoral, K. (1992). *The Primary Pressure Derivative (PPD) A New Diagnostic Tool In Well Test Interpretation*, Journal of Canadian Petroleum Technology, April 1992, https://doi.org/10.2118/92-04-06.

McClure, M. W., Jung, H., Cramer, D. D. and Sharma, M.M. (2016). *The Fracture-Compliance Method for Picking Closure Pressure From Diagnostic Fracture-Injection Tests*. Society of Petroleum Engineers. http://dx.doi.org/10.2118/179725-PA.

Miskimmins, Holditch, Veatch, (2019). *Hydraulic Fracturing: Fundamentals and Advancements*. Society of Petroleum Engineers, Monograph Series.

Mohamed, A., Nasralla, A., Sayed, M., Marongiu-Porcu, M., & Ehlig-Economides, C. (2011). *Global Model for Fracture Falloff Analysis*. Society of Petroleum Engineers, https://doi.org/10.2118/144028-MS .

Nicholson, A. Kirby, Hawkes, Robert V., and Bachman, Robert C. (2019). *Early Warning Systems - Using PTA Analysis of DFITs to Understand Complex Hydraulic Fractures and Optimize Treatment Designs*. Society of Petroleum Engineers. https://doi.org/10.2118/196194-MS

Nordgren (1972). Propagation of a Vertical Hydraulic Fracture, Society of Petroleum Engineers. https://doi.org/10.2118/3009-PA

Perkins, T.K. and Kern, L.R. (1961). *Widths of Hydraulic Fractures*, Society of Petroleum Engineers, https://doi.org/10.2118/89-PA
Marongiu-Porcu, M., Ehlig-Economides, C.A. and Economides, M.J.(2011). *Global Model for Fracture Falloff Analysis*. https://doi.org/10.2118/144028-MS .

Singh, P.K., Agarwal, R.G. and Krase, L.D.(1987). *Systematic Design and Analysis of Step-Rate Tests to Determine Formation Parting Pressure*, https://doi.org/10.2118/16798-MS

Trican MiniFrac Poster (2014). *Minifrac Analysis in Unconventional Reservoirs*, https://www.scribd.com/document/252188679/806-Poster-MiniFracAnalysis-FINAL-WEB

APPENDIX A:

Pressure Transient Analysis for Injection/Fall-Off Tests in Water Disposal Wells

Pressure Transient Analysis (PTA) stands as a foundational technique in petroleum engineering, offering insights into the intrinsic properties of reservoirs and wellbore. For injection and fall-off tests, an appropriately designed test can determine some or all the following: Formation Fracture Pressure, closure pressure, permeability, skin, initial pressure and average pressure. This appendix details the core principles of PTA within this specific context, with a particular emphasis on the historical evolution, mathematical underpinnings, and interpretive power of two important diagnostic tools: the Bourdet Pressure Derivative and the Primary Pressure Derivative (PPD).

Following theory development, recommendations and pragmatic interpretation strategies and challenges will be discussed.

A1. Fundamentals of Injection/Fall-Off Testing

Injection/fall-off (IFO) tests are specialized pressure transient tests performed on injection wells. These tests typically involve a period of fluid injection at a constant rate, followed by a shut-in phase during which the subsequent pressure decline, or fall-off, is monitored. The subsequent analysis of this measured pressure response yields critical information regarding both the reservoir and the wellbore.

A1.1 Purpose and Applications in Water Disposal and Waterflood Projects

Transient testing and analysis of injection wells are crucial for estimating reservoir properties in a variety of applications, including waterflood and tertiary recovery projects, as well as for the efficient and safe disposal of produced water. The comprehensive understanding of reservoir properties and near-wellbore conditions in injection wells is considered as vital as it is for producing wells. Water is commonly injected into subsurface formations for several primary reasons: pressure maintenance to enhance hydrocarbon recovery, the disposal of produced water, the implementation of waterflooding schemes, and water circulation in geothermal doublet systems. Injection Fall-Off (IFO) testing is recognized as one of the most significant methods for continuously monitoring injector performance over time in waterfloods, water disposal operations, and polymer floods.

A1.2 Key Parameters Derived from Injection/Fall-Off Tests

IFO tests provide a wealth of information concerning key reservoir parameters. These include the permeability-thickness product (k*h), which quantifies the reservoir's capacity to transmit fluids; the skin factor (s), an indicator of near-wellbore damage or stimulation; reservoir transmissibility, reflecting the ease of fluid flow through the reservoir; and mobility contrasts, which highlight differences in fluid flow properties between injected and in-situ fluids. The slope derived from the semi-log straight line portion of fall-off test data is specifically utilized to calculate reservoir transmissibility (kh/μ), the skin factor (s), and the radius of investigation (ri) of the test. Furthermore, early-time analysis of IFO tests can offer estimates of the length and height of hydraulic fractures, particularly if such fractures are induced during the injection process.

The parameters obtained from IFO tests are not isolated measurements but are intricately linked, forming an interconnected system that describes the reservoir and wellbore performance. For instance, the skin factor, which quantifies near-wellbore conditions, directly reflects the degree of wellbore damage or stimulation. Formation damage, as detailed in discussions on water quality and its impact on injectivity, directly influences the skin factor. Therefore, a high skin factor often points to formation damage, which in turn impairs injectivity and overall reservoir performance. The accurate determination of these interconnected parameters enables engineers to precisely diagnose operational issues, such as formation damage, optimize injection rates to maximize efficiency, and reliably predict the long-term performance of the well. This comprehensive understanding directly impacts the economic viability and environmental compliance of water disposal operations.

A1.3 Essential Considerations for Test Design and Data Acquisition

The successful execution of an injection/fall-off test hinges on meticulous design and data acquisition protocols. A fall-off test fundamentally involves injecting fluid at a constant rate, followed by a shut-in period during which the pressure decline is measured. To ensure the validity of the results, the test must have a near-constant injection rate throughout the injection phase and sufficient pressure falloff to yield a meaningful pressure transient.

Bottom-hole pressure measurements are generally preferred and considered superior to surface pressure measurements due to their direct reflection of reservoir conditions. However, surface pressure measurements may be utilized if it can be unequivocally demonstrated that a positive pressure was maintained at the surface throughout the fall-off period. The physical properties of the injected fluid, specifically its viscosity and density, should be maintained as uniform as possible throughout the test. Ideally, the facility's normal waste stream can serve as the test fluid, provided sufficient volume is available to sustain a consistent injection rate. Interference from nearby offset injection wells must be minimized or accounted for; this can involve stabilizing pressure conditions prior to the test or diligently recording the injection rates and surface pressures of adjacent wells throughout the test period. Finally, the fall-off portion of the test must be conducted for a duration sufficient to collect ample data points within the infinite-acting period, allowing for the clear development of the appropriate flow regimes.

Operational choices and inconsistencies during test execution can impact the quality of the acquired data and, consequently, the accuracy of the interpretation. Maintaining constant injection rates and stable operational conditions is paramount. Discussions regarding water quality and its propensity to cause formation damage, such as from fines, scales, or solids, underscore how operational factors directly influence injectivity and the resulting pressure response. Furthermore, the viscosity value applied in evaluating the test should reflect the fluid through which the pressure transients propagate, which may not always be the injected fluid, especially when significant mobility ratio changes occur. This highlights that operational decisions, including fluid quality, injection stability, and the management of offset wells, directly introduce variations into the data. If not properly addressed, these variations can lead to noise or non-reservoir effects, making accurate interpretation challenging and potentially resulting in erroneous conclusions about reservoir behavior or wellbore condition. This emphasizes the critical need for stringent quality control during every phase of test execution.

A deeper examination of mobility ratio reveals its diagnostic potential beyond simplified assumptions. While basic analysis often assumes a mobility ratio of unity for ease of calculation, the reality in many injection wells, particularly water disposal wells, is that injected fluid properties can differ significantly from those of the native formation fluids. This difference frequently leads to "significant mobility ratio changes" that are distinctly revealed by a change in slope on the fall-off plot, indicating the presence of "multiple fluid banks". This slope change is a direct physical manifestation of the mobility contrast, providing a unique diagnostic signature. For water disposal wells, where understanding fluid displacement fronts is critical, recognizing and interpreting these mobility ratio effects is crucial for assessing sweep efficiency, identifying potential channeling, or diagnosing injectivity issues related to fluid incompatibility. This moves the analysis beyond idealized homogeneous reservoir assumptions to a more realistic representation of subsurface dynamics.

A2. Diagnostic Plots in Pressure Transient Analysis

Diagnostic plots serve as indispensable tools in well test analysis, enabling engineers to qualitatively identify prevailing flow regimes and select the most appropriate interpretation models. Among these, the log-log plot of pressure changes and its derivative versus time holds particular significance due to its powerful interpretive capabilities.

A2.1 Introduction to Log-Log Diagnostic Plots (Pressure Change and Derivative vs. Time)

A diagnostic plot is fundamentally a scatter plot that simultaneously displays both the pressure change (ΔP, or drawdown) and its logarithmic derivative as a function of time, typically presented on a log-log scale. The pioneering introduction of the combined plot of log pressure change and log derivative of pressure change, plotted against a log elapsed time or superposition time function, is attributed to Bourdet et al. This innovative plotting technique was conceived primarily as an aid to type-curve matching, a method for comparing observed well test data to analytically generated reservoir response patterns.

The log-log diagnostic plot fulfills two primary objectives. First, it facilitates the matching of field data to pre-computed type curves, which represent theoretical pressure responses for various specified reservoir models. Second, and equally important, it provides a powerful visual means for diagnosing the underlying reservoir model itself, based on the characteristic shapes and trends exhibited by the pressure and derivative curves. Traditional type curve approaches, while valuable, often presented a challenge due to the inherent similarity in the shapes of different theoretical curves, which frequently made it difficult to achieve a unique and unambiguous solution during the matching process. The introduction of the pressure derivative on log-log plots directly addressed this limitation by providing clear and distinct characteristic shapes for various flow regimes. This mathematical transformation introduces a clearer visual distinction, which in turn leads to more unique and reliable interpretations. The diagnostic plot, particularly with the derivative, transforms well test interpretation from a potentially ambiguous curve-fitting exercise into a more robust and definitive process, significantly reducing the risk of misdiagnosis and enhancing confidence in the derived reservoir parameters.

A2.2 Significance of Characteristic Shapes for Flow Regime Identification

The utility of the diagnostic plot stems from its ability to reveal distinct shapes for different flow regimes on the derivative plot. This graphical representation excels at displaying multiple separate characteristics within a single graph that would otherwise be challenging to discern. A key advantage is its capacity to amplify heterogeneities within the reservoir, features that are often barely visible on conventional pressure-only plots. The logarithmic derivative is exceptionally sensitive to subtle variations in the shape of the falloff/drawdown curve, enabling the detection of behaviors that are difficult to observe when examining the drawdown curve alone. This sensitivity allows for a more nuanced and detailed understanding of the reservoir's response.

The analysis of the diagnostic plot significantly streamlines the selection of an appropriate conceptual model for the reservoir. For certain reservoir models, the values derived directly from the derivative curve can be used to rapidly estimate model parameters, providing a quick and efficient means of preliminary analysis. Overall, one of the most compelling advantages of diagnostic plots is their provision of a unified methodology for interpreting pumping test data, effectively consolidating and replacing numerous specialized tools and techniques that were previously required for different reservoir models.

The consistent observation that the derivative "amplifies" subtle changes and "heterogeneities" that are not apparent on pressure-only plots is a fundamental aspect of its power. This amplification is not merely a mathematical artifact; it directly reveals the underlying physical processes and boundaries within the reservoir that govern fluid flow. The specific response of the derivative, whether in its slope or overall shape, is a direct consequence of the reservoir's geometry, the properties of the fluids, and the conditions within the wellbore. This amplification allows for a more detailed and accurate "fingerprinting" of the reservoir system, enabling the identification of complex features such as dual porosity systems, layered formations, or specific hydraulic fracture geometries that might be overlooked or misdiagnosed using simpler analysis methods. This capability ultimately leads to the development of a more comprehensive and realistic reservoir model.

A3. The Bourdet Pressure Derivative

The Bourdet derivative represents a pivotal advancement in modern pressure transient analysis, providing a robust and widely adopted method for identifying flow regimes and comprehensively characterizing reservoirs.

A3.1 Historical Development and Foundational Contributions

The conceptual foundation for using the logarithmic derivative in well test interpretation can be traced back to Chow (1952), who demonstrated its application for estimating aquifer transmissivity. However, the Bourdet derivative, as it is known today, was rigorously developed by Dominique Bourdet and his colleagues in the 1980s. Their seminal work, particularly the publication by Bourdet et al. (1983), proposed the revolutionary approach of plotting the pressure derivative, rather than just pressure, against time on log-log coordinates. This innovation fundamentally transformed the landscape of well test interpretation..

The historical progression from reliance on assumed special cases to Bourdet's generalization for all cases was a paradigm shift in well test interpretation. The result was an emphasis on flow regime identification. Typical flow regimes are radial, linear, spherical and bilinear flow. Dynamically growing hydraulic fracturing also leads to flow regimes first identified by Marongiu-Porcu et al (2011) and extended by Bachman et al (2012, 2015) and Hawkes al (2018). This development facilitated a transition towards more quantitative and reliable interpretations, enabling more confident decisions regarding reservoir development and management strategies.

A3.2 Mathematical Formulation and Interpretation Principles

The Bourdet derivative is mathematically defined as the derivative of the pressure change with respect to the logarithm of time. Its formulation can be expressed as:

$$d\Delta P / d\log(t_e) = d\Delta P / d(\ln(t_e)) = t_e * d\Delta P / dt_e$$

where t_e is Agarwal’s effective time. for the falloff period ΔP

The definition of these terms follows:

ΔP = Last Pressure at End of Pumping – Pressure at time Δt into falloff

Δt = Time from end of injection (start of falloff)

t_e = Agarwal effective time, for a single rate injection and falloff, $t_e = t_p\Delta t/(t_p+\Delta t)$

t_p = Pumping time

PPD = Primary Pressure derivative, during falloff PPD = dP/dt

The interpretation plot consists of a log-log plot of ΔP, the Bourdet Derivative and the PPD versus Δt (not t_e). This formula is applied to compute the derivative of the pressure change relative to the logarithm of effective time. Interpretation of the Bourdet derivative necessitates an understanding of the various flow regimes that occur within a well and reservoir system. While powerful, the application of the Bourdet derivative is not without its challenges. Common limitations include the presence of noise within the pressure data, issues with overall data quality.

A3.3 Characteristic Flow Regimes Identified on Log-Log Plots

The Bourdet derivative is instrumental in identifying distinct flow regimes, each exhibiting a characteristic shape or slope on the log-log diagnostic plot.

- **Wellbore Storage:** This regime dominates the early-time pressure response, where the pressure change is primarily influenced by the changing fluid volume within the wellbore itself. On the Bourdet derivative plot, wellbore storage is typically characterized by a unit slope (a straight line with a slope of 1). The derivative is particularly effective in pinpointing the precise end of this wellbore storage period, allowing for the isolation of reservoir-dominated flow.
- **Infinite-Acting Radial Flow (IARF):** This crucial regime occurs when the pressure transient has propagated beyond the immediate vicinity of the wellbore and its associated effects but has not yet encountered any reservoir boundaries. On a log-log plot, the IARF regime is distinctly identified by a horizontal line (a zero slope) on the derivative curve. This characteristic plateau is fundamental for accurately estimating key reservoir properties such as permeability and the skin factor.
- **Linear Flow:** This flow regime is characteristic of fluid movement towards a linear feature, such as a hydraulic fracture or a long, narrow channel. On the log-log plot, both the pressure change and its derivative typically exhibit a half-slope (a straight line with a slope of 0.5), often appearing as two parallel lines.
- **Boundary Effects:** As the pressure transient continues to propagate, it may encounter reservoir boundaries, which manifest as distinct changes in the derivative plot:
- **Closed Outer Boundary:** Indicated by a sudden increase in the pressure derivative, typically evolving towards a unit slope. This signifies that the reservoir is finite and the pressure transient has reached its confines.
- **Constant-Pressure Outer Boundary:** Indicated by a sudden drop in the pressure derivative, often tending towards zero. This behavior can result from various pressure-support mechanisms, such as an active aquifer, a gas cap, or the influence of pattern injection wells.
- **Complex Reservoir Models:** The Bourdet derivative is also adept at diagnosing more complex reservoir architectures:
- **Dual Porosity/Permeability:** This model, common in naturally fractured reservoirs, is characterized by a distinctive "trough" or "valley" in the pressure derivative. This feature signifies the communication and fluid transfer between a high-permeability fracture network and a lower-permeability matrix rock.

- **Layered Systems:** A similar valley in the pressure derivative can also indicate a layered reservoir system. The analysis of layered systems is inherently complex due to the potential for different flow regimes, skin factors, or boundaries existing within each individual layer.
- **Hydraulic Fracturing Behavior:** It is a generally accepted principle that fluid flow through porous media alone rarely, if ever, produces a Bourdet derivative slope greater than one. However, specific non-reservoir phenomena, occur during a Data Frac Injection Test (DFIT). This occurs when a well is intentionally hydraulically fractured with a small volume of fluid pumped at high rate, and shut-in. The falloff period results in the well going through closure. For instance, during fracture closure (as observed in tight shale gas mini-fracs), the derivative slope equals 3/2. This specific diagnostic signature is a critical indicator, explicitly flagging the observed behavior as a non-reservoir geomechanical effect rather than a typical fluid flow phenomenon. This distinction is crucial for accurately interpreting the underlying physics.

The general rule that reservoir flow typically produces derivative slopes less than or equal to one (e.g., unit slope for wellbore storage, zero for radial flow, half for linear flow) is a cornerstone of interpretation. However, the occurrence of a specific 3/2 slope during fracture closure, explicitly identified as a non-reservoir geomechanical effect, represents a critical diagnostic capability. This specific response is a direct consequence of the unique physics governing fracture closure, which results in a derivative behavior distinct from that of typical porous media fluid flow. This allows engineers to differentiate between fluid flow phenomena and geomechanical events, such as fracture closure or opening. This capability is vital for operations like hydraulic fracturing, assessing caprock integrity in steam-assisted gravity drainage (SAGD) projects, or ensuring containment in disposal wells. It significantly expands the diagnostic power of the Bourdet derivative beyond traditional fluid flow characterization.

Flow Regime	Typical Bourdet Derivative Slope/Shape	Corresponding Physical Interpretation	Example Application/Context
Wellbore Storage	Unit slope (slope = 1)	Pressure response dominated by changing fluid volume in wellbore.	Early-time data, regardless of reservoir type.
Infinite-Acting Radial Flow	Horizontal plateau (slope = 0)	Unimpeded fluid flow into/out of wellbore from an extensive, homogeneous reservoir.	Middle-time data, used for k and s estimation.
Linear Flow	Half-slope (slope = 0.5)	Flow to a linear feature, e.g., hydraulic fracture.	Fractured wells, flow within linear channels.
Closed Outer Boundary	Increasing slope (approaching 1)	Pressure transient has reached a no-flow boundary (e.g., sealing fault).	Finite reservoirs, compartmentalized systems.
Constant-Pressure Outer Boundary	Decreasing slope (approaching 0)	Pressure transient has reached a constant-pressure source (e.g., aquifer, gas cap, pattern injector).	Reservoirs with strong pressure support or interference.
Dual Porosity/Permeability	Characteristic "trough" or "valley"	Fluid transfer between high-permeability fracture network and low-permeability matrix.	Naturally fractured reservoirs (e.g., carbonates, shales).
Layered System	Potential "valley" or complex shape	Flow in multiple layers with varying properties.	Commingled or crossflow reservoirs.
Fracture Closure (Geomechanical)	Slope = 3/2	Pressure decline during hydraulic fracture closure.	Mini-frac tests, disposal wells operating near fracture pressure.

Table A1: Characteristic Flow Regimes on Log-Log Diagnostic Plots (Bourdet Derivative)

This table provides a standardized reference for interpreting the complex visual patterns observed on log-log diagnostic plots. By clearly outlining the expected derivative behavior for each flow regime, it enables a more efficient and accurate diagnosis of reservoir and wellbore conditions. This is particularly beneficial during real-time wellsite analysis, allowing for rapid qualitative assessment. Furthermore, the table serves as an effective educational aid, reinforcing the visual interpretation skills essential for well test analysis by consolidating information from various theoretical models into a practical, actionable format.

A sampling of reservoir flow regimes during shut-in are shown in Figure A.1 from the *Fekete* PTA Poster (2009). Corresponding open hydraulic fracturing flow regimes during shut-in are shown in Figure A.2 from the *Trican* Minifrac Poster (2014).

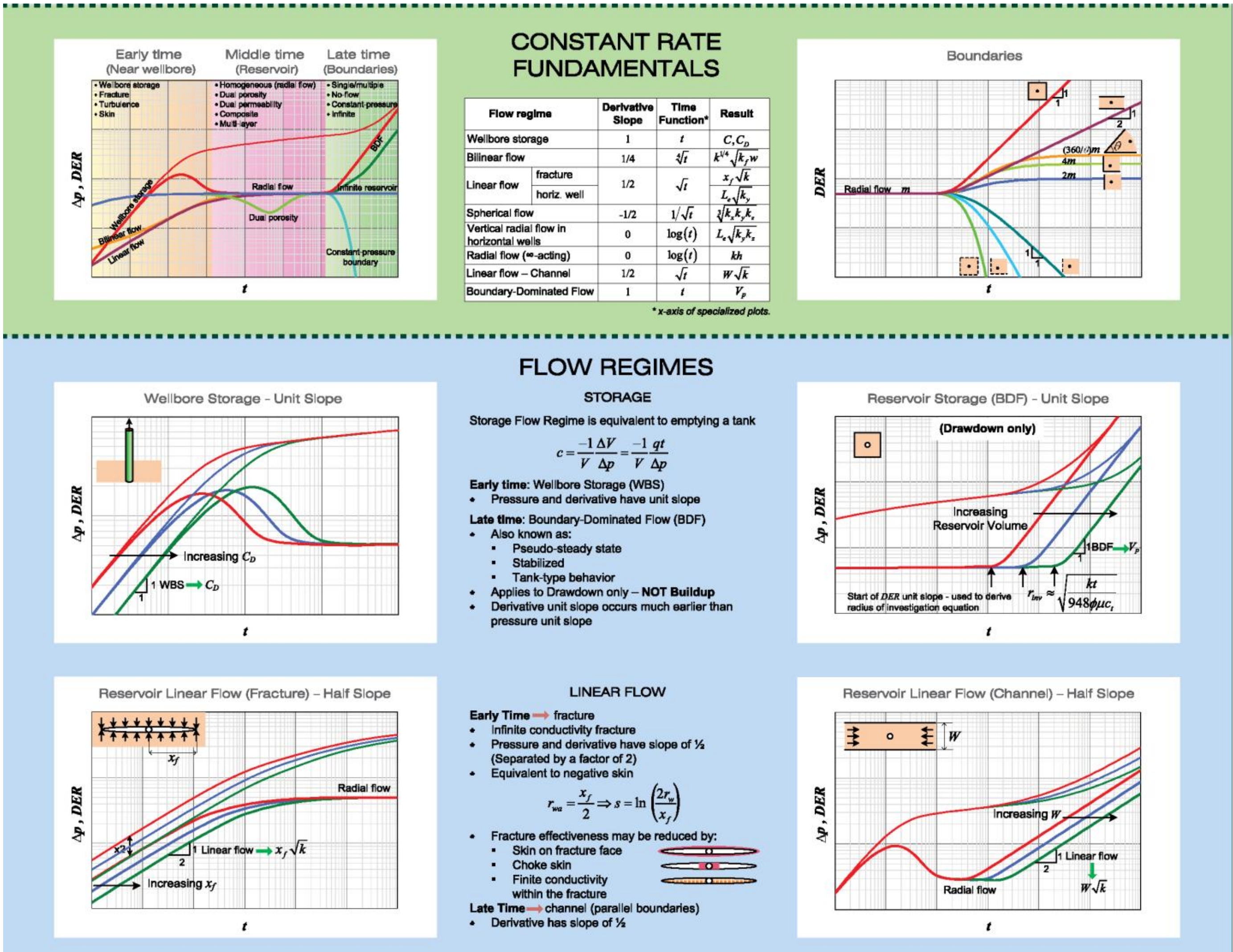

Figure A.1: Sampling of Reservoir Flow Regimes (From *Fekete* PTA Poster)

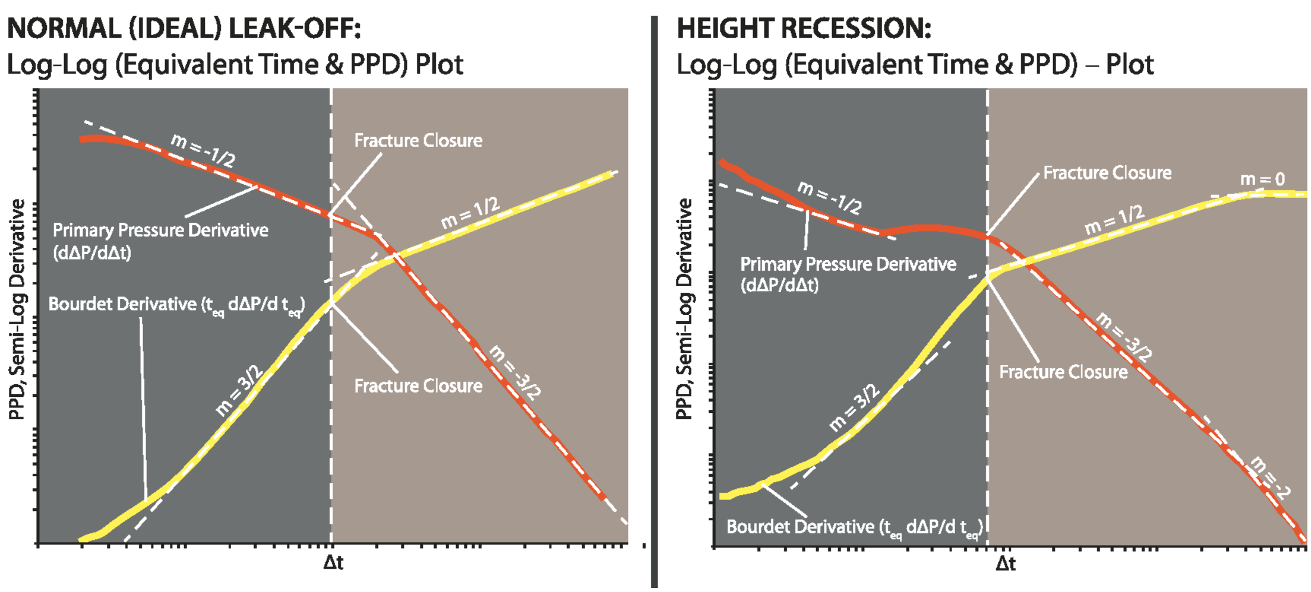

Figure A.2: Hydraulic Fracturing Flow Regimes (From *Tricican* Minifrac Poster)

A4. The Primary Pressure Derivative (PPD)

While the Bourdet derivative excels at identifying reservoir flow regimes during build-ups/falloffs, Mattar and Zaoral's (1992) Primary Pressure Derivative (PPD) offers a distinct and complementary diagnostic tool. In traditional PTA analysis it can differentiate wellbore effects from true reservoir responses. Later the idea was extended to DFIT analysis to identify unique aspects of hydraulic fracture closure.

A4.1 Origins and Evolution

The 1980s are widely acknowledged as the "decade of the derivative" in pressure transient analysis, a period marked by significant advancements based upon extending the work of Bourdet et al (1983). The next advance was Mattar and Zaoral's (1992) PPD. The PPD plot allowed identification of anomalous wellbore-related events which can cause measured pressure to deviate, rising or falling, independently of true reservoir effects. The time range of these anomalous wellbore events are called PPD violations, and are excluded from flow regime analysis and interpretation.

The PPD has an independent diagnostic capability to the Bourdet derivative curve as shown by Bachman et al (2012, 2015). The Bourdet derivative relies on the equivalent time concept, which is a type of superposition which can include multiple varying rates during the test. The PPD curve does not rely on superposition. Under optimal conditions the flow regimes identified by the two curves will be identical. Plotting the PPD on the Bourdet derivative plot is strongly recommended. Late time flow regimes should be compared for the Bourdet derivative and PPD curves for consistency. A table identifying various derivative slopes to their associated flow regime is given in Hawkes et al (2018).

In the monitoring phase, most tests are analyzed without accounting for the cumulative injection volumes prior to the test. Typically, only a short injection period prior to the actual injection/falloff test is included. This is done for ease of analysis and has unintended consequences. Gringarten (2008) studied the impact of truncating the rate portion of the test on falloff analysis. At late shut-in times the Bourdet derivative curve has higher values and a steeper slope than test interpretations including the full rate history. This may lead to an incorrect interpretation of flow regimes and determination of average pressure. The PPD curve is not affected by truncating the rate schedule. When the late time PPD curve gives a different flow regime than the Bourdet derivative curve, a careful review of the interpretation methodology is warranted. Both the PPD and Bourdet derivatives should give consistent flow regimes at all time ranges.

A4.2 Unique Aspects of DFIT Interpretation

DFIT tests are fundamentally different than classic PTA test in that a dynamically generated hydraulic fracture is strongly interacting with the static reservoir. In a DFIT, the pressure falloff versus time curve frequently has a S shaped feature, a classic non-reservoir effect, and is identified as a PPD violation. Barree et al (2009) call this phenomenon Height Recession/Transverse Storage (HRTS) and it is related to changing fracture storage during closure. Identifying this feature allows the pick of two important points, the

Nolte/Barree tangent closure and the contact pressure (or contact closure), first identified by McClure et al (2013). These picks have traditionally been made using the specialized combination G function plot.

The interpretation community disagrees as to which closure value is the proper closure pressure. The tangent closure stress value is always the lower value. For reporting purposes, it is important to report both values. The recommendation is to use the average of the two values as a reported closure pick. If HRTS does not occur, there is only tangent closure, and it is the closure stress. When reporting, it is vital to given pressure gradients at formation depth (True Vertical Depth = TVD). Gradients greater than ~22.6 kPa/m (1.0 psi/ft) are normally above the overburden gradient and are red flags.

A5. Interpretation Considerations

A5.1 Formation Appraisal Tests

During the appraisal phase the most important output from of the test is the identification of the maximum permissible wellhead injection pressure. For interpretation all measured pressures must be converted to BHP conditions at midpoint of perforations (MPP) or the mean depth of the horizontal wellbore. The first step is to convert the gauge pressure to BHP depth using only the hydrostatic column of the test fluid. The analysis will proceed with these pressures as input.

All reported falloff related pressure interpretations (Farfield Fracture Extension Pressure (FFEP), closure stress, initial pressure, and observed pressure 24 hours into the shut-in) will be reported at this depth. Additionally, the pressure/stress gradient will be reported for all these values. The acceptable wellhead pressure may be calculated in one of two ways.

The conservative maximum wellhead pressure is the appropriate closure stress (times the BCER safety factor) minus the hydrostatic column. A higher surface pressure can be applied for by performing an appropriate wellbore hydraulics calculation, accounting for frictional loss in the vertical portion of the wellbore only. This pre-supposes that the test wellbore configuration represents the project state. If there is a different test, then project wellbore diagrams and calculations must be provided. All diameters and roughness coefficients must be documented. The total amount of friction loss in the vertical section must be reported along with the hydrostatic column pressure. Previous BCER documents gave default pipe friction pressure loss parameters. These are now rescinded.

All field tests, even if uninterpretable, must be submitted to the BCER complete with raw field data. In the case of an uninterruptible test default regulatory BCER guidelines will be implemented.

A5.2 Annual Monitoring Tests

The methodology discussed in the previous sections apply. Additional requirements include:

1. A discussion of the cumulative fluids used within the interpretation model must be reported, along with the actual cumulative well injection into the well at the time of the test.

2. The specifics of the reservoir areal extent used in models must be clearly specified.
3. The type of outer boundary condition (infinite acting, no flow, constant pressure or mixed) must be stated. If a constant pressure outer boundary is used, report the value.
4. Interpretations are based upon the pressure falloff. The report must also include the calculated pressure response during actual injection for a minimum of 1 year prior to the test and plotted versus observed data.
5. Both the PPD and Bourdet derivatives during the falloff must be shown. If inconsistent flow regimes occur, the issue of flow regime inconsistency at late time must be addressed.

A6. Interpretation Challenges

This section will address primary challenges facing interpreters after an IFO test has been completed.

A6.1 Test Goes on Vacuum

During well appraisal, an IFO may go on vacuum during shut in. Disposal wells are normally drilled in higher permeability formations, so that large injection rates can be maintained. The formation itself can be under-pressured. Under-pressured reservoirs have initial reservoir pressures that are less than the hydrostatic column of fresh water. This is exasperated by the fact that disposal fluids have a higher specific gravity than fresh water. For high permeability wells pressure falloff during a test can occur quite rapidly and the surface pressure can rapidly go on vacuum. Downhole gauges, if deployed will give accurate pressure data. Surface pressures will read a pressure close to zero. The introduction of a vacuum results in an increase in wellbore storage by orders of magnitude, due to the formation of a gas column at the top of the wellbore. This distorts a downhole pressure to the point that normally no further reservoir interpretation is possible. If no reservoir interpretation is possible prior to going on vacuum the test is uninterpretable. A re-test may be required with a downhole shut-in tool above the pressure gauge. This greatly increases the cost of testing.

An IFO test during well monitoring is less susceptible to this issue as the near wellbore area pressures up to an over-pressured state.

A6.2 Monitoring Well – Interpretation Commentary

When performing monitoring testing, the test is made significantly more difficult as usually the average pressure at testing time is the primary requirement. A traditional analysis now includes a material balance portion to it. The choice of drainage area and how much of the injection history to include are paramount. Performing material balance requires a full rate history to be included in the test interpretation. The only exception is if a constant pressure boundary condition is used. Then the average pressure is not being calculated it is being assigned. The assignment is the assumed boundary pressure, or a value very close to it.

It is better to assign a pressure at a set time after shut-in (recommend 12 hours) as P*, which will act as a surrogate for the average pressure. Since disposal wells are normally high permeability this arbitrary fixed shut-in time should be past all near wellbore effects. The changing value of P* from year to year is an acceptable indicator for assessing reservoir fill up.

A constant pressure boundary condition is not the same as an infinite acting reservoir. For the infinite acting reservoir there is still pressure drop going out to infinity. This is not the case for a constant pressure boundary condition. They would be the same if in the infinite acting case the permeability was infinite at the distance to the constant pressure boundary to infinity. Invoking a constant pressure boundary at a particular distance means the well occupies a poorer quality portion of the reservoir compared to the surroundings in every case. This seems unreasonable in most cases.

A further issue with the constant pressure boundary condition interpretation, is that the modeled well eventually has a steady state pressure response. The pressure is constant at all points in the model at a set time. An infinite acting reservoir does not have this behavior, pressure continually drops for all time, due to an ever-expanding drainage volume and a pressure drop over the entire expanding area.

A dynamically growing hydraulic fracture for all time has a slight increase in pressure with time for the most reasonable Perkins-Kern-Nordgren (PKN) constant fracture height model, Perkins & Kern (1962) and Nordgren (1972). Any well that is injecting at constant rate and constant pressure for long periods of time likely has a dynamically growing fracture of some sort, as opposed to a steady state non-fractured response.

A qualitative check on fall-off pressures can also be used to assess the likelihood of a dynamically generated fracture. Any well capable of injecting >500 m3/d should have a very rapid pressure falloff and a radial or linear flow regime within one hour. If pressure fall-off after this time is still significant and no identifiable flow regimes exist during a test, then the well is likely of lower permeability with a large dynamic fracture.

APPENDIX B:

FRACTURE EXTENSION PRESSURE (FEP) DETERMINATION & IN COMPARISON TO LITHOSTATIC GRADIENT IN STEP-RATE-TESTS (SRT'S)

B1: Fracture Extension Pressure Measurement Independent from Friction and Tortuosity Effects

Figure B1, the example shown in EX-1, illustrates a successful SRT with both surface and Bottom Hole (BH) pressures provided. Clear identification of pre-fracturing (reservoir feeding) and fracture extension behavior is observable with the transition occurring at the vertical line marked as "Dynamic Frac Pressure". While fracturing occurs at this point on the chart corresponding to a rate of ~575m3/d, the surface pressure measured at this rate of 16726 kPa represents an unknown combination of fracture extension pressure, friction and tortuosity. The value representing only the Fracture Extension Pressure (FEP) is often taken as the y-intercept with injection rate = 0.[1] This value removes friction and tortuosity from the measurement.

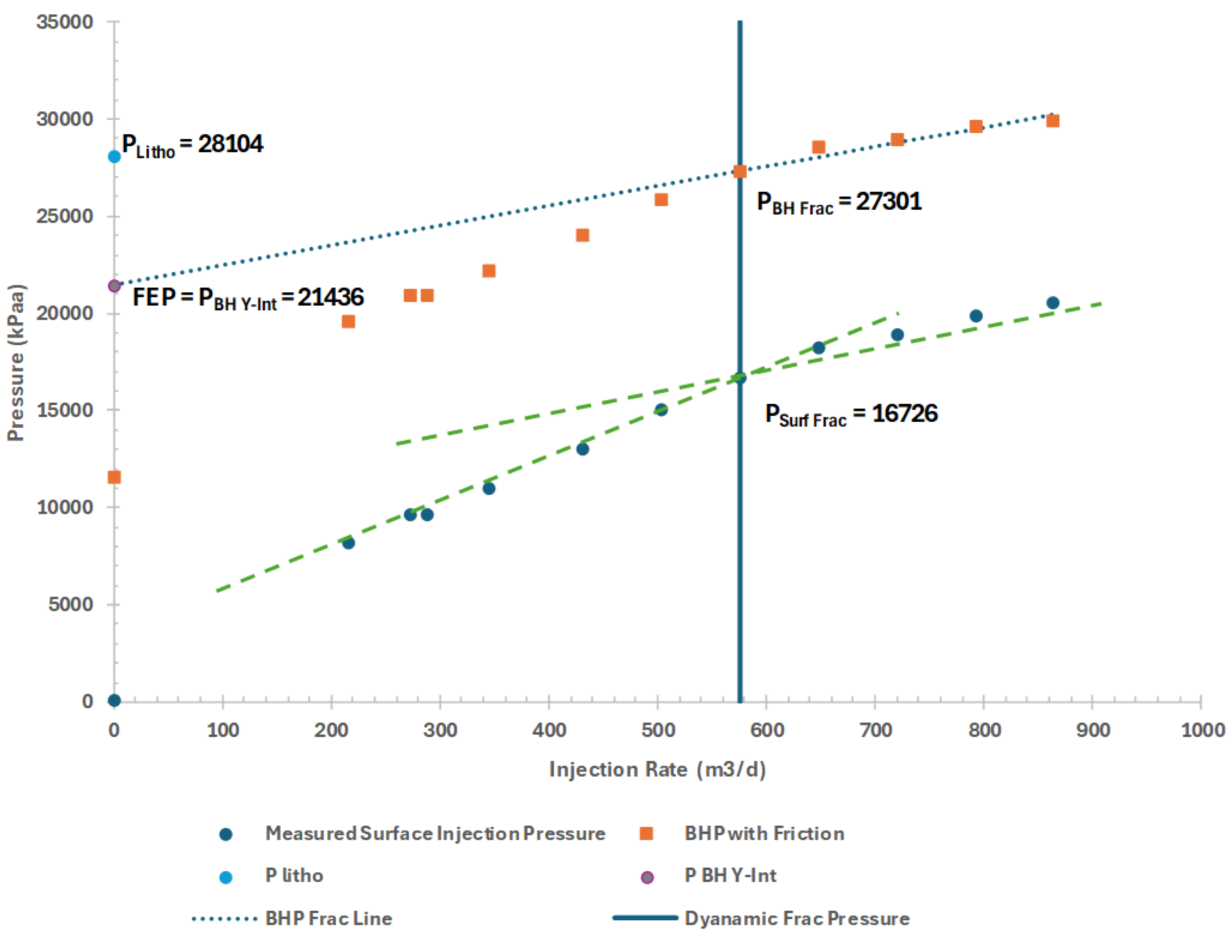

Figure B1: Determination of FEP from SRT

---

[1] **Hydraulic Fracturing Fundamentals and Advancements, SPE Monograph, Society of Petroleum Engineers, Miskimmins, Holditch, Veatch, 2019, ISBN 978-1-61399-719-2, p. 497-498**

In low permeability reservoirs a Diagnostic Fracture Injection Test (DFIT) may be conducted to measure key geomechanical and reservoir properties, including FEP. The use of Pressure-Transient-Analysis (PTA) techniques can be used to separate the smaller values for friction and tortuosity expected in a lower-rate test. A FEP values, defined as Farfield Fracture Extension Pressure (FFEP) in SPE 196194 and outlined in Appendix A may be determined.

In rare cases, SRT and DFIT PTA FEP measurements may be compared if both test types are applied in the same setting. Figure B2 shows the cartesian plot of pressure and pump rate data for a DFIT followed by a SRT (step-down) in a low-permeable formation.

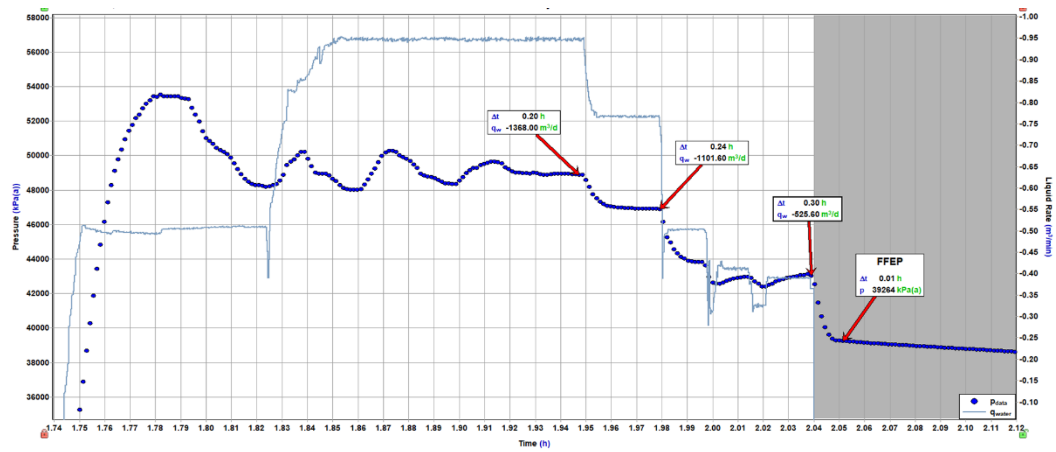

Figure B2: DFIT and SRT Pump Chart

The PTA Log-Log diagnostic plot of the post-injection fall-off with Bourdet derivative and PPD are shown in Figure B3. The fall-off shows brief storage and friction followed by fracture closure behavior. The PTA-derived FFEP is picked, as per SPE 196194, at the end of the wellbore effects (storage, friction) and beginning of fracture closure. FFEP is 39284 kPaa.

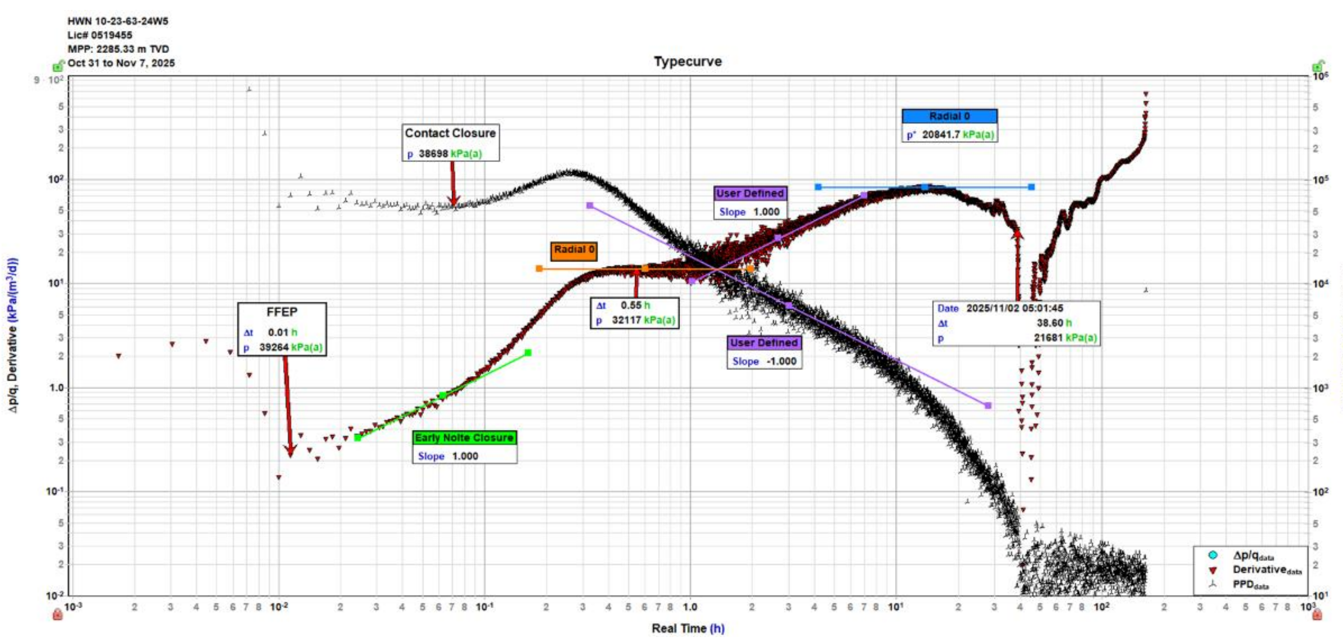

Figure B3: Post Injection Fall-off PTA Log-Log Diagnostic Plot

In Figure B4, The SRT portion of the test is analyzed using the same technique outlined in Figure B1. Note that no pre-frac injection data is present as this is a low-permeability reservoir. The extrapolation of the BH pressure data to the y-intercept yields a value of 39175 kPaa which is nearly identical to the FFEP determined from Figure B3. This example provides validation of the y-intercept in SRT's representing the FEP value.

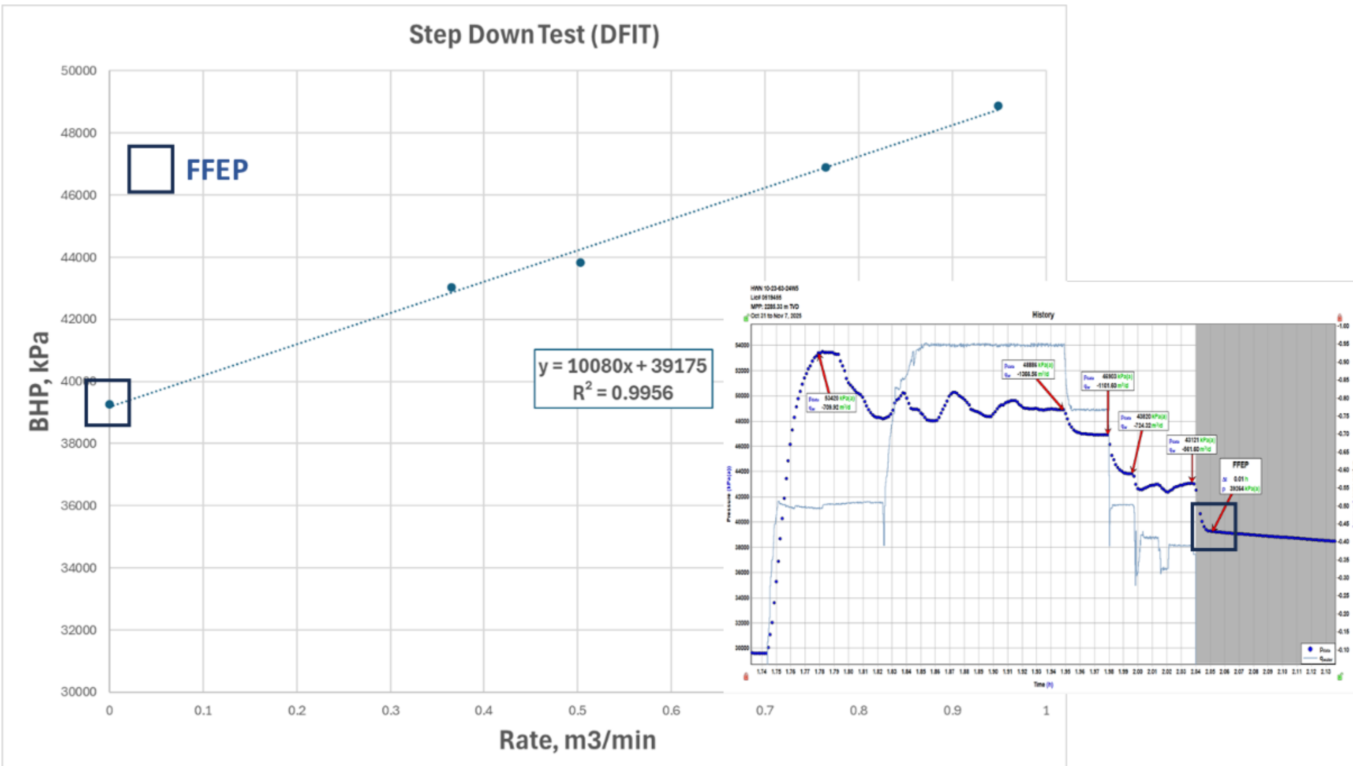

Figure B4: Step-Rate-Test (SRT) Analysis

B2. Why use 90% of the Lithostatic Gradient as the Threshold for FEP?

In NE BC FFEP gradient values determined from DFITs are often near 20 kPa/m. This is a function of a higher stress setting in a tectonically active region of Western Canada. While no amount of fracturing is desired in disposal wells, an upper safe threshold is the lithostatic gradient (usually 24 kPa/m in NE BC). FEP values above lithostatic may generate hydraulic fractures in any plane, including horizontal (pancake fractures). Hz-plane fractures may propagate long distances due to bedding plane weaknesses or natural fractures and faults.

A safety factor of 90% of the lithostatic gradient (21.6 kPa/m), combined with the more conservative SRT y-intercept FEP value provides a consistent method for setting MWHIP. Where risk or uncertainty are increased (eg. CO_2 disposal, sour fluid injection, induced seismicity settings) a safety factor of 80% or lower may be justified by the regulator.

In Appendix C we discuss a review of select BC DFITs applied during initial testing of disposal wells with notes outlining why DFITs are not normally a recommenced procedure for determining MWHIP in higher-permeability reservoirs.

APPENDIX C:

SUMMARY OF DFIT REVIEW

C1. Recommendations to Develop Revised Initial and Annual Testing Guidelines

1. Pressure Diagnostics Ltd. was engaged to review 11 select DFITs to critique the analyses techniques and results.
2. PDL recognizes the importance of these tests compared to regular production well Initial-Pressure requirements. An elevated level of care is recommended for testing and analysis for disposal wells.
3. PDL was only able to fully reanalyze a test on 1 of the 11 wells due to missing data or compromised data (e.g. vacuum, pressure disruptions).
4. Most of the tests were given a 'Low' (unacceptable) confidence rating for Fracture Extension Pressure, FFEP.
5. Many wells had 'Med' or 'High' (acceptable) measurement of Pore Pressure, Pri....often by waiting for the well pressure to stabilize for a reading vs. an interpreted/extrapolated value.
6. Many execution and interpretation issues need to be addressed.
7. PDL proposes writing guides for testing, analysis and interpretation to be included into a revised Guide

C2. Question: What's Missing from current practices?

Answers:

- Careful execution to avoid pressure disruptions and poor data.
- Use of PTA Log-Log Diagnostics: Did I frac or feed?
- A lack of appreciation for Pressure Gradients: Closure cannot be < than hydrostatic and should not be > lithostatic
- A lack of appreciation for the devastating effect of vacuum; even with BH gauges: Wellhead Vacuum = "My test is done…"
- In some cases, a lack of redundancy/corroboration of key parameters; Operators should measure key values 2x, especially if results are ambiguous.

C3. Background

The British Columbia Energy Regulator (BCER) contracted Pressure Diagnostics Ltd. (PDL) to review Diagnostic Fracture Injection Tests (DFIT), Injection Fall-off (InjFO) Tests, and Step-Rate Tests (SRT) in 11 wells. These tests were submitted to the regulator as part of applications to use the subject wells for water disposal.

PDL has reviewed and critiqued the Operator's (or designated analyst's) reports, and where possible, provided our own interpretation of the tests using data files provided by the BCER. PDL has documented this work in the presentation that follows and an accompanying *Microsoft Excel* spreadsheet.

The spreadsheet tabulates all the information that was requested by the BCER email of 28-Mar-2024.

PDL reviewed the current BCER water disposal well application guidance documents. We interpret that the key measurements (or calculated values) to be determined for injection wells is:

1. Maximum Wellhead Injection Pressure, MWHIP.
2. Initial Pore Pressure, Pri.

C4. Discussion

Assuming the 11 DFITs reviewed are a representative sample of tests for injection well applications, the following issues have been identified:

1. Testing execution often lacks care to preserve the best quality pressure data after a DFIT or InjFO test. Pressure disruptions due to rigging out of equipment or a de-pressuring of gauges may compromise important periods of the test, or the entire test.

2. Higher permeability and under-pressured reservoir (Pri lower than that required to hold a full column of water to the surface) will rapidly drop surface pressure to less than zero-gauge wellhead pressure (vacuum) which compromises the test thereafter. Even with the installation of Bottom-Hole (BH) gauges, the rapid change in well fluid compressibility with a vacuum will often render a test invalid. A new testing procedure for under-pressured reservoirs is recommended.

3. Higher permeability wells may not fracture with a lower-rate & volume injection (DFIT). Utilizing DFIT analysis techniques (as was observed in a few of the tests) may be misleading and may result in erroneous results. A means to identify the correct testing procedure and analysis technique needs to be included in industry guidelines.

4. Operators should consider the setting for test data (high or low perm, over or under-pressured reservoir) and use pressure gradients (pressure/depth) as a tool to validate results. FEP gradient values > lithostatic are suspect. Fracture Closure pressure gradients that are < hydrostatic are erroneous. Operators should be encouraged to validate results with a redundant test (e.g. DFIT + SRT).

C5. Results

All operator test reports were reviewed critically with the goal of rating key pressure measurement (Break-Down, Fracture Extension, Fracture Closure & Pore Pressure) with a confidence rating of High, Med or Low.

- ❖ High: Result is acceptable as a stand-alone result.
- ❖ Med: Result may be acceptable with the judgement of a knowledgeable expert or redundant/corroborating data.
- ❖ Low: Result is unacceptable.

Focusing on the key pressures FEP and Pore Pressure, our review of 18 tests (11 wells, 2 wells had multiple tests) yielded 12 'Low' ratings for FEP but only 3 'Low' ratings for Pore pressure.

Improvement in the quality of testing and analysis for FEP appears most necessary.

C6. Recommendations following DFIT reviews

PDL recommends proceeding with further work to:

1. Highlight the importance of these tests compared to regular production well Initial-Pressure requirements. Introduce redundancy.
2. Write recommendations for specs. and procedures for gauges, installation, rig-up/rig-out; test details for DFIT, InjFO, SRT and other possible tests.
3. Specify procedures for BH gauges c/w WR plug isolation for under-pressured reservoirs.
4. Identify when fracturing vs. feeding and test accordingly. Possibly introduce Log-Log Diagnostic flow-regime analysis.
5. Outline analysis requirements. Review and recommend revisions to Guidelines for defining MWHIP especially when test results are not clear.
6. Make all this as simple, clear, and efficient as possible for industry to adopt.

C7. Summary of Why are DFITs Not Recommended for Future Initial Testing of Disposal Wells

1. DFITs are designed for low-perm reservoirs. Disposal wells are typically placed in high-perm settings.
2. A successfully executed and analyzed DFIT in a bounding layer (e.g. cap-rock or shale) may identify closure but this value is difficult to equate to an acceptable MWHIP.
3. Classic DFIT interpretation specialized G-Function plots may appear to show fracture closure even when a fracture may not have been created (Figure C1).
4. DFIT interpretation is deemed to be more nuanced and prone to misinterpretation than a properly executed SRT.

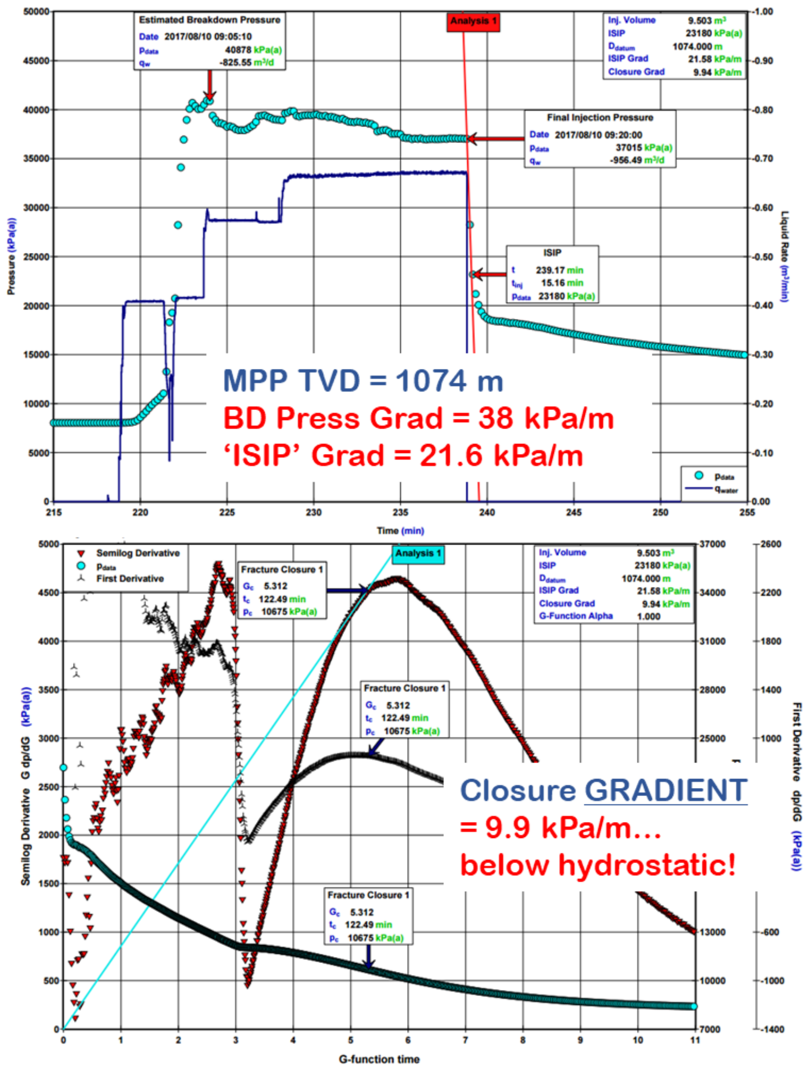

Figure C1: Example Mis-Interpreted DFIT