Step Rate Testing:
Determining Fracture Pressure for Injection Wells

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Overview

- What is Fracture Pressure?
- Why is Fracture Pressure Important?
- How can we Best Estimate Fracture Pressure?
  - Step Rate Testing
    - Method and Analysis
    - Potential for Error
    - Best Practices to Minimize Error
What Is Fracture Pressure?

Consider the Basic Stresses Present in the Reservoir System:

- **Overburden Stress** – The stress caused from weight of overlying rock.

- **Matrix Stress** – The stress present in the reservoir rock matrix.

- **Pore Pressure** – The pressure exerted by the compressed fluid in the reservoir pore spaces.
The overburden stress acts as a downward force on the reservoir.

It is being countered by the formation matrix and the fluid within the pore spaces.

At the same time, the formation matrix is resisting the pore pressure.
In-Situ Stress Balance

- The system is held in balance, that is:
  - Overburden Stress = Matrix Stress + Pore Pressure

- An increase in pore pressure (through injection) will decrease the matrix stress
  - Matrix will be held less in compression and more in tension

- Eventually, the rock matrix will be unable to counter the pore pressure increase
  - Initiation of a new fracture
  - Opening of an existing fracture

- Fracture Pressure - *The pressure at which a reservoir system shifts from matrix flow to fracture dominated flow*
Matrix Flow vs. Fracture Dominated Flow

Matrix Flow:
Fracture Pressure has not yet been reached;
Fluid flows through the pore network
Matrix Flow vs. Fracture Dominated Flow

Fracture Dominated Flow:
- Fracture Pressure has been reached;
- Pressure has become high enough to create or open pre-existing fractures in the rock matrix.
Why is Fracture Pressure So Important?

1) Operational

- Drilling: Will dictate the maximum mud densities and pump pressures that can be used
- Completion: Critical in designing effective fracture stimulations

2) Regulatory

- Class I injection wells are limited by law to operating pressures that do not fracture the injection zone
  - Reduces the potential for injection fluids to enter an overlying formation (enhancing protection of USDWs)
How can we Estimate Fracture Pressure?

**Step Rate Testing:**

- Injection into the reservoir at progressively higher rates
- Record the pressure response seen in the reservoir
- Pressure response can be graphically analyzed to estimate fracture pressure
  - Shift from matrix flow to fracture dominated flow
Idealized Step Rate Plot
Rate, Surface Pressure and Bottomhole Pressure vs Time

Pressure Increases for Each Rate Step Begin to Lessen

Bottomhole Pressure (BHP)

SHP and BHP Begin to Converge

Rate

Surface Pressure (SHP)
Hydrostatic Pressure

SHP or WHP = 0 psi

Static Well Conditions (No Flow):

- A column of fresh water (SG = 1.0) exerts 0.433 psi/ft
- Ex. In a 6,000 ft well, the hydrostatic pressure at the bottom of the well (BHP) is 2,598 psi (6,000 ft * 0.433 psi/ft * 1.0)
- Surface pressure (SHP) is zero.

BHP = 2,598 psi
Friction Loss

SHP or WHP = Pump Pressure

Dynamic Well Conditions (Flowing):

- Friction loss is dependent on flow rate, diameter of pipe, and the roughness coefficient of the tubing.
- Roughness is an estimation and varies according to tubing wear.
- Increases exponentially with increasing flow rate.

BHP = SHP + Hydrostatic Pressure – Friction Losses

Bourgoyne, Millhelm, Chenevert, Young, Applied Drilling Engineering, 1991
Idealized Step Rate Plot
Rate, Surface Pressure and Bottomhole Pressure vs Time

- **Pressure Increases for Each Rate Step Begin to Lessen**
- **Bottomhole Pressure (BHP)**
- **SHP and BHP Begin to Converge**
- **Surface Pressure (SHP)**

**Axes:**
- Y-axis: Pressure (psig)
- X-axis: Time (Minutes)
Idealized Step Rate Plot
Final Pressures for Each Rate Step

Estimated Fracture Pressure = 4,500 psi (BHP)
Slope Change Indicating Possible Fracture Initiation

Felsenthal, “Step Rate Tests Determine Safe Injection Pressures in Floods”, The Oil and Gas Journal, Oct. 28, 1974
Idealized Step Rate Plot
Pressure Ranges for Each Rate Step

Pressure Ranges Decrease for Rate Steps Following Fracture Point

Fracture Pressure = 4,500 psi

Pressure Ranges are Roughly Equal for Rate Steps Leading up to Fracture Point
Effect of Friction Loss

Bottomhole Pressure Neglecting Friction Losses
(BHP = SHP + Hydrostatic)

Actual Bottomhole Pressure
(BHP = SHP + Hydrostatic - Friction Loss)

Friction Loss Down Tubing

Observed Surface Pressure
Erroneous Results Due to Neglecting Friction

Without Accounting for Friction Losses:
Plot Remains Linear
Fracture Pressure = ??

Correctly Accounting for Friction Losses:
Plot Changes Slope
Fracture Pressure = 4,500 psi
Implications of Previous Example

- **Actual Fracture Pressure = 4,500 psi (BHP)**
  - Equates to Surface Injection Pressure of 2,600 psi
  - Class I Guidelines: Maximum Permitted Injection Pressure = 2,340 psi
  - Will inject safely below formation fracture pressure

- **Incorrect Estimate Fracture Pressure = 7,900 psi (BHP)**
  - Equates to Surface Injection Pressure of 5,200 psi
  - Class I Guidelines: Maximum Permitted Injection Pressure = 4,680 psi
  - Will be Fracturing the Formation through its Entire Operational Lifetime
Best Practices for Step Rate Testing

1) The well should be shut in for long enough to let bottomhole pressures and formation pressures equalize

2) Lower permeability reservoirs will require longer time steps

3) Begin at a very low rate (0.25 – 0.5 BPM) so early steps do not exceed fracture pressure

4) Constant rates and equal time step durations are critical for an accurate test analysis

5) Use of a bottomhole pressure gauge is highly recommended
Conclusions

- Failure to correctly account for tubing friction can have a dramatic impact on test results
  - Much higher estimates or failure to identify fracture pressure
  - Permitted pressures that may exceed regulatory guidelines

- Bottomhole gauges will increase test accuracy since friction loss at high injection rates in tubing of unknown condition can be difficult to predict
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