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INJECTION WELL SEMINAR:
How Injection Technology Works and is the Basis for Regulation

Ground Water Protection Council 2024 UIC Conference

Presented By:
Ken Cooper, M.S., P.E.
Petrotek Corporation
Ground Water Research and Education Foundation

Petrotek Corporation
5935 South Zang Street, Suite 200
Littleton, Colorado 80127
303-290-9414 1-877-879-1480
www.petrotek.com

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Safety Moment
Courtesy of AESC and OSHA Alliance

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Outline

1. Course Introduction
2. Brief UIC Background and History
3. How and Why Injection Wells Work
   (some of the basic inter-related physics)
4. Understanding Operations and Compliance
   (some of the basic inter-related physics)
5. Mechanical Integrity
6. Reservoir Testing

Scheduled breaks for questions at "half-time" and at the end of the session (as long as the group would like to stay)

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Objectives
Understanding

1. ….. injection well function to determine and prioritize critical elements of compliance and maintenance
2. ….. the behavior of injectors helps us evaluate the safety of operational and permitting decisions
3. ….. how the features and processes that define injection inter-relate allows us see the "big picture" of compliance and performance

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Is Training Required?

- **Federal Regulation**
  - Training is required for operators by 40 CFR 144 and 146
- **Permit Conditions and State Programs**
  - Example: "All injection and withdrawal activities shall be monitored by an individual who is trained and experienced in such activities"
  - Example in Part I.E.6: "Proper Operation and Maintenance: Proper operation includes effective performance, adequate operator staffing and training…"

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Training Needs – Why?

- To protect the environment:
  - On behalf of the public, regulators need to understand regulated activities to ethically, fairly, and effectively oversee permitted operations
  - Operators must understand the technology they use to meet their moral, legal, and fiscal obligations to protect the environment and be efficient
- Lack of understanding will lead to operator error and questions about the public license (and permits) needed to operate. All stakeholders (the public, shareholders, etc.) expect and deserve competent operations.
- Lack of regulator understanding will lead to inefficient and ineffective compliance focus. The environment will be less protected and incremental opportunities to protect the environment will be lost as less protective options and operating locations are encouraged by poorly implemented regulatory programs.
- There are real negative consequences to a lack of understanding that go beyond wasting time, money, and damaging the public trust.
- Jointly – we have moral imperatives and individual responsibilities as the regulated and regulatory community to understand what we are doing.

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Introduction - Injection Wells UIC History and Background

The Purpose of Disposal Wells

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- When constructed and operated as required by law, EPA studies have determined that injection wells can be used to safely and effectively remove wastewater from exposure pathways in our biosphere
  - This applies to all types and classes of injection wells
  - Proving that regulatory requirements are met helps show that environmental protection goals are satisfied

Define Well and Underground Injection

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- **Well:** A bored, drilled, or driven shaft, or a dug well or dug hole where the depth is greater than the largest surface dimension; or an improved sinkhole; or a subsurface distribution system
- **Underground Injection:** Subsurface emplacement of fluids through a well
- **UIC:** Underground Injection Control
- **Fluid**: Any material that flows under a pressure gradient including liquid, gas, semi-solid, or sludge

Define Aquifer and USDW

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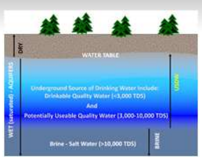

- **Aquifer:** Geologic formation that is capable of yielding a significant amount of water to a well or spring
- **Underground Source of Drinking Water (USDW):** An aquifer or portion of an aquifer that:
  - Supplies any public water system *or* contains a quantity of ground water sufficient to supply a public water system, *and*
  - Currently supplies drinking water for human consumption, *or*
  - Contains fewer than 10,000 mg/L total dissolved solids *and* is not an exempted aquifer

Mission of the UIC Program

The reason for SDWA UIC permits

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- The primary mission of Federal and State UIC programs is to protect underground sources of drinking water from contamination by regulating injection well construction and operation

History of Injection Well Technology

This is a proven, well understood, long-term disposal method

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- A.D. 300-400: Injection well use first documented, salt dissolution and extraction in China
- Use in the US began in the early 1900s
- Only 4 industrial wells known before 1950
- Before salt water disposal, most oilfield injectors were used for oil reservoir pressure maintenance, then water floods
- Today there are over 180,000 oilfield Class II wells
- More than 800 Class I industrial wells are permitted (more than 80% are non-hazardous)
- Up to 3 billion gallons per day injected; 2 million gpm

(Over 4,500 Olympic sized swimming pools or more than 10 Empire State buildings)

Regulatory Timeline

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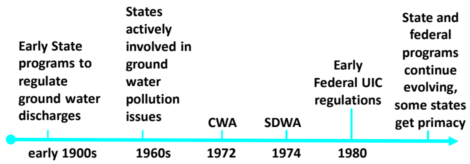

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Six Different EPA Injection Well Classifications

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- Varying potential for endangerment depending on typical depth, injectate type, and geologic setting
- Generally categorized based on common injectate source, design, and operating characteristics

- Class I (Industrial & Municipal Waste Disposal Wells)
- Class II (Upstream Oil and Gas Injection Wells)
- Class III (Mining Wells)
- Class IV (Shallow Hazardous and Radioactive Injection Wells)
- Class V ("Other" Wells)
- Class VI (Geologic Sequestration Wells)

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Injection Well Background

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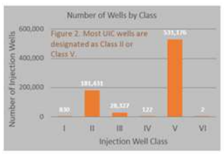
EPA UIC Fact Sheet ; https://www.epa.gov/uic/uic-fact-sheet

Most wells are Class II or Class V



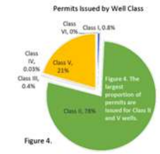


Figure 4.

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How and Why Injection Wells Function

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Basic Function of Injection Wells

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- Injection wells can be visualized as vertical pipelines constructed of multiple layers of pipe and cement
- Designed and constructed to convey fluid from surface down to an injection formation - keeping the injectate isolated from usable water, other resources, and unpermitted formations
- Must be sited so there is a disposal formation that can accept and store the fluid injected into the well with competent cap rock to keep it isolated in the subsurface

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A "Vertical Pipeline"

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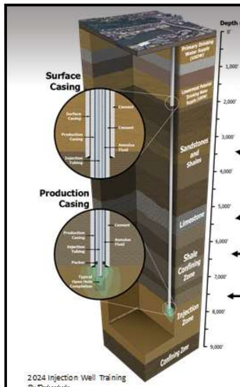

USDW

Alternating Zones of Permeable and Impermeable Rock

Primary Confinement (Cap Rock)

Top of Injection Interval

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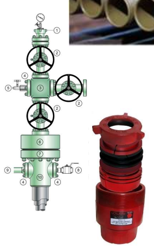
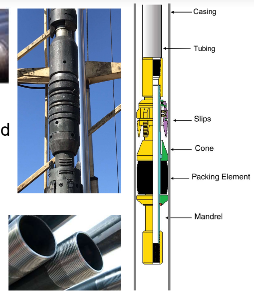
Well Components of the "vertical pipeline"



- Wellhead
- Casing
- Cement
- Tubing
- Packer



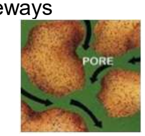
Where Does the Waste Go?

- Fluid is injected down through a well and into a porous rock unit saturated with brine
  - native brine fluid is displaced, and
  - fluids are transmitted away from the well from pore space to pore space by primary and/or secondary permeability
  - native fluid and injectate in connected pores are compressed and the rock pore space expands
- No big voids or tanks underground being filled
- Larger injection reservoirs help promote larger injection capacity that lasts

Let's Define some Terms and Features

Porosity

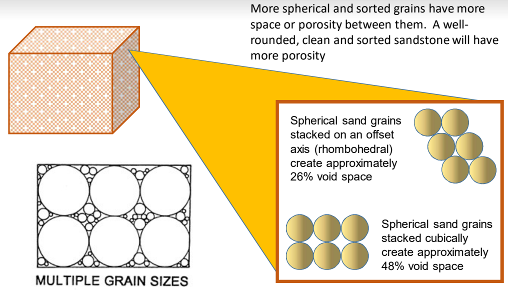
- Void space within a "solid" made up of minute openings and passageways
- Typically reported as a percent of the bulk volume



- Under a microscope, visualize a sponge
- One cubic foot of rock with 25% porosity could contain almost 2 gallons of water

Porosity

More spherical and sorted grains have more space or porosity between them. A well-rounded, clean and sorted sandstone will have more porosity



Sandstone at 39X Magnification

www.researchgate.net

Permeability

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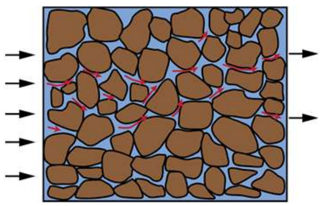
- Material property that allows liquid or gas to move through the porosity of a rock



Permeability

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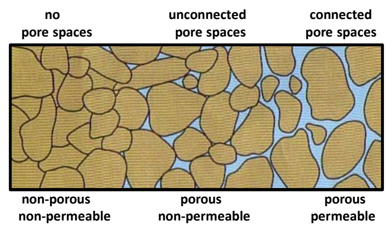
- Liquid or gas can only move through the **connected** porosity of a rock



A reason annual falloff tests are important, how well are pores still connected?

Water Compressibility

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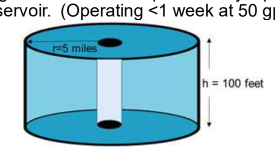
- Water has a compressibility of approximately 3x10^{-6} gal/gal/psi
- A sealed 1,000,000 gallon tank (100% porosity) would see a 1 psi pressure increase if 3 gallons of water were added
- For a bounded reservoir with a radius of 5 miles, thickness of 100 feet, and porosity of 10%, injecting 500,000 gallons would raise pressure by 1 psi in the entire reservoir. (Operating <1 week at 50 gpm)
- $c = \frac{-1}{v}\frac{\Delta v}{\Delta p}$



System Compressibility

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- Rock matrix of an injection formation can have compressibility similar to brine, effectively doubling the ability to store injectate at the same pressure increase
- Reservoir extent is important; larger is better than compartmented systems that have flow boundaries
- 640 acre spacing (1-mile^2) can be large for O&G production, but small for disposal purposes
- 5,280' x 5,280' x 100' x 12% = 2.5 billion gallon pore volume
- 6 months @ 25 gpm (857 bpd) = 6.5 million gallons
- $c_t = \frac{-1}{v}\frac{\Delta v}{\Delta p} = 6e^{-06}$/psi
- Δp = 6.5 million gal/(2.5 billion gal*6e^{-06}/psi) = 433 psi

Review So Far: What is Critical for Injection?

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- Porosity-Thickness to store the compressible fluid
- Porosity-Thickness to connect the pore spaces
- System (Rock & Fluid) Compressibility
  - large reservoir volumes
  - thickness and lateral extent

Now We Need…..

- Pressure to Move Fluids Into and Thru a Reservoir
- Efficient Wellbore Communication to a Reservoir

How Does Injection Pressure Work in a Well System?

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- What factors influence injection pressure at a well, in a reservoir, and how?
- Density, Temperature, and Friction
- How are they inter-related?
- How do these factors influence pressure in a well and a reservoir?
- Influences on performance and compliance

Pressure

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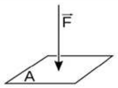
- Force per unit area



- Common oilfield units: pounds of force per square inch (psi) $P(\text{psi}) = \frac{F(\text{lb})}{A(\text{in.}^2)}$ psig = psia -14.7 (at sea level)
- Force (in the form of pressure) is needed to inject fluids through a well into an injection zone. The pressure can be sourced from gravity (hydrostatic pressure from fluid weight) and/or a pump.
- Fluids only move from higher pressure to lower pressure

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Density

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- Density or (volumetric mass density) is mass per unit volume $\rho = \frac{m}{V}$
- Brine specific gravity (based on TDS, often a required permit measurement) is the ratio of brine density to the density of fresh water at the same temperature and pressure $SG = \frac{\rho}{\rho_{water}}$
- Common oilfield units: pounds per gallon or grams per cubic centimeter
- Density typically decreases when gas is forced into a liquid
- Density depends on the composition of a substance and changes with pressure and temperature

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Temperature & Density

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- Temperature - the "degree" or intensity of heat present in a substance, referenced to a standard and measured on a definite scale
- Typical oilfield units, degrees Fahrenheit
  water freezes at 32 F and boils at 212 F at sea level and 1 atm of pressure
- Density typically increases as fluids are compressed (the original volume becomes smaller as it is pressurized)
- Density typically decreases as fluids are heated because they expand to occupy more volume
- If fluids are contained in a sealed system then pressure changes when the fluid volume expands or contracts

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Temperature & Density

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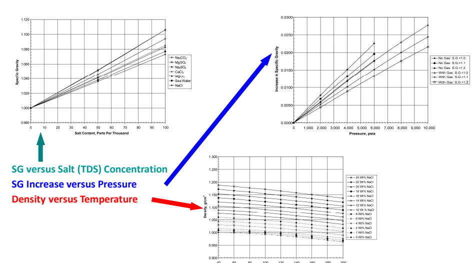

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Hydrostatic Pressure

Pressure at depth is the result of the weight of liquid acting on a unit area at that depth plus any pressure at the surface

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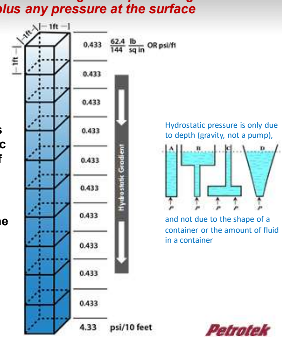
STATIC WELL (not flowing)

- A Column of Fresh Water (SG =1.0) Exerts 0.433 psi/foot
- Calculated as 62.4 pounds of water exerted by a cubic foot of water on an area of 1 square foot (aka 144 square inches)
- At a depth of 10 feet, the Hydrostatic Pressure of the Fluid Column is 4.33 psi = (10 feet * 0.433 psi/ft * 1.0)

also: $P_{HYD} = \rho \times g \times h$



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Density and Hydrostatic Pressure

One reason fluid sampling to get Total Dissolved Solids (TDS) measurements is important

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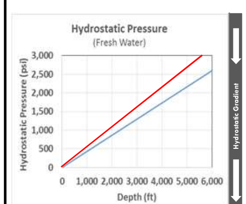

STATIC WELL (NO FLOW)

- A Column of Fresh Water (SG =1.0) Exerts a pressure of 0.433 psi/foot
- At a depth of 6,000 feet, the Hydrostatic Pressure of the Fluid Column is 2,598 psi = (6,000 feet * 0.433 psi/ft * 1.0)
- For Higher Density Fluid more dissolved salt), a Column of Brine (SG =1.2) Exerts 0.52 psi/ft = 1.2 * 0.433
- At a depth of 6,000 feet, the Hydrostatic Pressure of the Fluid Column is 3,120 psi = (6,000 feet * 0.52 psi/ft)

Higher TDS (Higher Density) Fluid Adds 522 psi at 6,000 feet – At The Same Wellhead Pressure

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Temperature – Viscosity & Density
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- Temperature changes density (and compressibility)
- Temperature and density change viscosity
- Viscosity is a measure of the internal resistance of a fluid to flow against itself (a ratio of shear stress to shear rate)
- Common oilfield units: centipoise (millipascal-second)
- Brine viscosity is a strong function of temperature, it decreases quickly as temperature increases
- Viscosity is strongly dependent on fluid composition, more than density

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Temperature & Viscosity
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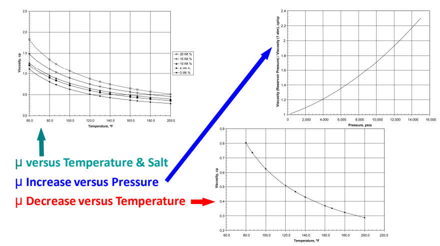

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Friction
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A main reason for well design and flow rate measurement

- Friction (measured as pressure loss) in fluid flow is a measure of the force resisting relative motion by fluid against itself
- Depends on the tendency of the liquid to resist flow (viscosity)
- Influenced by the surface over which fluid moves; greater force is generated flowing over a rough surface
- Depends on the velocity of the fluid flow. If the velocity becomes large; turbulent flow instead of laminar flow can significantly increase friction loss (this is part of the reason why tubing size, wellbore completion details, and near wellbore pore size in a reservoir can be important)

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Friction and Flow
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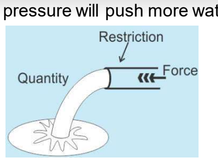
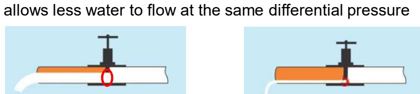
- Greater water pressure will push more water through the same pipe



- More resistance (smaller valve opening causing more friction) allows less water to flow at the same differential pressure



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Tubing Friction Loss
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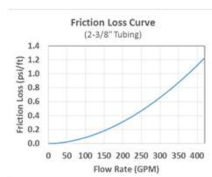

For 6,000 feet of tubing, friction matters 150 gpm = 1,100 psi, 50 gpm = 150 psi

Friction Loss

DYNAMIC WELL (flowing)

- **Friction loss per foot is dependent on flow rate, diameter of pipe, and the roughness coefficient of the tubing**
- **Roughness is an estimate and varies according to pipe material, scale, tubing condition & wear**
- **Friction increases exponentially with increasing flow rate**
- **Friction increases strongly with increasing viscosity and roughness, less with increased density**

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The Process of Injection
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(assembling the puzzle pieces)

- Pressure is force applied per an area
  - psi = pounds force per square inch
  - Pascal = kg force per meter second^2 = Newton/m^2
- Average column of air from sea level to space exerts 14.696 pounds of hydrostatic force on one square inch (psi) of the earth's surface (1 atm)
- Just one foot of fresh water column exerts a hydrostatic force of 0.433 psi
- During injection, pressure from any pump and the hydrostatic head from fluid weight forces fluid down through well equipment into fluid filled rock pore space

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Energy is Needed for Injection to Work

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- Picture a stockpile of available energy at surface
  - + (transfer pump, injection pump, fluid mass & gravity)
- Fluid moves along a pressure gradient if a pathway to a zone of lower pressure exists
- Pressure increases as energy is added (pumping or if a taller or more-dense fluid column exists (more fluid weight applied with depth) from surface to the location where force is acting – hydrostatic head
- Pressure is lost to friction when obstacles are encountered
  - \- (valve, elbow, flow line, wellhead, packer, perforation, screen, well/formation interface, pore throat)

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What Happens in the Reservoir?

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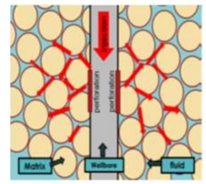
- Reservoir pressure increases over time as the fluid volume added is compressed into the reservoir
  - Injection reservoirs should be large, try to avoid boundaries & interference (these cause more "back-pressure")
  - $\Delta P = \Delta V_W / (V_W C_W)$
    C_W = 3 to 5 X 10^{-6}/psi
- For a 1-mile sealed square box with infinite permeability, 100' thick zone, $C_W = C_F$, (12% porosity), dp = 433 psi after 6 months at rate of 25 gpm



- **But reservoir pressure (and compression) is not uniform,**

.........it varies with distance because of friction as fluid moves from pore space to pore space

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Reservoir Pressure Change, Delta P (Δp)

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- Exponential integral, line source solution of the radial diffusivity equation

$$\Delta p = 70.6 \frac{q\,\mu\,B}{k\,h} \; Ei\left[\frac{-948\,\Phi\,\mu\,c\,r^2}{k\,t}\right]$$

- Pressure increase is greatest at the wellbore, and varies dramatically (log) with distance and time based on two parameter groups:

$$\Delta p = 162.6 \frac{q\,\mu\,B}{k\,h} \left[\log \frac{k\,t}{\Phi\,\mu\,c\,r^2} - 3.23\right]$$

Be careful, ln or log approximations of the Ei function are only accurate for appropriate time (larger time for small k and large radius)

Matthews and Russell (1967)

mobility, k/μ, is in both terms

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Pressure Rise Vs. Distance Vertical Well, Radial Flow

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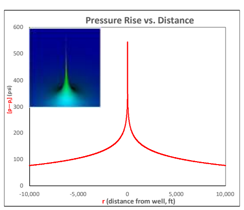
$$(p - p_i) = 70.6 \frac{qB\mu}{kh} * Ei\left(\frac{-948\Phi\mu c_t r^2}{kt}\right)$$

$q = 1{,}440$ bpd (1 bpm)
$B = 1.01$ RB/STB
$\mu = 1.00$ cp
$k = 50$ md
$h = 100$ ft
$\Phi = 10\%$
$c_t = 6.00E^{-6}\ psi^{-1}$
$t = 87{,}600$ hours (10 years)



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Reservoir Pressure Change, 2-D

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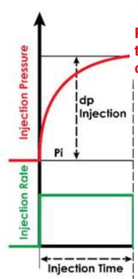
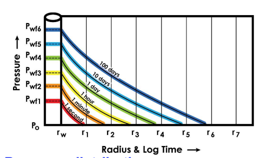


Pressure increases over time at any location with continued injection



Pressure distribution extends deeper into reservoir with continued injection

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Reservoir Pressure Distribution, 3-D

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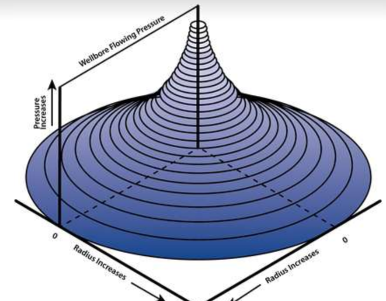

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Pressure Interference
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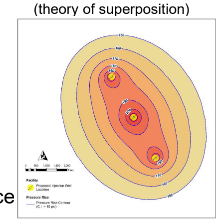
Infinite-acting System

Well Interference

The pressure from each well "interferes" with other sources and is additive at each location in the reservoir (theory of superposition)



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Superposition
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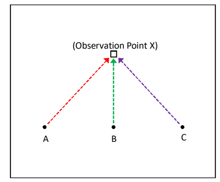
- Theory of superposition: pressure buildup at any point in a reservoir is the sum of the respective pressure buildup from each individual offset well
- Consider an observation point (X) and three offset vertical injection wells (A, B and C)
- Pressure buildup equation can be applied to each respective distance and summed
  - For simplicity, assume equal rates and equal injection times for A, B, C



$$(p - p_i)_X = \left(70.6\frac{qB\mu}{kh}\right) * \left[Ei\left(\frac{-948\Phi\mu c_t (r_{A-X})^2}{t}\right) + Ei\left(\frac{-948\Phi\mu c_t (r_{B-X})^2}{t}\right) + Ei\left(\frac{-948\Phi\mu c_t (r_{C-X})^2}{t}\right)\right]$$

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Factors that Define Pressure in a Well and Reservoir
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$$\Delta p = 162.6 \frac{q \mu B}{k h} \left[\log \frac{k t}{\Phi \mu c r_w^2} - 3.23 + 0.869 s \right]$$

- μ = viscosity: (temperature; also composition & density)
- c = compressibility: (density: temperature, pressure)
- B = water formation volume factor, reservoir barrel/stock tank barrel: (temperature, pressure, density; also composition)
- friction: (viscosity: temperature, also mechanical properties)
- rate, permeability, thickness, time, porosity, radius, skin

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These Factors Are Inter-related
52

- Temperature alters fluid density
- Temperature and density impact viscosity
- Viscosity and density influence friction loss
- Density defines fluid column weight (hydrostatic head) and generates increased pressure with depth
- Viscosity is a main factor in completion friction loss (skin)
- Viscosity is a primary factor defining the "frictional" pressure required to move fluid through a porous media

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Operations and Compliance

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System Performance
Why Does This Matter - Operations?
54

- Injection pressure is typically only measured at surface (a permit requirement)
- If there is friction loss between the pressure compliance measurement point and the wellhead, available pressure to inject may be reduced
- If viscosity changes with different processes or over time, wellhead pressure and apparent injectivity (gpm/psi) at the wellhead may change without any actual change of well performance

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System Performance (2)

55

- Well design depends on expected friction loss, and viscosity is a significant factor determining friction – tubing size determines casing size, casing size determines bit size, bit size influences rig choice, all impact well cost
- Required injection pressure can increase over time as fluids get compressed over a larger area
- If injectate cools the area around a wellbore, higher viscosity fluid will be present in the cooled area which will require more pressure to sustain constant rates

System Performance (3)

56

- If tubing condition (roughness or ID) changes due to scale, increased tubing friction might be mistaken as formation damage (skin) or reduced permeability-thickness (kh)
- Cold weather might reduce injectate temperature and increase viscosity, resulting wellhead pressure increases that could be mistaken as formation damage
- Properly normalizing pressure to a reference depth datum near the completion is necessary to correct for hydrostatics and friction in performance analysis

Permitting and Compliance
Why Does This Matter - Regulatory?

57

- Bottom hole pressure (BHP) is critical, so pressure corrections to depth based on density (hydrostatic head) must be properly considered if fracturing of the injection zone rock at the base of the casing is to be avoided
- Rate, tubing size, and roughness change tubing friction loss and are critical inputs to maximum surface injection pressure assignments. Since well rate capacity is proportional to pressure, this is critical to disposal capacity

Permitting and Compliance (2)
The monitoring data we collect is important

58

- If density or viscosity are variable, caution must be used if wellhead injection pressure monitoring data are used to compare permit assumptions to well performance – a WHP history match might be wrong
- Annual ambient monitoring (falloff testing) is used to show compliance and should include justification for the specific gravity used to correct pressure data to a reference datum depth

Permitting and Compliance (3)

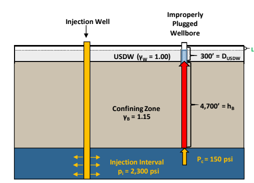
59

- Permit compliance verification needs to consider density, temperature, and friction since they are inter-related factors that influence well pressures
- These factors also define pressure rise in the reservoir around a well. Pressure distribution around a well is critical to determine if legacy wells have the potential to endanger a USDW
- Critical Pressure (Pc), Cone of Influence (COI) and Area of Review (AOR) are all "pressure – driven"

Critical Pressure Rise (P_c)

60

- The reservoir pressure increase that has the potential to push fluid up a hypothetical open pathway from the Injection Zone to the USDW

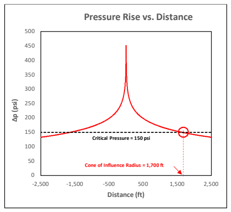


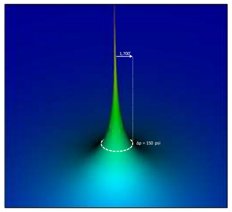
$$P_c = 0.433\, psi/ft\ [\gamma_B h_B + \gamma_W (D_{USDW} - L)] - p_i$$

γ_B = specific gravity of brine or mud (1.15)
h_B = height of brine or mud column (4,700')
γ_W = specific gravity of USDW (1.00)
D = depth to base of USDW (300')
L = water level in USDW (45')
p_i = initial pressure of injection interval (2,300 psi)

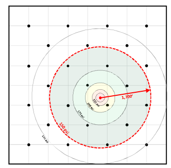
$$P_c = 150\ psi$$

Illustrating Cone of Influence





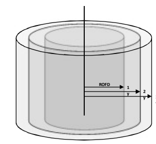
Illustrating COI Based AOR

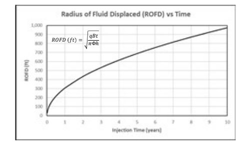


- Consider a 640-acre section drilled with 40-acre and infill spacing
- An idealized single vertical injection well will induce a critical pressure rise extending as shown – pressure level defines COI and therefore 'area of review'
- All wells inside the AOR that penetrate the injection interval will require confirmation of adequate plugging / mechanical integrity

Illustrating Radius of Fluid Displacement Based AOR

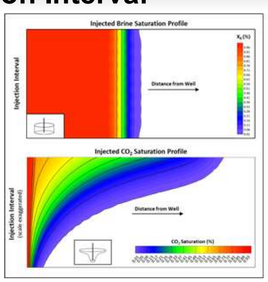
- Radius of fluid displaced (ROFD) is a volumetric calculation
  - Includes: injection rate (ft³/day), time of injection (days), thickness, porosity
  - Excludes: permeability, viscosity
  - Incremental growth of radius slows with time (square root)



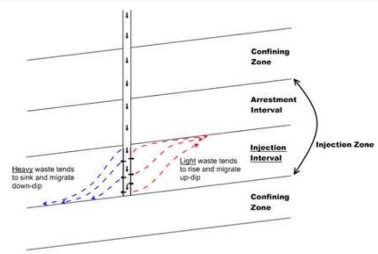


Fluid Movement In The Injection Interval

- Pressure gradients due to active injection
- Residual pressure gradients due to past site injection
- Gravity driven drift due to density differences (picture a lava lamp)
- Offset production and injection activities
- Natural background hydraulic gradients



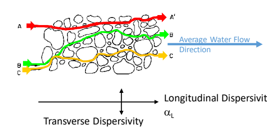
Fluid Movement In The Injection Interval



- Density drift up-dip or down-dip

Fluid Movement In The Injection Interval

- Dispersion reflects the fact that different pathways result in different flow vectors, resulting in a mixing with native brine and a net spreading of the solute plume



Fluid Movement In The Injection Interval

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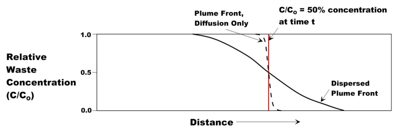
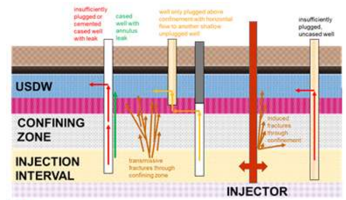
- Diffusion occurs due to molecular motion of waste constituents because of concentration gradients



Confinement

68

- Large areal extent of Injection Zone and Confining Zone
- Avoid nearby faults or abandoned wells that could leak
- Separation between USDW and Injection Zone
- Sealing capability of Confining Zone/Arrestment Interval
- Operate below Confining Zone fracture gradient pressure



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Mechanical Integrity – Monitoring and Testing

What is Mechanical Integrity?

70

- Example Interpretation – a well has integrity if there is “no significant leak in the well and the mechanical components of the well function in a manner protective of the environment and human health”
- EPA – 40 CFR 146.8 (a) "an injection well has mechanical integrity if: (1) there is no significant leak in the casing, tubing, or packer; and (2) there is no significant fluid movement into an USDW through vertical channels adjacent to the injection well bore”

What is Mechanical Integrity?

71

- Part I – Internal integrity, does a well annulus hold pressure? Often the first (and only) thought when discussing integrity. Is there a sufficient pressure seal of the annular space between wellhead, tubing, packer and casing?
- Part II – External integrity, are fluids moving out of intended formations? Do fluids move where they should not along the outside of the casing?
- There are multiple facets to well integrity and multiple ways to test or verify each part:
  - tubing, wellhead, packer
  - casing (internal or external)
  - well component conditions including cement (at shoe or up-hole)

When Do We Have Mechanical Integrity (MI)?

72

- No Significant Leaks at Wellhead
  (Inspection, Monitoring, Annulus or Other Pressure Tests)
- No Significant Leaks Through Casing
  (Monitoring, Annulus or Other Pressure Tests, Logging)
- No Significant Leaks in Tubing or Packer
  (Monitoring, Annulus or Other Pressure Tests, Logging)
- No Significant Channeling Behind Pipe (Outside Casing)
  (Logging such as: Temperature, Radioactive Tracer, Oxygen Activation or Noise)
- Downhole Inspection Logging May Indicate the Potential for Current/Future Leaks or Channeling

Operational Monitoring An Ongoing MIT?

73

- Annulus Pressure
  Is the well demonstrating the same diurnal, stop/start behavior? Does injection of hot fluid cause pressure to rise, cold fluid and shut-in cause a pressure drop that decays?
- Pressure Differential
  Is annulus pressure - injection pressure differential changing over time when the well is started or stopped? Can the well maintain differential pressure, more nitrogen use?
- Annulus Fluid Level/Use
  Sudden, substantial drops in annulus fluid tank level without a concurrent operating change (Pi, Ti)? Inability to maintain annulus fluid to surface? Increased annulus fluid use (gallons per month turned into gallons per day and then gallons per hour)?
- Well Behavior Response and Conditions
  Does a well respond as expected to changing injectate temperature?
  Is fluid leaking from the wellhead seals, fluid or bubbles coming from casing/casing or casing/tubing annulus?

How can we tell if fluid level is dropping if well annulus or tank level is allowed to go to 0? We should always be able to "see" a level, even if we need to add fluid.

Annulus System Operation

74

- Annulus Pressure
  A pressure differential from the annulus into the injection tubing will guarantee that waste cannot contact the casing, and therefore cannot enter a USDW
- Annulus Pressure and Level Changes
  In a sealed system, if temperature increases, pressure will increase and annulus level will rise. The reverse happens for during cooling cycles, level and pressure can drop significantly when a well cools.
- Tubing Size Actually Changes
  System pressures and temperatures cause the tubing to balloon or contract, and to corkscrew as it gets longer when temperature increases since it is fixed in the wellhead and in the packer. These events change annulus volume. An annulus tank allows the well to respond with reduced pressure swings.
- Long Term Matters Most
  Look at material balance for the annulus liquid, not the nitrogen gas (if present). Over many cycles of start/stop, high/low pressure, increased/reduce temperature did the annulus "use" fluid? Even the seasons matter. Dramatic drops in level over a short period of time without a reason are often a cause for further investigation.
- Annulus Tank
  Annulus tanks act as a "shock absorber" to allow a well to take and give back fluid as conditions change. A nitrogen blanket is more easily compressed and stores energy.

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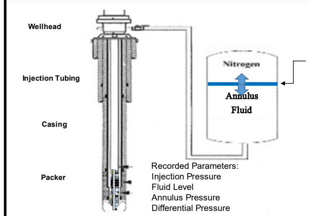
Annulus Systems Measuring Part I (Internal) Integrity

75



Fluid level changes in the tank with Pressure and Temperature as fluids/equipment expand and contract

When well pressure drops, annulus tank nitrogen expands to support pressure level (and N_2 might be added), fluid returning into the tank compresses the N_2 gas

The system uses N_2 gas as a "shock absorber"

Any fluid added is recorded and reported

Much bigger pressure variations can happen in a well system with no tank (and no nitrogen)

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Idealized Annulus Pressure Changes

76

- $c = \frac{-1}{v}\frac{dv}{dp}$ = coefficient of isothermal compressibility

  Assuming that well annulus volume is constant, then annulus fluid compressibility supplies all energy
- $C_w = 3.2 \times 10^{-6}$/psi

  In a 2,500 gallon annulus, a 3% pressure loss per hour at 1,000 psi test pressure is equivalent to an idealized, continuous annulus water use rate of approximately 6 gallons per day with no temperature or injection pressure change
- The isothermal annular volume change tested can be estimated using the compressibility equation:

$$\Delta V = (P_I - P_F) \times V \times C_w$$

where:

ΔV = volume change required to reach new pressure
P_I = initial pressure
P_F = final pressure
V = capacity of the annulus
C_w = compressibility of water (3.2×10^{-6})
remember that other fluids like diesel or nitrogen have a larger compressibility factor

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Thermal Expansion of Water

77

Since temperature is rarely constant, thermal effects can make a well look like it is "using" fluid when the components and fluid are only shrinking (but increasing temperature could hide a leak)

$$\Delta V = (T_1 - T_2) \times V \times \beta_w$$

where:

ΔV = volume change due to temperature change
T_1 = initial temperature
T_2 = final temperature
V = capacity of the annulus
β_w = thermal expansion coefficient of water (approximately 1.5×10^{-4}/Degree Fahrenheit)

For a 2,500 gallon annulus, a 20 degree F change could be equivalent to an 8 gallon volume change (assuming nothing else changes except temperature)

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What is Mechanical Integrity Testing (MIT)?

78

- Data acquisition and evaluation to determine the characteristics of a well and of well conditions to measure or infer information showing that the well components function to:
- Contain fluid inside permitted equipment
  - Confine injected fluids in the permitted formations
  - Prevent cross flow between zones that the well has penetrated
  - Protect the USDW, human health and the environment

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When is MIT Conducted?

79

- Upon completion of a new well
- Upon completion of a workover
- For permit compliance Part I annual or bi-annual & Part II every 5 years (Class I)
- When operators and regulators interpret well behavior as indicating a possible failure
- Well intervention planning
- Prior to well closure

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Why an Unscheduled MIT?

80

- If well behavior indicates a possible failure
  - Significant irregular variation of annulus or tubing pressure
  - Significant irregular variation of annulus fluid level
  - Significant use of annulus fluid
  - Wellhead evidence
  - Loss of ability to maintain annulus pressure
  - Loss of ability to maintain annulus fluid to surface
  - Can be expensive, risks occur during any field work, need to be justified
  - "Significant" is typically well dependent

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Types of Mechanical Integrity Tests

81

- Annulus Pressure Test
  Can well components hold pressure to a regulatory standard and are fluids contained inside injection well components?
- Production Logging
  Where is fluid moving inside or in proximity to a wellbore?
- Inspection Logging
  What are the characteristics, conditions and changes measured for the materials of well construction?
- Operational Monitoring
  Does a well respond as expected to injection or shut-in? Can annulus pressure be maintained and does the annulus require fluid additions to maintain compliance?

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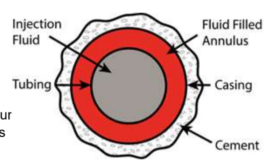
Annulus Pressure Tests

82

- Pressure Vessel Test of Fluid Filled Space Between the Casing and Tubing, Isolated By the Wellhead and Packer
- General Procedure
  - pressure-up
  - install certified gauge
  - isolate well from tank
  - monitor pressure change
  - verify annulus full of fluid
- Variable Requirements
  - % pressure change per hour
  - record of data/observations
  - regulatory witness, if possible



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Annulus Pressure Tests

83

- **SAPT or APT**
  Run under static or dynamic conditions, dynamic (while injecting) can be challenging
- **Limitations**
  Temperature changes/recovery, injection pressure, well stress can influence results.
  Is the well still equilibrating so the tested behavior is masked or enhanced?

  The volume of fluid required to apply the test pressure increase should be measured – are you testing the whole annulus?
- $c = \frac{-1}{v}\frac{dv}{dp}$ = coefficient of isothermal compressibility
  Assuming that well annulus volume is constant and is isolated from the tank, then the annulus fluid compressibility supplies all energy

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Annulus Pressure Tests

84

- The volume of fluid required to apply the test pressure increase should be measured – are you testing the whole annulus?
- The annular volume tested can be estimated using the compressibility equation:

  $\Delta V = (P_T - P_F) \times V \times C_w$

  where:

  ΔV = volume required to reach test pressure
  P_T = test pressure
  P_F = final pressure
  V = capacity of the annulus
  C_w = compressibility of water (3.2×10^{-6})

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What Can A Pressure Test Show?

85

- Part I MIT (annulus pressure tests = APT) are run by raising the annulus pressure above the maximum operating range. The pressure on the annulus fluid is exerted on all internal parts of the annulus. If the annulus pressure declines, a leak in the tubing, casing, wellhead or packer seals is possibly occurring.
- Similar to a surface pressure vessel (tank) test - the annulus is just an oddly shaped, tall, underground cylindrical tank.

Why Test At a Higher Pressure Than Normal Operation?

86

- The test requirements are similar to testing any pressure vessel. Using ASTM standards pressure vessels are typically tested at above the maximum working pressure
- Exerting higher than normal forces on a vessel gives some assurance that a vessel will not fail during normal use
- Higher pressure differentials during testing can magnify a leak
- Excessive test pressure requirements can be impractical for some wells and lead to premature well component failures

APT Failure, What Happens?

87

- Typically re-run test after checking all connections for possible leaks
- The well may be allowed more time to reach thermal equilibrium
- The well is removed from service until the leak is located and repaired
- Often, a workover rig is required to dismantle the well for further testing and/or repair
- Additional tests may be performed after the well is removed from service and dismantled

Integrity Issue or Normal Behavior?

88

- Temperature change tends to occur logarithmically (similar to reservoir pressure buildup or falloff). Effects reduce quickly with time but are well and situation dependent. (A 10 minute shut-in for test stabilization will almost never be enough, 24 hours rarely needed)
- The temperature and pressure conditions in a well are due to the full history of all historical changes over the whole well length, dominated by most recent operations
- Remember that a well might appear to "use" annulus fluid when injectate temperature cools the well and/or tubing injection pressure is reduced (the shock absorber worked)
- There is a time lag between changing conditions and a new stable well and annulus tank level/pressure
- If a well is not leaking, annulus tank fluid level will eventually return to original level if/when conditions return to original
- A well that is cooling down significantly during fresh water injection start-up or an annulus pressure test might look like integrity failure, but remember pressure drops due to cooling

Production Logging (Part II or "External" MIT)

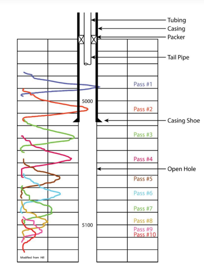
89

- Radioactive Tracer Survey (RAT or RTS)
  Flow profile to measure gamma emissions from a slug of RA material while injected fluid moves downhole
- Temperature Log
  Static and/or dynamic, look for temperature changes due to differences between injectate and formation temperature trends
- Pulse Neutron/Oxygen Activation Log
  Create a short-lived tracer behind pipe and follow it with a high resolution detector
- Acoustic Noise and Other Logs
  Measure a sound or other result to "see" where injected fluid is moving

Radioactive Tracer (RAT)

90

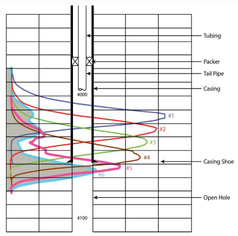
- Detects Fluid Exit Point
- Hazard Potential
- Baseline logs important for background and depth correlation
- Release tracer in tubing
- Chase down tubing/casing
- Measure gamma
- Follow slugs
- Example shows downward flow entering openhole below casing shoe



Radioactive Tracer

91

- Commonly Iodine 131 (NaI) with a 8.04 day half-life
- Measurable radioactivity is a function of distance and the materials between source and detector
- Different diameters within a wellbore will result in different flow velocity at a constant rate
- Example shows upward flow behind casing
- Time drive (packer checks) also useful
- Flow profile splits/distribution can be quantitatively calculated for designed tests (like velocity shots)



Temperature

92

- Static or Dynamic (Differential) – allows investigation above casing shoe through pipe
- Original geothermal profile versus depth is impacted by lithology
- Well temperature profiles are defined by geothermal profile, well construction features and history of injection/production
- Extended Stabilization Period
- Slow Logging Speed - 30 fpm
- Interpretation best when compared to other logs
- The entire history of injection temperature influences logs, most recent temperature dominates detailed signature
- After well shut-in temperature, recovery toward natural gradient happens slower where more heat has been introduced or removed by fluids moving through pathways

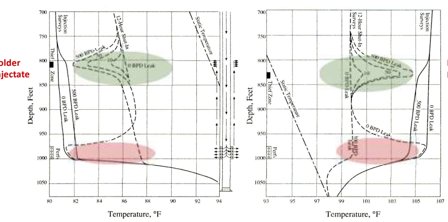
Temperature

93

- Look for temperature signature from areas of convection where fluid is flowing rather than only conduction where heat has simply been transferred across and through materials

Picture an open window with air flow to cool a room versus putting your hand on a cold window pane

Colder Injectate

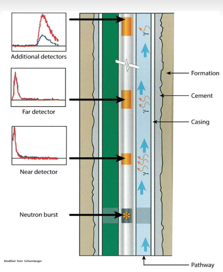


Hotter Injectate

Oxygen Activation

94

- Create your own "tracer" with a 7.35 second half-life
- Look for decay signature as fluids behind pipe interact with the neutrons introduced if the fluid moves behind casing and emits radiation from a new depth
- Background gamma exists and detection must be statistically meaningful
- Tool must be configured for upward or downward flow to maximize resolution
- Allows investigation above casing shoe



Activation Water Flow

95

Oxygen Activation:

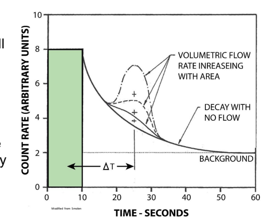
1) High energy neutrons activate oxygen
2) Oxygen goes through a few intermediate stages before releasing a gamma-ray and returning to its low energy state.
3) Process has a half-life of 7.35 seconds.

$$^{16}O + n \rightarrow p + {}^{16}N^{*} \overset{\beta}{\rightarrow} {}^{16}O^{*} \rightarrow {}^{16}O + \gamma$$

Oxygen Activation

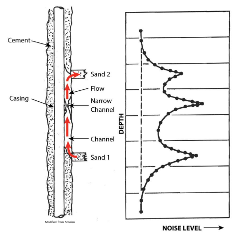
96

- Thermal neutron capture, inelastic collisions and activation (decay) products all contribute to gamma ray signature
- Detection is happening through fluids, pipe and cement behind casing
- Background gamma can give false positive if not statistically meaningful
- Tool can detect activated fluids moving inside tubing or casing annulus if there is an eddy



Noise Logging
97

- Fluid movement (turbulence) generates sound – and can originate inside or outside the casing
- A background "dead well" response should be recorded
- Total amplitude and variable frequency spectrum can be recorded using sensitive downhole microphones
- Often used for gas but can be used for liquid
- Not as common for water injection wells
- Allows investigation above casing shoe



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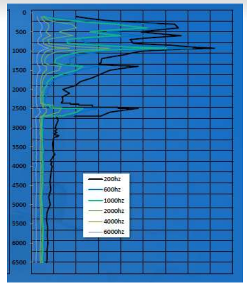
Noise Logs
98



Frequency and amplitude of sound is function of fluid type, differential pressure, and flow rate

Filtered frequencies enhance depth of investigation

Can Be Highly Interpretive

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Inspection Logging
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- Sonic and Ultrasonic Casing evaluation
- Traditional Cement Bond Logs
  CBL, RCBL/SBL evaluation of cement presence, properties, bond to pipe, and bond to formation
- Electromagnetic Casing Inspection
  Magnetic Flux Eddy Current casing thickness, shape, condition, changes (assuming previous comparable logs available)
- Caliper Log
  Internal pipe diameter, shape and large breaches
- Downhole Cameras
  Visual inspection of component conditions

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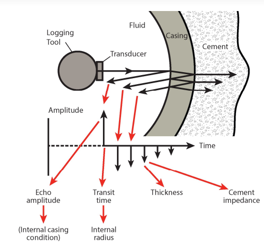
Ultrasonic Logs
100

- Acoustic signals are used to vibrate/resonate materials and are reflected/refracted off material interfaces
- Resonance frequencies, signal attenuation, and reflection amplitude/timing (pulse echo) are used to infer and map the acoustic impedance and properties of casing and material in the external casing annulus
- Allows investigation inside and outside casing



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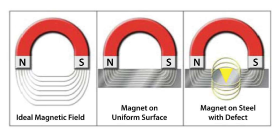
Magnetic and Current Logs
101

- Magnetic fields vary due to irregular surfaces in metal
- Current moves through metal differently depending on thickness and properties
- Pad and phase shift tools allow investigation inside and outside casing
- Can provide insight into metal loss, OD & ID of pipe, type of corrosion, relatively small defects and penetrations



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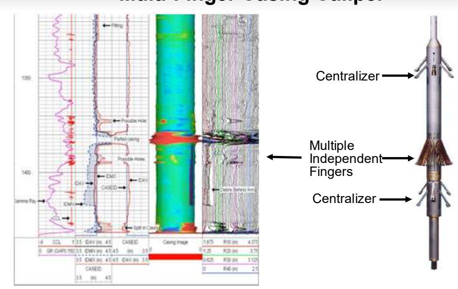
Casing Inspection Logs
102

Multi-Finger Casing Caliper



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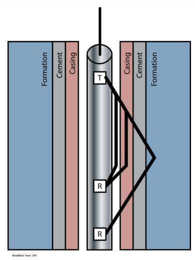
Cement Bond Logs
103

- Acoustic signal emitted by tool is refracted and reflected differently along and from interfaces and within well components
- Older CBL logs tend to average signal and are less sensitive to channels
- Segmented (SBL) and Rotating Segmented (RCBL) have higher resolution
- Amplitude and timing of how pipe "rings" can be interpreted to infer cement properties, and how it is bonded to pipe and formation
- No direct measurement of "seal"
- Low compressive strength cement and micro-annulus effects influence results
- Allows investigation outside casing above shoe



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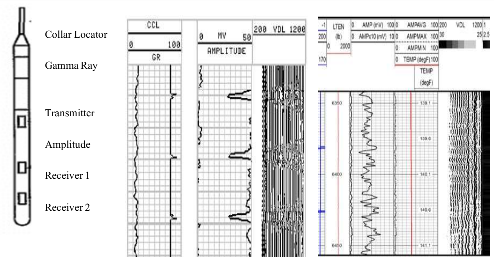
Cement Bond Logs CBL-VDL
104



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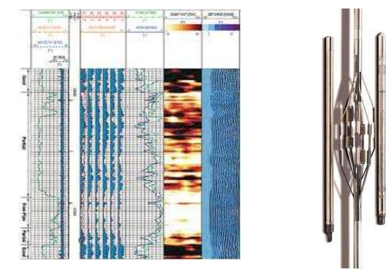
Cement Bond Logs
105

Segmented Bond Tools (CET, PET, SBT)



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Caliper and Video Logs
106

- Downhole Video - visual inspection of interior pipe surfaces, downhole equipment and fluid entry in certain cases
- Can be obscured by fluid opacity and scale, yields qualitative information
- Calipers - internal ID or significant surface irregularity can be measured with multi-finger caliper tools
- Allows investigation inside pipe, often only catastrophic failures can be detected

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Design & Analysis Issues - Optimize MIT
107

- Design test procedures for specific well and implement deliberate procedures, not just default service company oilfield practices – think about the system physics
- Consider well history and stability in test design
- Have details and a good understanding of downhole conditions and equipment (dimensions, material grades, thicknesses, etc.)
- Use current wellhead, completion schematics, and lithology profile when designing and analyzing data
- Consider all available data during analysis, sometimes more than one log or test may be required for conclusive results

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Field Practice - Optimize MIT
108

- Ensure depths are correlated
- Determine if calibration is current, and equipment is responding in a reasonable way
- Many logs require fluid above the tool depth to collect meaningful data
- Record all events and activities for use in later analysis
- Run baseline data and repeat sections or vary procedures to investigate further when there are questions or irregularities
- Consult historic logs to see if there have been problems collecting data or well idiosyncrasies exist
- Specify KB or GL - and all other units (psia vs psig)

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RESERVOIR TESTING BASICS

The Periodic Reservoir Pressure Testing Requirement

CFR 146.13(D)(1)……….the Director shall require monitoring of the pressure buildup in the injection zone annually, including at a minimum, a shutdown of the well for a time sufficient to conduct a valid observation of the pressure falloff curve.

What is Pressure Transient Testing?

- A well test that involves recording pressure versus time to determine how flow rates influence pressure behavior measured in a well
- Mathematical relationships between flow rate, pressure and time are applied to data to infer properties and conditions of the well and reservoir

Main Types of Pressure Transient Tests

- Fall-off or Build-up
  Stable flow period followed by pressure recovery period after the shut-in of a tested well
- Drawdown or Injection (Single or Multi-rate)
  Pressure decrease/increase during stable test well flow periods
- Step Rate
  Injection pressure increase versus time for multiple, consecutive, constant rate, equal duration steps
- Interference (Standard or Pulse)
  Observation (test) well pressure response due to rate changes in offset active well

What Can Be Determined From Pressure Falloff Testing?

- Transmissibility
  - Product of permeability and thickness “kh/u”
- Determination of reservoir boundaries
  - Faults
  - “Pinchouts”
  - Influence of other wells
- Near Wellbore Conditions (“skin damage”)
- Evidence of Fracture Propagation
- Reservoir Pressure Increase

Ideal Conditions for Testing

- Single well in a reservoir
- Isotropic and homogenous
- Initial shutdown period for reservoir stabilization
- Long period of sustained constant rate injection
- Instantaneous well shutdown
- Adequate time for measurement of reservoir pressure after shutdown

Why Perform Well Testing? 115

- Reservoir characterization over a larger scale around a well than logs or cores can investigate
- Real-world field confirmation of well capacity and pressures
- Assessment of well condition (completion efficiency from borehole into disposal reservoir, aka skin factor)
- Evaluate fracture pressure
- Determine reservoir continuity - pressure interference between wells and inter-well/directional properties

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Why Perform Well Testing? (Regulatory) 116

- Ambient monitoring requirements (40 CFR 146.13 & 146.68)
- Investigate/confirm permeability-thickness and reservoir extent assumptions used for cone-of-influence calculations
- Verify that well conditions remain consistent over time with values used as the basis for regulatory approvals
- Provide insight regarding reservoir pressure trends for comparison to model projections in permits and/or no-migration demonstrations

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Why Perform Well Testing? (Technical) 117

- Assist with ongoing understanding of realistic well capacity, operating limitations, changing conditions, expected maintenance costs, and well life expectancy
- Aid with differentiation of reservoir limitation or wellbore conditions as potential reasons for decreasing capacity
- Provide insight into wellbore plugging for the evaluation of treatment options (timing and near wellbore or deep damage)
- Provide insight regarding reservoir pressure trends for comparison to projections that might impact migration (manage liability)

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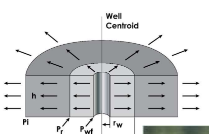
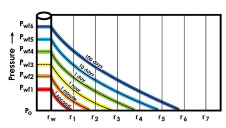
How Does Fall Off Testing Work? 118

Pressure propagates in a reservoir as a log function of time and distance from the source term (well)





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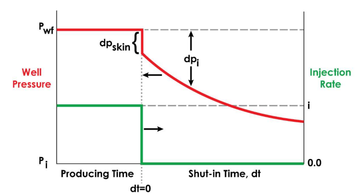
How Does Fall Off Testing Work? 119

A rate change at a well will cause a pressure change in the reservoir that can be measured in a well



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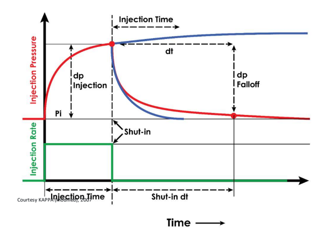
How Does Fall Off Testing Work? 120

The pressure change is represented by the superposition of new shut-in rate, q = 0, on the prior injection rate



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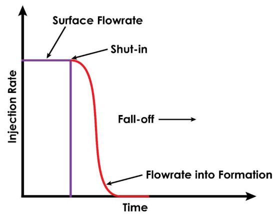
How Does Fall Off Testing Work?

121

Must account for changes from surface to bottom hole and for the transition from open borehole to porous media



How Does Fall Off Testing Work?

122

- Exponential Integral (Ei) solution to Diffusivity Equation
- Log approximation
- Basic analyses assume radial flow with homogenous & isotropic conditions
- More complicated scenarios require more complex treatments and introduce analysis uncertainty

Differential equations used to represent pressure behavior in a porous media also used to evaluate heat transfer and electricity

Basic Fall Off Analysis Equations

123

$$\Delta p = -162.6 \frac{q \mu B}{k h} \left[\log \frac{k t}{\Phi \mu c r_w^2} - 3.2275 + 0.869 s \right]$$

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

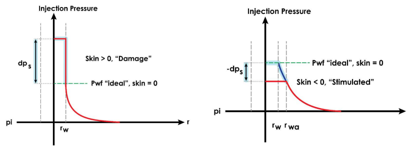
$$s = 1.1513 \left[\frac{P_{1hr} - P_{wf}}{m} - \log \left(\frac{k}{\Phi \mu c r_w^2} \right) + 3.2275 \right]$$

Earlougher (1977), Matthews and Russell (1967)

What Is Skin Factor?

124

A mathematical convenience related to equivalent wellbore radius used to represent wellbore performance as compared with an ideal completion



Courtesy Schlumberger (modified), 2006

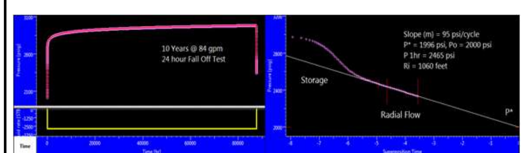
Falloff Test Analysis

125

- Plotting and processing pressure changes as various functions or history-matches of observed data to idealized predictions allows us to infer well and reservoir properties
- Diagnostic dp/derivative log-log plot
- Semi-log plots
- Complex functions and superposition

What Does an Ideal Fall off Test Look Like?

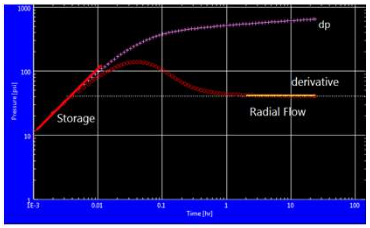
126



History plot (Pressure [psig], Liquid rate [STB/D] vs Time [hr]) Semi-Log plot: p [psig] vs Superposition Time

What Does an Ideal Fall off Test Look Like?

127



Log-Log plot: p-p@dt=0 and derivative [psi] vs dt [hr]

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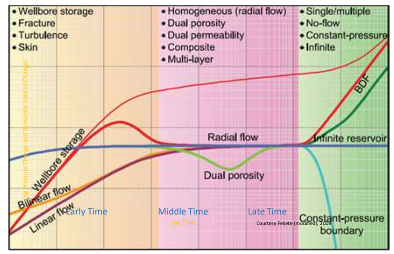
Flow Regimes – Pattern Recognition

128

Near wellbore, reservoir or boundary conditions?



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Assumptions Matter Falloff Testing Uncertainty

129

- Total Historical Injection Volume (Pseudo Time, Tp)
- Rates and Pre-test Flow Period Duration
- Year to Year Operating Changes
- Offset Injection
- Changing Mobility (k/u)inner/(k/u)outer or Transmissivity (kh/u) with Distance
- Reaching Heterogeneity or Boundary

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Fall off Test Analysis – Compliance Use

130

- Differences between Pi, Pwf, P*, Pave, P1hr
- Pwf is "flowing" pressure impacted by near wellbore effects, skin, well geometry, friction, density, viscosity
- P* aka "false pressure" only = Pi in an ideal infinite acting reservoir, limited use and requires corrections for reservoir geometry
- P1hr is extrapolation from radial-flow slope "m", used for calculations and is not 1-hour gauge value

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Analysis Issues - Optimize Fall off Testing

131

- Assuming "good" pressure data is obtained, useful pressure transient analysis is not possible without good rate data;

  garbage q in = garbage kh/u out
- If Pi, Pwf and P* are unrealistic in a graphical or simulation match the interpretation could be misleading
- Wellbore transients typically dominate reservoir transients
- Simple models that acknowledge uncertainty can sometimes provide more insight than overly complicated approaches that are not justified nor unique
- Fall off tests must be used in context with all available information

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How Can We Estimate Fracture Pressure With Well Testing?

132

- **Step Rate Testing**
  - Injection into the reservoir at progressively higher rates in multiple equal time step increments
  - Record the pressure response seen in the reservoir
  - If all reservoir and fluid properties are constant, a predictable pressure change will result from each rate change
  - Pressure response can be graphically analyzed to estimate when flow characteristics change
    - A shift from matrix flow to fracture dominated flow may be observed if less additional pressure is required for similar rate change steps at higher pressure

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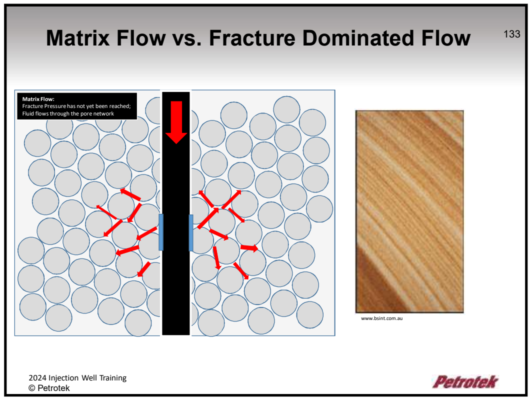

Matrix Flow vs. Fracture Dominated Flow
133
Matrix Flow:
Fracture Pressure has not yet been reached;
Fluid flows through the pore network
www.bsint.com.au
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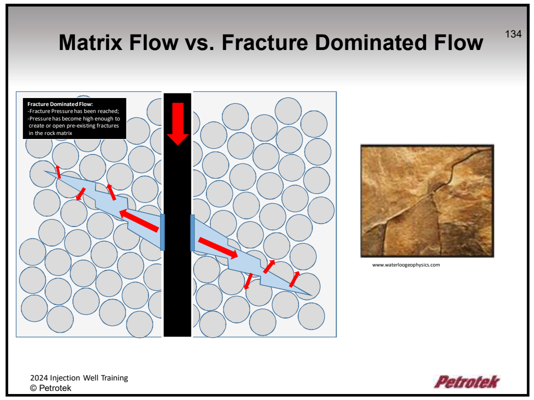

Matrix Flow vs. Fracture Dominated Flow
134
Fracture Dominated Flow:
-Fracture Pressure has been reached;
-Pressure has become high enough to create or open pre-existing fractures in the rock matrix
www.waterloogeophysics.com
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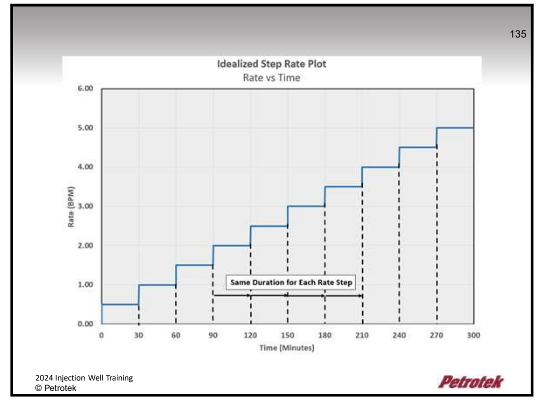

135
Idealized Step Rate Plot
Rate vs Time
Rate (BPM)
Time (Minutes)
Same Duration for Each Rate Step
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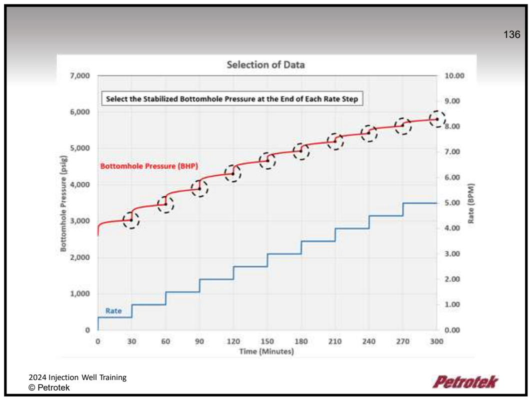

136
Selection of Data
Select the Stabilized Bottomhole Pressure at the End of Each Rate Step
Bottomhole Pressure (BHP)
Rate
Bottomhole Pressure (psig)
Rate (BPM)
Time (Minutes)
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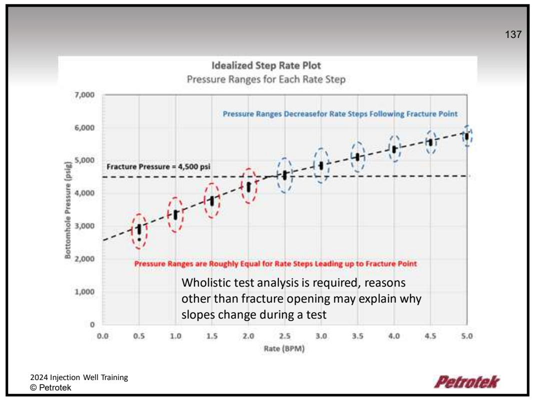

137
Idealized Step Rate Plot
Pressure Ranges for Each Rate Step
Pressure Ranges Decreasefor Rate Steps Following Fracture Point
Fracture Pressure = 4,500 psi
Pressure Ranges are Roughly Equal for Rate Steps Leading up to Fracture Point
Wholistic test analysis is required, reasons other than fracture opening may explain why slopes change during a test
Bottomhole Pressure (psig)
Rate (BPM)
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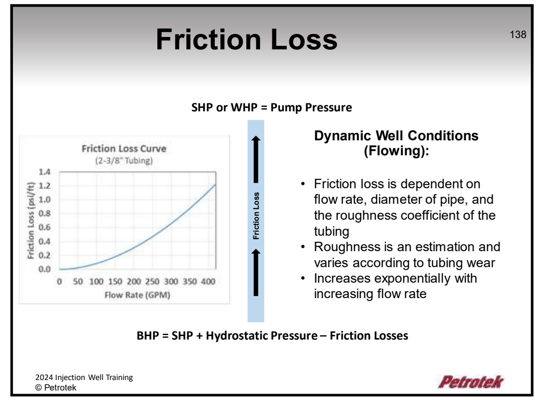

Friction Loss
138
SHP or WHP = Pump Pressure
Friction Loss Curve
(2-3/8" Tubing)
Friction Loss (psi/ft)
Flow Rate (GPM)
Friction Loss
Dynamic Well Conditions (Flowing):
• Friction loss is dependent on flow rate, diameter of pipe, and the roughness coefficient of the tubing
• Roughness is an estimation and varies according to tubing wear
• Increases exponentially with increasing flow rate
BHP = SHP + Hydrostatic Pressure – Friction Losses
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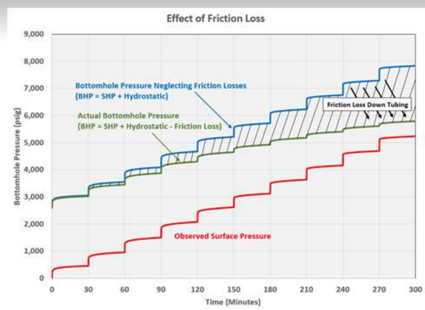

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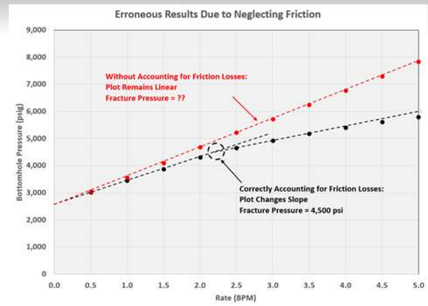

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Discussion & Questions

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Contact Information

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Ken Cooper
ken.cooper@petrotek.com

Petrotek Corporation
5935 South Zang Street, Suite 200
Littleton, Colorado 80127
303-290-9414
1-877-879-1480
www.petrotek.com

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