HOW SEVERAL COMMON FACTORS INFLUENCE INJECTION WELL PERFORMANCE, TESTING AND PERMITTING: DENSITY, TEMPERATURE, AND FRICTION

GROUNDWATER PROTECTION COUNCIL ANNUAL UNDERGROUND INJECTION CONTROL CONFERENCE
February 2018; Tulsa, Oklahoma

KEN COOPER
LEWIS WANDKE & RICHARD PITTS

PETROTEK ENGINEERING CORPORATION
OBJECTIVES

- How pressure makes the injection process work
- What factors influence injection pressure (and how)?
- Density, Temperature and Friction
- How are they inter-related?
- How do these factors influence pressure in a reservoir?
- Influences on performance, permitting and compliance
- Summary, observations, and questions
WHY THESE FACTORS MATTER - PRESSURE

- Operational decisions about well capacity and future maintenance inaccurate without proper inclusion
- Monitoring, test design, well design and well data analysis of limited use without incorporating
- Initial permitting decisions and compliance evaluation cannot be completed without proper assessment
HOW DOES INJECTION WORK?

- Fluid moves from higher to lower pressure
- Pressure is force per area
  - $\text{psi} = \text{pounds force per square inch}$
  - $\text{Pascal} = \text{kg force per meter second}^2 = \text{Newton/m}^2$
- Average column of air exerts 14.696 pounds of force on one square inch of the earth’s surface (1 atm)
- During injection, pressure forces fluid through well equipment into fluid filled rock pore space
HOW DOES INJECTION WORK?

- Porosity – rock property of having void (pore) space within a solid, only useful if connected. Fluid in the connected pores can be compressed.

- Permeability – rock property that allows fluid to move through the porosity of a rock due to differential pressure; pressure is lost with distance into a reservoir due to flow resistance.

- Fluid and Rock Compressibility (3 to $9 \times 10^{-6}$/psi)
HOW INJECTION WORKS? ENERGY

- 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 is lost when obstacles are encountered - (valve, elbow, flow line, wellhead, packer, perforation, screen, well/formation interface, pore throat) – friction
- Pressure increases as energy is added (pumping or as a taller fluid column exists (more fluid weight) from surface to the location where force is acting – hydrostatic head
Total pressure in an injection system at depth must always exceed pressure in the formation for injection to be possible.

Energy is balanced in a system from surface, down a well, and into an injection formation.

Pressure data without a depth reference (and a fluid density to allow depth normalization) is of little use to evaluate how an injection system works.
SUMMATION OF PRESSURES ADDED AND LOST

start at static atmospheric surface pressure (equilibrium)

+ use transfer pump to fill tank (now hydrostatic head)

- friction loss in flow line to injection pump suction

+ increase pressure with injection pump

- friction loss in flow line and wellhead (monitored WHP)

- + pressure from filling tubing to surface (vacuum injection)

+ pressure exerted by weight of fluid column with depth

- - friction loss in tubing with depth

- - friction loss in completion (perforations/skin damage)

- - formation pressure resistance in porous media (stimulation)

- - original formation pressure at distance into the reservoir
Density or (volumetric mass density) is mass per unit volume.

Brine specific gravity is the ratio of brine density to the density of fresh water at the same temperature and pressure.

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.
DENSITY AND HYDROSTATIC PRESSURE

STATIC WELL (NO FLOW)
- A Column of Fresh Water (SG = 1.0) Exerts 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, a Column of Brine (SG = 1.2) Exerts 0.520 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 * 0.520 psi/ft * 1.0)

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

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.
TEMPERATURE & DENSITY

- SG versus Salt Concentration
- SG Increase versus Pressure
- Density versus Temperature

2018 GWPC UIC Conference
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

Brine viscosity is a strong function of temperature, it decreases quickly as temperature increases

Viscosity is strongly dependent on composition, less on density
TEMPERATURE & VISCOSITY

- $\mu$ versus Temperature & Salt
- Increase versus Pressure
- Decrease versus Temperature
Friction (measured as pressure loss) in fluid flow is a measure of the force resisting relative motion by fluid against itself. It depends on the tendency of the liquid to resist flow (viscosity). The nature of the surface over which fluid moves influences friction; greater force is generated flowing over a rough surface. The velocity of the fluid flow also affects friction. If the velocity becomes large, laminar flow instead of turbulent flow can significantly increase friction loss.
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 and tubing condition & wear.
- Friction increases exponentially with increasing flow rate.
- Friction increases strongly with increasing viscosity, less with increased density.

For 6,000 feet of tubing friction matters:
- 150 gpm = 1,100 psi
- 50 gpm = 150 psi
Reservoir pressure increases over time as compression occurs with volume
  • Injection reservoirs should be large, try to avoid boundaries & interference (these cause more pressure)
  • $\Delta P = \Delta V_W / (V_W C_W)$; $C_W = 3$ to $5 \times 10^{-6}$/psi

For a 1-mile square box, 100’ thick zone, $C_W = C_F$, (12% porosity), $dp = 438$ psi after 6 months at rate of 25 gpm

But reservoir pressure is not uniform, it varies with distance
In a porous media, reservoir pressure increase is greatest nearest the wellbore, and it changes dramatically (logarithmically) with distance and time based on two primary parameter groups:

\[ \Delta p = 162.6 \frac{q \mu B}{k h} \left[ \log \frac{k t}{\Phi \mu_c r^2} - 3.23 + 0.869s \right] \]

Matthews and Russell (1967), page 49

Only viscosity is in both terms
Radius of fluid displacement = \( \left( \frac{qt}{\pi h \phi} \right)^{1/2} \)
WHAT FACTORS INFLUENCE RESERVOIR PRESSURE?

\[ \Delta p = 162.6 \, \frac{q \mu B}{k h} \left[ \log \frac{k t}{\Phi \mu c r_w^2} \right] - 3.23 + 0.869 \, s \]

- \( \mu = \text{viscosity} \) - (temperature; also composition)
- \( c = \text{compressibility} \) - (density: temperature, pressure)
- \( B = \text{water formation volume factor, reservoir barrel/stock tank barrel} \) - (temperature, pressure, density; also composition)
- \text{friction (viscosity: temperature, also mechanical properties)}
- \text{rate, permeability, thickness, time, porosity, radius, skin}
These factors are inter-related

- Temperature alters fluid density
- Temperature and density impact viscosity
- Viscosity and density influence tubing friction loss
- Density defines fluid column weight (hydrostatic head) and increases pressure with depth
- Viscosity is a main factor in completion friction loss (skin)
- Viscosity is a primary factor defining pressure required to move fluid through a porous media
Injection pressure is typically only measured at surface.

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.
SYSTEM PERFORMANCE (2)

- 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, all impact well cost.

- Required injection pressure can increase over time just to overcome the reservoir pressure losses being generated in a growing area around the well where cooling causes higher viscosity.
SYSTEM PERFORMANCE (3)

- If tubing condition (roughness or ID) changes due to scale, increased tubing friction might be mistaken as formation damage.
- Cold weather might reduce injectate temperature and increase viscosity, associated wellhead pressure increases 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.
Pressure corrections to depth based on density (hydrostatic head) must be properly considered in cone-of-influence (COI) and fracture pressure calculations.

Rate, tubing size, and roughness can significantly change tubing friction loss calculations and are critical inputs to maximum injection pressure assignments.

Formation temperature can be much higher than injectate temperature and is more appropriate for reservoir pressure rise calculations at distance (COI) from a wellbore but may not be the best for projecting capacity or WHP.
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.

Annual ambient monitoring should include justification for the specific gravity used to correct pressure data to a reference datum depth. Gradient surveys throughout a tubing string provide more accuracy than a grab sample in wells with variable density.

Petition and permit compliance verification should consider density, temperature, and friction since they are inter-related factors that influence well pressures.
KEN COOPER, P.E., M.S.
ken.cooper@petrotek.com

LEWIS WANDKE, P.E.
lwandke@petrotek.com

PETROTEK ENGINEERING CORPORATION
5935 SOUTH ZANG STREET, SUITE 200
LITTLETON, COLORADO 80127 USA
303-290-9414
www.petrotek.com

all rights reserved