Technical Considerations for CO_2 Injection

Lewis Wandke
PETROTEK CORPORATION

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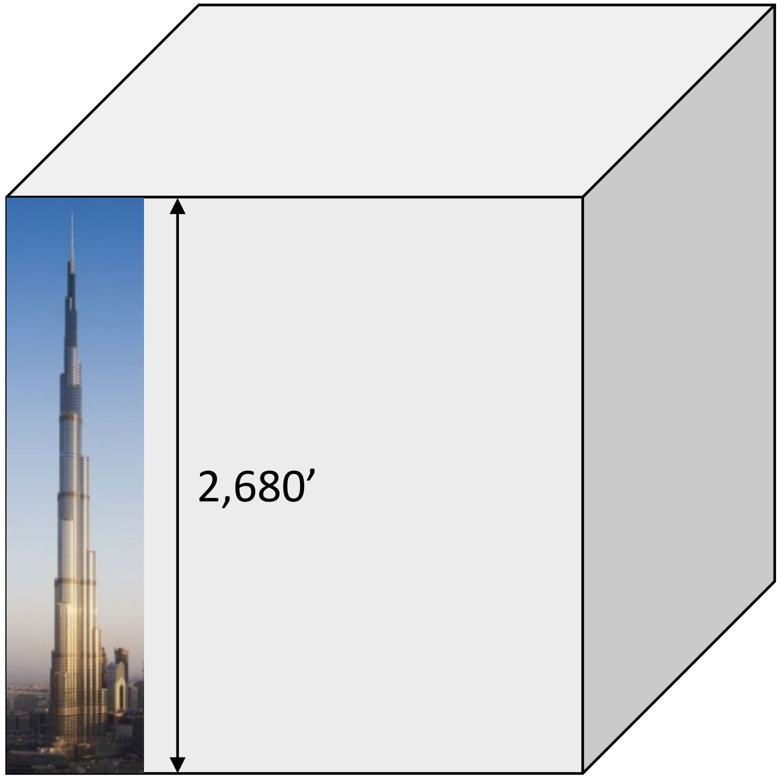
Introduction: CCS Landscape

- **Current U.S. CCS Environment**
  - ~185 individual Class VI wells pending approval
  - ~15 Class VI wells approved
  - 1 Class VI well with significant operational history
    - ~4.7 million metric tons injected to date

CO_2 Unit Visualization

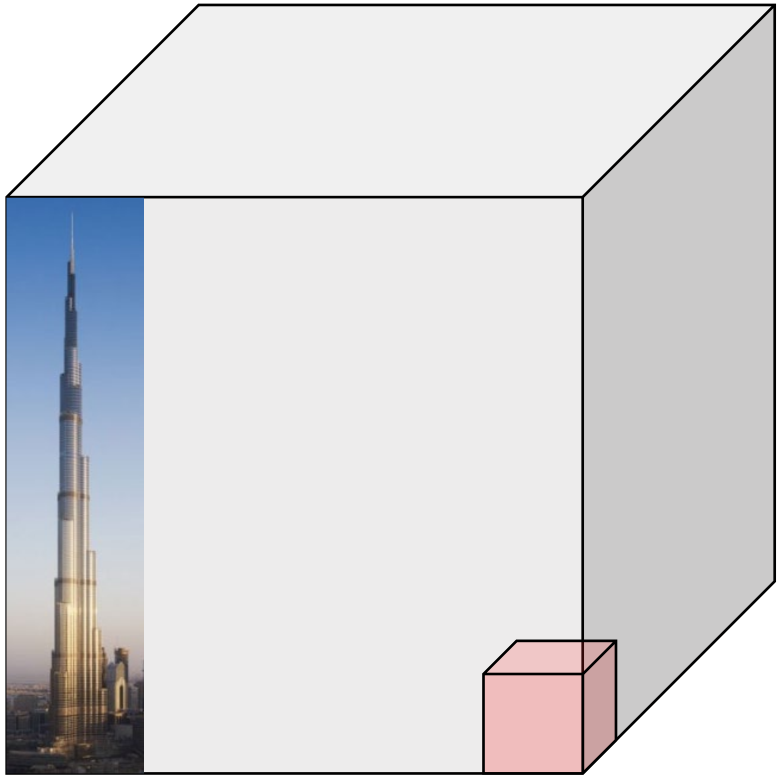
- **CO_2 exists as a gas in our normal environment**

- At STP (60F, 14.7 psi),1 million metric tons occupies an approximate ½ mile cube



CO_2 Unit Visualization

- **CO_2 transitions to a supercritical liquid at reservoir conditions**
  - >88 deg F; >1070 psi
  - 1 million metric tons occupies a ~450 ft cube



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CO_2 Emissions

- **U.S. ranks 11th in per capita CO_2 emissions**
  - 14.9 tonnes/person annually
  - 1 million tonnes offsets the annual emissions of 67,000 Americans
  - Total emissions of 5.1 billion metric tons/yr
  - ~10,000 Class VI wells required to offset total U.S. emissions assuming average injection of 500 kMTA/yr

Country	2022 Per Capita CO_2 Emissions (tonnes)
Qatar	37.6
United Arab Emirates	25.8
Bahrain	25.7
Kuwait	25.6
Brunei	24.0
Trinidad and Tobago	22.4
Saudi Arabia	18.0
New Caledonia	17.6
Oman	15.7
Australia	15.0
United States	14.9

OurWorldInData.org/co2-and-greenhouse-gas-emissions

Regulatory Considerations

- **Significant differences between CO_2 and brine injection:**
  - Surface Operations
    - CO_2: Wellbore hydrostatics change over time
      - Important when converting SHP to BHP
    - Brine: ~constant wellbore hydrostatics
  - Reservoir Behavior
    - CO_2: multi-phase plume behavior which incorporates relative permeability and capillary pressure dynamics
    - Brine: 100% water-saturated
  - Drift behavior
    - CO_2: Significant vertical and areal plume migration over short-term
    - Brine: Possible over long-term assuming density differences

Regulatory Considerations

- **These differences impact all aspects of UIC:**
  - Area of Review
    - CO_2: Plume can easily extend outside of COI boundary
      - AOR boundary becomes a composite of pressure + plume
    - Brine: Plume is generally much smaller and contained within COI
  - Corrective Action
    - CO_2: migrates upward by default (no pressure required)
    - Brine: requires pressure to migrate upward
  - Long Term Monitoring
    - CO_2: Monitoring wells assess post-operational plume containment
    - Brine: P&A well at end of project

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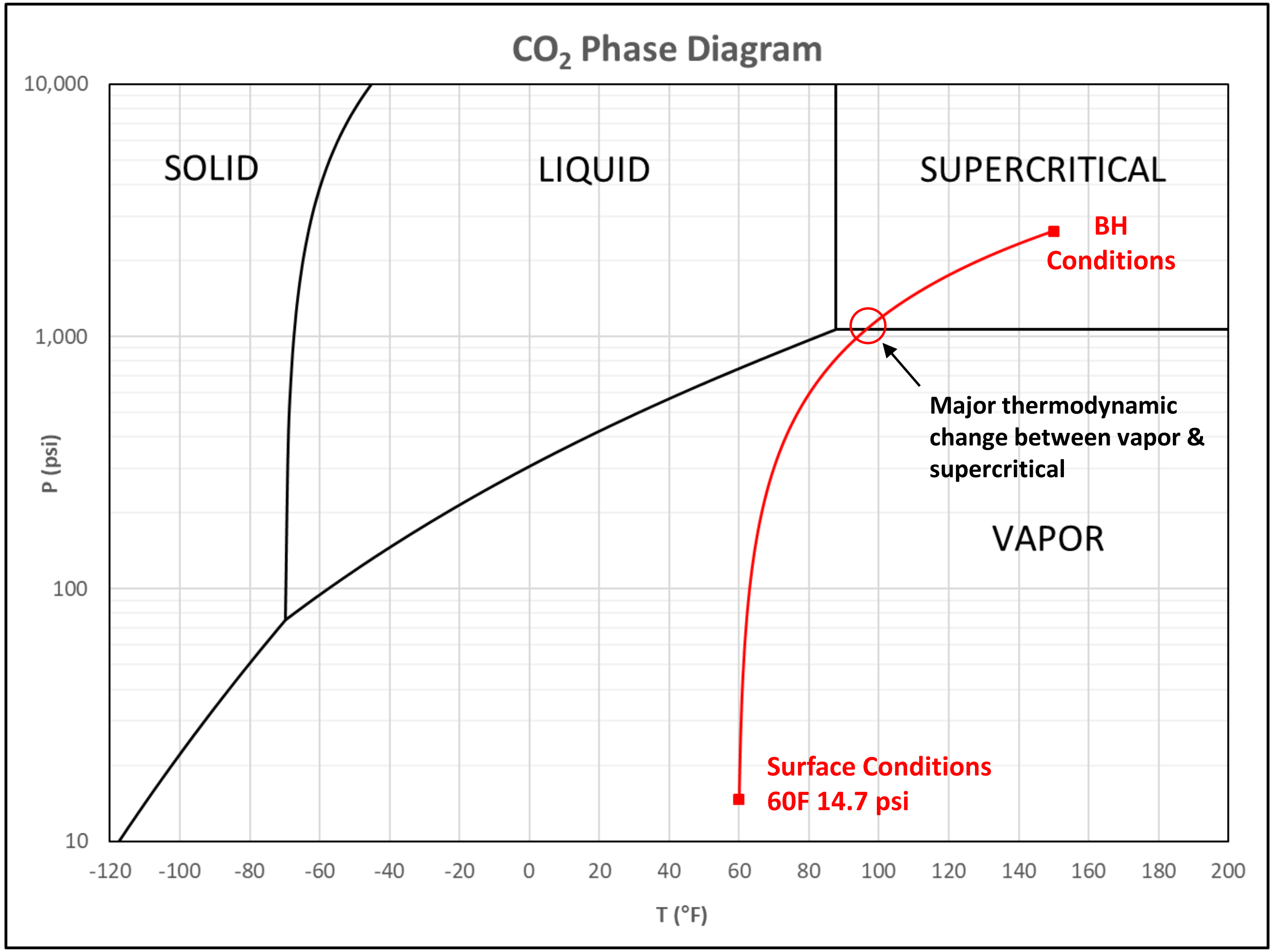
CO_2 vs Brine: Physical Properties

- **CO_2 is much more compressible than brine, even as a liquid**
  - CO_2 density is more susceptible to changes in temperature and pressure between surface and downhole conditions
  - CO_2 liquid density is significantly less than brine (except for extreme cases)
  - Surface injection pressure is required to:
    - Create liquid/supercritical conditions
    - Overcome initial reservoir pressure

Normal Gradient Conditions



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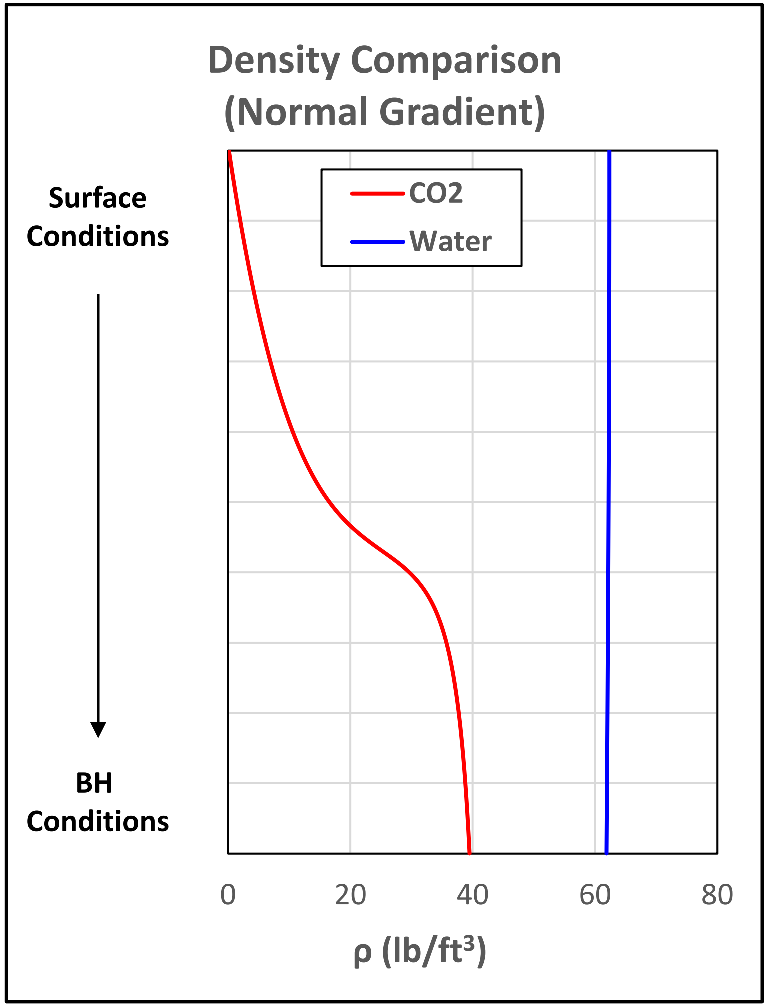
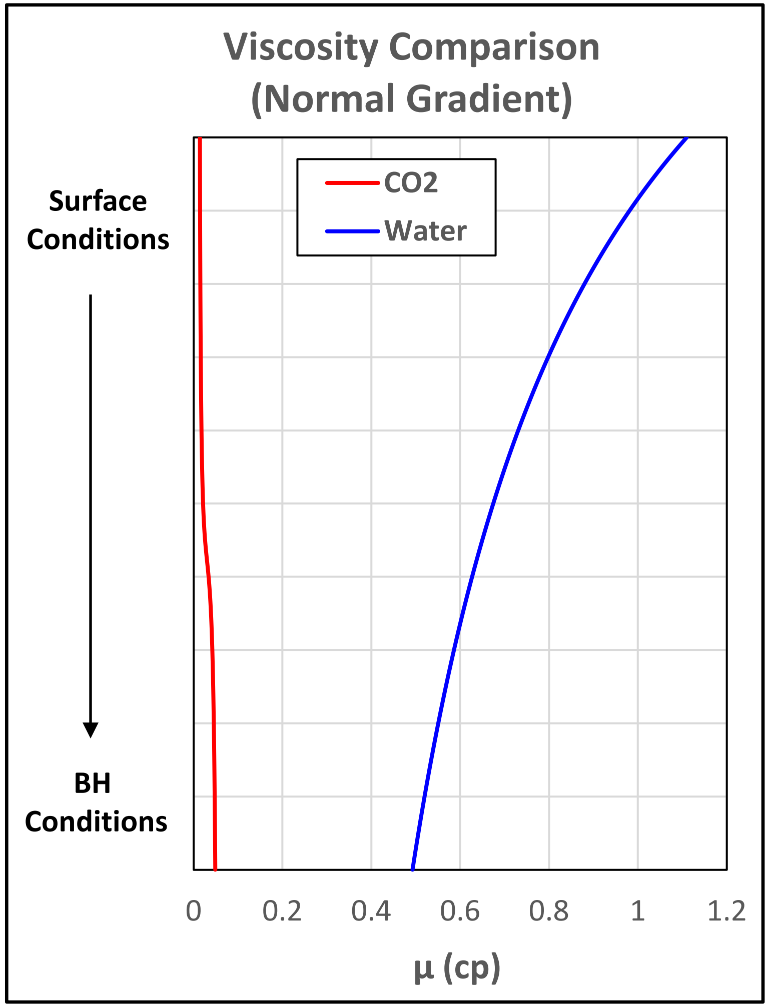
CO_2 Density and Viscosity





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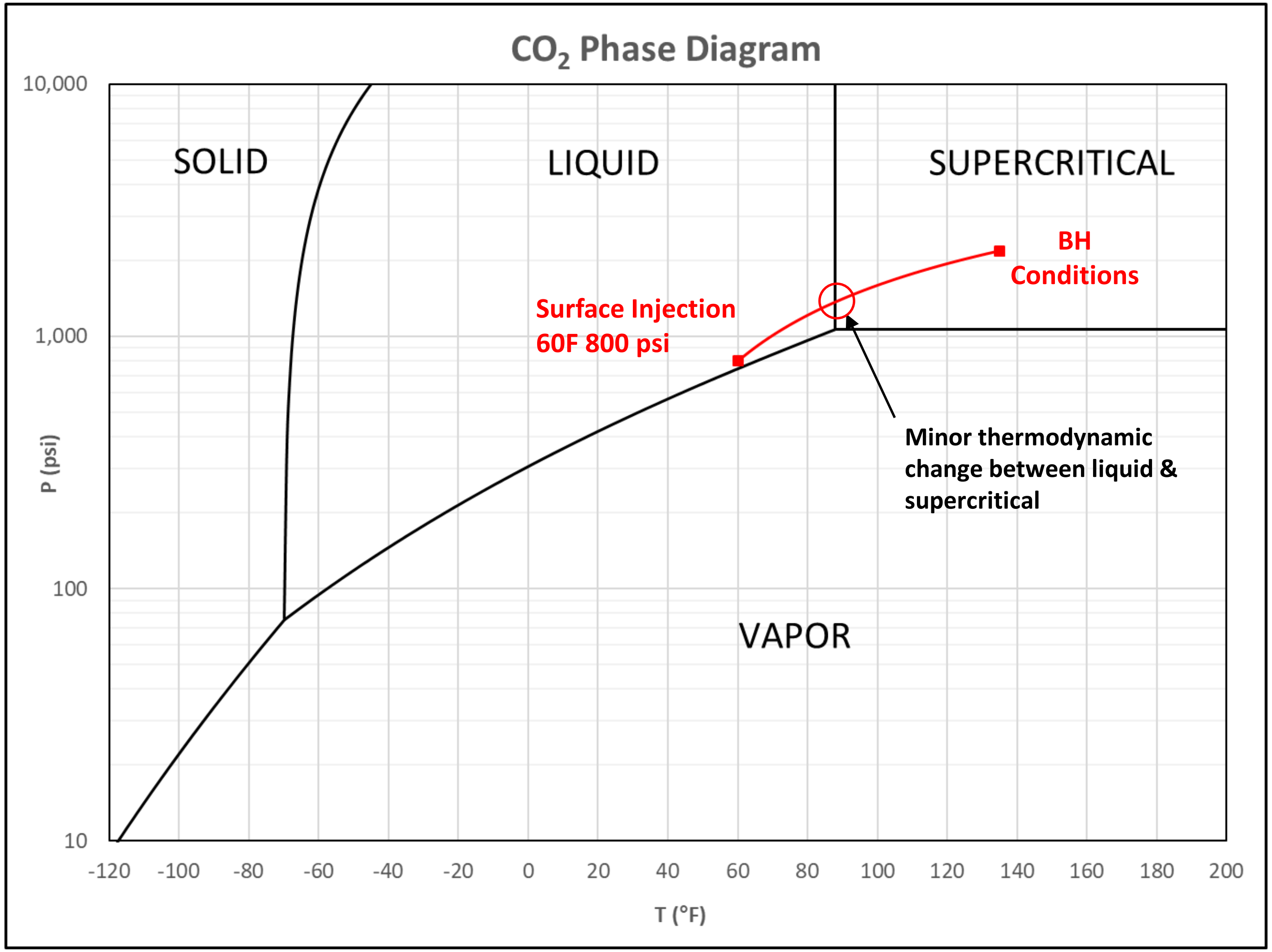
CCS Liquid Injection Conditions



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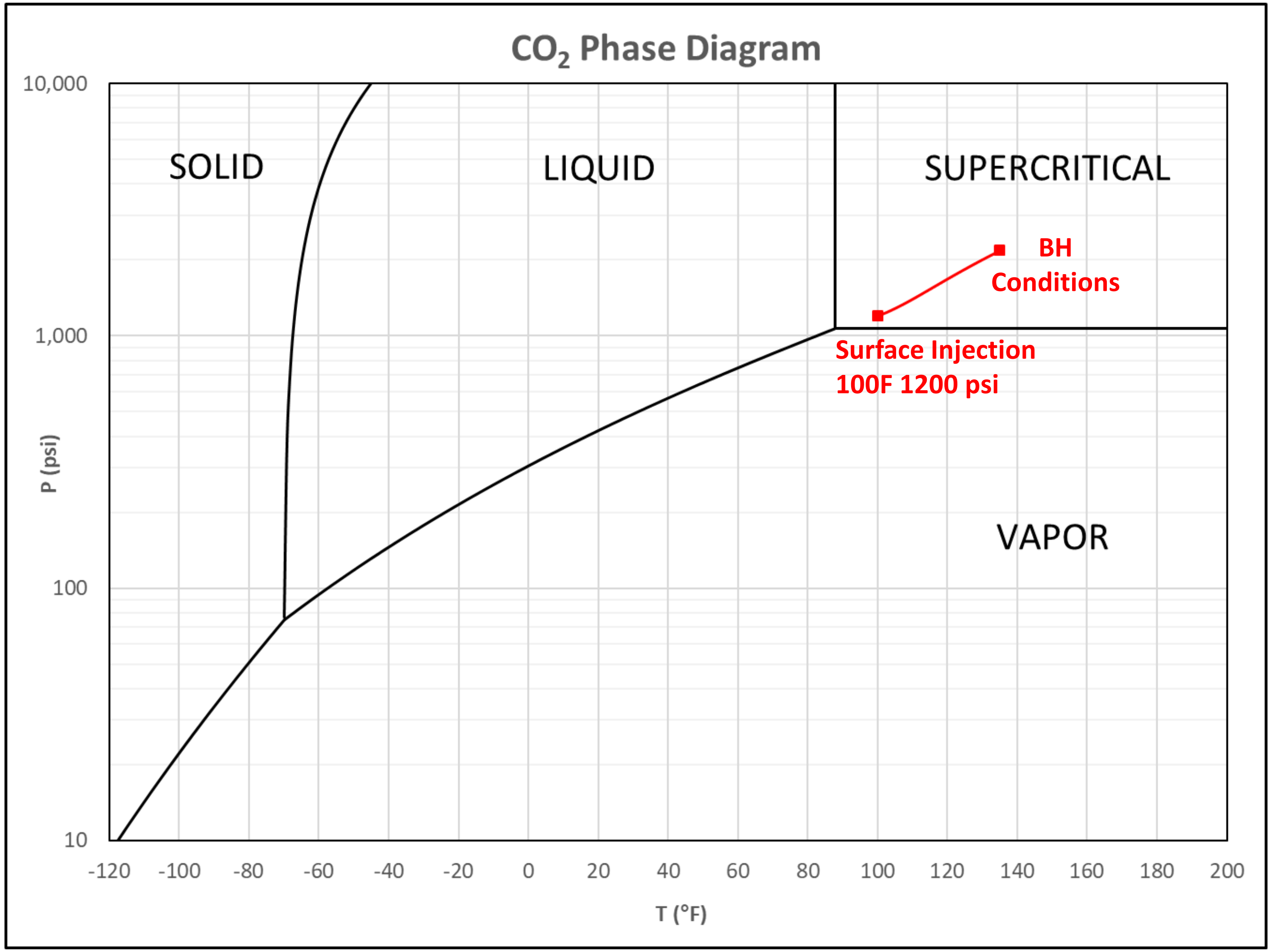
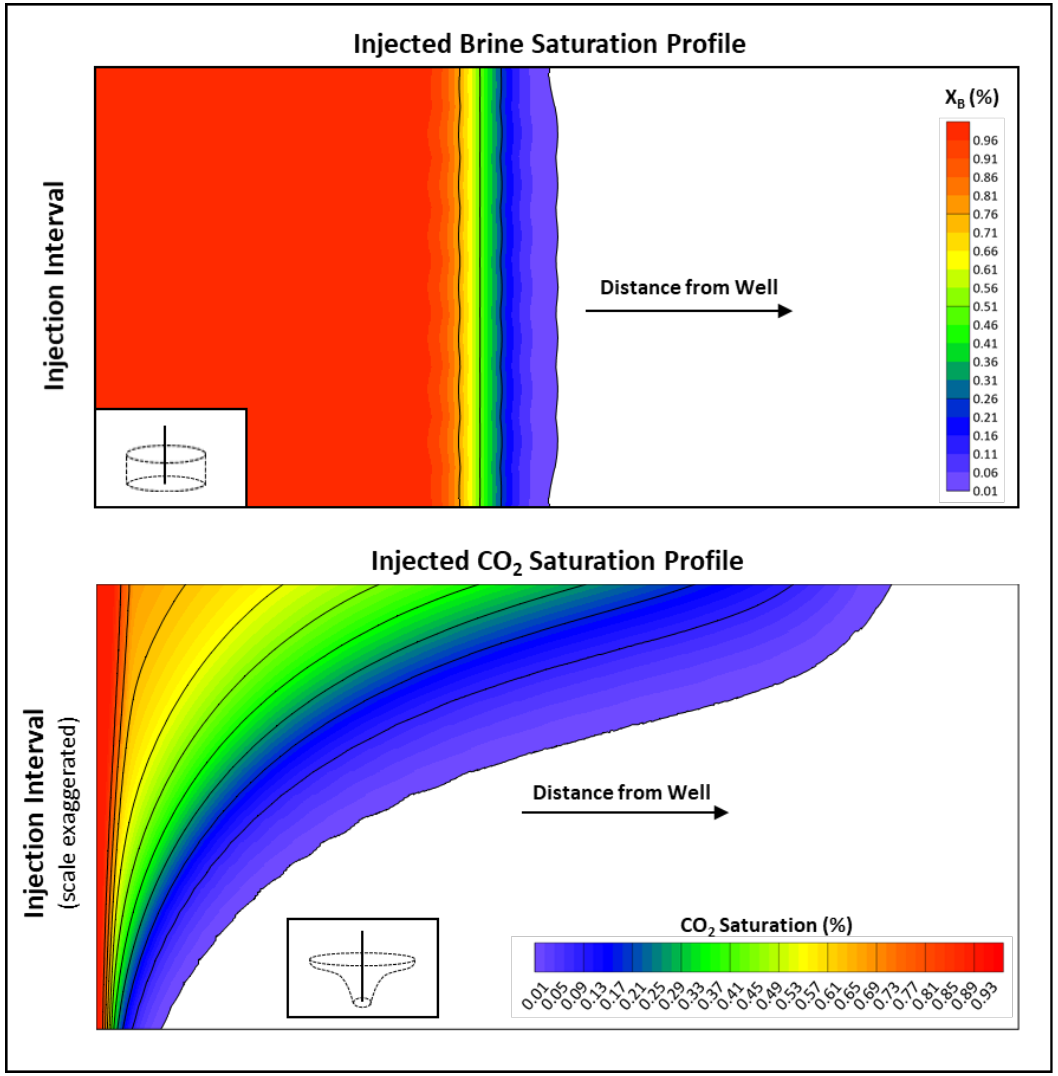
CCS Supercritical Injection



Brine vs CO_2 Plume Behavior



- Reservoir pore volume is utilized very efficiently during brine injection
  - Piston-like plume displacement
  - Narrow dispersive front

- CO_2 plume is compressible and migrates upwards
  - Wide dispersive front
  - Majority of CO_2 remains near-wellbore
  - Idealized result; actual behavior depends on multiple reservoir characteristics

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Plume Modeling

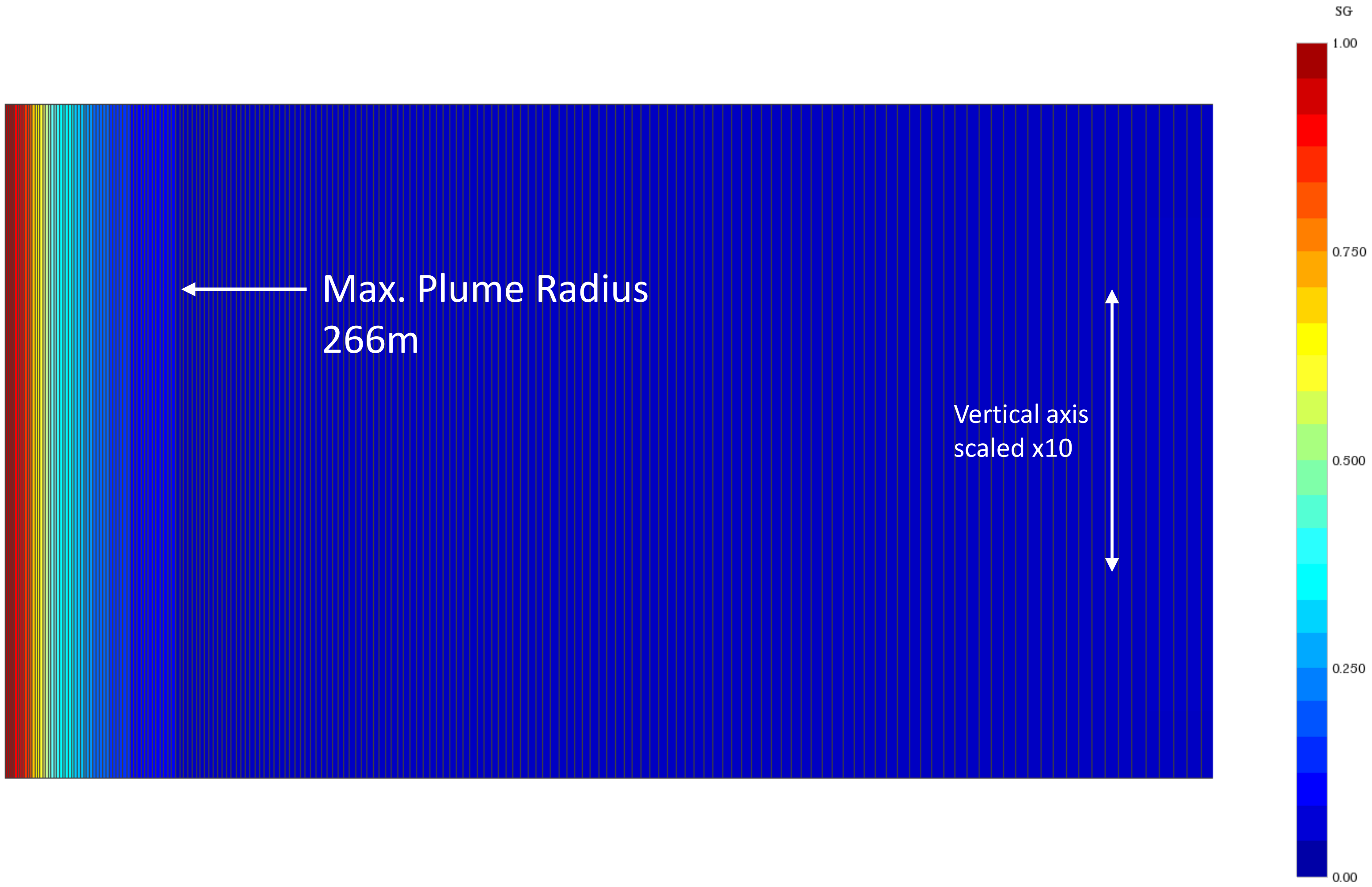
- Radial Modeling
  - 2D solution (cross section extending away from well)
  - No structural considerations or geologic features
  - Generally smaller models with faster run times (ideal for basic screening)
- Cartesian Modeling
  - 3D solution
  - Incorporates areal structure and geologic features (faults)
  - Necessary for accurate depictions of plume behavior in multiple dimensions
    - Post-operational Drift

Radial Modeling Example

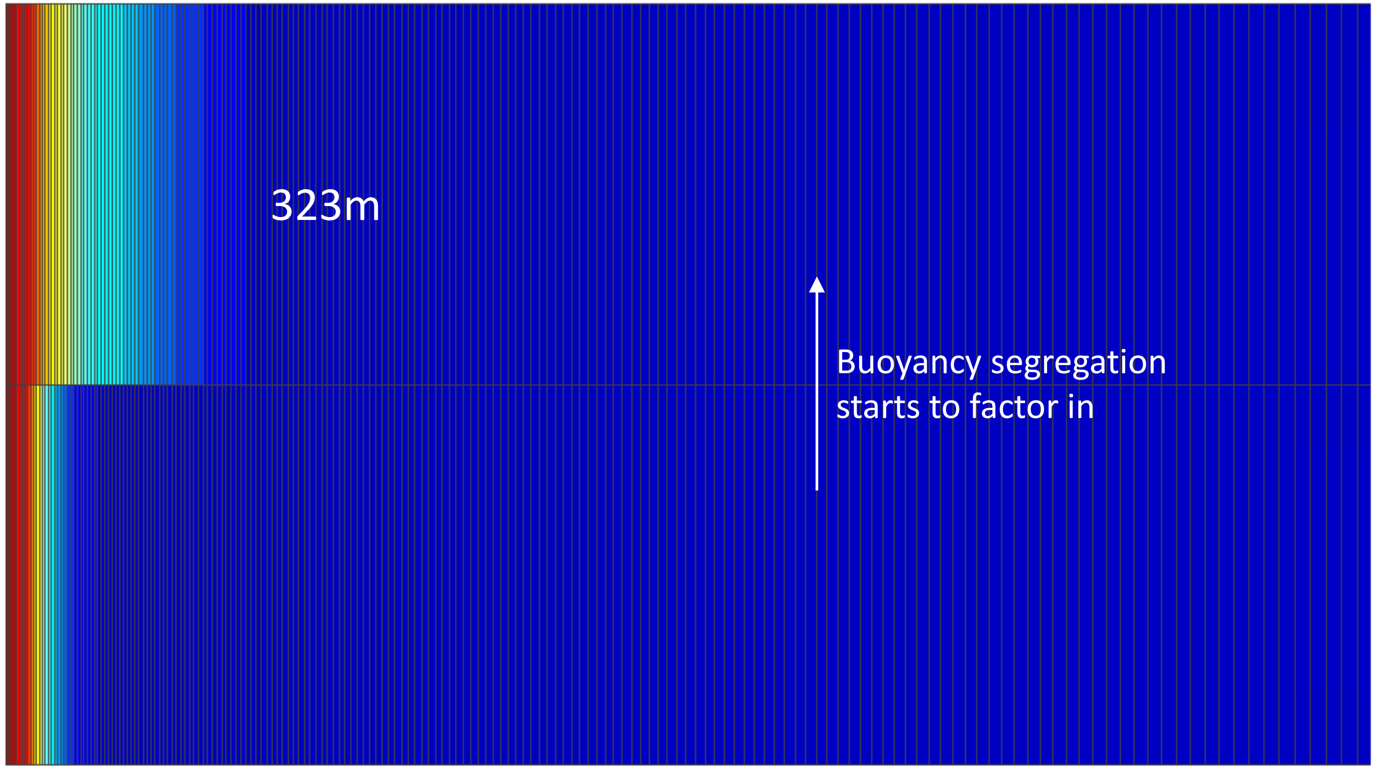
- Radial Model Parameters
  - h = 100 m
  - Φ = 10%
  - k_h = 100 md
  - k_v = 10 md
  - p_i = 1,500 psi + 1.42z (0.433 psi/ft)
  - T = 120°F (isothermal)
  - Q = 10 kg/s = 315,360 metric tons/yr
  - t = 1 year

- No capillary pressure

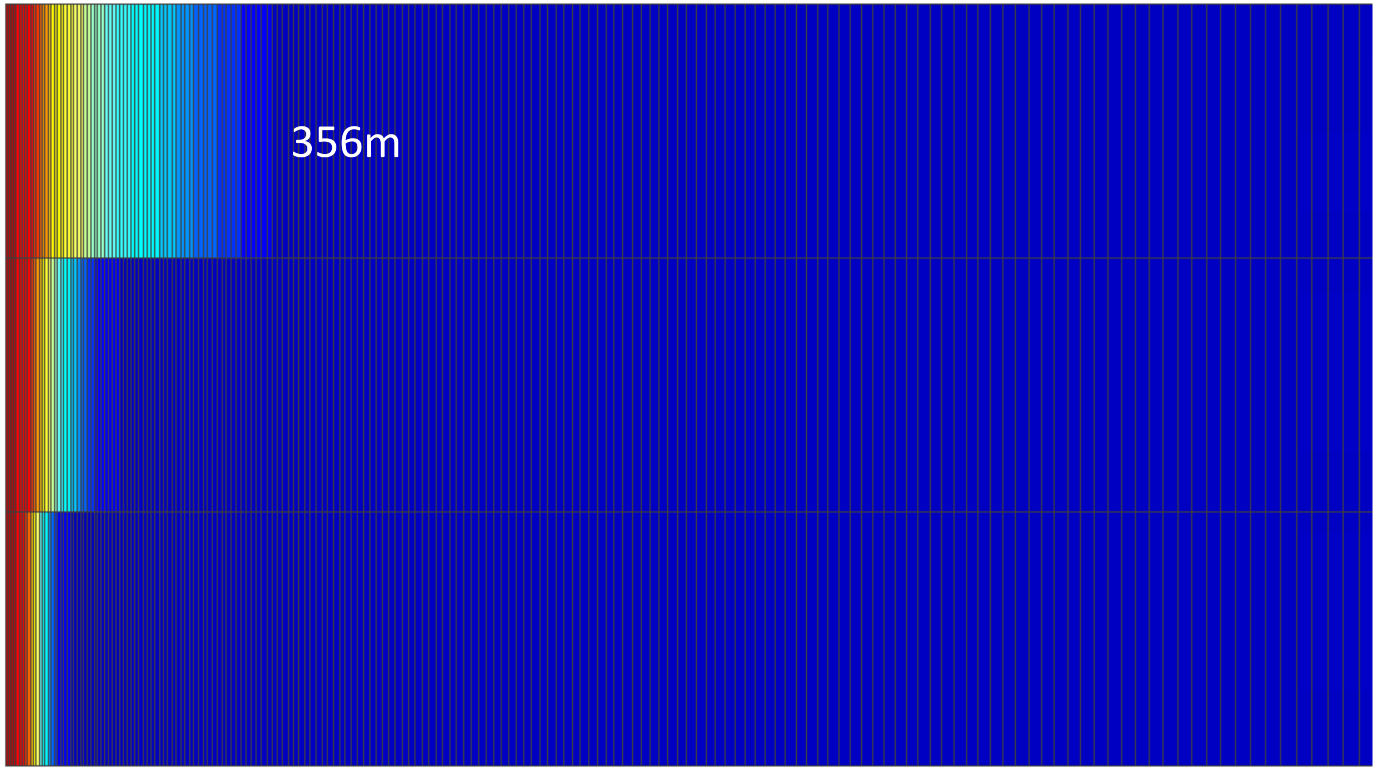
Modeling Dynamics – Single Layer



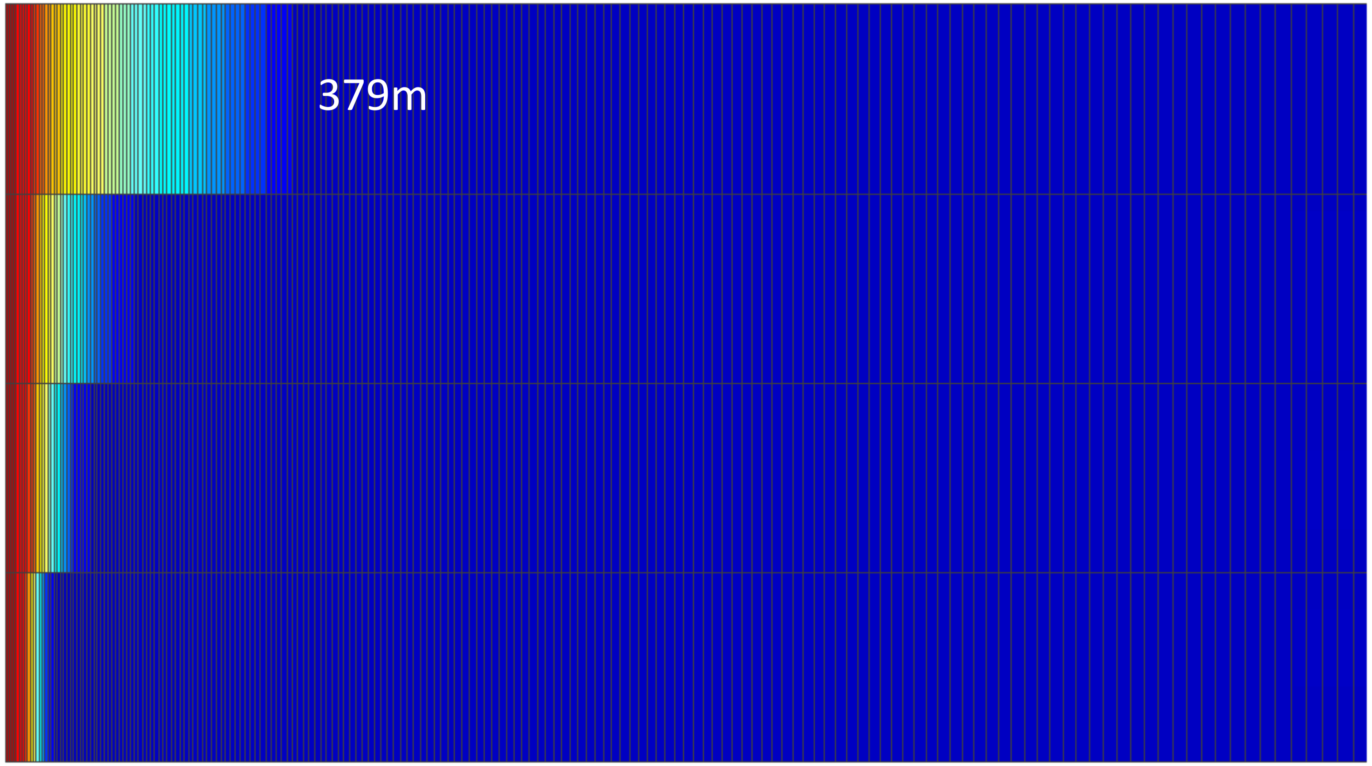
Modeling Dynamics – 2-Layer



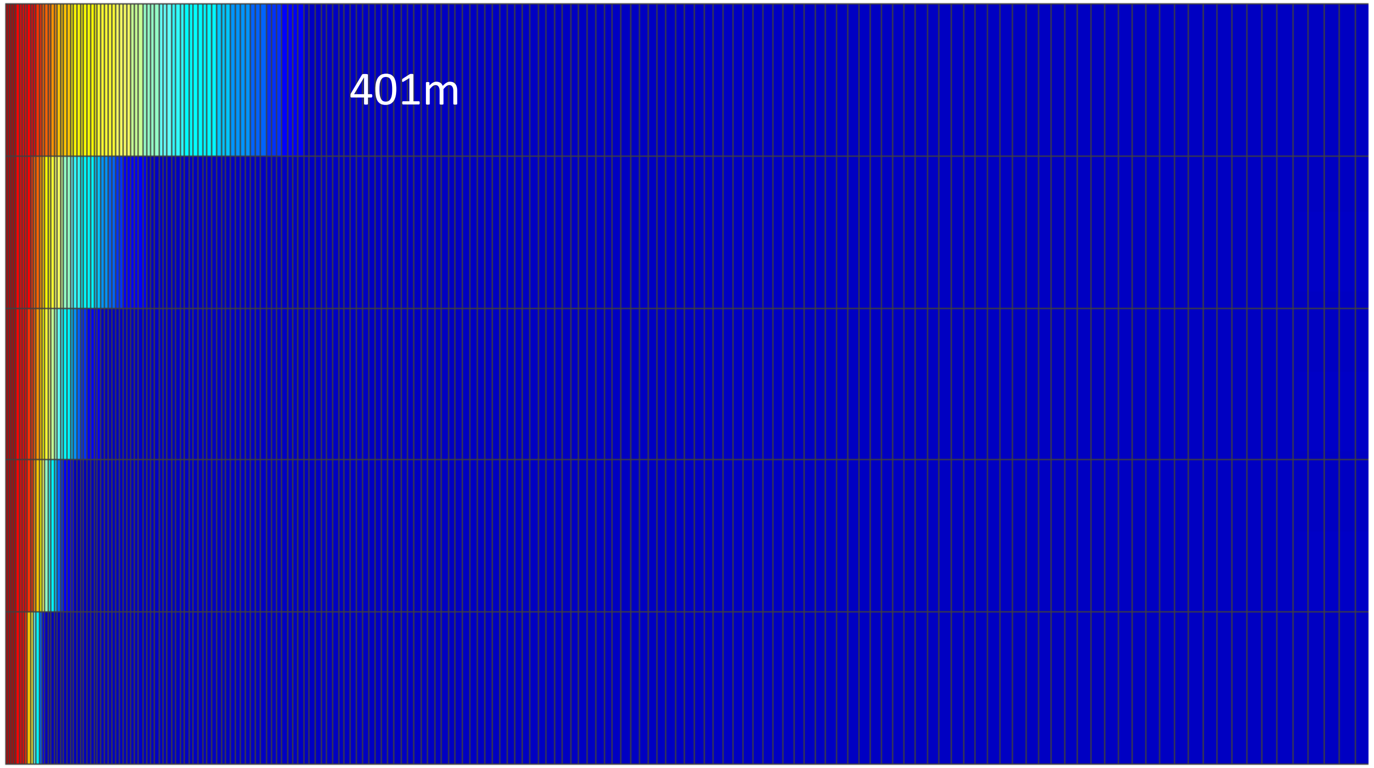
Modeling Dynamics – 3-Layer



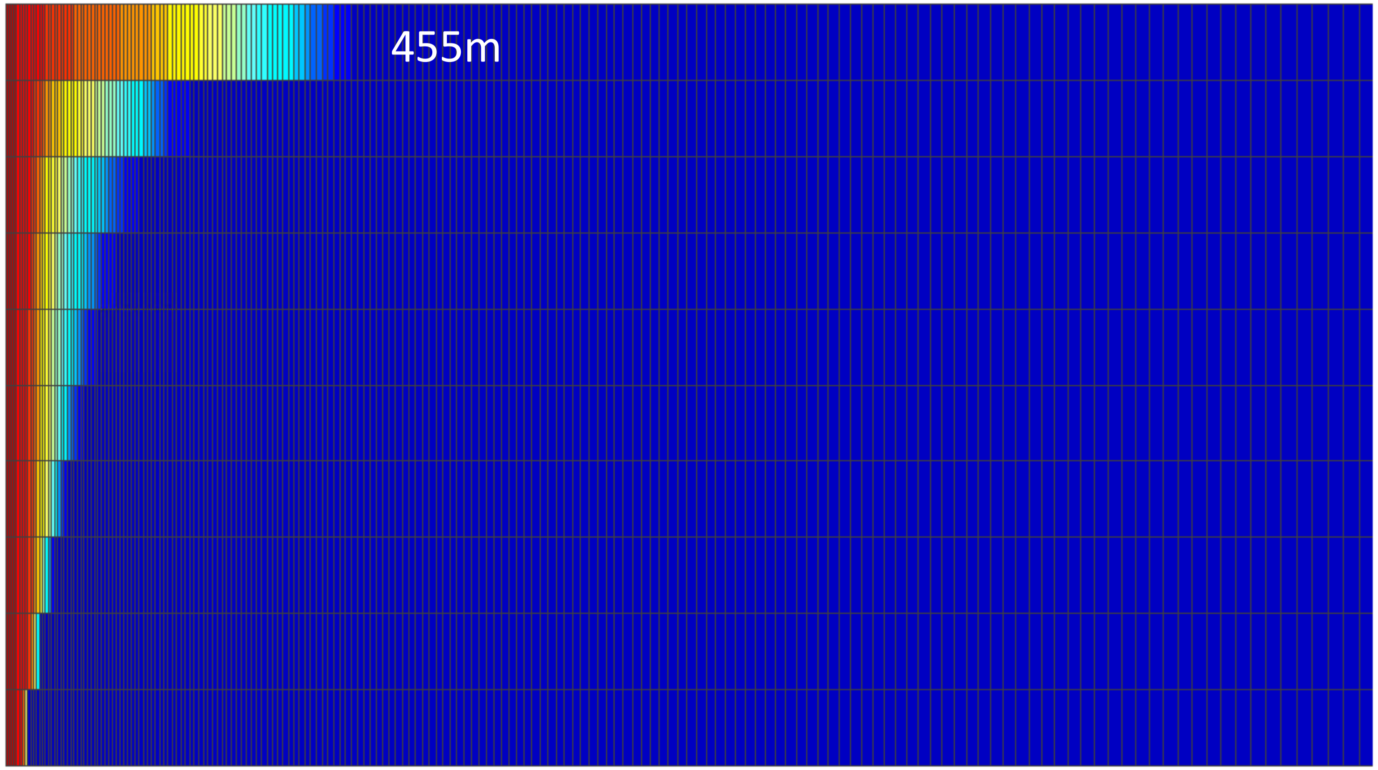
Modeling Dynamics – 4-Layer



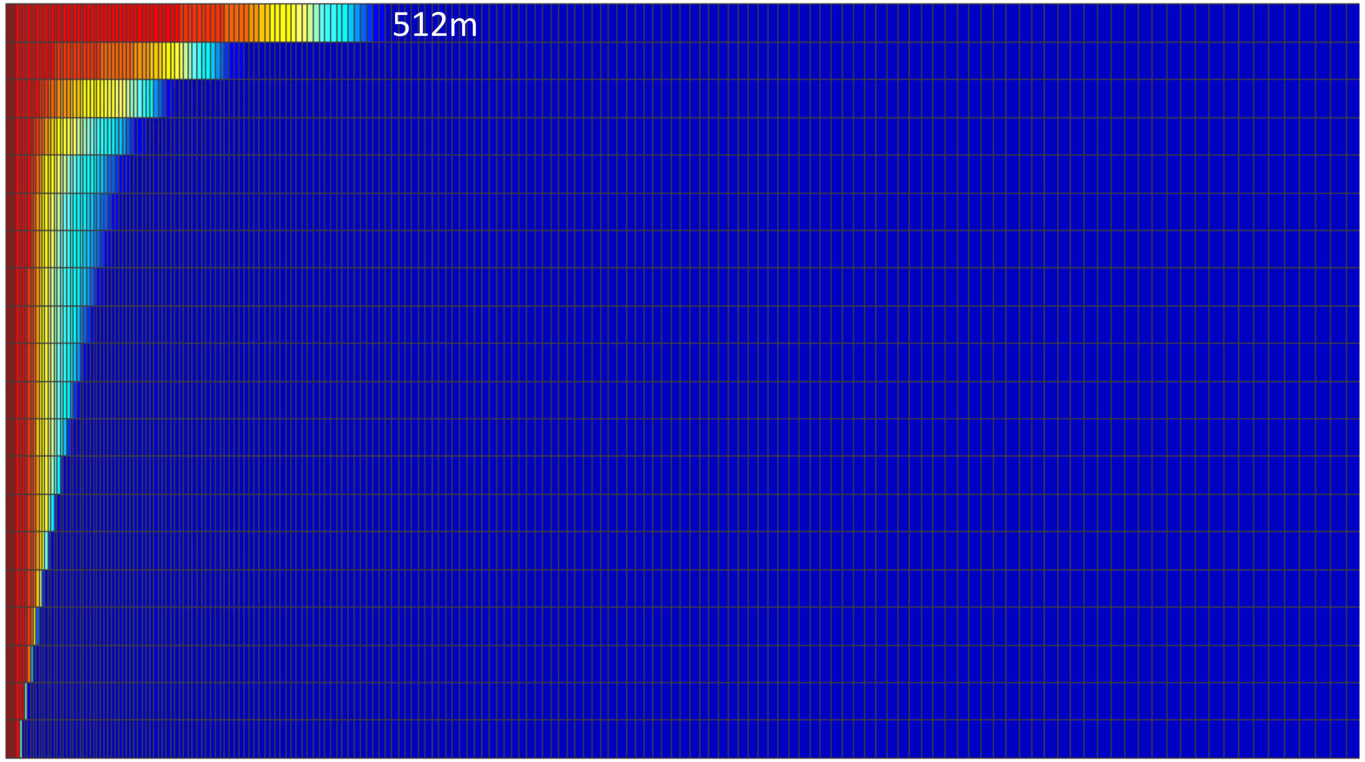
Modeling Dynamics – 5-Layer



Modeling Dynamics – 10-Layer



Modeling Dynamics – 20-Layer



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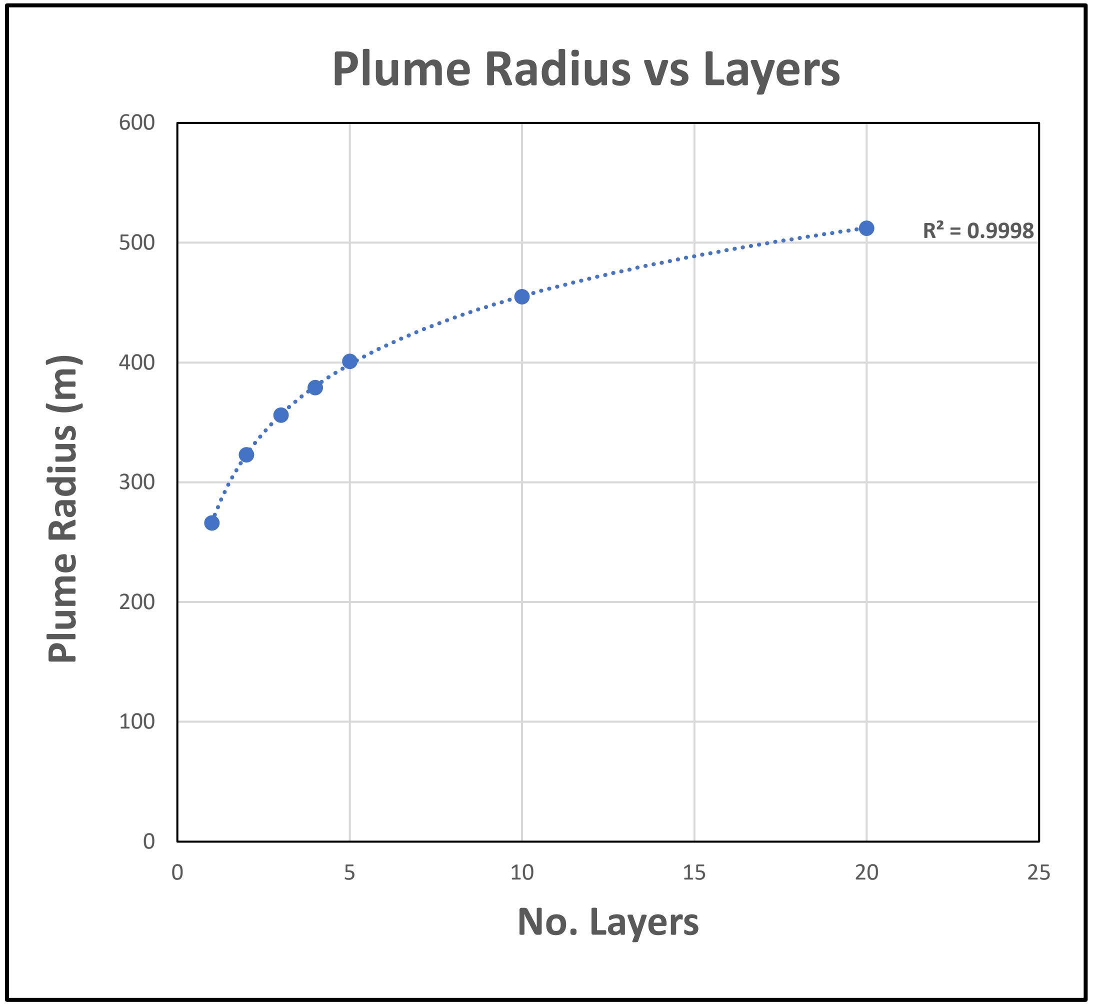
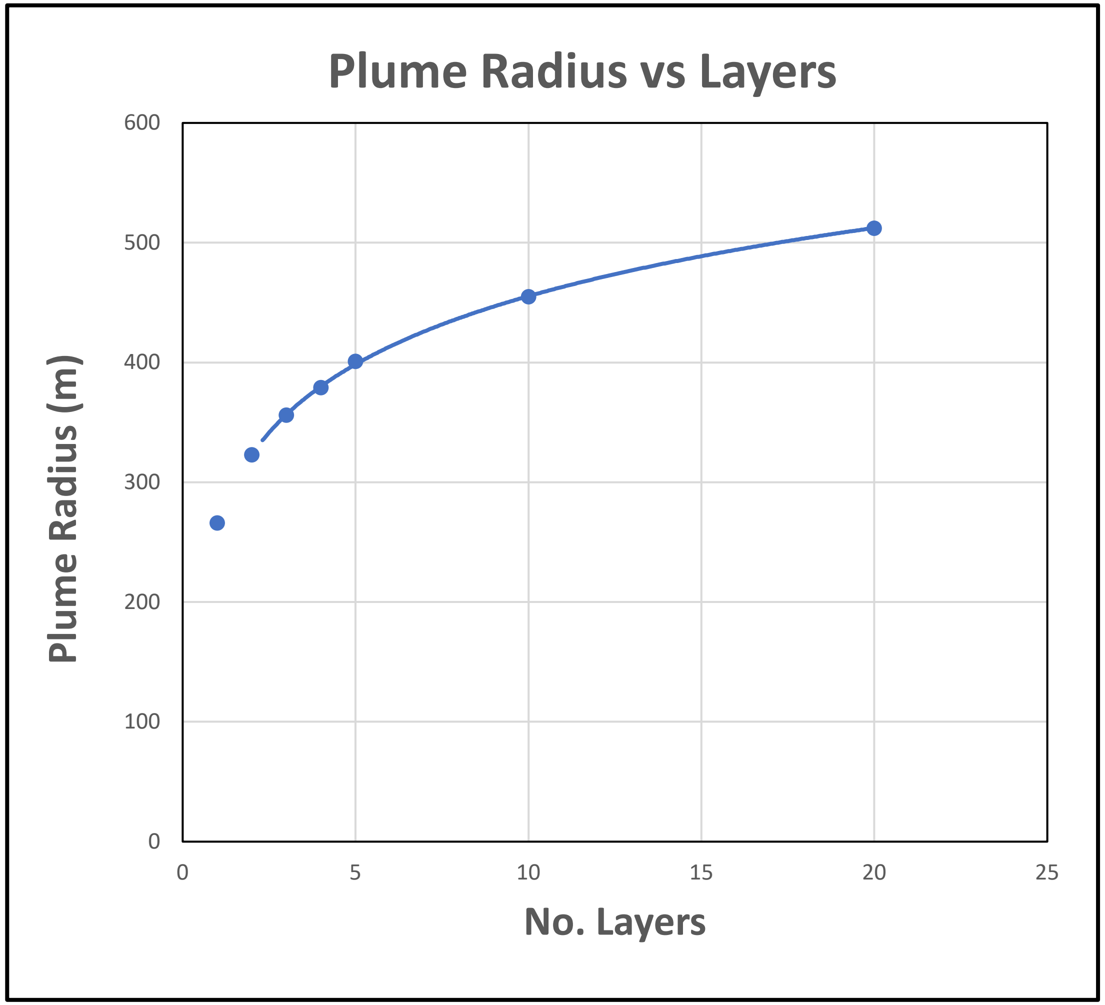
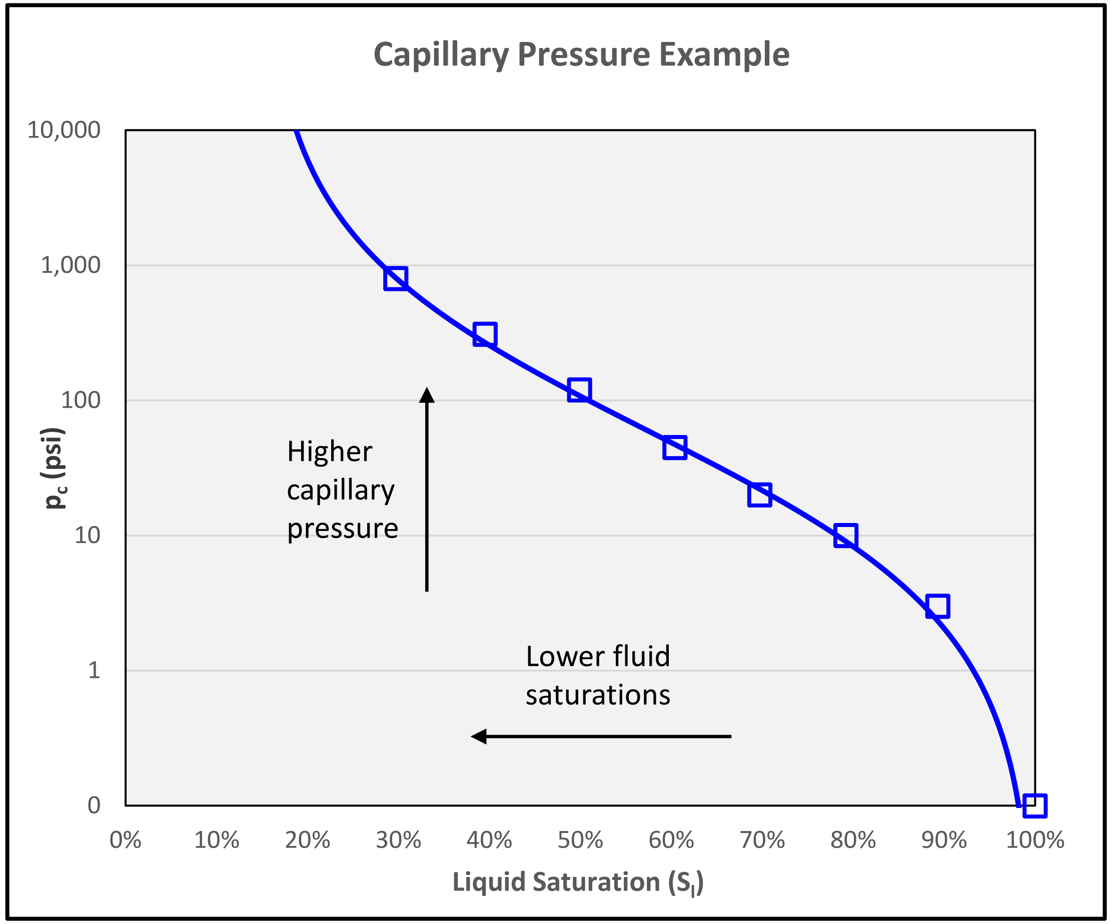
Layering Effects on Plume Extent





Capillary Pressure



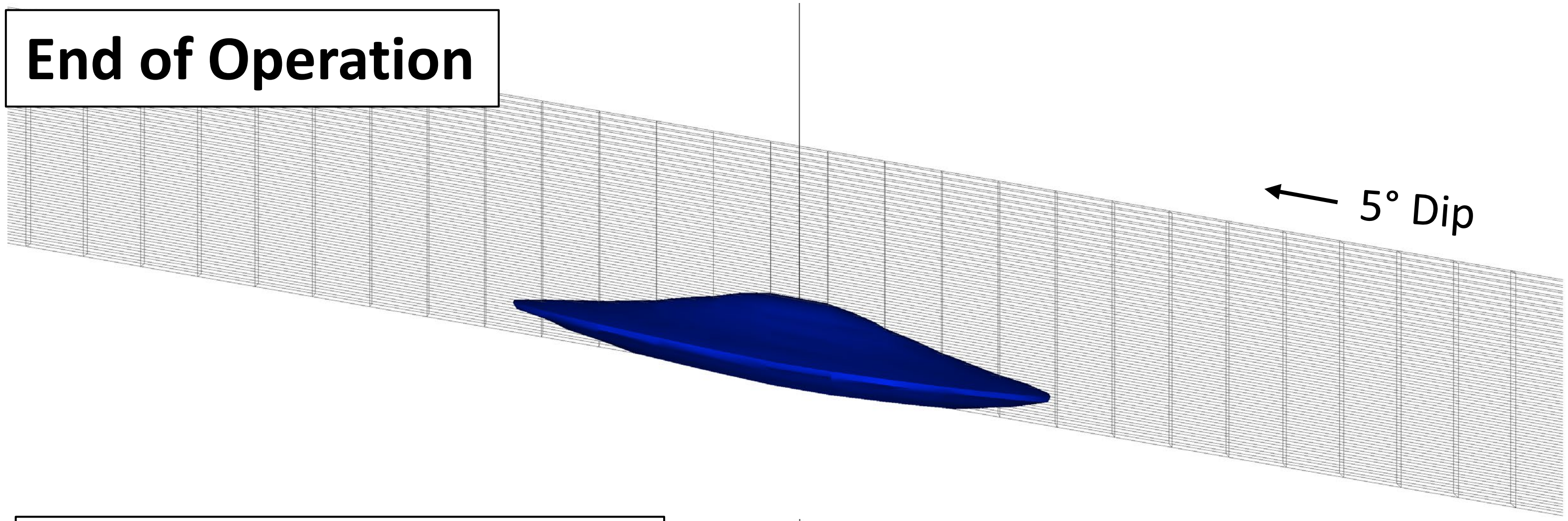
- Capillary pressure – pressure required to displace wetting phase (brine)
  - Function of interfacial tension, pore size and pore distribution
  - Defines relative permeability
  - Ultimately increases pressure, lowers injectivity and constrains plume drift

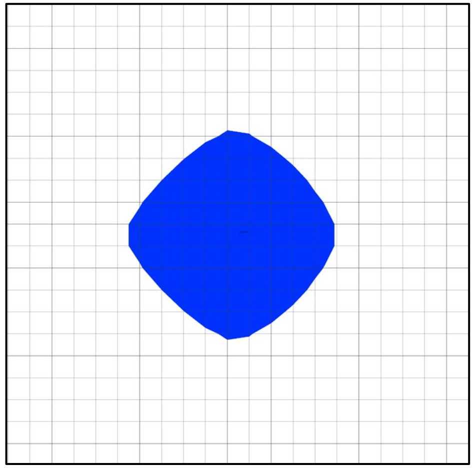
Post-Operational Drift

- CO_2 will migrate to the top of the injection interval and also migrates up-dip
- Drift behavior influenced by several variables:
  - Formation structure
  - Local boundaries
  - Final pressure distribution
  - Vertical permeability
  - Capillary pressure
- Plume stabilization ultimately occurs when buoyancy and capillary pressure reach equilibrium

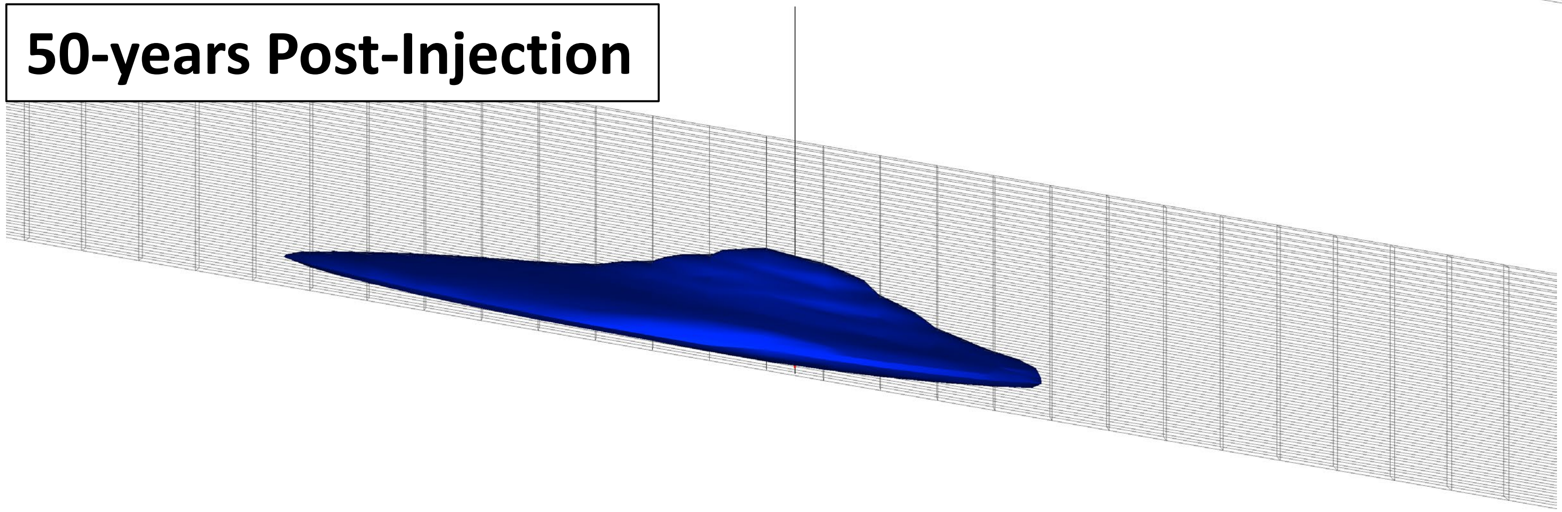
Cartesian Results – No Capillary Pressure

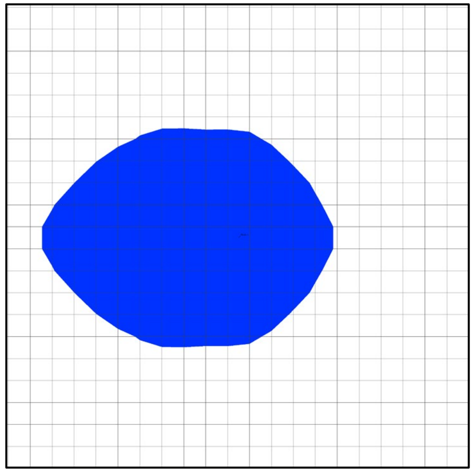
End of Operation



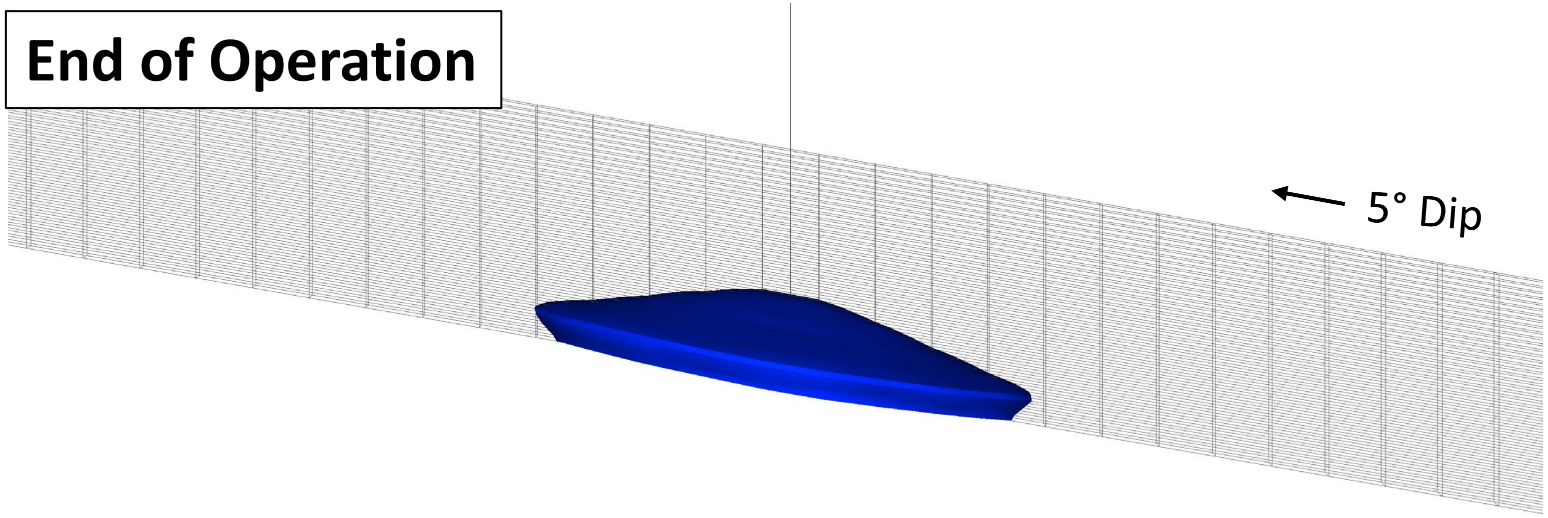


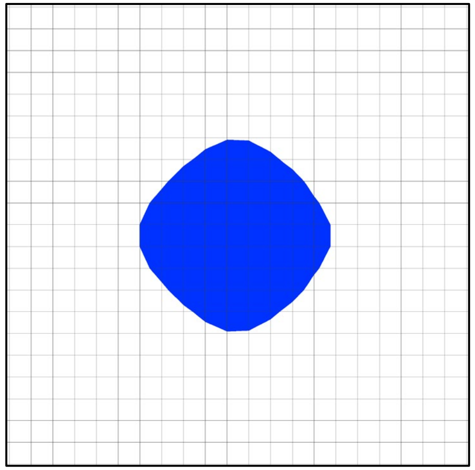
50-years Post-Injection

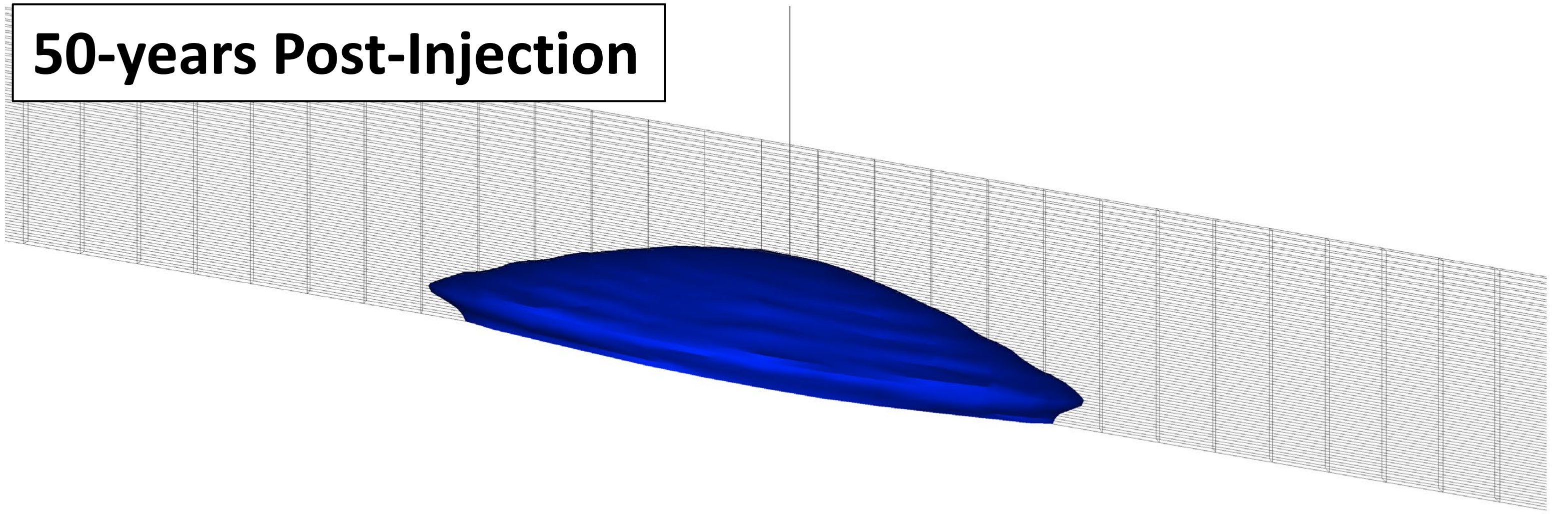


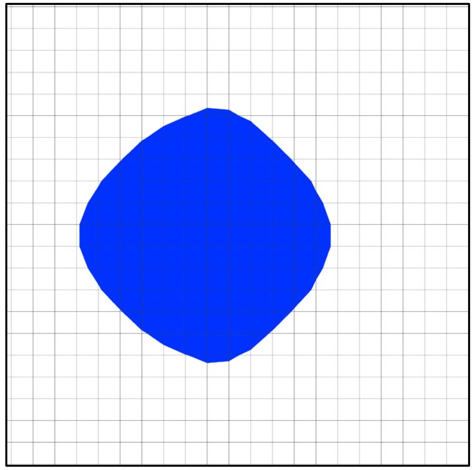


Cartesian Results – Capillary Pressure









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Defining Injection Capacity

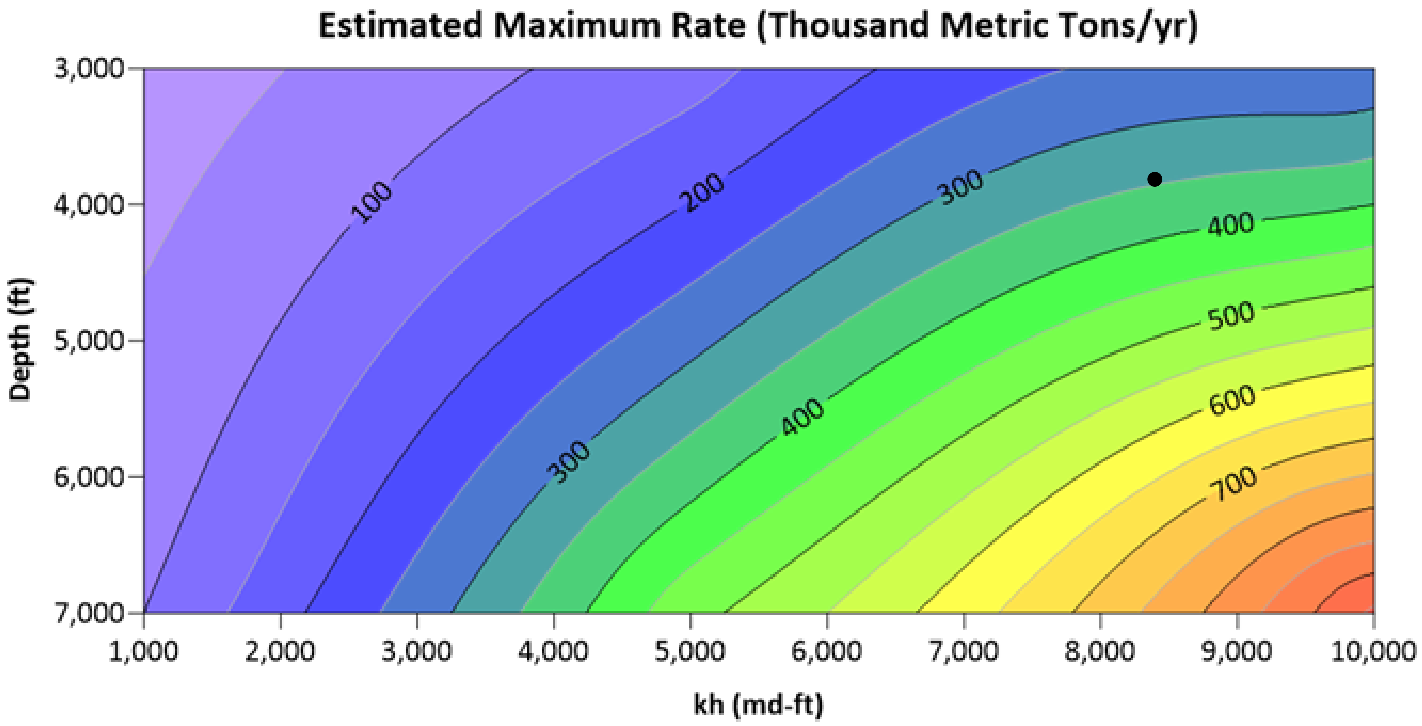
- ‘Pore space’ is often cited in CCS capacity discussion
  - Function of porosity only
- Capacity is better defined as the maximum volume that can be injected while remaining below fracture pressure
  - Function of permeability-thickness, fracture pressure and depth
  - Additional depth allows for a larger delta-p window between initial and maximum pressures

Defining Injection Capacity

- Depth of 5,000 ft:
  - Initial pressure = 0.433 psi/ft = 2,165 psi
  - Max Pressure = 90% of 0.6 psi/ft frac gradient = 2,700 psi
  - Max Δp = 535 psi
- Depth of 10,000 ft:
  - Initial pressure = 0.433 psi/ft = 4,330 psi
  - Max Pressure = 90% of 0.6 psi/ft frac gradient = 5,400 psi
  - Max Δp = 1,070 psi
- Pressure and temperature (vs. depth) factor into CO_2 properties but are less important

Feasibility Screening

- **Maximum injection rate (and ultimate storage capacity) can be screened using general site assumptions**



- Assumptions:
  - 20 year injection
  - Normally pressured reservoir
  - T = 60 + 0.015 deg/ft
  - Φ = 10%

- Constraints:
  - Fracture pressure = 0.60 psi/ft
  - Final pressure = 90% of frac pressure

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Questions and Discussion

Lewis Wandke
PETROTEK CORPORATION
5935 S. Zang Street, Suite 200
Littleton, CO 80127
lwandke@petrotek.com

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