Reservoir Engineering Aspects of Geologic Storage of CO_2

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www.sequestration.org

TM

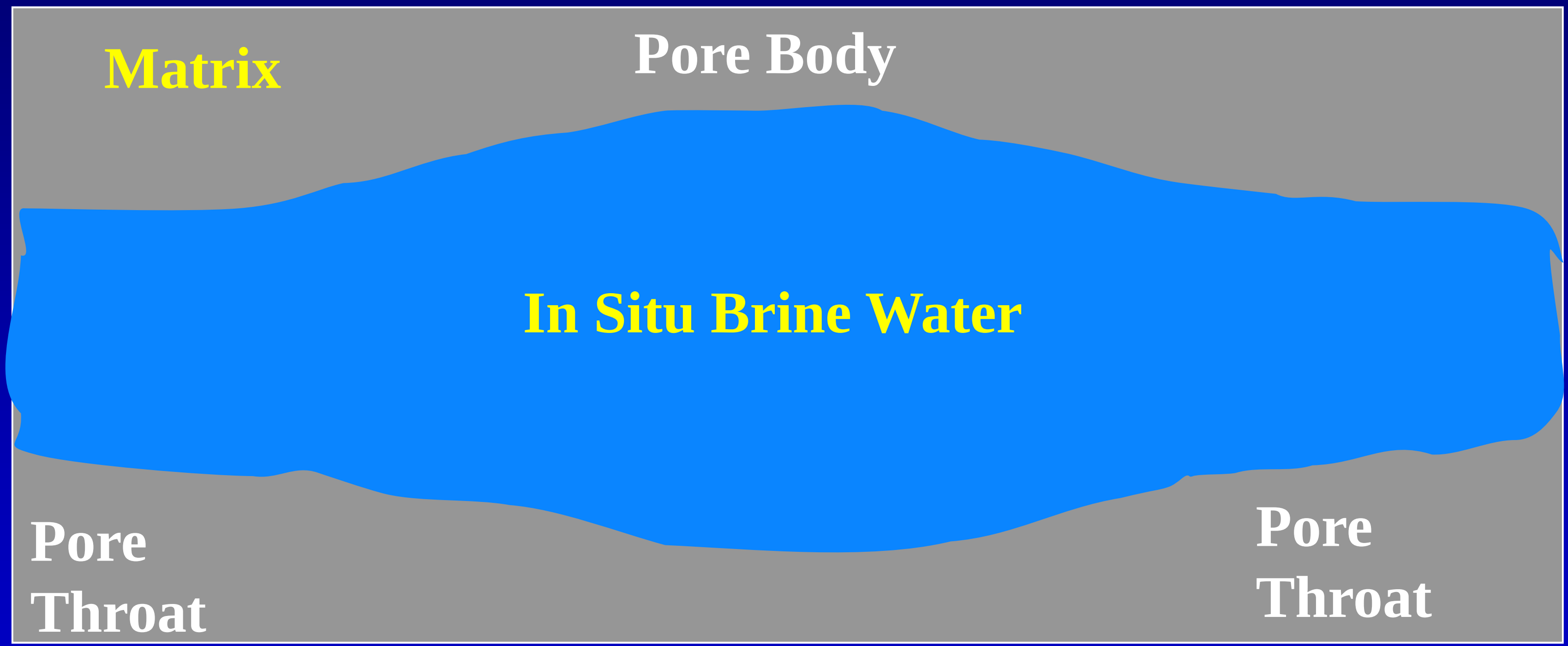
What is Geologic Storage?

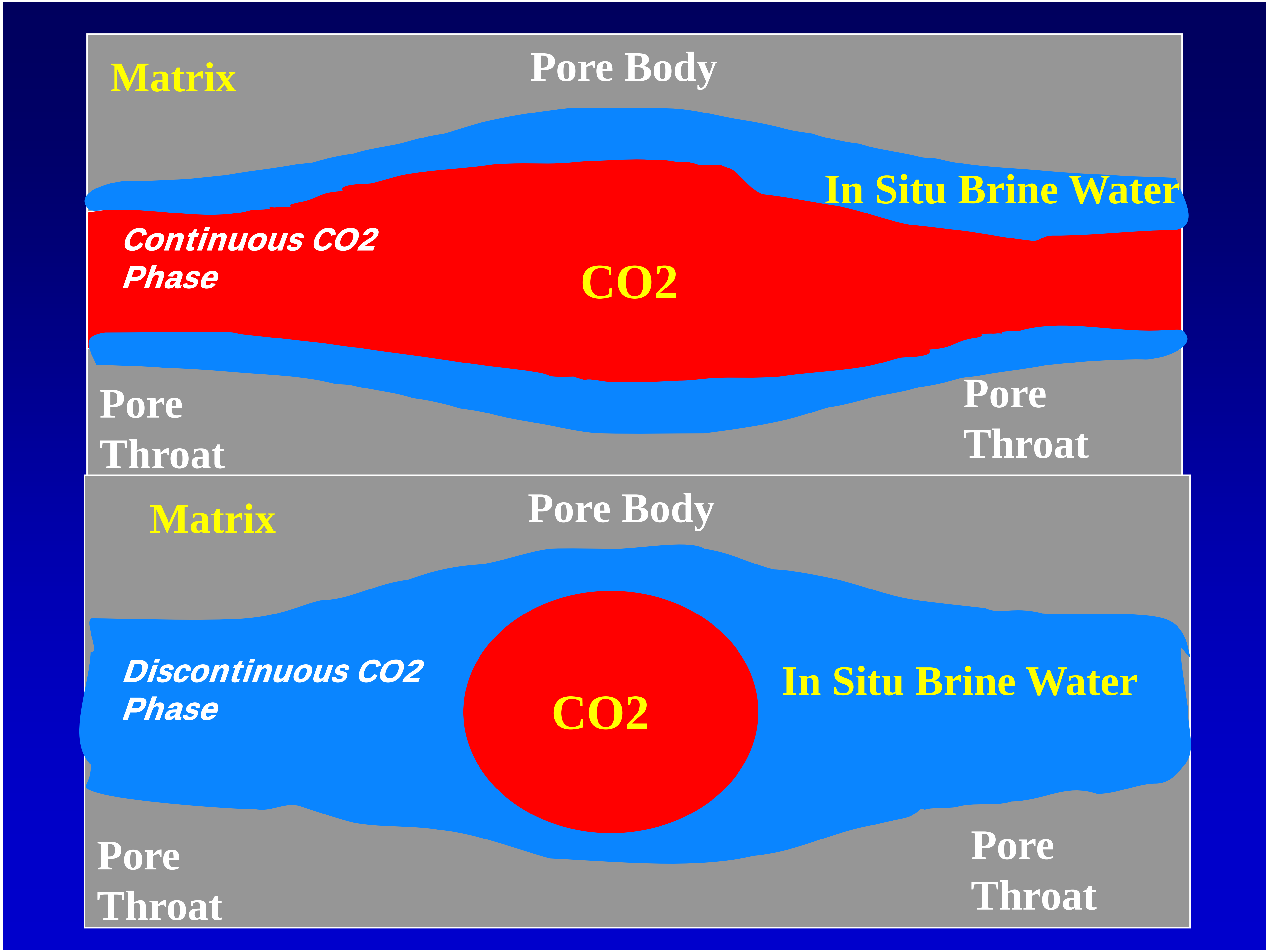
- Injection of any fluid into a porous and permeable formation for short or long term storage
- Types
  - Industrial waste (generally water based)
  - Natural gas
  - CO_2

CO_2 Storage Mechanisms

- Free phase CO_2
  - mobile
  - immobile (capillary trapping)
- Dissolution (solubility in brine)
- Mineral precipitation
- Enhancement by geologic structures

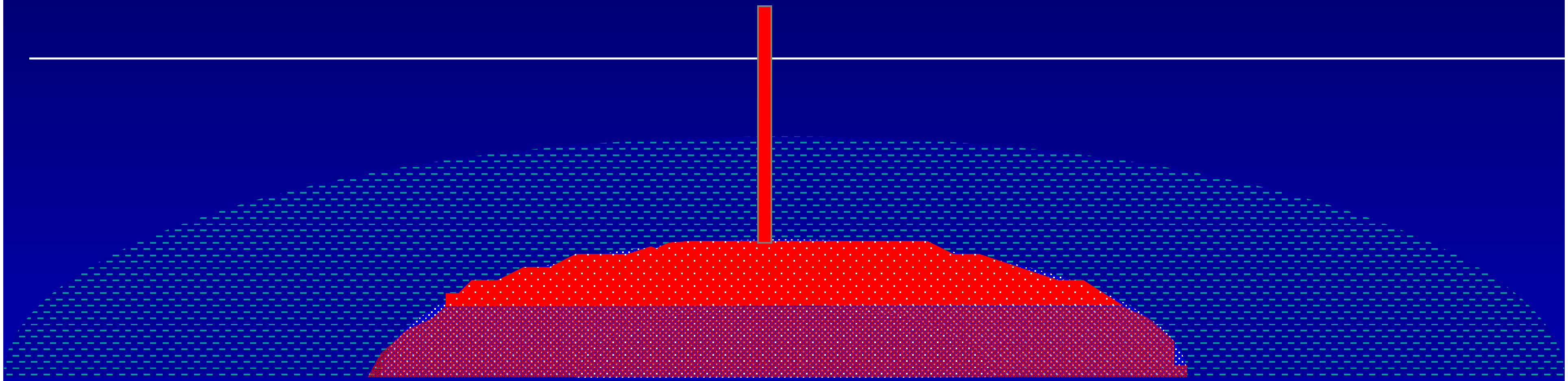
Storage Mechanisms: Pores' Throats and Bodies





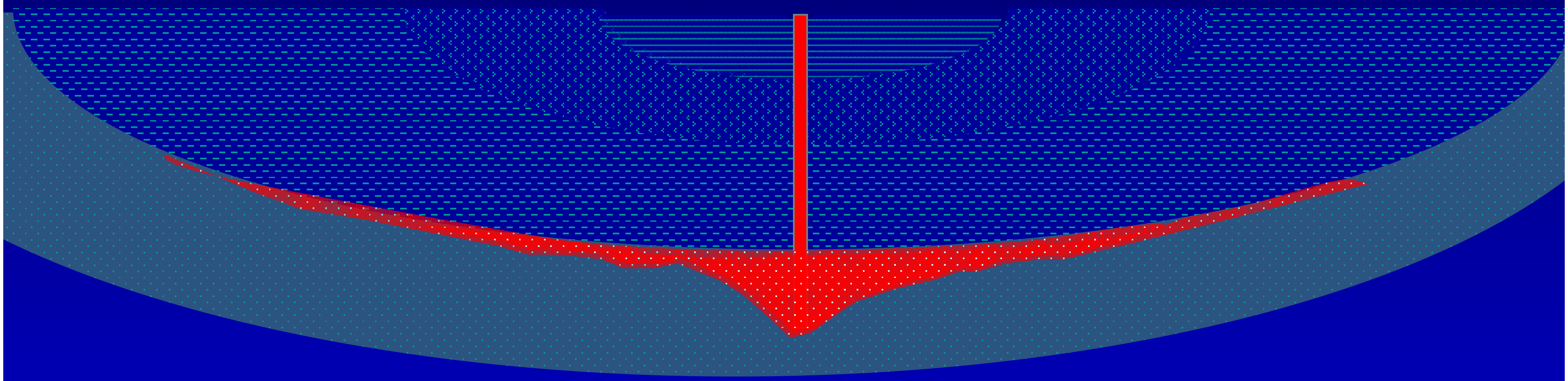
Matrix
Pore Body
In Situ Brine Water
Continuous CO2 Phase
CO2
Pore Throat
Pore Throat
Matrix
Pore Body
Discontinuous CO2 Phase
CO2
In Situ Brine Water
Pore Throat
Pore Throat

Storage Mechanisms: Geologic Structure



- **CO_2 less dense than saline water in saline formation**
- **CO_2 “pool” forms at the top of subsurface geologic structure, that dissolves in water with time.**

Storage Mechanisms: No Geologic Structure



- No CO_2 "pool" forms at the top of subsurface geologic structure
- CO_2 continues to migrate until a geologic trap is reached, CO_2 is capillarily trapped or dissolves in water.

Site Screening and Site Selection

- Site Screening
  - High level cursory assessment of multiple sites leading to hierarchy of better sites or areas
- Site Selection
  - Specific and detailed study of single sites leading to a choice of a specific site
- Similar attributes are studied, but without differing degrees of certainty in the data

Regulatory Issues

Consideration

- Protection of underground sources of drinking water (USDW)
- CO_2 migration vertically and horizontally

Design

- Wellbore integrity
- Breach geologic containment
  - Fracture propagation pressure
  - Capillary entry pressure
- Geologic heterogeneity

Operational Issues

Consideration

- Available CO2 storage volume
- Daily injection rate and pressure
- CO_2 migration vertically and horizontally
- Pore space ownership

Design

- Thickness, area, porosity
- Injection zone
  - Thickness and permeability
  - Depth and pore pressure
  - Fracture pressure
- Caprock
  - Capillary entry pressure
  - Fracture propagation pressure
- Geologic heterogeneity

The Ideal CO_2 Storage Site

- Injection zone:
  - High horizontal permeability and porosity
  - High fracture propagation pressure
  - Low vertical permeability
- Caprock (vertical seal):
  - Thick, non-reactive composition
  - High capillary entry pressure and fracture propagation pressure
- Both areally extensive

Design Criteria

- Reservoir Characterization
- Reservoir Pressure and Temperature
- Injection Rates and Injection Pressure
- Perforated Interval

Reservoir Characterization

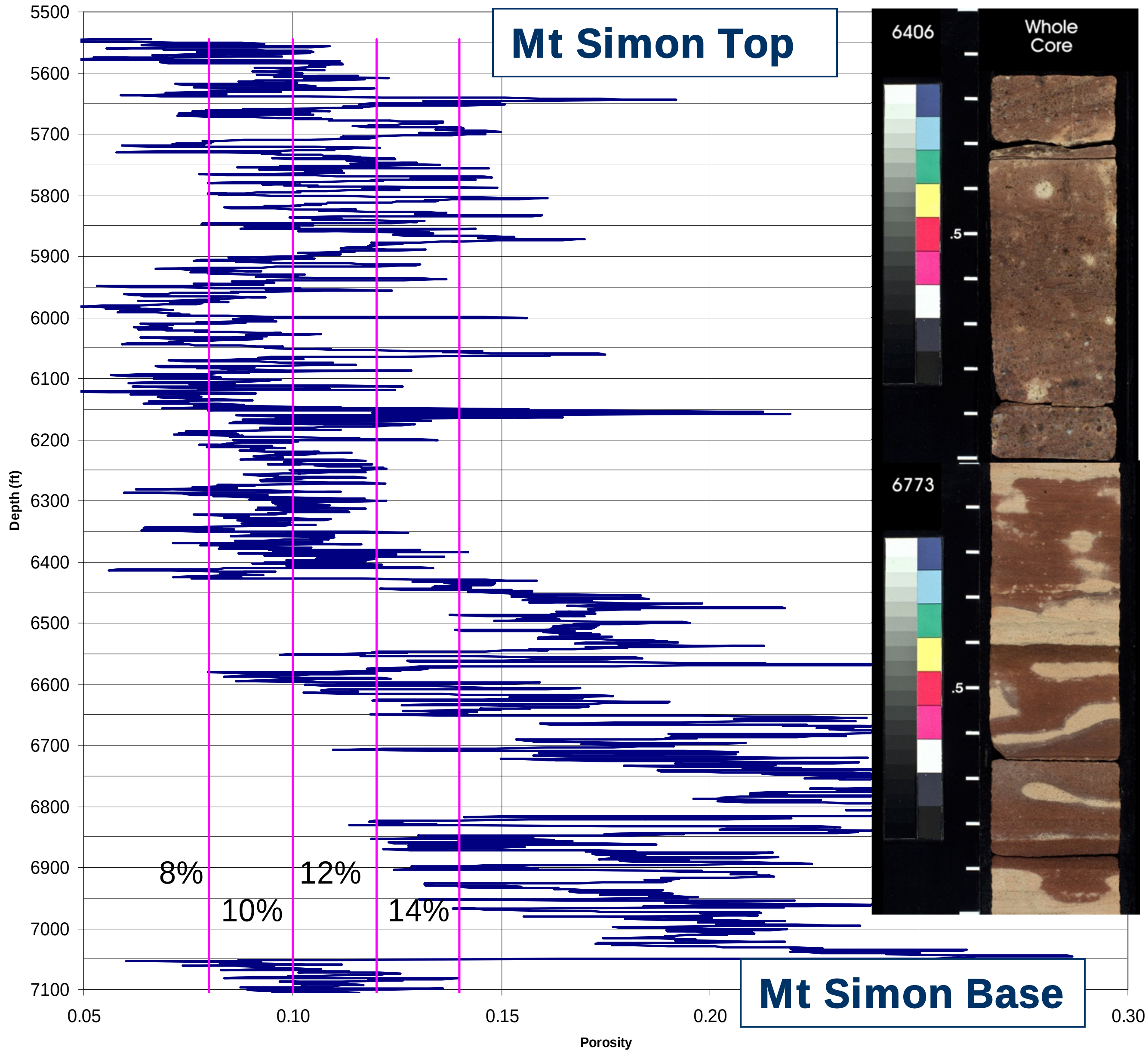
- Porosity: effective and total
- Thickness: net and gross
- Permeability:
    - absolute and relative
    - Horizontal and vertical

Porosity and Permeability

- Importance of Petrography
- Thin Section indicated micro-fractures
  - Investigating: in situ vs. post coring development of micro-fractures

Depth, ft MD	6763	7045
ϕ, %	28.5	28.6
k, md	43.2	1440

Gross and Net Thickness



Porosity Cutoffs

Neutron-Density Porosity

Net and Gross Thickness

	Porosity Cutoff, %			
Depth	**8**	**10**	**12**	**14**
5545-7050	*1322*	*1009*	*744*	*569*
h_{net}/h_{tot}	0.878	0.670	0.494	0.378
5545-5900	310	229	105	34
5900-6150	145	51	23	9
6150-6430	249	120	33	10
6430-6650	220	211	188	152
6650-6820	170	170	168	166
6820-7050	230	230	228	200

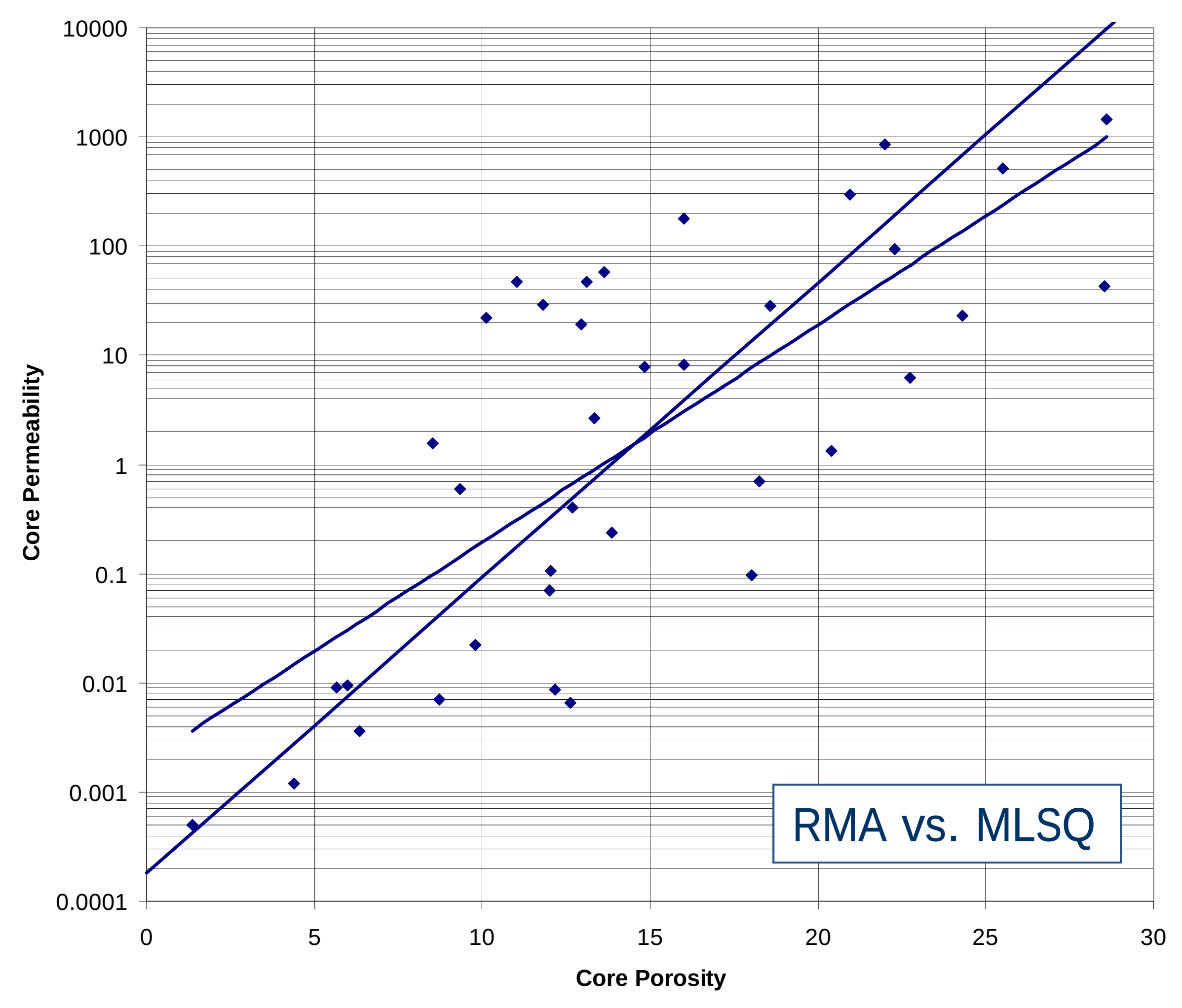
Horizontal and Vertical Permeability

- Horizontal Averaging
  - Arithmetic average: general, linear, parallel flow
  - Geometric average: injection well-radial flow
- Vertical Averaging
  - Harmonic average-general, series flow

Predicting Permeability from Porosity

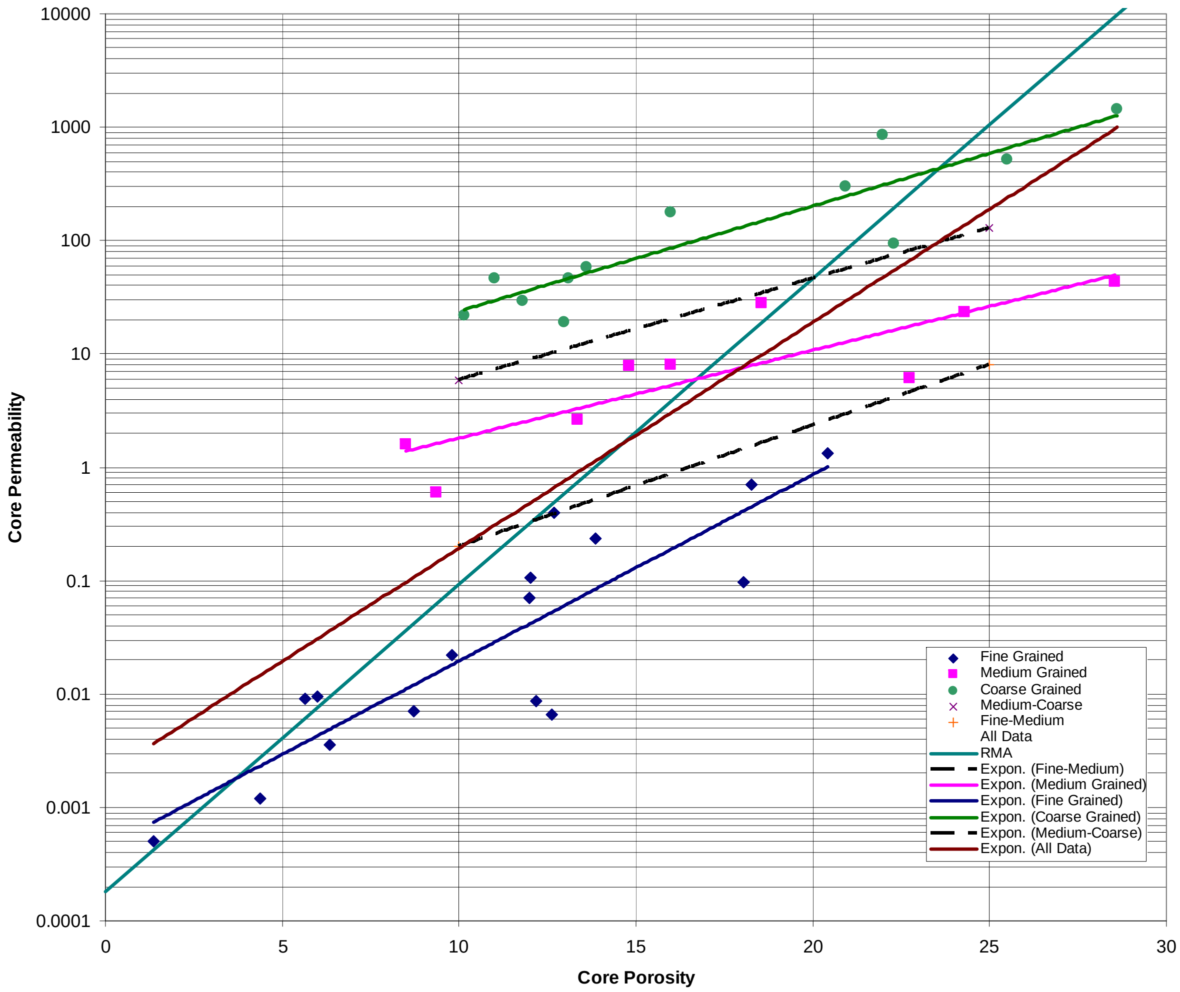
- Core Analyses: permeability-porosity
- Log Analyses-Correlations w/ Porosity Logs
  - Nuclear Magnetic Resonance
  - Neutron-Density
  - Sonic

Absolute Permeability-Core Data



- Depth Shift: core to log
- Transform core porosity to core permeability
- Conventional semilog plot not good predictor of perm

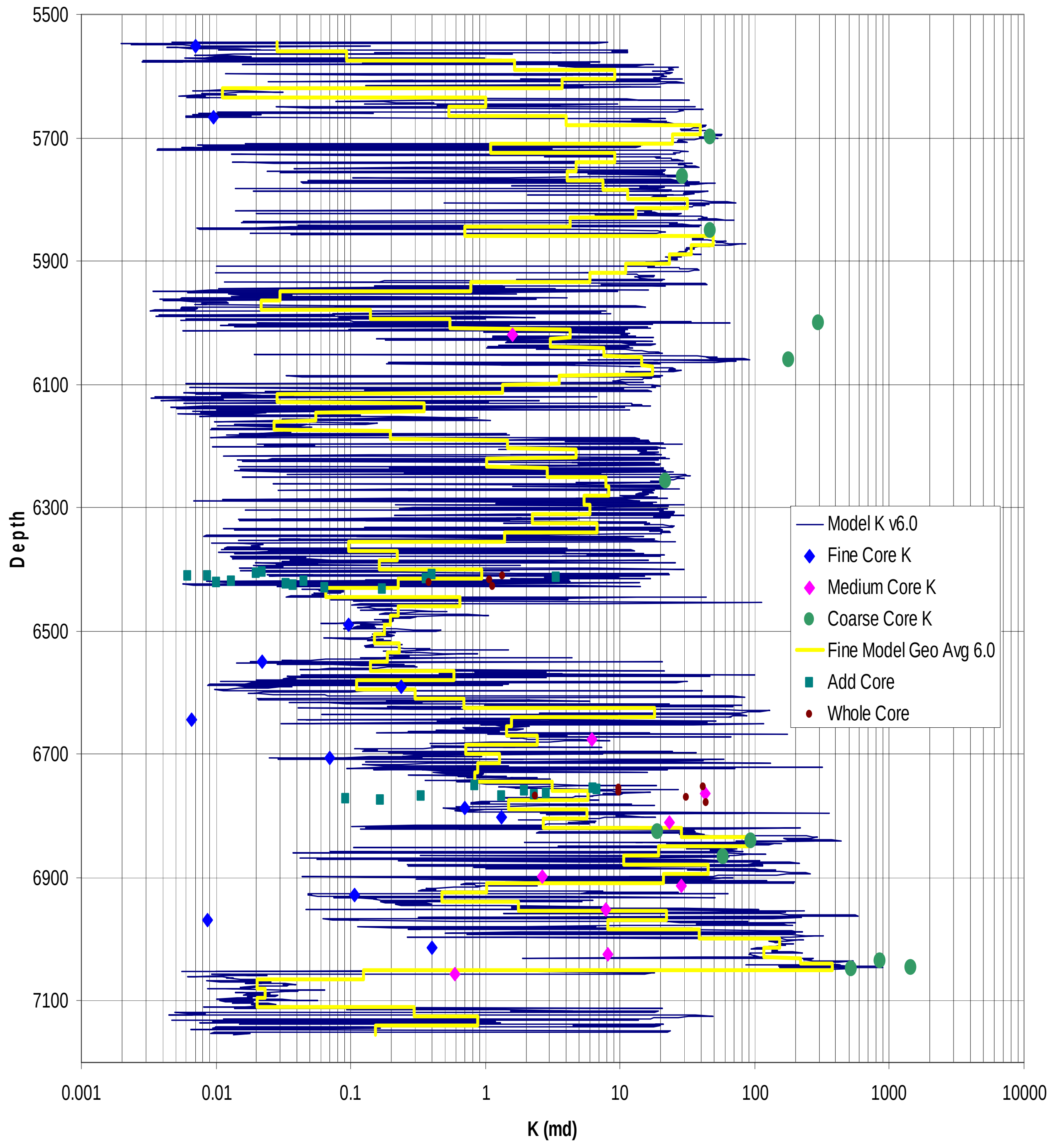
Absolute Permeability- ϕ-k Transform Based on Grain Size



- Sub-divide data by grain size
- Better representation of the core data
- How to pick transform based on log response?

Geologic Model: Absolute Permeability

15 ft model



Vertical Permeability and Scale

Core*	k_h	K_{varth} 1.5”	K_{vhar} 30’	K_v/k_h 1.5”	K_v/k_h 30’
6404 - 6433	0.33	0.031	0.011	1.0	0.033
6751 - 6779	2.3	0.94	0.30	0.55	0.013
All	1.2	0.43	0.019	0.76	0.016

*Does not include 10 ft of whole used for whole core analyses

Injection Rates and Pressure

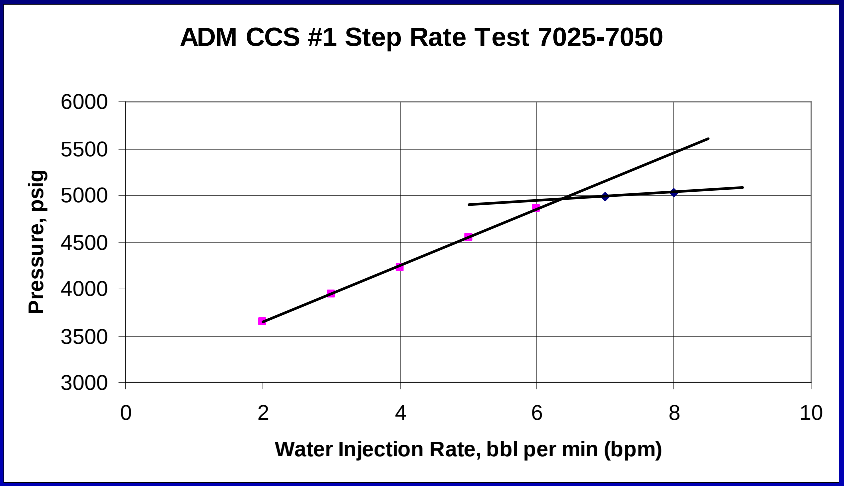
- Fracture Pressure
  - Seal
  - Reservoir
- Capillary Entry Pressure
  - Seal

Fracture Pressure-Reservoir

- Mechanical tests of core sample
- Mini-frac tests-wireline
  - Small volume pump test, maximum rate restricted.
  - Too high perm, too low pressure increase, not fracture
- Injection step rate test
  - After completion (casing and perforation)

Fracture Pressure-Reservoir: Step Rate Test

- Water injection at various stabilized and increasing rates
- Pre-fracture pressure buildup greater than post-fracture buildup
- Depth correction
  - Brine density
  - Gauge and perf locations



- Fracture does not propagate or grow to the size of stimulation-type fracture.

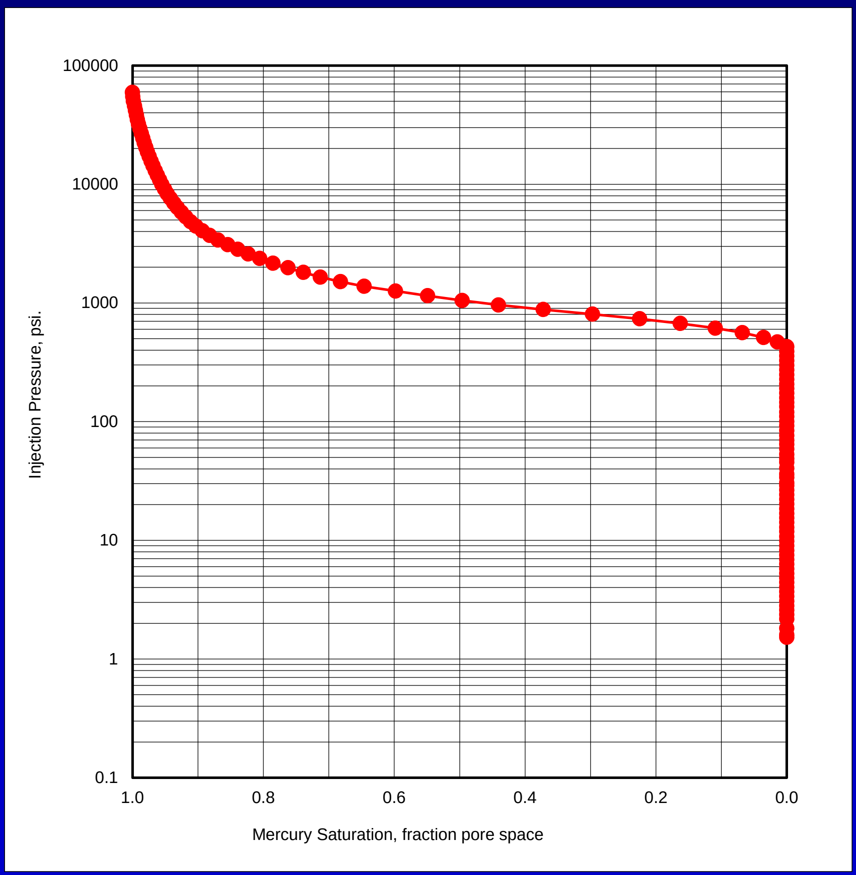
Fracture Pressure-Seal

- Mechanical tests of core sample
- Mini-frac tests-wireline
  - Likely successful, on lower perm seals, but must find something that is non-shale
  - Non-shale likely less representative of the entire seal
  - Tool’s probe contact small, thin beds

Capillary Entry Pressure-Seal

- Laboratory tests
  - Mercury injection, high pressure
  - Porous plate, low pressure with reservoir fluids
- Seal/reservoir interface
  - Compare capillary entry pressure to pore pressure *increase* due to injection immediately below seal

Capillary Entry Pressure-Seal



- Entry pressure: minimum pressure required to reduce wetting phase saturation below 100%
- Convert from Hg pressure to brine-CO_2

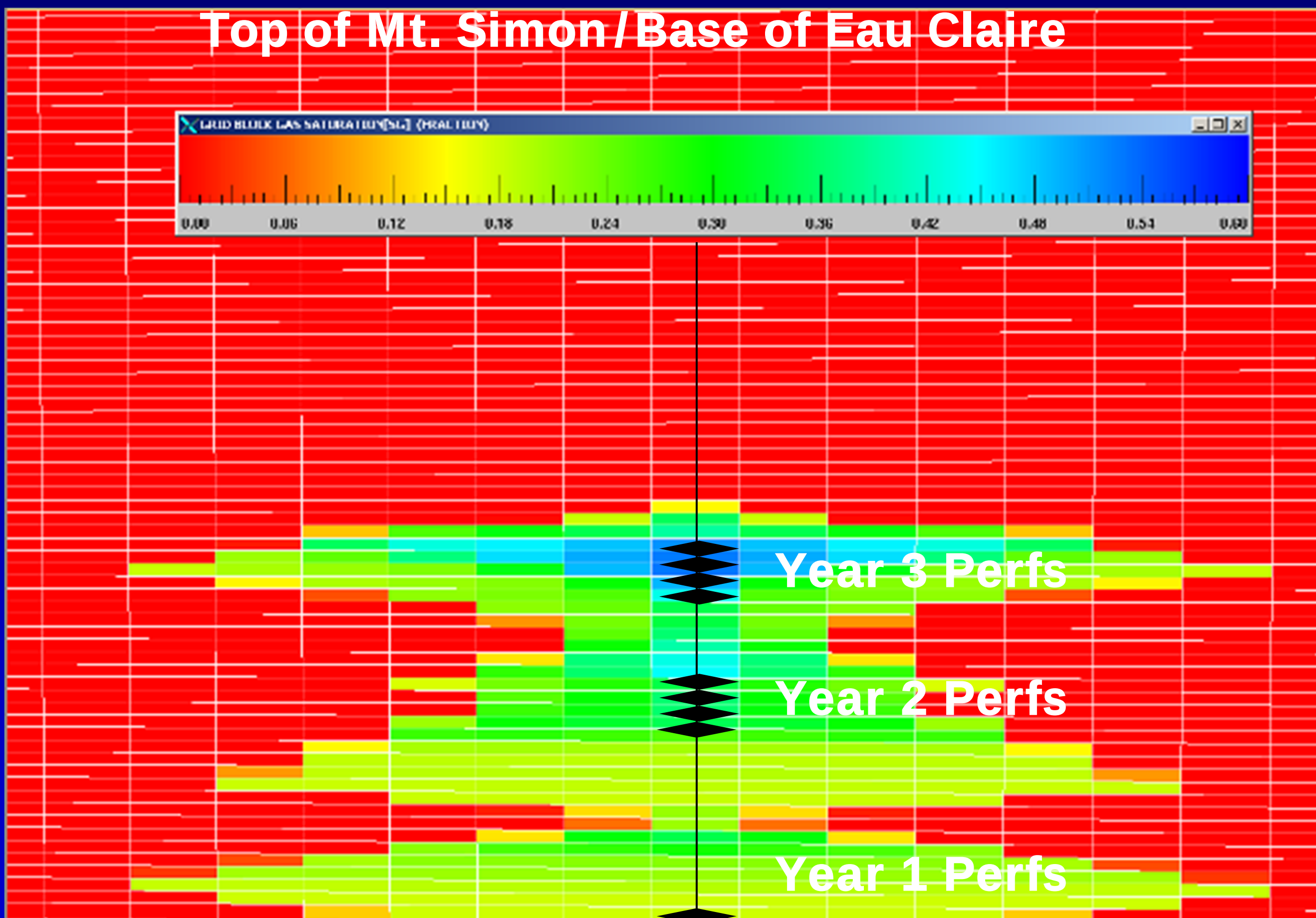
Injection Zone Pressure and Temperature

- Density of CO_2
  - Storage capacity
  - Hydrostatic pressure of CO_2 in injection tubing
- Injection Pressure
  - surface injection pressure
    - Pipeline delivery pressure
    - Compressor design
    - Wellhead and wellbore tubular design

Perforated Interval

- Storage efficiency
- Caprock interaction
- Near-wellbore flow restrictions

Operating Criteria: CO_2 Plume (4D) Distribution, contd.



Perforation Strategy:

Perforate bottom to top in annual increments

Cell size: 220 x 220 x 15 ft

Conclusions

- Many design elements are geologic based
- Caprock integrity necessary for vertical containment
- Wellbore integrity necessary for out-of-zone releases

Conclusions, contd.

- CO_2-brine relative permeability challenges
- Seal/Caprock characterization importance
- Distribution of free-phase CO_2 and incremental pressure increase

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