Migration Rates and Formation Injectivity to Determine Containment Time Scales of Sequestered Carbon Dioxide

By Lauri A. Burke

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Conversion Factors

SI to Inch/Pound

Multiply	By	To obtain
	Length	
centimeter (cm)	0.3937	inch (in.)
meter (m)	3.281	foot (ft)
kilometer (km)	0.6214	mile (mi)
	Area	
square centimeter (cm^2)	0.1550	square inch (in^2)
	Volume	
cubic meter (m^3)	6.290	barrel (petroleum, 1 barrel = 42 gal)
	Mass	
kilogram (kg)	2.205	pound avoirdupois (lb)
	Pressure	
kilopascal (kPa)	0.1450	pound per square inch (lb/in^2)
	Density	
kilogram per cubic meter (kg/m^3)	0.06242	pound per cubic foot (lb/ft^3)
kilogram per cubic meter (kg/m^3)	0.008345	pounds per gallon (ppg)
kilogram per cubic meter (kg/m^3)	0.000434	pounds per square inch per foot (psi/ft)
	Permeability	
square meter (m^2)	1.01325×10^{12}	darcy (D)
darcy (D)	9.869233×10^{-13}	square meter (m^2)

Temperature in degrees Celsius (°C) may be converted to degrees Fahrenheit (°F) as follows:

°F=(1.8×°C)+32.

Temperature in degrees Fahrenheit (°F) may be converted to degrees Celsius (°C) as follows:

°C=(°F-32)/1.8.

Table of Symbols

A	Cross-sectional area
D	Depth
F_D	Fracture gradient at depth
H_D	Hydrostatic gradient at depth
K	Bulk modulus
k	Matrix permeability
L	Lateral distance
P	Pressure
Q	Darcy fluid-flow rate
v	Interstitial pore velocity
V_p	Velocity of compressional-waves in the formation
α	Hydraulic diffusivity
β	Bulk compressibility of the formation
β_f	Fluid compressibility
Δ	Gradient differential
ΔP	Maximum pressure differential
η	Fluid viscosity
ϕ	Fractional porosity
μ	Shear modulus
ρ	Density
τ	Time scale

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U.S. Geological Survey

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Overview

- Abstract and Introduction
- Methodology
- Fluid Flow Modeling
  - Hydraulic Diffusivity
  - Darcy's Law of Fluid Flow
- Permeability Classifications
- Formation Injectivity
- Maximum Pressure Differential
- Conclusions

Abstract

Supercritical carbon dioxide exhibits highly variable behavior over a range of reservoir pressure and temperature conditions. Because geologic sequestration of supercritical carbon dioxide is targeted for subsurface injection and containment at depths ranging from approximately 3,000 to 13,000 feet, the investigation into the physical properties of this fluid can be restricted to the pressure and temperature conditions likely encountered in the sedimentary strata within this depth interval. A petrophysical based approach was developed to study the widest range of formation properties potentially encountered in sedimentary strata. Fractional porosities were varied from 5 to 95 percent, in 5-percent increments, and permeability values were varied over thirteen orders of magnitude, from 10.0 darcys down to 1.0 picodarcy.

Fluid-flow modeling incorporated two constitutive equations from fluid dynamics: hydraulic diffusivity for near-surface applications, and Darcy's Law for deeper formations exhibiting higher pressure gradients. Based on the flow modeling results, first-order approximations of carbon dioxide lateral migration rates were determined. These first-order approximations enable the establishment of a permeability classification system for dividing the subsurface into flow units that provide short, moderate, and long-term containment of carbon dioxide. These results enable a probabilistic determination of how fluids will enter and be contained in a subsurface storage formation, which is a vital step in the calculation of the carbon dioxide storage capacity of a reservoir.

Additionally, this research establishes a methodology to calculate the injectivity of a target formation. Because injectivity describes the pressure increase due to the introduction of fluids into a formation, the relevant application of injectivity is to determine the pressure increase, due to an injection volume and flow rate, that will induce fractures in the reservoir rocks. This quantity is defined mathematically as the maximum pressure differential between the hydrostatic gradient and the fracture gradient of the target formation.

Injectivity is mathematically related to the maximum pressure differential of the formation, and can be used to determine the upper limit for the pressure increase that an injection target can withstand before fracturing.

Introduction

- This study quantifies first-order approximations for the time scales of carbon dioxide (CO_2) lateral migration through a 1.0-kilometer (km) representative volume of rock

- For characterization and classification of subsurface strata into subdivisions based on petrophysical criteria, and

- Incorporated into the U.S. Geological Survey assessment methodology for fully probabilistic determination of the storage capacity of geologic formations for CO_2 sequestration (Brennan, et al., 2010; Burruss et al., 2009)

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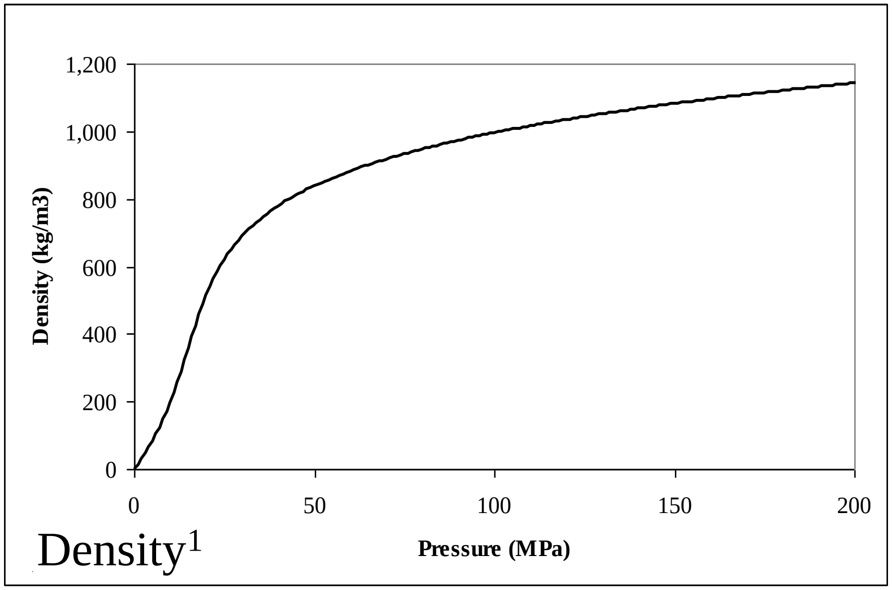
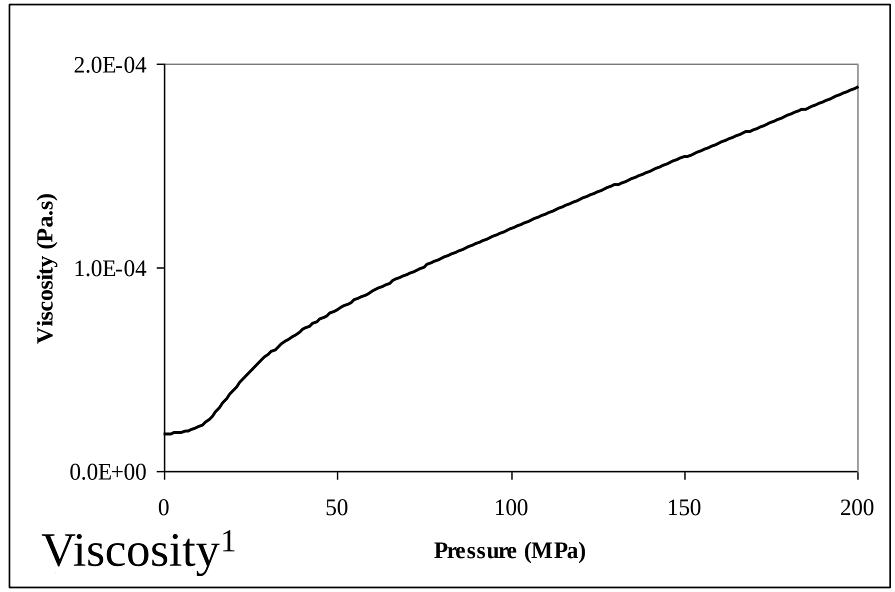
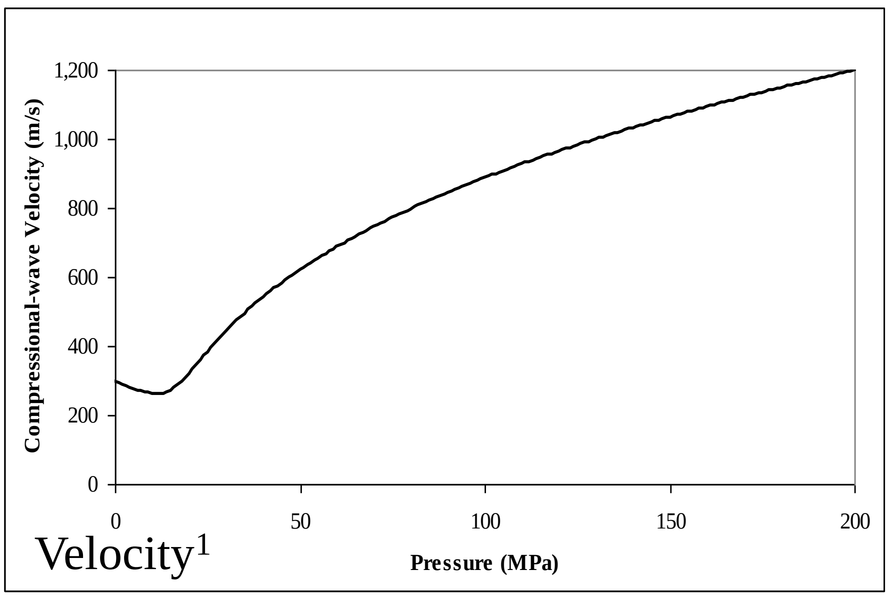
Thermophysical Properties of CO_2



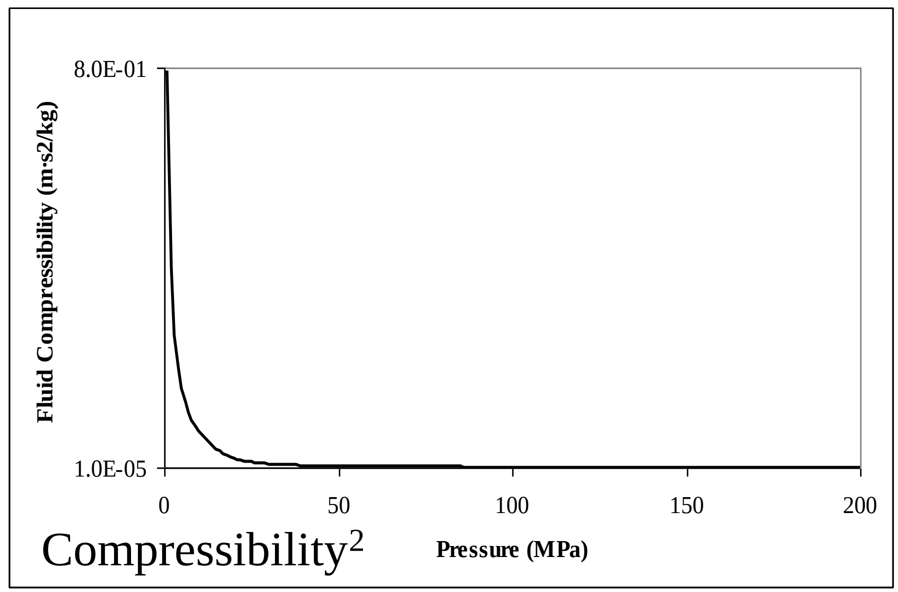
Density[1]



Viscosity[1]



Velocity[1]



Compressibility[2]

[1] Data from Lemmon and others, (2011) using Span and Wagner (1996) equations

[2] Calculated from $V_p=[(4/3\mu+K)/\rho]^{½}$

(Burke, 2011)

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Approach

- CO_2 sequestration is targeted for injection and subsurface containment at depths from approximately 3,000 to 13,000 ft

- Midpoint is 8,000 ft
  - Normally geopressured region with 100,000 parts per million total dissolved solids:
    0.465 psi/ft (Schlumberger, 2012)
  - Generalized geothermal gradient for shallow crustal rocks:
    1.65 °F/100ft (Sheriff, 1994)
  - Average surface temperature: 68 °F

- Pressure and temperature conditions of an "average" sedimentary formation at 8,000 ft: 25.5 MPa and 200 °F

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Fluid Flow Modeling

Hydraulic Diffusivity time scale, τ_{hd} , in years:

$$\tau_{hd} = \frac{L^2}{2\alpha} \qquad \text{where} \qquad \alpha = \frac{k}{\eta\left(\dfrac{\phi\beta}{1-\phi} + \phi\beta_f\right)}$$

Darcy's Law time scale, τ_D, in years:

$$\tau_D = \frac{\eta\phi L^2}{k\Delta P} \qquad \text{from} \qquad Q = \frac{kA}{\eta}\frac{\Delta P}{L} \qquad \text{and} \qquad v = \frac{k\Delta P}{\eta\phi L}$$

Flow Modeling Parameters

	Property	Variable	Value	Units
CO_2 Properties	Viscosity	η	5.00E-05	kg/m·s
	Fluid Density	ρ	628.06	kg/m^3
	Fluid Compressibility	β_f	1.66E-02	MPa^{-1}
	Compressional-wave Velocity	V_p	390.28	m/s
Rock Properties	Bulk Compressibility	β	3.10E-02	MPa^{-1}
	Lateral Distance	L	1.00	km
	Fractional Porosity	ϕ	varies	dimensionless
	Matrix Permeability	k	varies	D
	Darcy Pressure Differential	ΔP	25.5	MPa

Fluid Properties

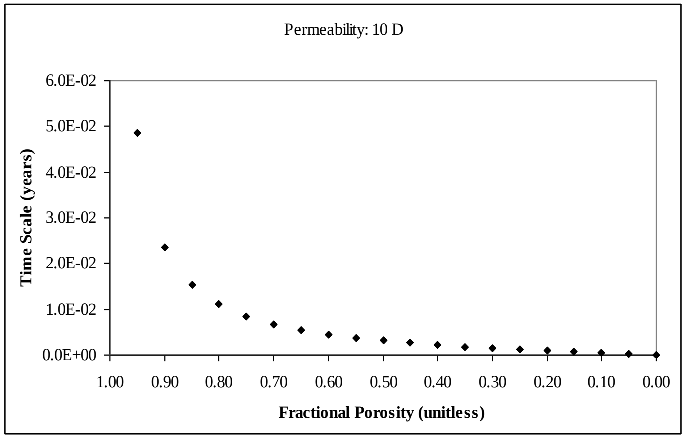
- At 25.5 MPa and 200 °F

Rock Properties

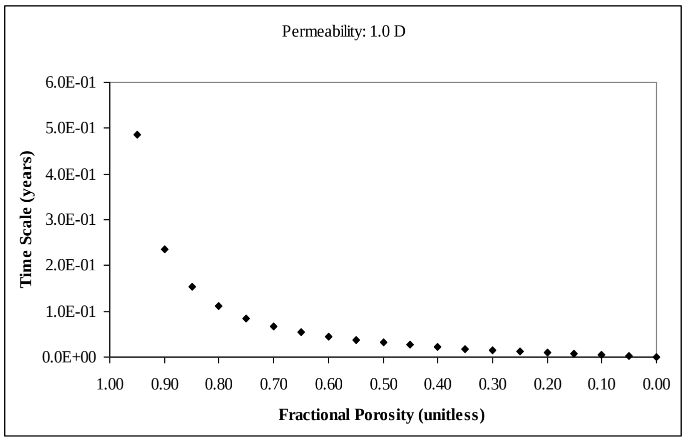
- Fractional porosity varies from 0.05 to 0.95
- Matrix permeability varies from 1.00E+01 to 1.00E-12 D

Hydraulic Diffusivity Results

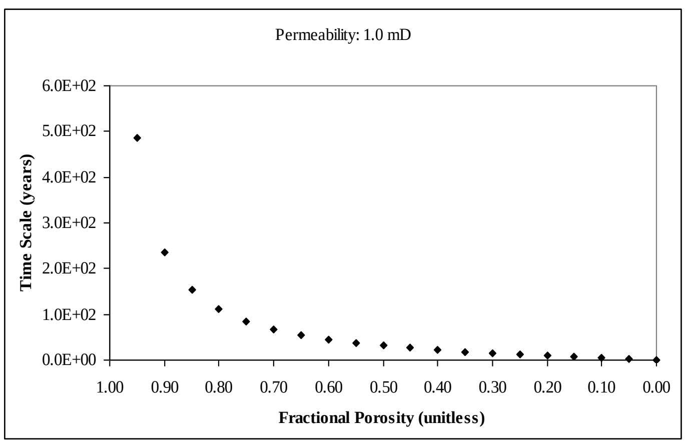
10.0 D



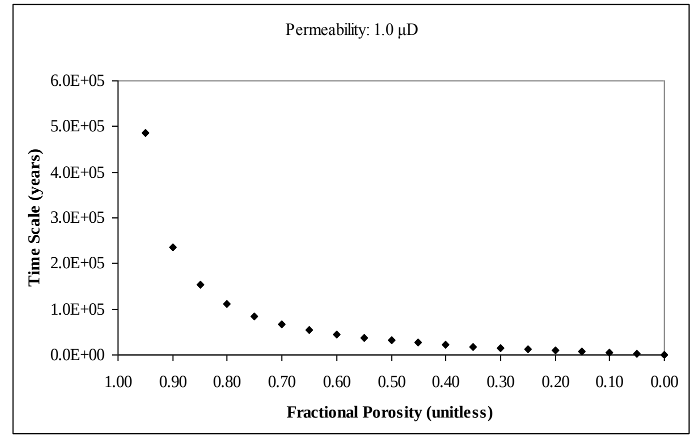
1.0 D



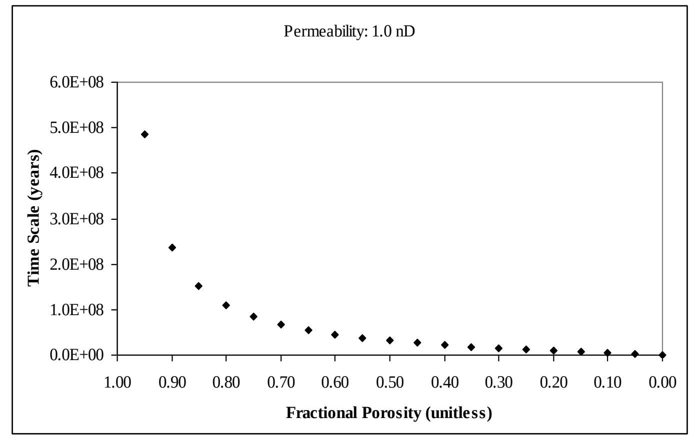
1.0 mD



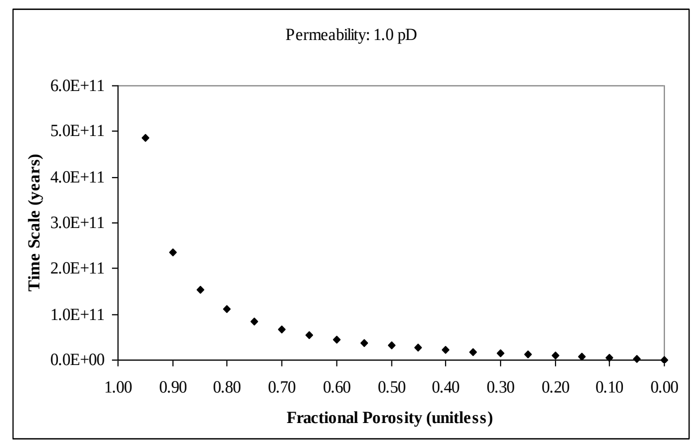
1.0 μD



1.0 nD



1.0 pD



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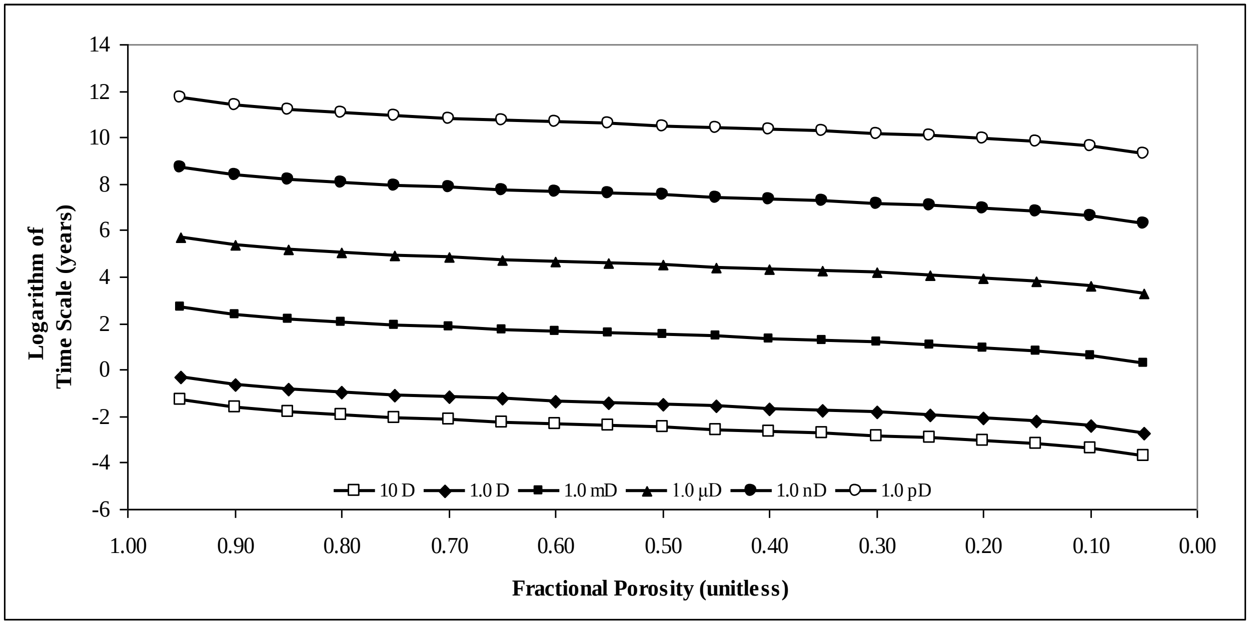
(Burke, 2011)

Hydraulic Diffusivity Results



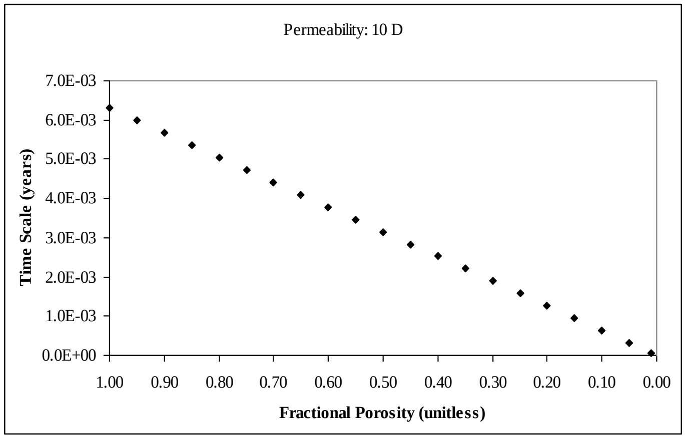
Permeability (Darcy)	Lower Bound (Years)	Average (Years)	Upper Bound (Years)
10.0 D	1.0E-3.70	1.0E-2.50	1.0E-1.63
1.0 D	1.0E-2.70	1.0E-1.50	1.0E-0.31
1.0 mD	1.0E+0.30	1.0E+1.50	1.0E+2.68
1.0 μD	1.0E+3.30	1.0E+4.50	1.0E+5.68
1.0 nD	1.0E+6.30	1.0E+7.50	1.0E+8.68
1.0 pD	1.0E+9.30	1.0E+10.50	1.0E+11.68

Several days to several weeks
Up to six months
Several hundred years, 500 years
Several thousand years
Hundreds of millions of years
Billions of years

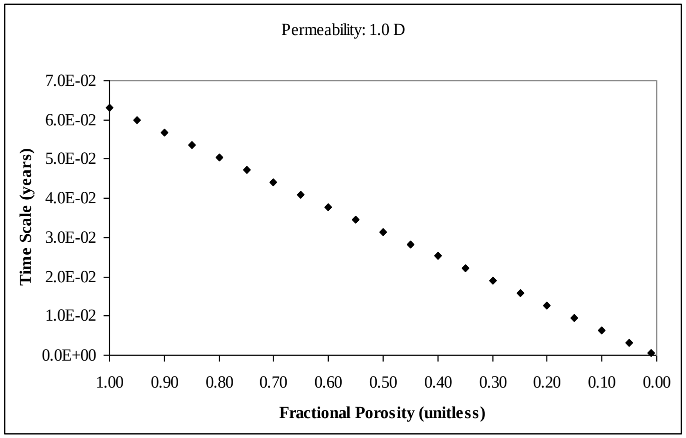
(Burke, 2011)

Darcy’s Law of Fluid Flow

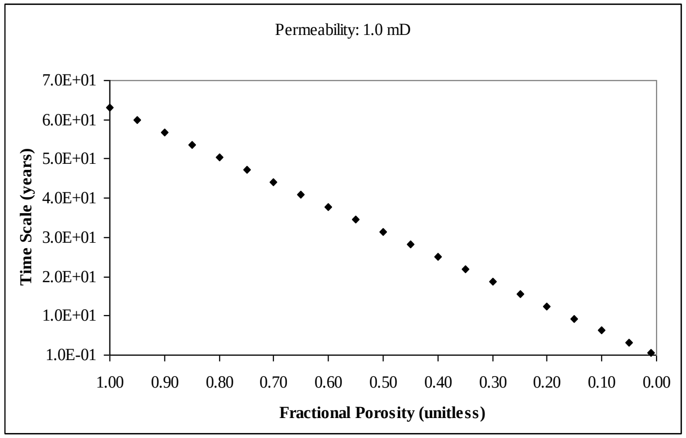
10.0 D



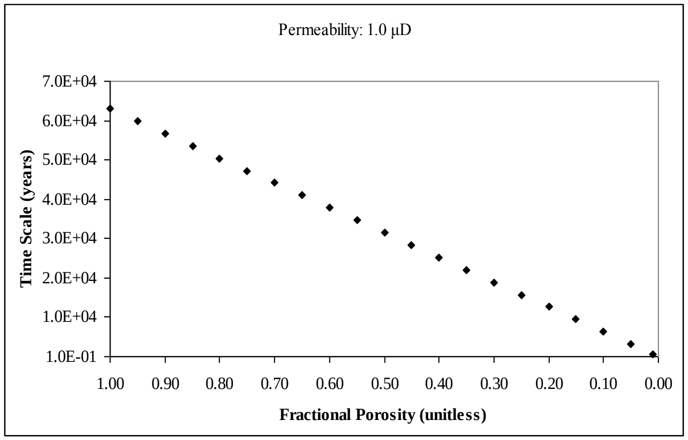
1.0 D



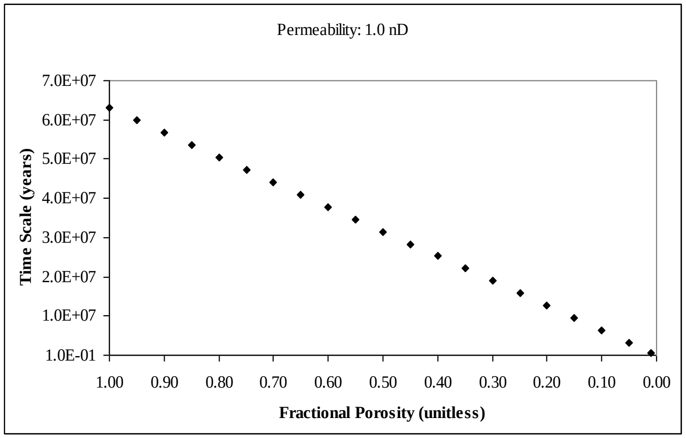
1.0 mD



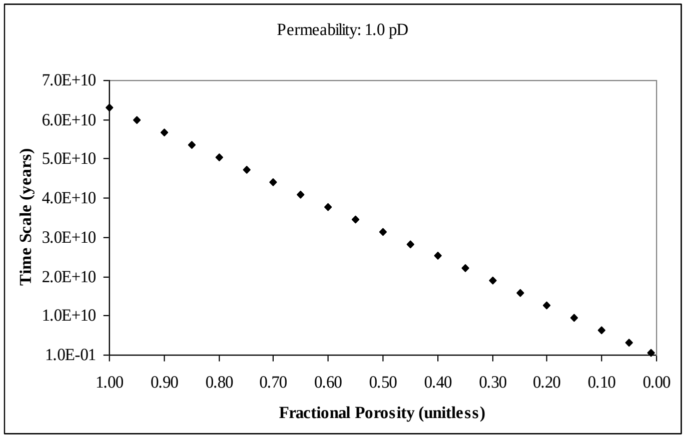
1.0 µD



1.0 nD



1.0 pD



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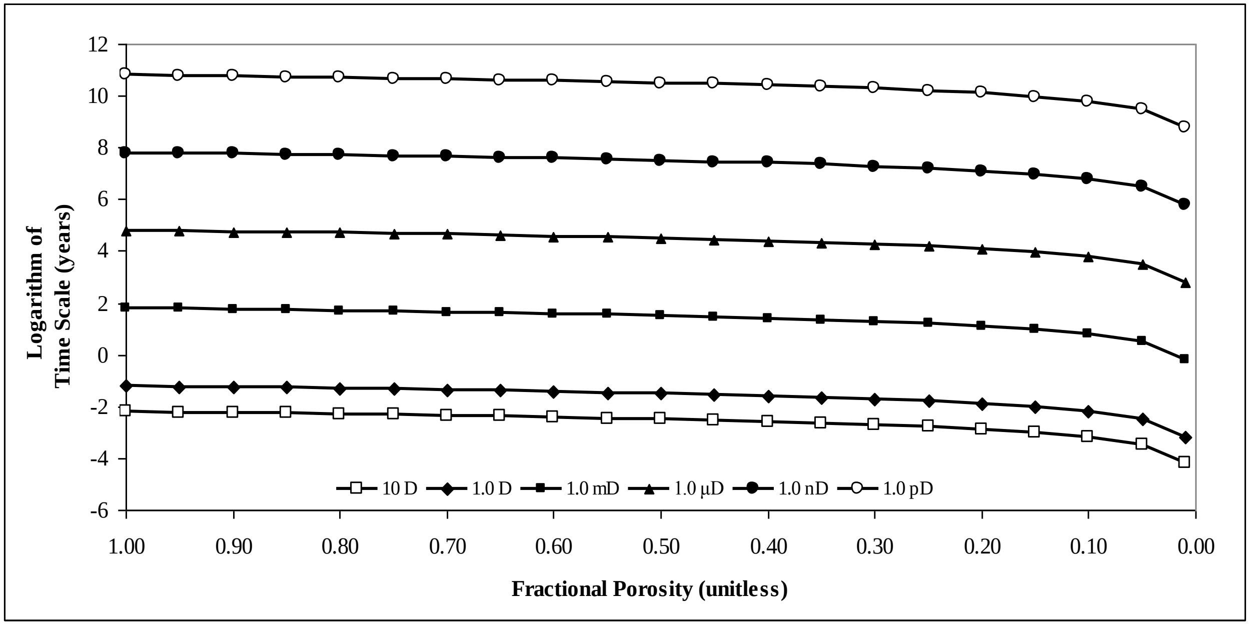
(Burke, 2011)

Darcy’s Law of Fluid Flow



Permeability (Darcy)	Lower Bound (Years)	Average (Years)	Upper Bound (Years)
10.0 D	1.0E-3.50	1.0E-2.60	1.0E-2.22
1.0 D	1.0E-2.50	1.0E-1.60	1.0E-1.22
1.0 mD	1.0E+0.50	1.0E+1.40	1.0E+1.77
1.0 µD	1.0E+3.50	1.0E+4.40	1.0E+4.77
1.0 nD	1.0E+6.50	1.0E+7.40	1.0E+7.77
1.0 pD	1.0E+9.50	1.0E+10.40	1.0E+10.77

Several days to weeks
Several months
6 months up to 60 years
Hundreds to several thousands of years
Tens of millions of years
Billions of years

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(Burke, 2011)

Permeability Classifications

Classification	Permeability Range (Darcy)
Class I	Class I $\geq$ 1.0 D
Class II	1.0 D $\geq$ Class II $\geq$ 1.0 mD
Class III	Class III $\leq$ 1.0 mD

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Formation Injectivity

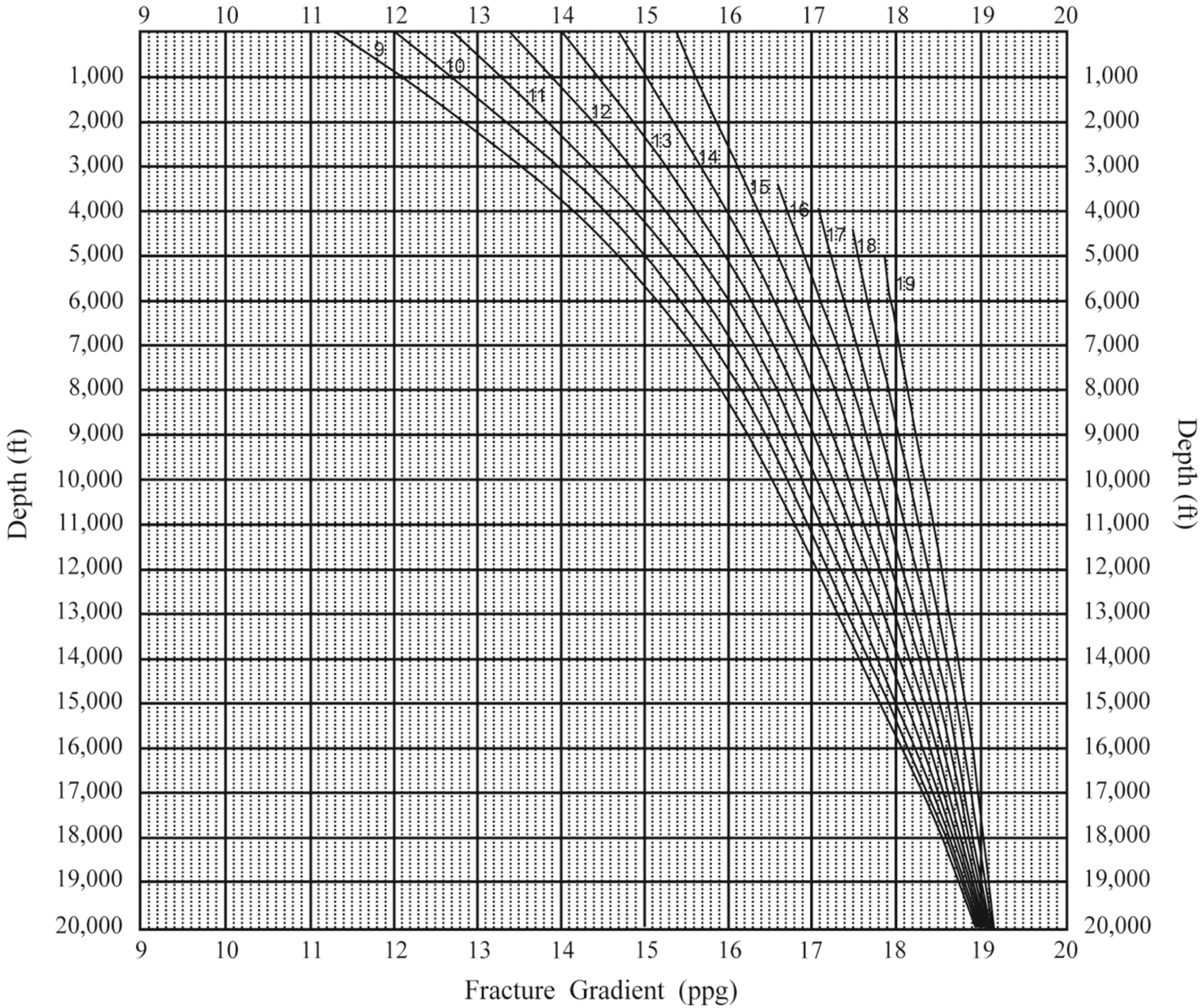
- The Oilfield Glossary (Schlumberger, 2012) defines an injectivity test as a procedure that is used to determine "the rate and pressure at which fluids can be pumped into the treatment target without fracturing the formation."

- According to Craft and Hawkins (1991) an injectivity index quantifies the pressure increase due to pumping a known rate and volume of fluids into the formation, and is the ratio of the injection flow rate divided by the pressure increase.

Formation Injectivity

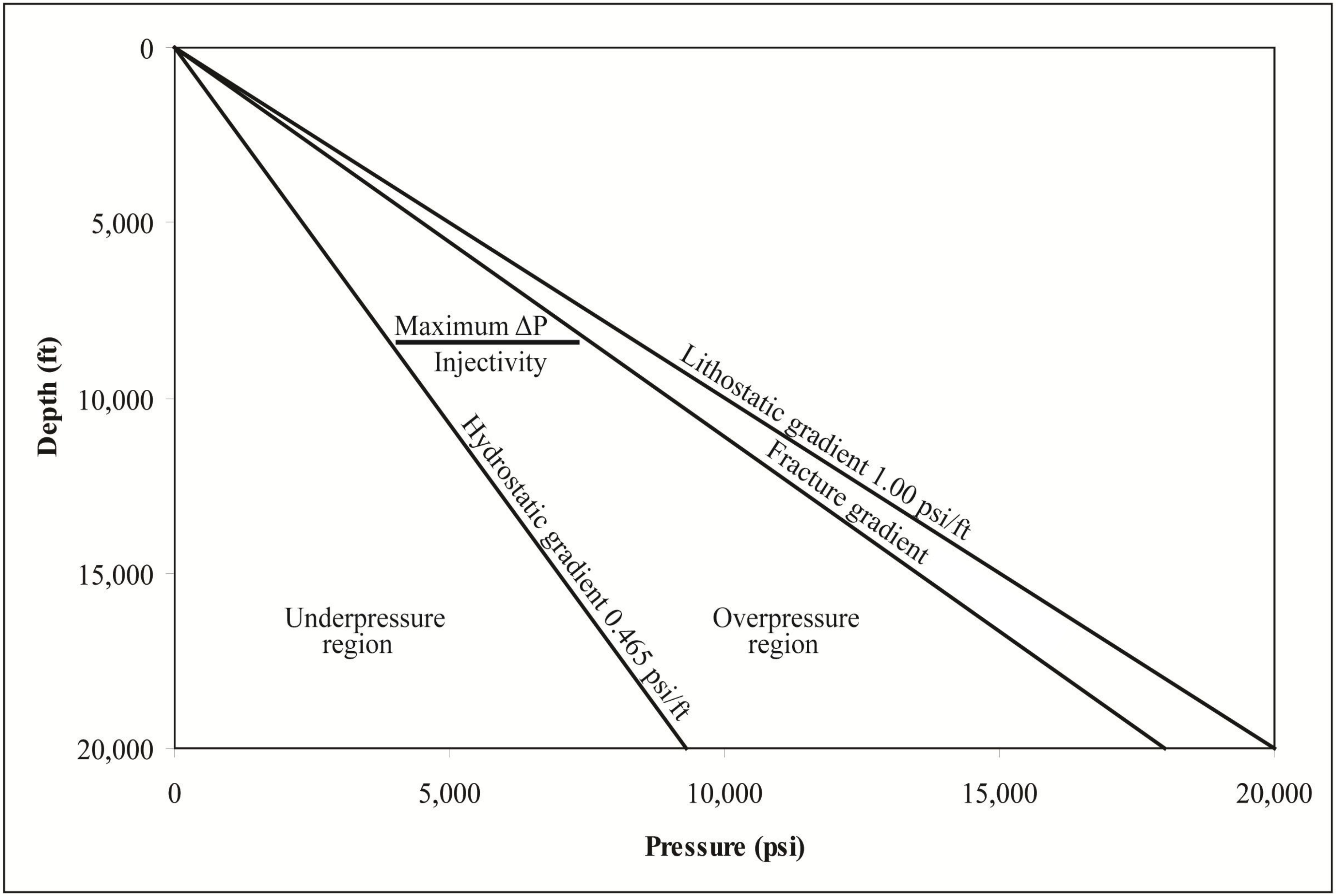
- Injectivity describes the pressure increase due to the introduction of fluids into a formation.
- The most interesting and relevant application of injectivity is to determine the pressure increase that will fracture the reservoir rocks. This is related to the fracture gradient.

Fracture Gradients



(Modified from Eaton, 1969)

Pressure Gradients



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(Burke, 2011)

Maximum Pressure Differential

Maximum Pressure Differential, ΔP_D, evaluated at a specific depth, D, is defined as:

$$\Delta P_D = \left| F_D - H_D \right|$$

F_D fracture gradient as a function of depth, and

H_D original reservoir pressure gradient or hydrostatic gradient as a function of depth

This relation assumes that the formation is not already fractured due to overpressuring, and that ΔP_D will always be a positive value, that is, increasing The pressure differential will not close the fractures.

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(Burke, 2011)

Conclusions

- Quantification of the first-order approximations of the time scales involved in the lateral migration of sequestered CO_2 through a given volume of rock enables a general estimation of the containment timeframes of the sequestered gas. This study investigated these time scales for formations exhibiting permeabilities from 10.0 darcy to 1.0 picodarcy and porosities from 0.05 to 0.95.

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Conclusions (2)

- Fluid flow modeling for determining fluid migration time scales
  - Calculate generalized time scales of lateral CO_2 fluid migration, given information about average reservoir temperature, pressure, permeability, and porosity.
  - Hydraulic diffusivity time scales exhibit hyperbolic decay contours; Darcy fluid flow time scales exhibit decreasing linear trends.
  - The orders of magnitude can be approximated as linear over a wide range of permeability-porosity values.
  - Similar order of magnitude results for diffusivity and Darcy flow suggest that these first-order approximations, derived from two separate equations with different input values, yield a reliable estimation of the CO_2 lateral migration time scales.

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Conclusions (3)

- Formations categorized by:
  - Class I permeability may not provide adequate, long-term containment of sequestered CO_2 in the absence of physical trapping mechanisms. Fluid migration occurs on the order of days to weeks.
  - Class II permeability represents the most favorable scenario for injection and containment of CO_2. The order of magnitude for 1.0-km lateral migration of carbon dioxide through a given volume of rock ranges from several years to several thousand years.
  - Class III permeability may not represent viable injection targets without formation treatments such as hydraulic fracturing or permeability enhancement. Lateral fluid migration occurs on the order of several hundreds to several hundred thousands of years.

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