Federal Regulation and Technical Requirements for Onshore Geologic Storage of Carbon Dioxide

Presented at:

Webinar on Carbon Capture and Storage (CCS): Risks of CO_2 Leakage from Geological Reservoirs and Pipelines

June 1, 2023

Dominic DiGiulio, PhD

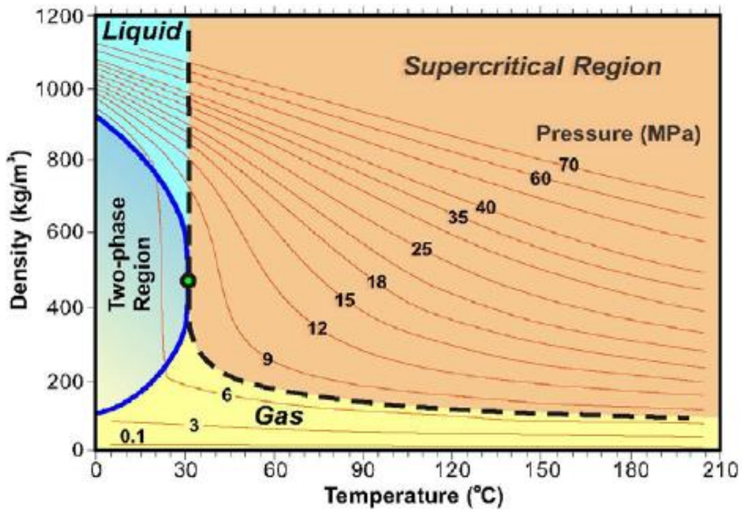
CAES
CENTER FOR APPLIED ENVIRONMENTAL SCIENCE

Presentation Outline

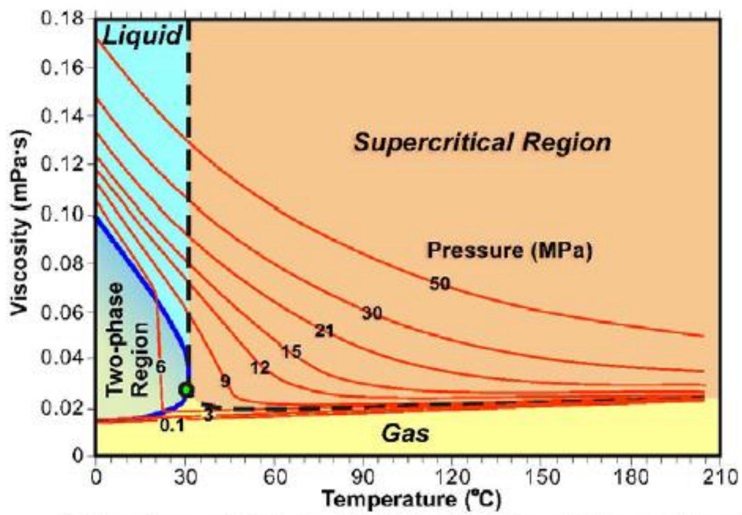
- What is geologic storage of CO_2?
- What federal regulations govern geologic storage of CO_2?
- What are basic technical aspects of geologic storage of CO_2?
- Are abandoned wells a concern for impact to groundwater resources and release to the atmosphere?

Properties of CO_2

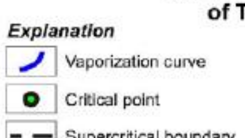
Critical Point = 31.3°C, 7.4 MPa (1074 psig)



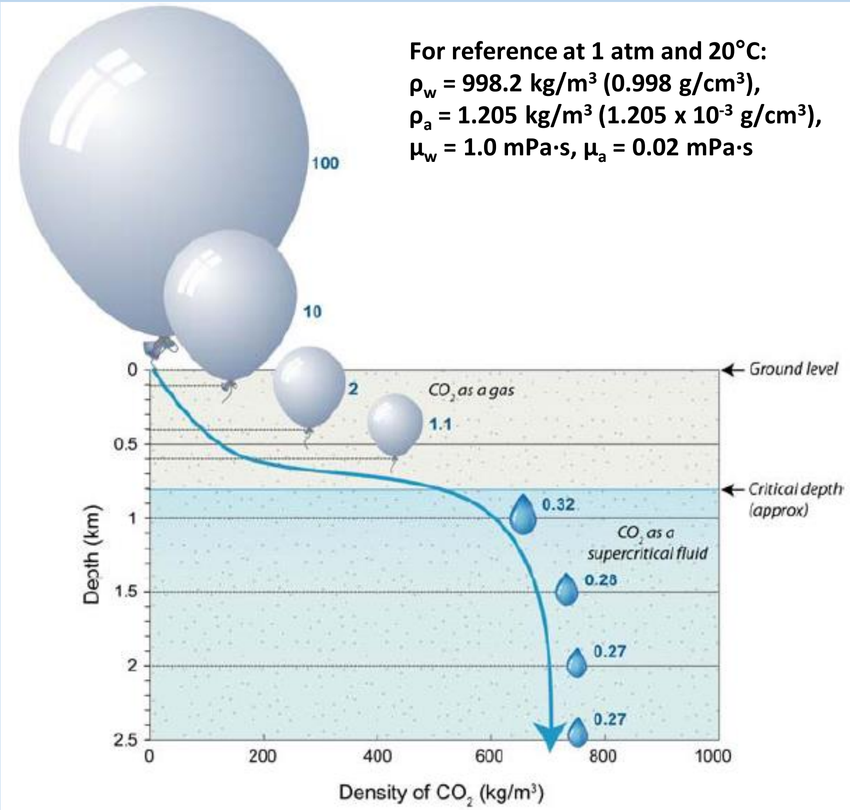
(a) Equations of State for CO_2 Giving the Phase State as a Function of Temperature, Pressure, and Density



(b) Equations of State for CO_2 Giving the Phase State as a Function of Temperature, Pressure, and Viscosity



Source: *After Nordbotten et al (2005), Fig. 2*



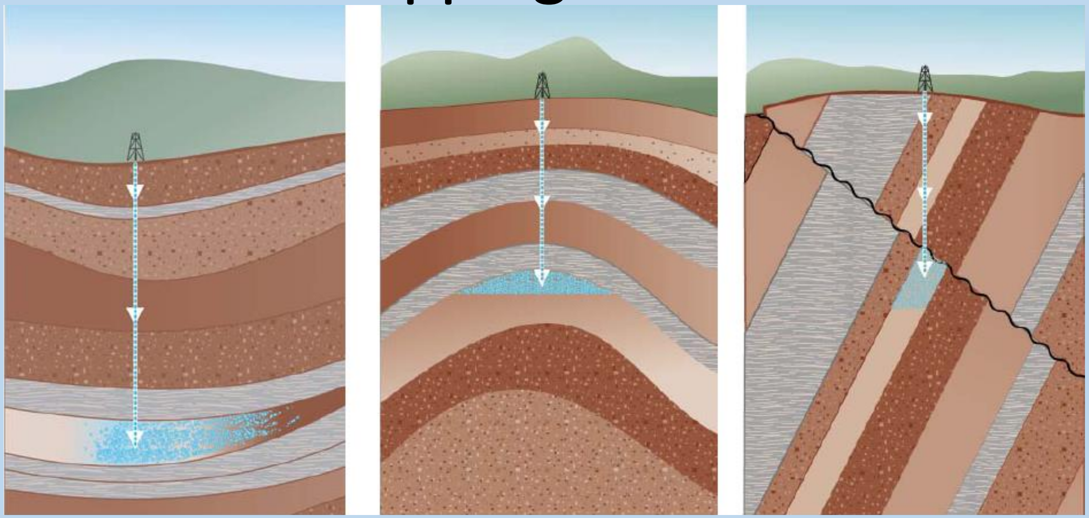
For reference at 1 atm and 20°C:
ρ_w = 998.2 kg/m³ (0.998 g/cm³),
ρ_a = 1.205 kg/m³ (1.205 x 10^{-3} g/cm³),
μ_w = 1.0 mPa·s, μ_a = 0.02 mPa·s

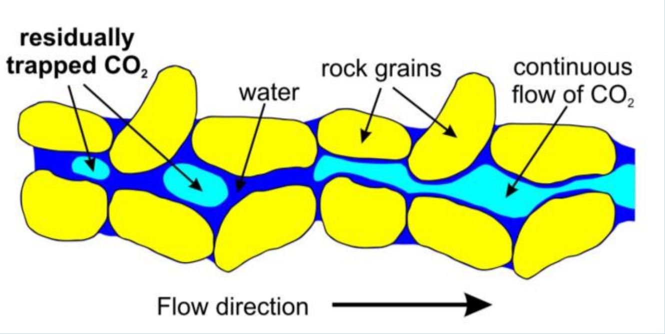
From CO2STORE, 2007

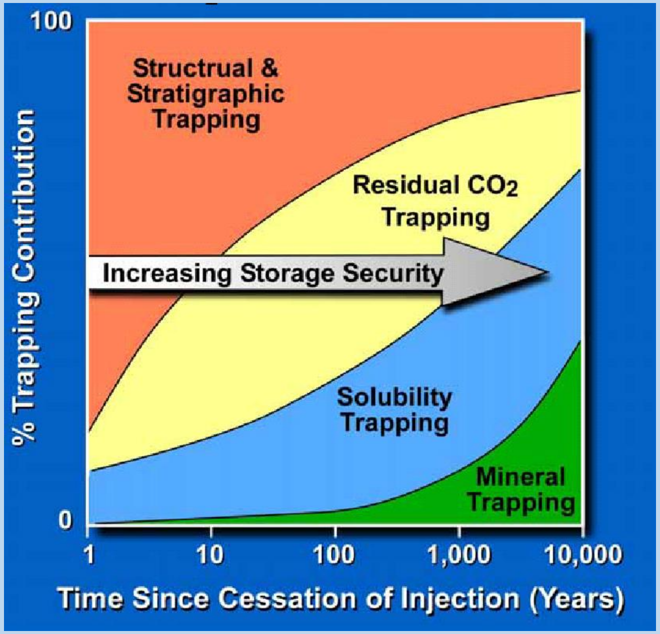
- Pore space availability requires CO_2 storage as a supercritical fluid.
- Storage of CO_2 as a supercritical fluid requires a depth of at least 800 m (~2600 ft).
- Density of supercritical CO_2 is less than water or brine (buoyancy – need for a confining layer).
- Viscosity of supercritical CO_2 is less than water (mobility)

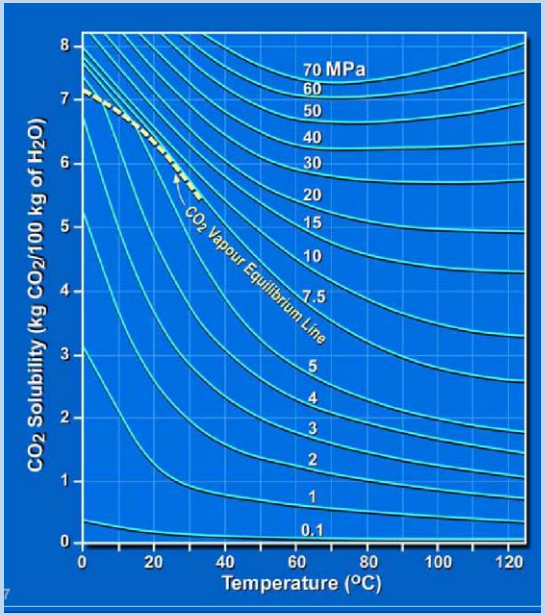
Trapping Mechanisms

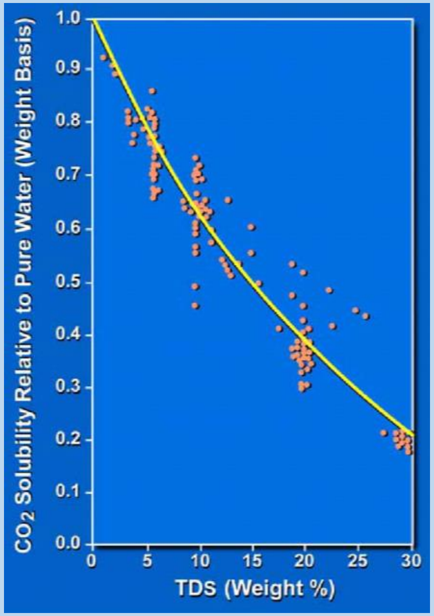
CO2CRC, 2008











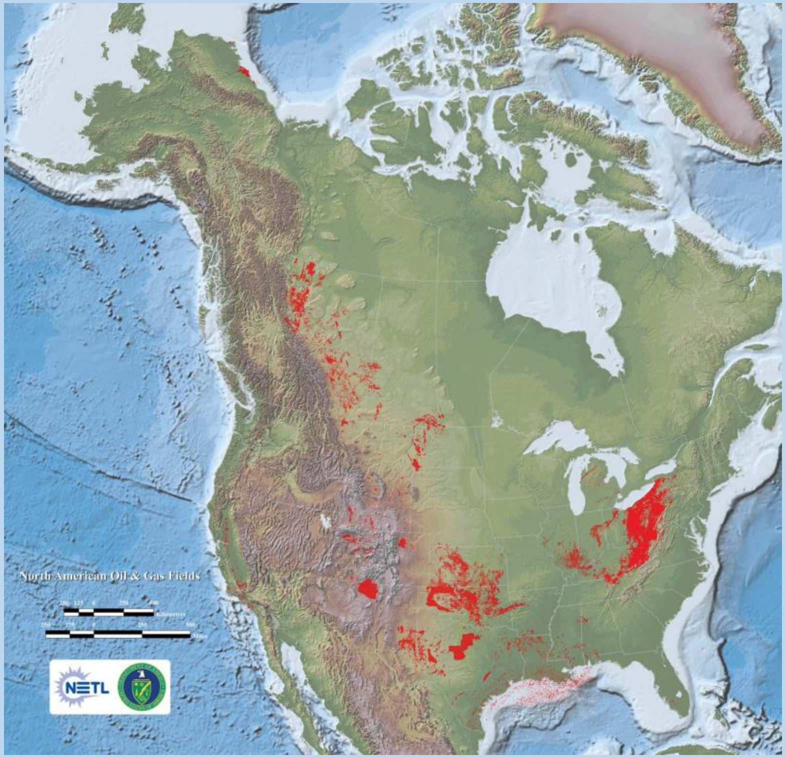
From *IPCC Special Report on Carbon dioxide Capture and Storage*

$$CO_2(g) + H_2O \leftrightarrow H_2CO_3 \leftrightarrow HCO_3^- + H^+ \leftrightarrow CO_3^{2-} + 2H^+$$

Mineral Trapping $\left(Ca^{2+}, Mg^{2+}, Fe^{2+}\right)CO_3$

- Most trapping (at least initially) is stratigraphic (confining layer).
- CO_2 displaces brine which can be later displaced by brine causing capillary trapping.
- CO_2 solubility generally decreases with increasing temperature (thermal gradient) and salinity (brine).
- The safest form of trapping is mineralization occurs over hundreds or thousands of years (need for very long storage times).

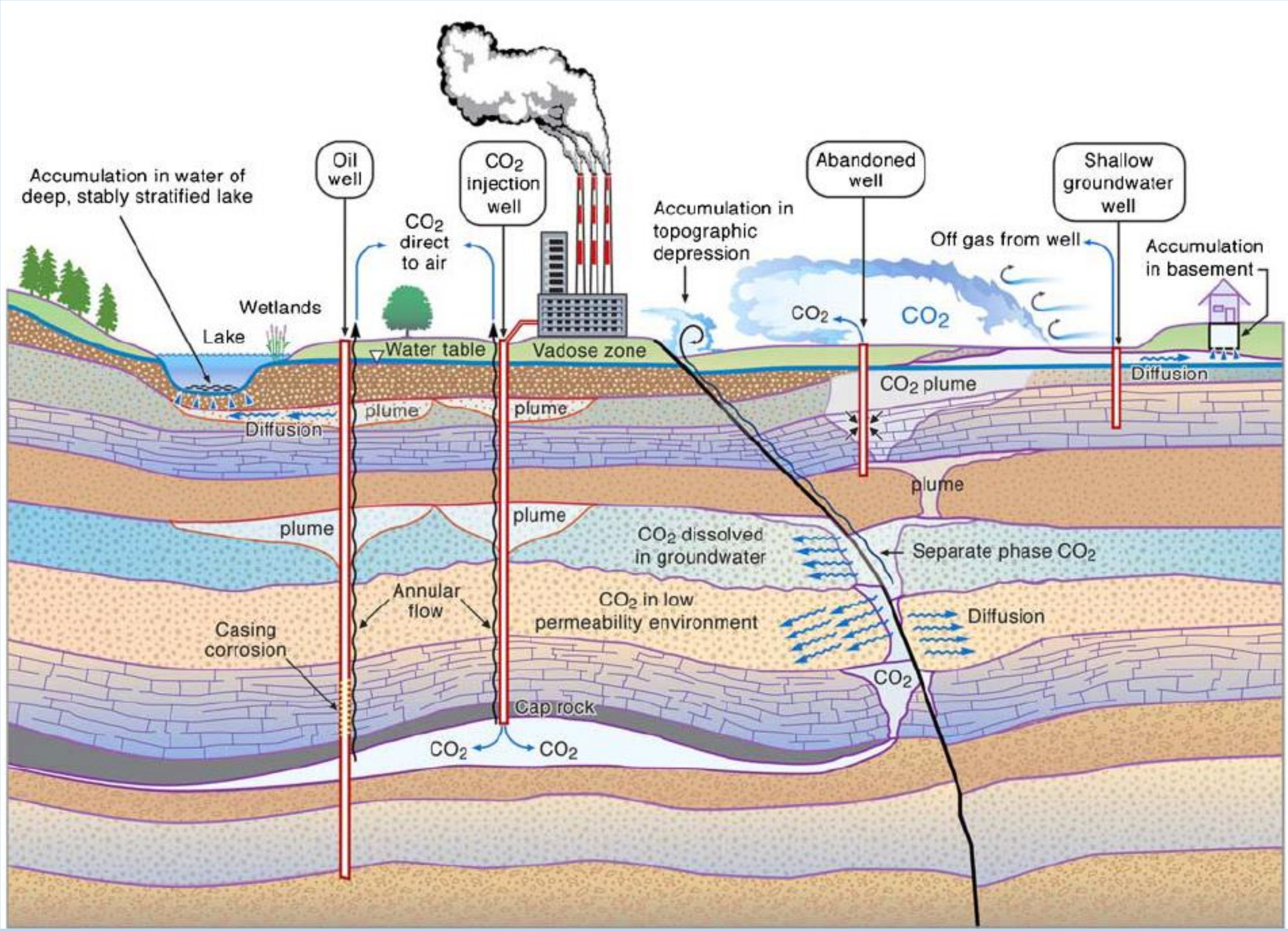
Storage in Depleted Oil and Gas Reservoirs and Saline Aquifers



- Geographically limited.
- Overlying confining layers have prevented upward migration of hydrocarbons for millions of years (under initial pressurized conditions and absence of well penetrations).
- Extensively well log, and other data (e.g., seismic surveys) are available.
- Infrastructure already in place.
- Many abandoned wells, some difficult to locate, decades old, constructed or plugged with materials that would not be able to withstand long-term exposure to CO_2 or pressurized conditions necessitating corrective action.

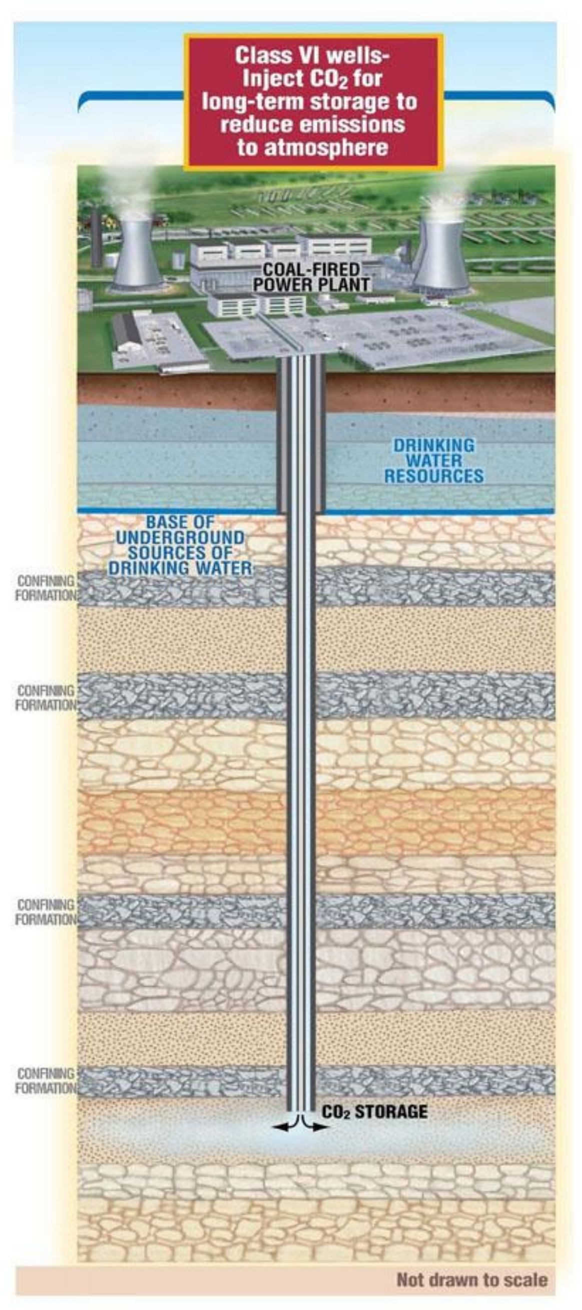
- Greater storage capacity (13X to 93X).
- Geographically extensive.
- Poorly characterized.
- Need for an extensive confining layer
- Other use (produced water disposal) and over-pressurization.

Risk Pathways for Geologic Storage of CO_2



From Benson and Hepple (2005)

Regulation of Geological Storage of CO_2



Federal Requirements Under the Underground Injection Control (UIC) Program for Carbon Dioxide (CO2) Geologic Sequestration (GS) Wells – Federal Register/Vol. 75, No. 237/Friday, December 10, 2010 (Section 1422 not 1425)

Mandatory Reporting of Greenhouse Gases, Injection and Geologic Sequestration of Carbon Dioxide, 40 CFR Parts 72, 78, and 98, Final Rule, Wednesday, December 1, 2010

The purpose of the Class VI Rule is to protect Underground Sources of Drinking Water (USDWs).

The purpose of Subpart RR is to verify the amount of CO_2 sequestered and collect data on CO_2 surface emissions.

Class VI Rule requires determination of an Area of Review (AoR).

Subpart RR requires determination of Active and Maximum Monitoring Areas (AMA, MMA).

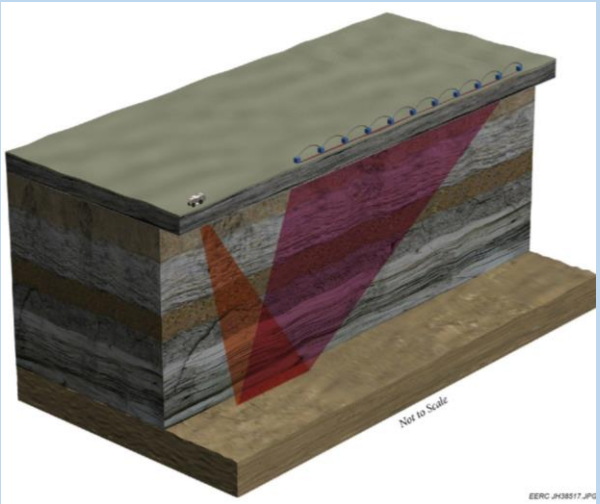
Class VI Rule requires submittal of a *Testing and Monitoring Plan*.

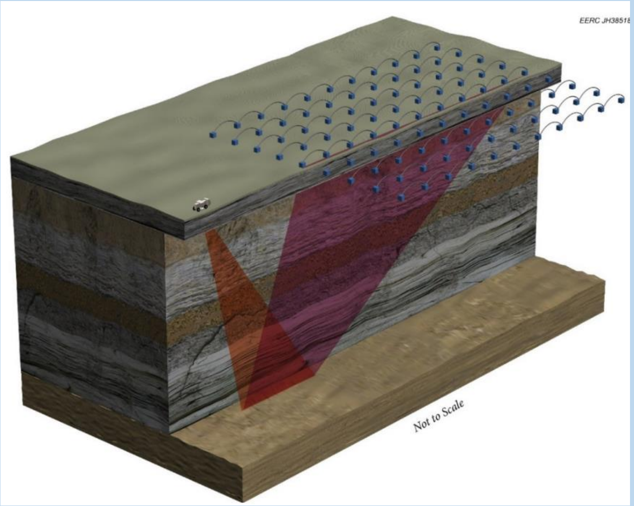
Subpart RR requires submittal of a *Monitoring, Reporting, and Verification (MRV) Plan*.

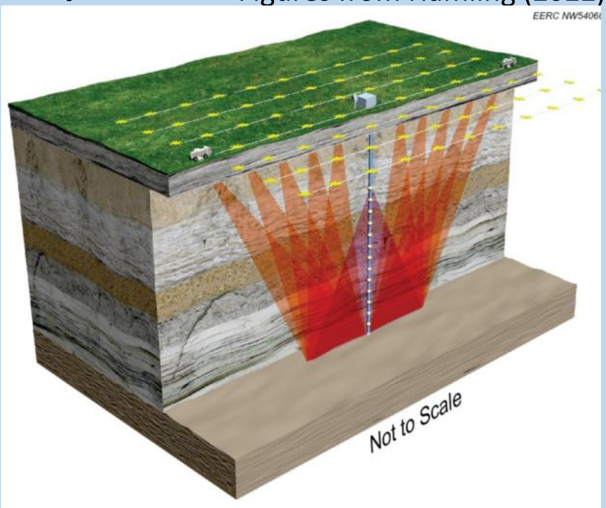
An Environmental Assessment/Impact Statement may be required under the National Environmental Policy Act (NEPA) if conducted on federal or tribal land (NEPA). States may also have additional requirements (e.g., the California Environmental Quality Act in California).

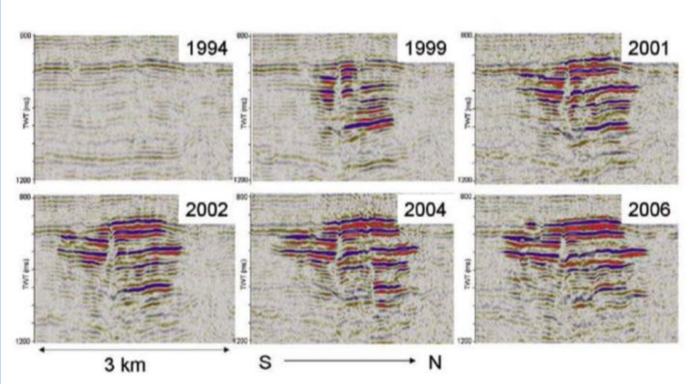
Site Characterization – Seismic Surveys

Figures from Hamling (2022)









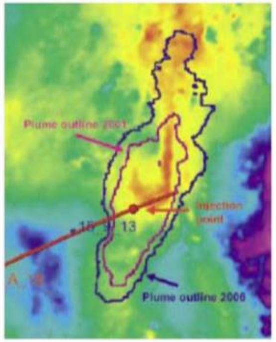
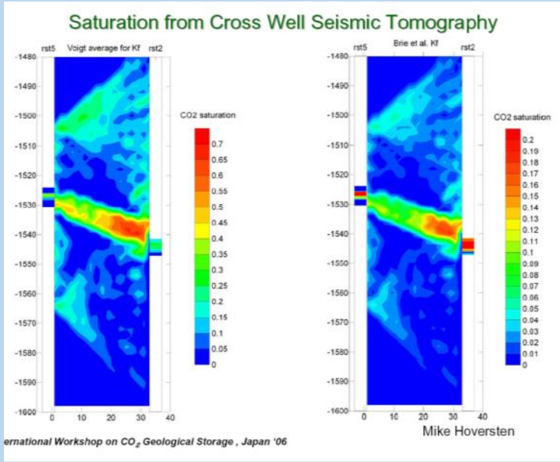


Figure from Arts et al., 2008



- Generation of sound waves reflected off geological layers.
- Sophisticated software and experience to interpret results.
- Stratigraphy (thickness, areal extent)
- Location, type, orientation, juxtaposition, and properties of known or suspected faults and fracture systems
- Effectiveness depends on lithology, porosity, density contrast of fluids.
- 2-D seismic has linear arrangement of receivers.
- 3-D seismic has arrangement of receivers on a grid and provides higher resolution and accuracy.
- Vertical seismic profiling - source is on surface and detector is downhole.
- Cross-well seismic tomography – source and detector are downhole in different wells

Site Characterization – Well Logs, Core Samples, Fluid Testing, Fracture and Pump Tests

Wireline Well Logging

Determination of depth, thickness, porosity, permeability, mineralogy, lithology, and salinity.

- Resistivity
- Spontaneous potential
- Gamma ray
- Porosity

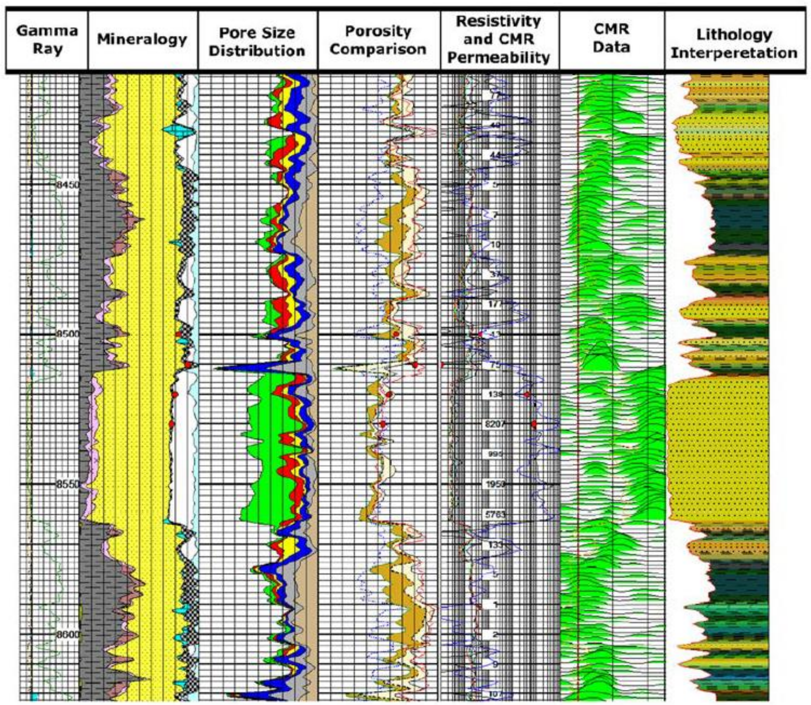


Figure 4-2: Example of an Open-Hole Wireline Log

(SECARB, Final Report: Plant Daniel Project Closure Report, Volume 1 of 2, 2010)

Core Samples

Provide information to support stratigraphic correlation, interpretation of depositional environments, and wireline log calibration

- Must be collected from injection and confining zones but director may require collection from first permeable formation overlying confining zone and/or other zones
- Lithology, thickness, grain size, sedimentary structures, diagenetic features, contacts, textural maturity, oil staining, fracturing, and porosity.
- Petrology and mineralogy; petrophysical properties; and geomechanical properties
- May consider relative permeability, capillary pressure, fluid compatibility, wettability, and pore compressibility.

Formation Fluid Sampling

- pH, SC, reservoir pressure, and static fluid level.
- May include major anions and cations, pH, temperature, pressure, alkalinity, TOC, and total inorganic carbon, isotopes

Pump/Fracture Gradient Tests

- Fall-off testing (permeability)
- Leak-off testing (fracture gradient)

Multi-Phase Numerical Flow Modeling

- Storage capacity
- Magnitude and areal extent of free-phase CO_2 and pressure buildup
- Monitoring (sample locations, timing, expected results)
- Trapping mechanisms (buoyancy driven flow, dissolution)
- Hysteresis
- Physical Heterogeneity

- Problems of scale
- Sensitivity and stochastic analysis
- Requires calibration (e.g., observed versus simulated pressure buildup and CO_2 saturation)

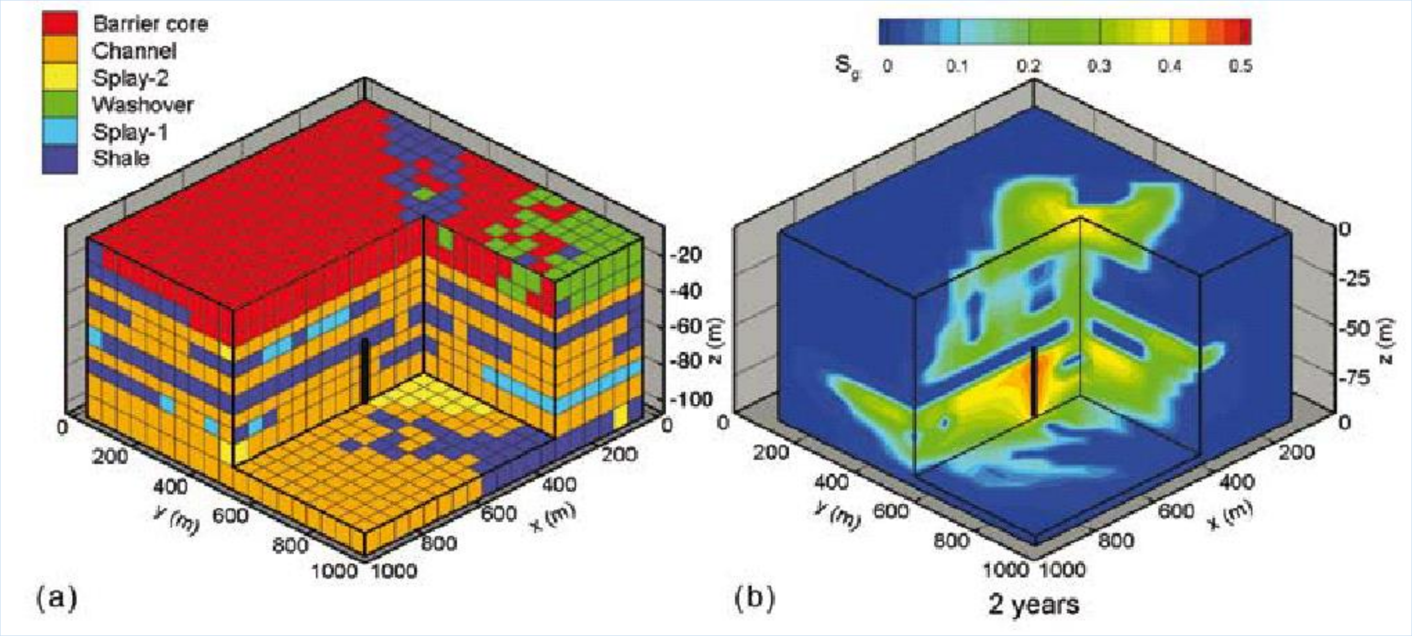
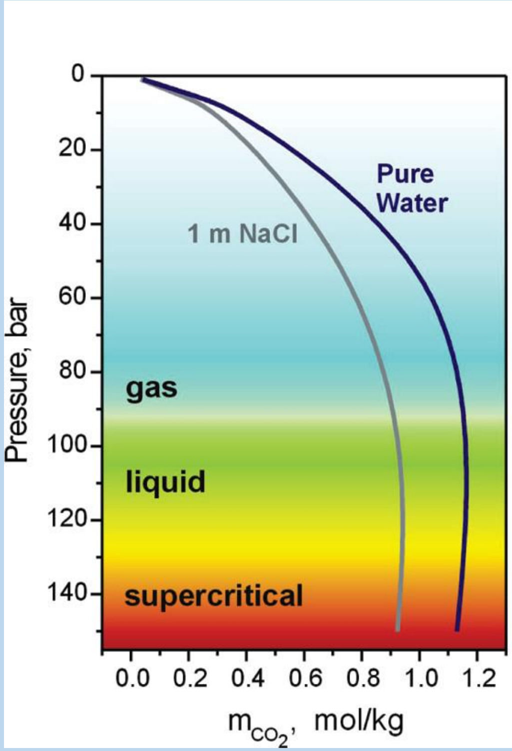
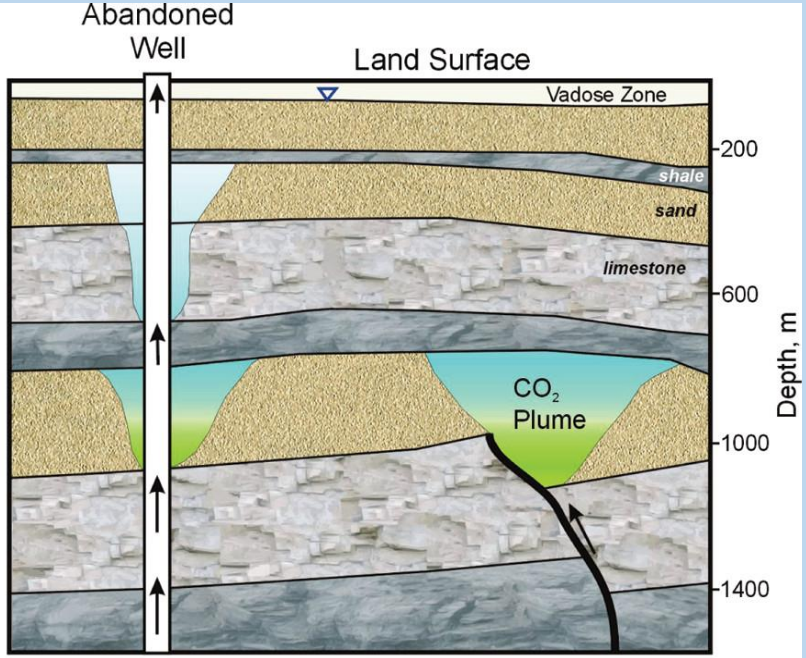


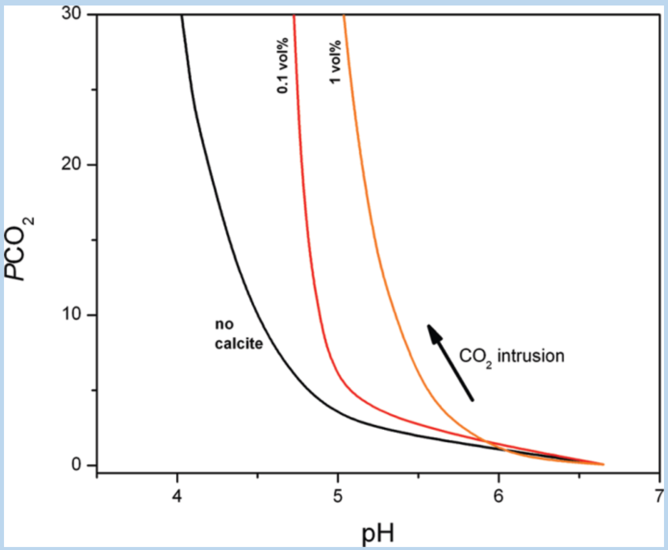
Figure from Doughty and Pruess, 2004

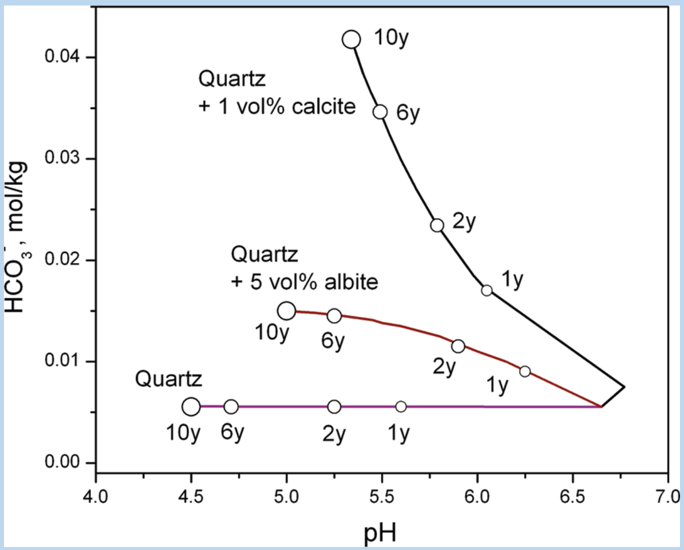
Geochemical Modeling

- Compatibility of the carbon dioxide stream with fluids in the injection zone(s) and minerals in both the injection and the confining zone(s)
- Speciation, dissolution/ precipitation, ion-exchange, sorption (precipitation could reduce pore volume but increase mineralization)
- Equilibrium and kinetic batch geochemical modeling versus coupled transport/geochemical modeling (scale issues).
- Monitoring strategies.









Figures from Wilkin and DiGiulio (2010)

Geomechanical Modeling

- Historic and induced seismicity (critical infrastructure, leakage through caprock, faults, and well penetrations)
- Critical pore fluid pressure evaluation (induced seismicity, fault activation, caprock fracture)
- Ductility, rock strength, fracture gradient (unintentional hydraulic fracturing
- Directional orientation and magnitude of principal stresses
- Geomechanical Modeling (coupled with flow or uncoupled using pore pressure field)
- Probabilistic and sensitivity analysis
- Microseismic monitoring
- Surface deformation monitoring.

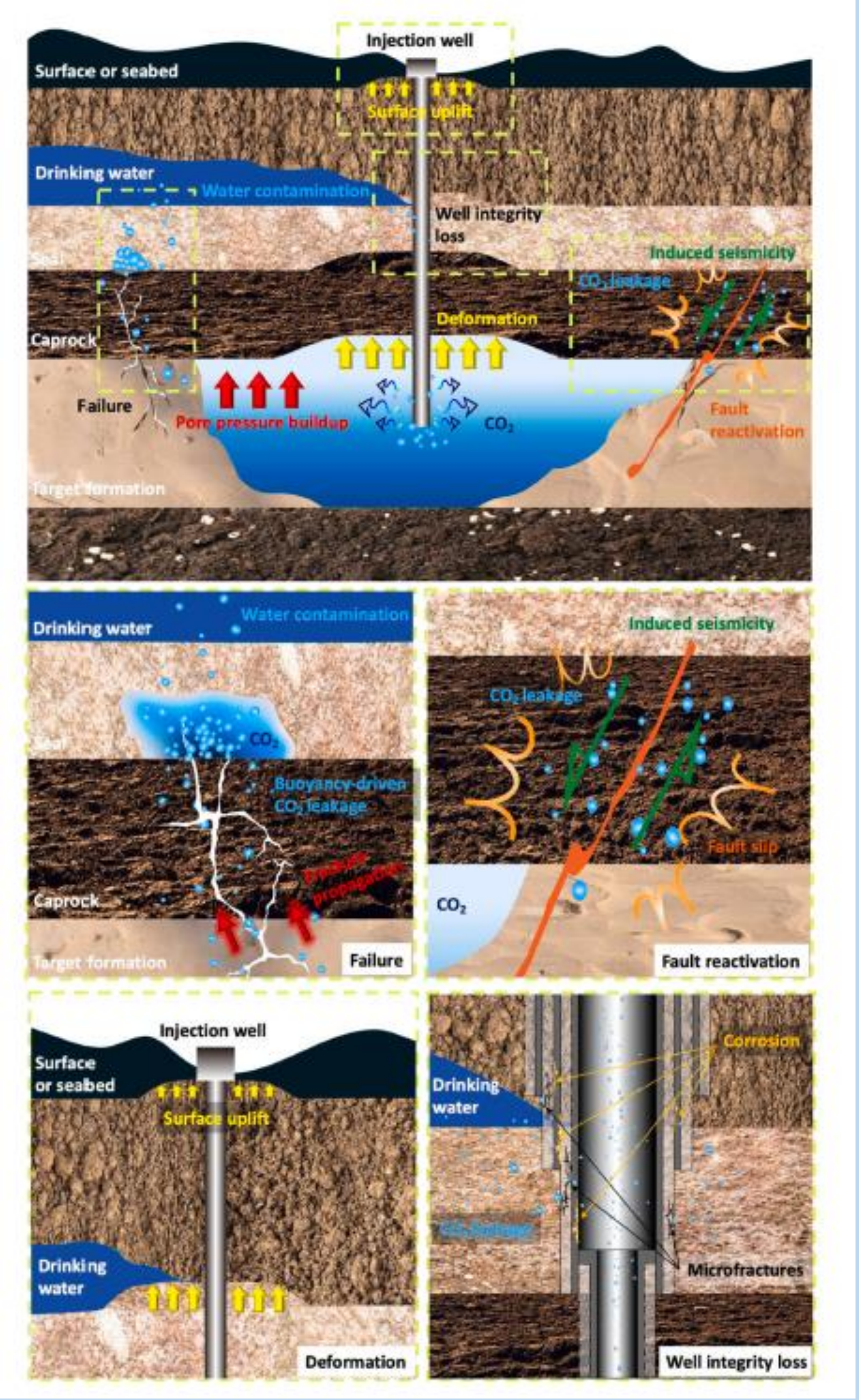


Figure from Song et al., 2023

Injection Well Construction

- Deviation checks during drilling.
- If > 50 ppm water content, corrosion-resistant materials are suggested.
- Injection pressure < 90% fracture pressure.
- Surface casing or multiple strings of surface casing below base of the lowermost USDW.
- All casing strings cemented to the surface (staging if necessary).
- Injection must occur through tubing compatible with CO_2 stream.
- The annulus between long-string casing and tubing must be filled with a noncorrosive fluid, be higher than injection pressure, and continuously monitored.
- Quarterly monitoring of well materials for corrosion.
- Alarms and automatic surface shut-off systems are required.

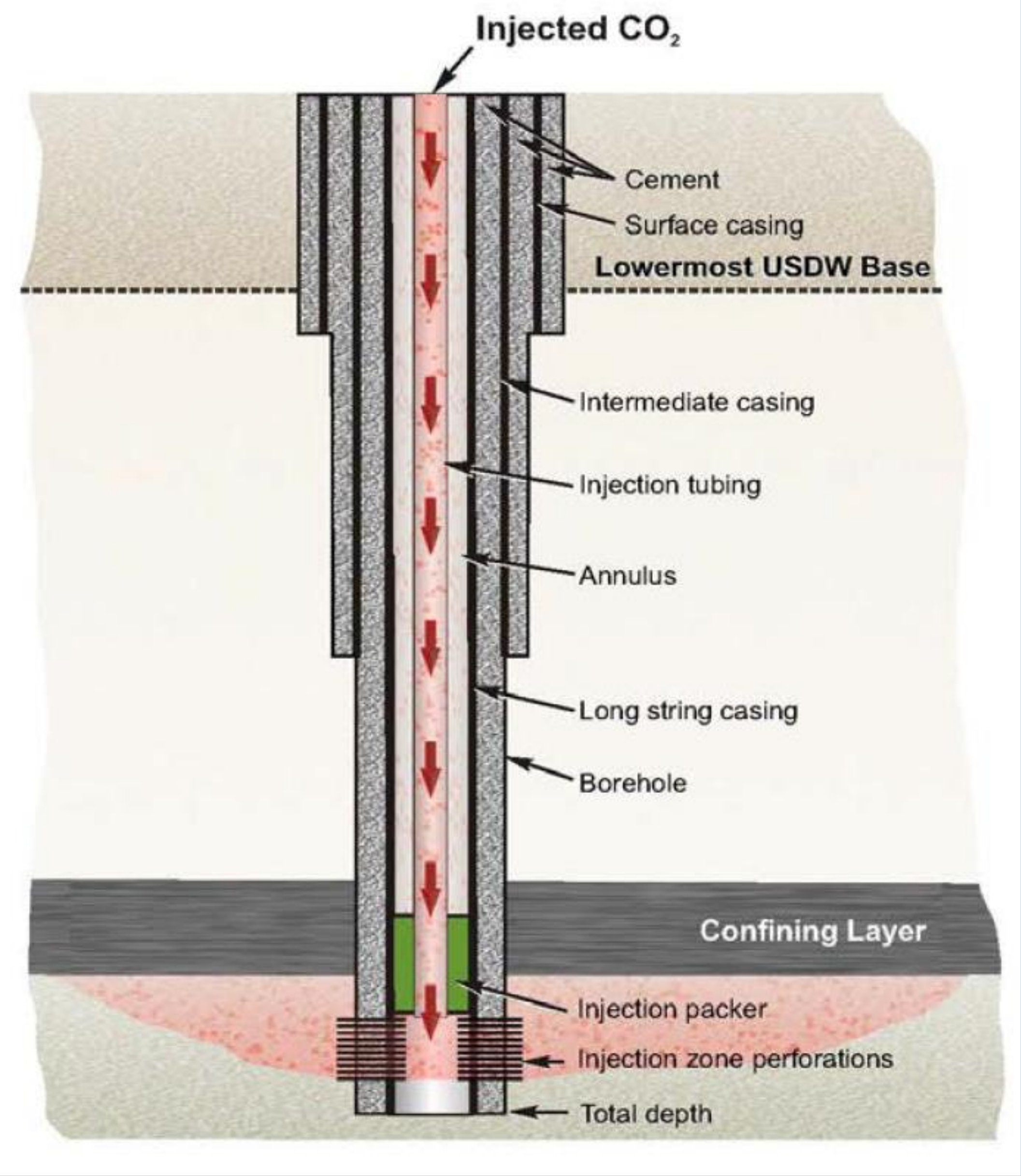


Figure from EPA (2013)

Internal Mechanical Integrity Testing

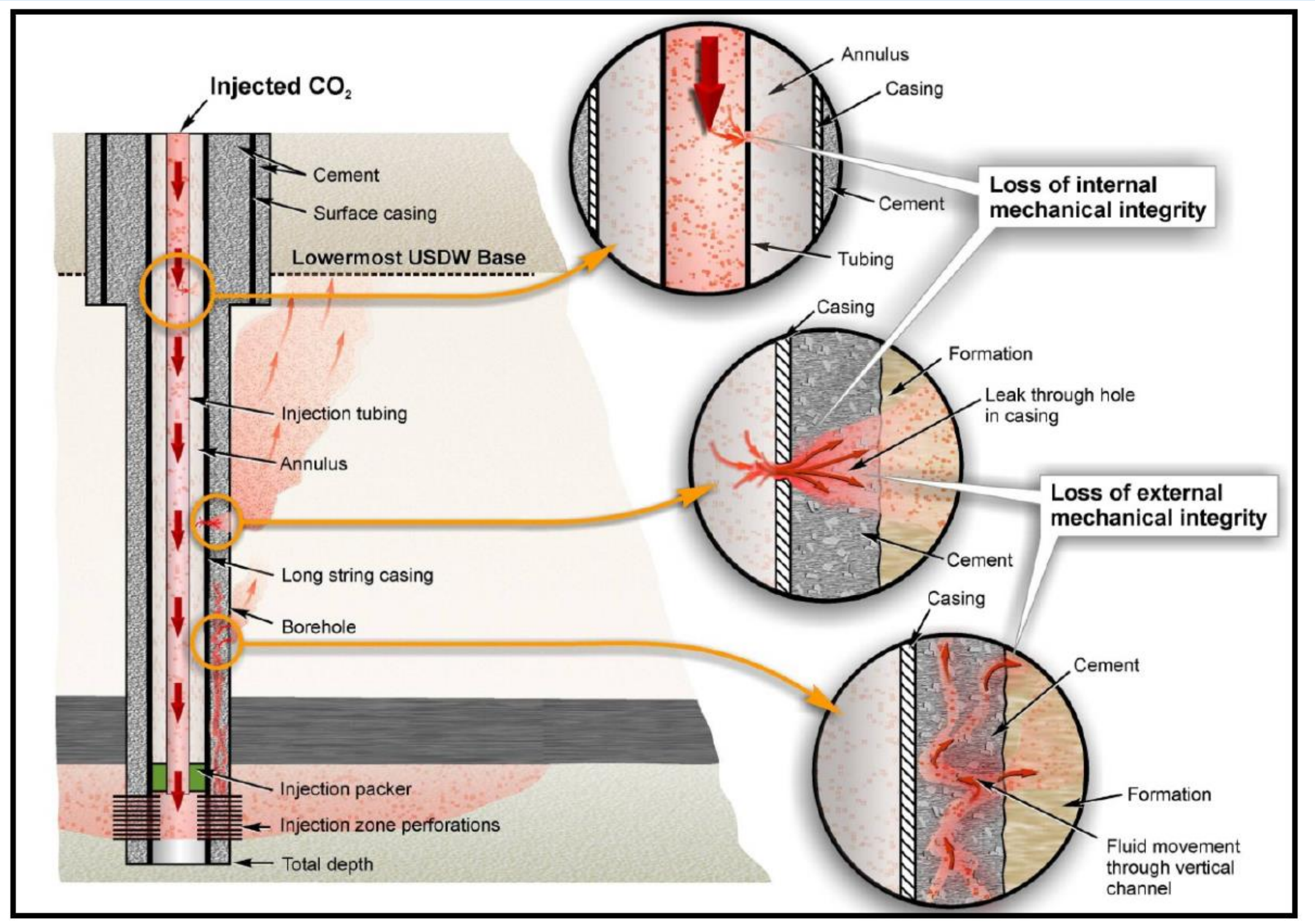
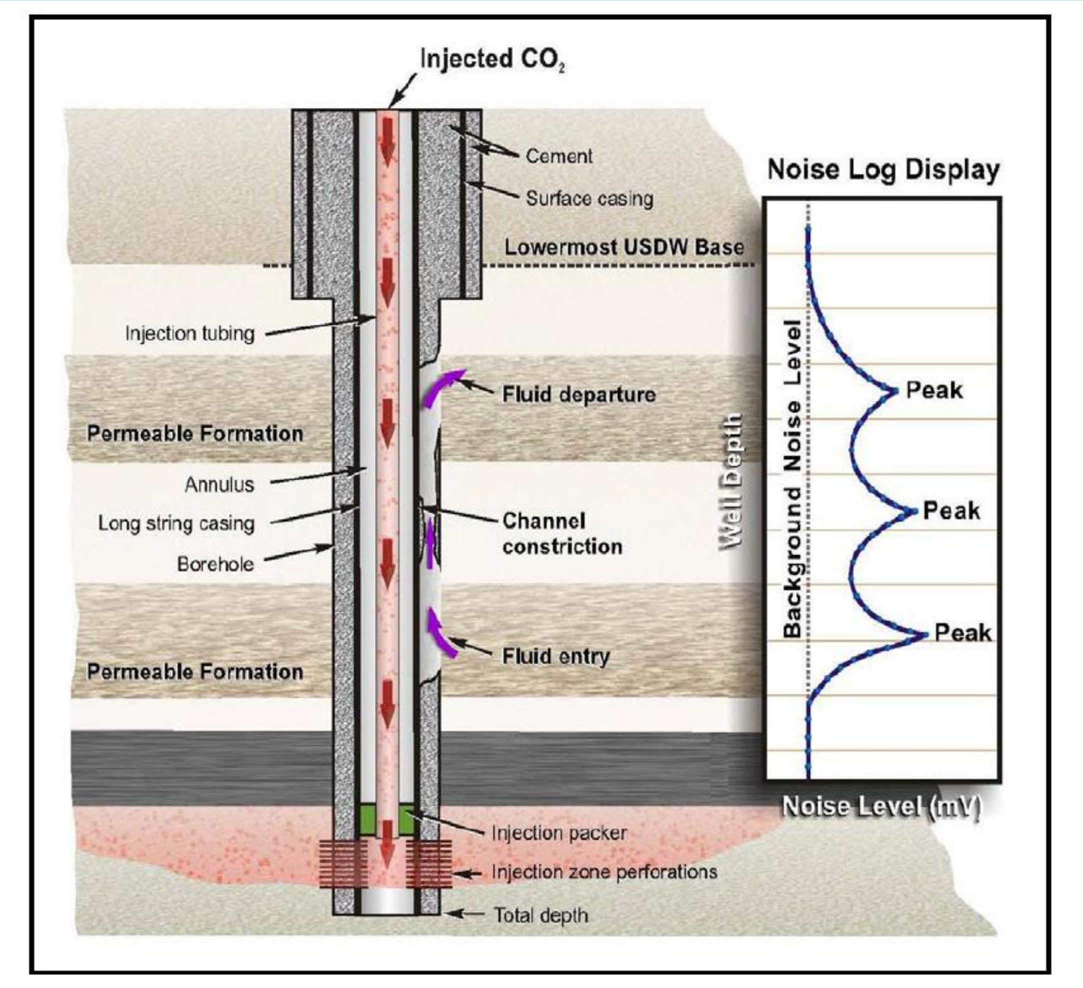
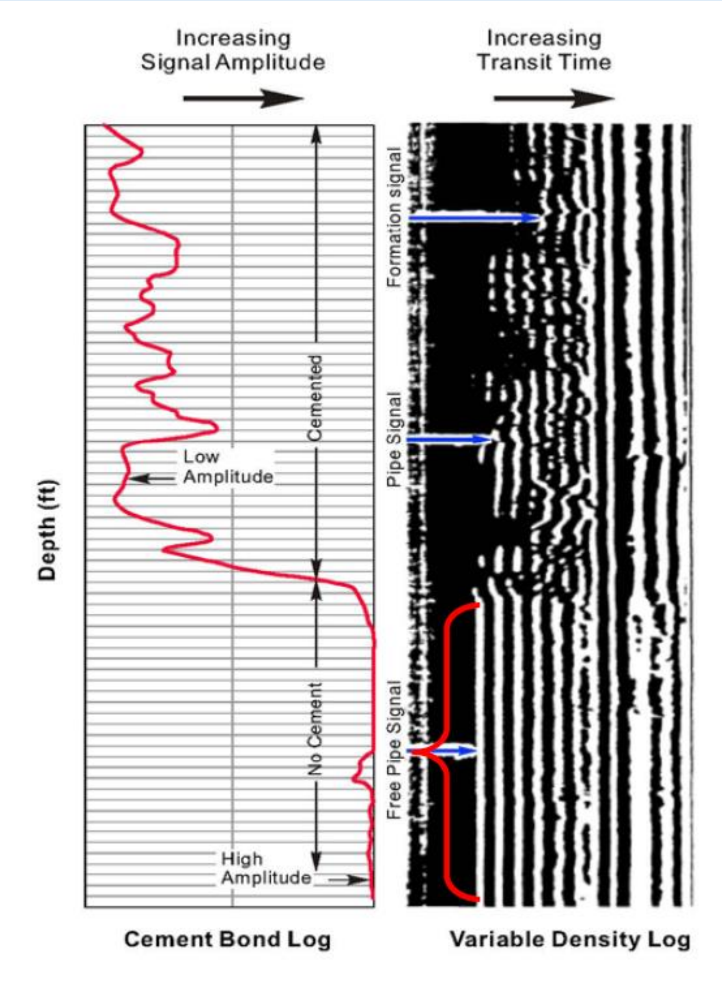


Figure from EPA (2013)

- A standard annular pressure test is required prior to injection. Applied pressure, time, and acceptable pressure loss though are not specified in regulations.
- Continuously monitoring of injection pressure, injection rate, injected volume, pressure on the annulus between the tubing and long-string casing and volume of liquid additions to the annulus system required.

External Mechanical Integrity Testing





Figures from EPA (2013)

- External MIT must be conducted prior to injection, at least once per year until the injection well is plugged, and prior to plugging.
- An oxygen activation log, temperature log, or noise log must be utilized.
- Cement bond and variable density logs are required after setting and cementing the surface casing and long-string casing

Class VI Area of Review (AoR)

- Areal extent of free-phase CO_2 and elevated pressure capable of rise to an USDW in an open conduit (end of injection).
- Initial pressure: under-pressured, normally-pressured, over-pressured (relief wells).
- Multiple injection well consideration.
- Maps illustrating location of all wells penetrating confining layer, known or suspected faults, water bodies, mine and quarries.

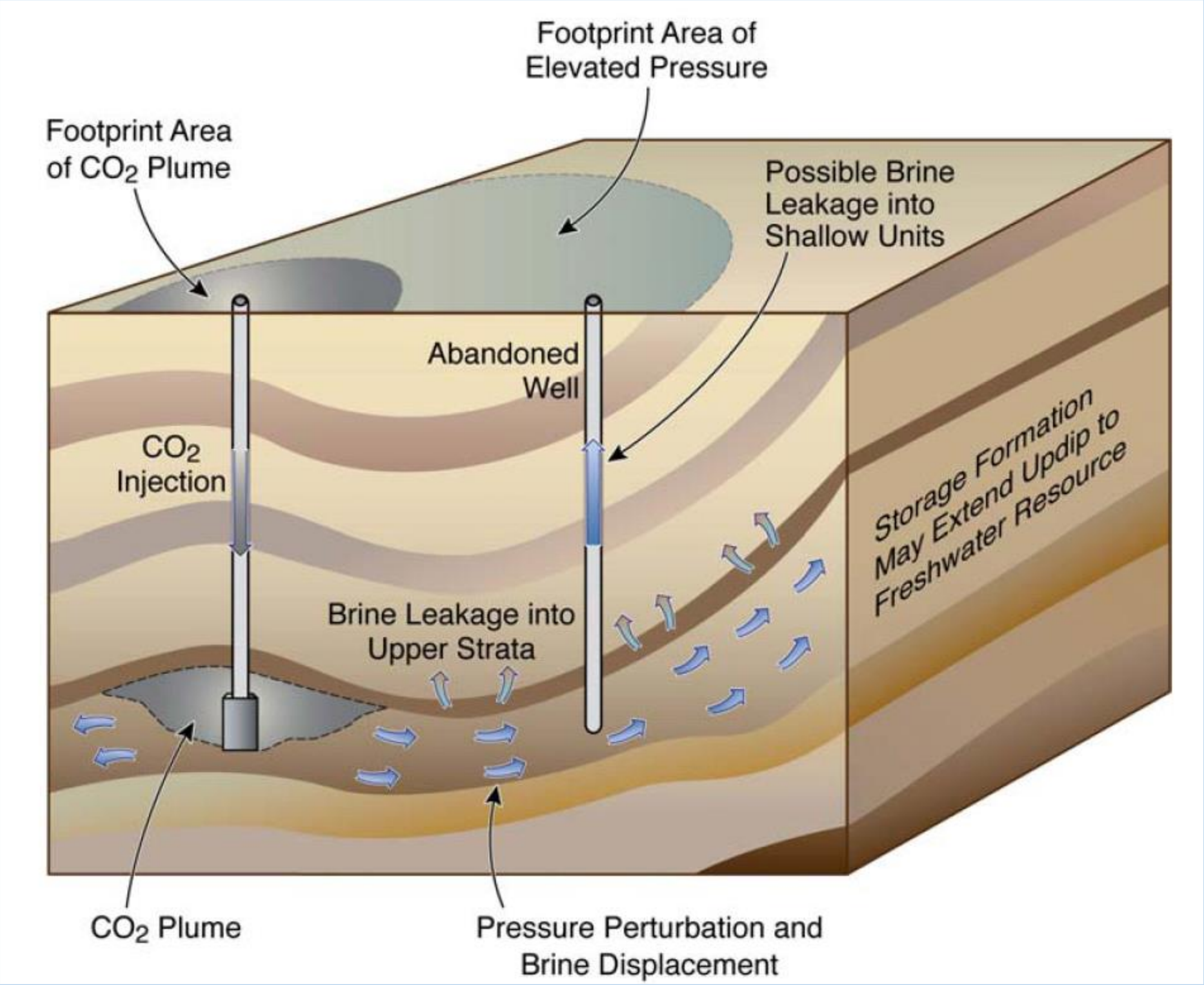


Figure from Birkholzer et al., 2008

Groundwater Monitoring

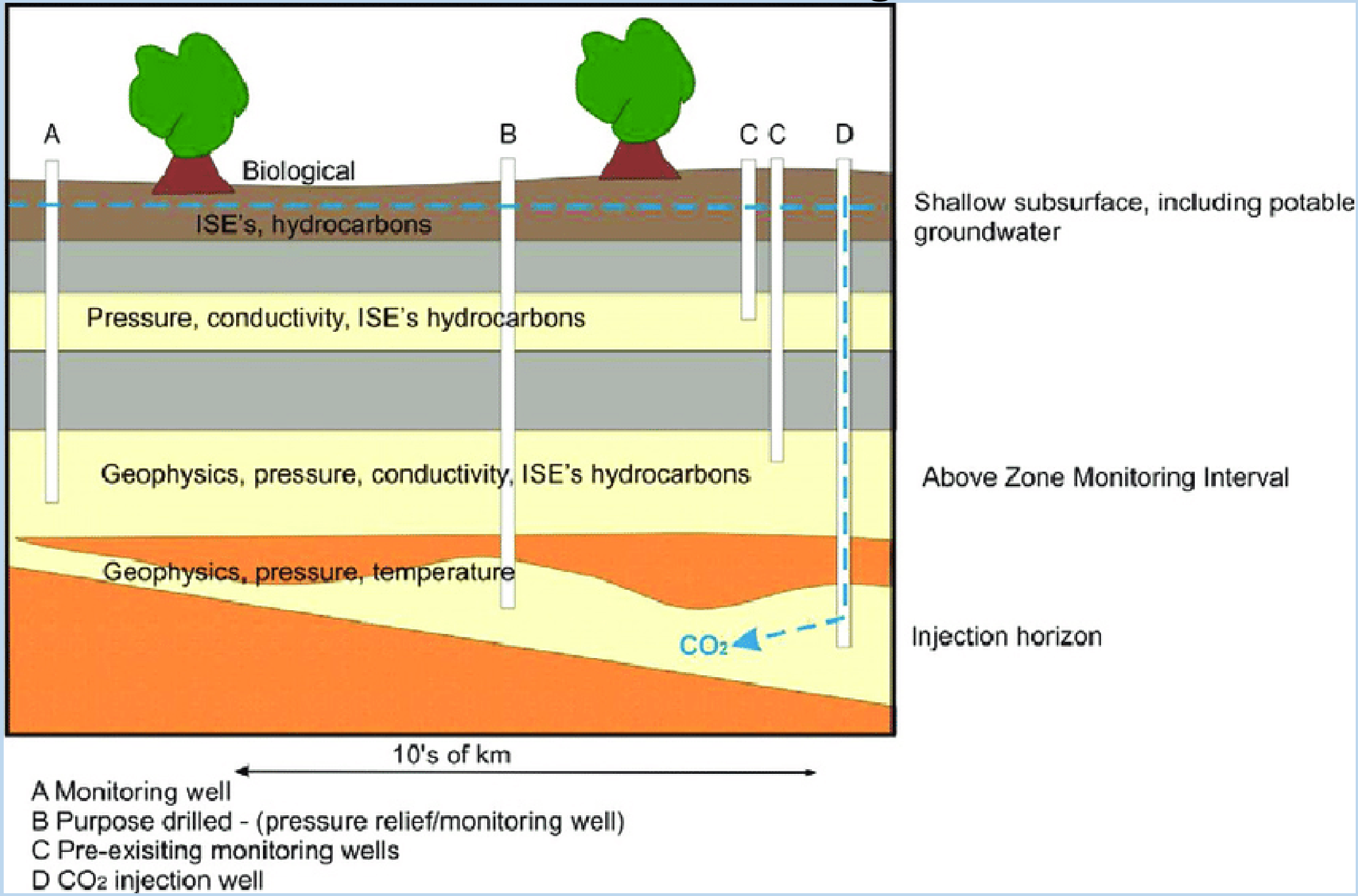
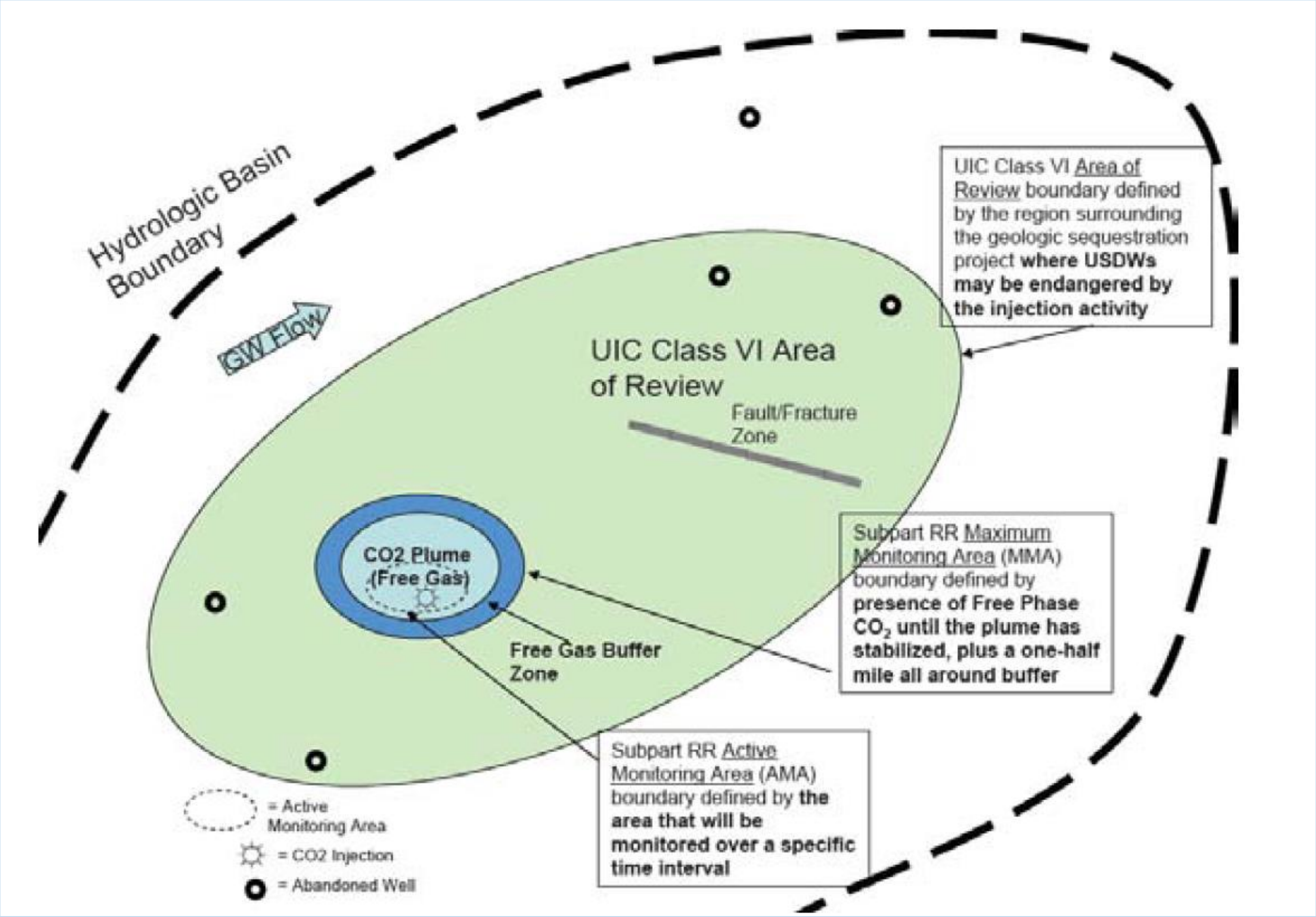


Figure from Stalker et al 2012

- Monitoring of pressure front in the injection zone required.
- Above zone pressure/geochemical monitoring interval recommended (loss of confinement).
- Periodic monitoring of groundwater quality above the confining zone(s) is required for comparison with baseline geochemical data.
- Previously existing wells may be converted to use as monitoring wells.

Areas of Review: Subpart RR Greenhouse Gas Reporting



- Active Monitoring Area (AMA) Superposition of two areas: (1) expected free-phase area at end of AMA period plus ½ mile; (2) expected free-phase area 5-years after end of AMA period.
- Maximum Monitoring Area (MMA) Equal to or greater than the area expected to contain free-phase CO_2 plume after stabilization plus at least ½ mile.

Soil-Gas and Flux Chamber Monitoring

- Soil-gas and flux monitoring can (not mandatory) be conducted under Subpart RR of the Greenhouse Gas Mandatory Reporting Rule.
- Release of gas into the vadose zone could be accompanied by compositional changes in soil gas (e.g., CH_4, C2-C4 hydrocarbons, CO_2, $\delta^{13}C$, Δ14C, H_2, He, H_2S, ^{222}Rn).

Figure from DiGiulio et al. (2023)

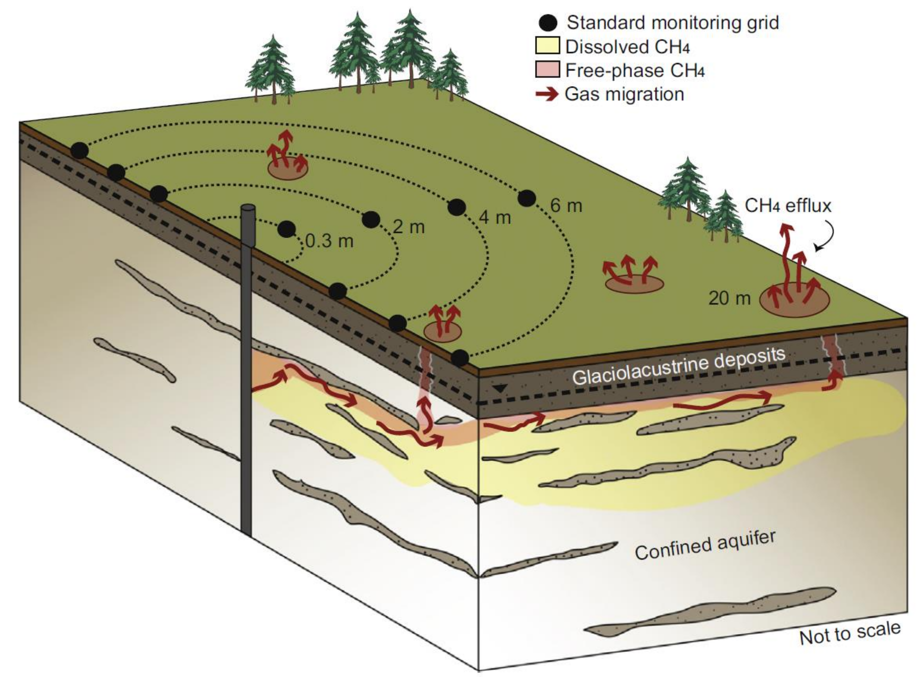


Figure from Forde et al (2019)

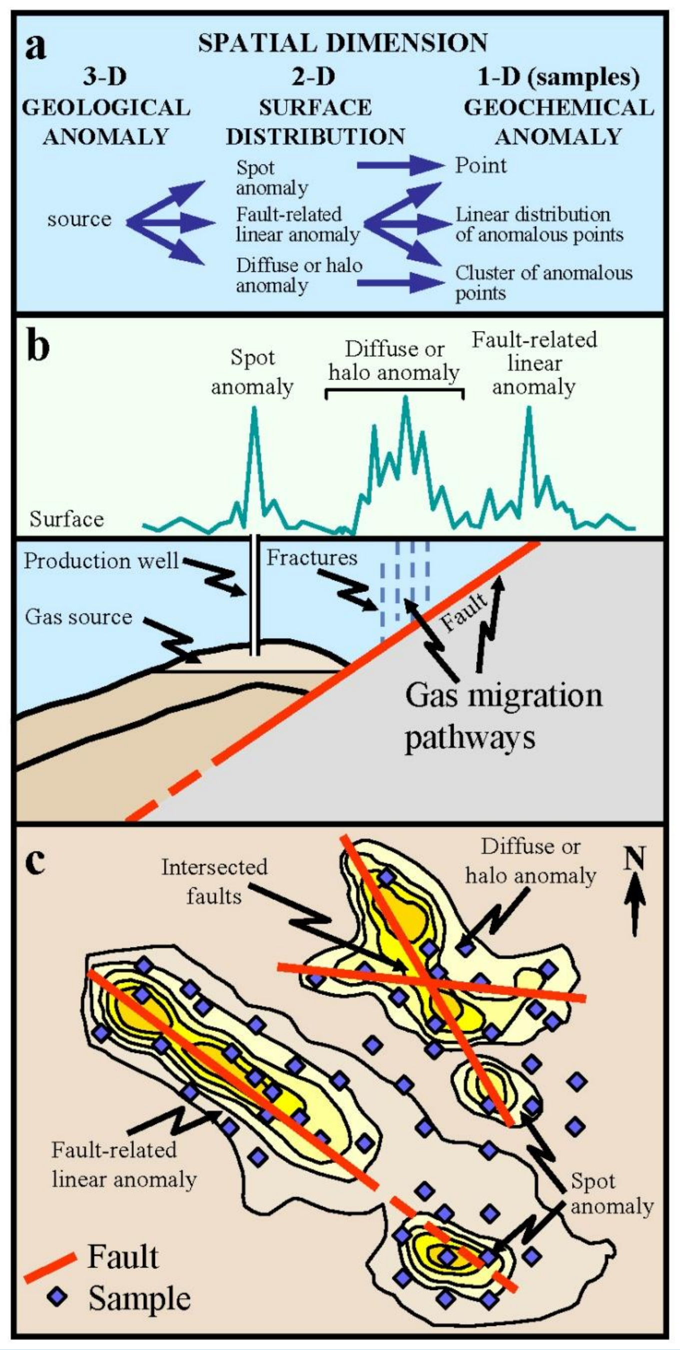
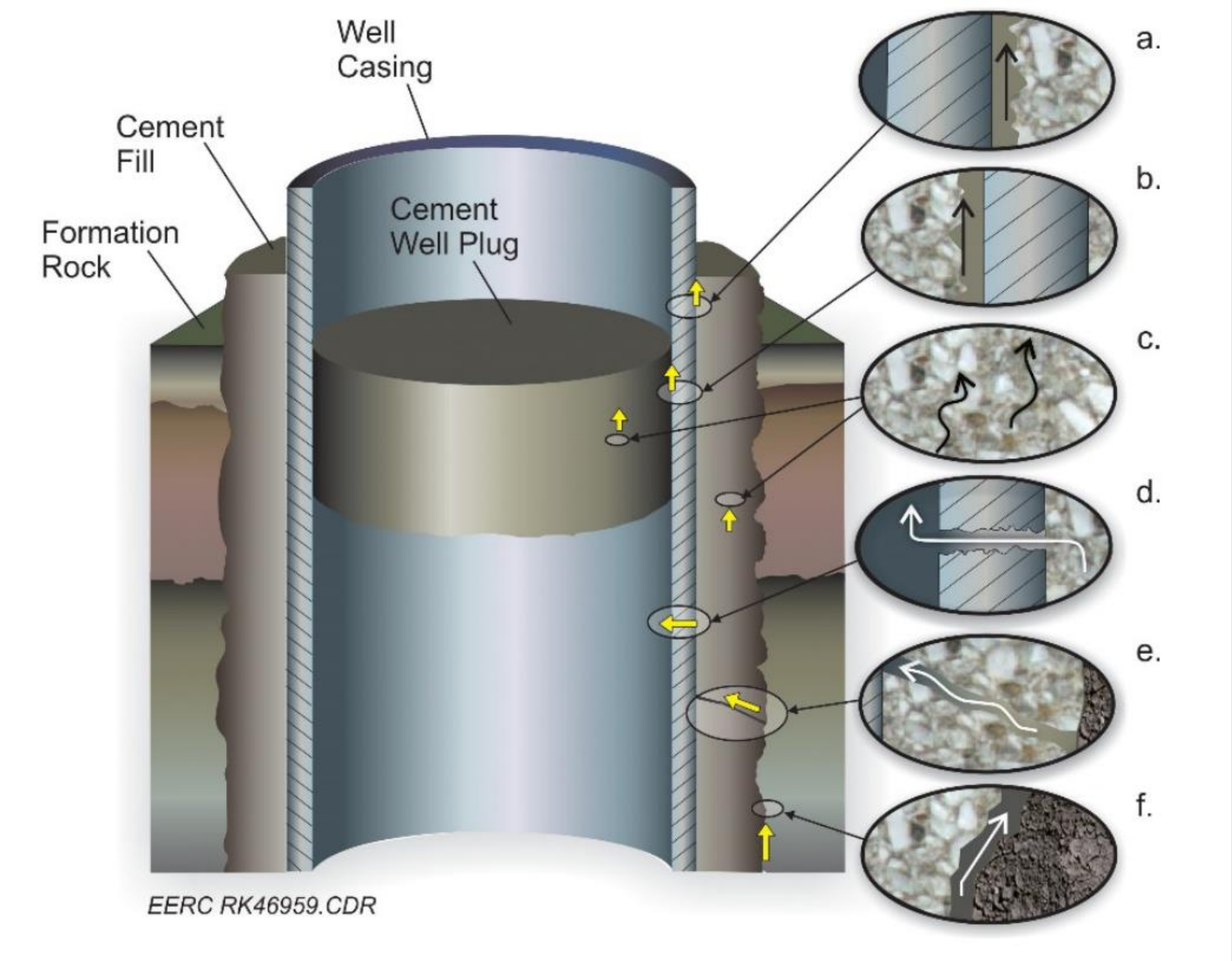


Figure modified from Ciotoli et al., (2004)

Leakage from Abandoned Wells

- Generally recognized as a primary leakage pathway for CO_2.
- Over 3.2 million abandoned wells in the United States with locations unknown for a large number of wells.
- Well plugging technology has evolved over time so older (e.g., prior to 1950s) plugged wells have insufficient integrity.
- Abandoned wells could come in contact with free-phase CO_2 or highly pressurized brine over time with material incompatibility.



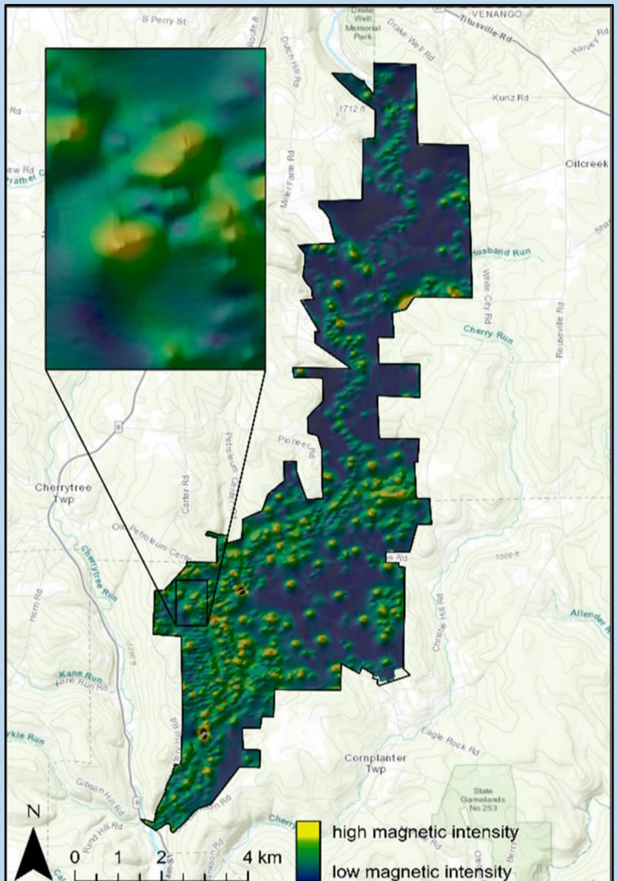
From Gasda et al. (2004)

Even properly plugged wells may:

- Contain zones (i.e., annular spaces) that could serve as a conduit for fluid movement.
- Have well plugs may have degraded over time because of corrosive conditions.
- Have been plugged with cement that could degrade when in contact with a carbon dioxide plume.

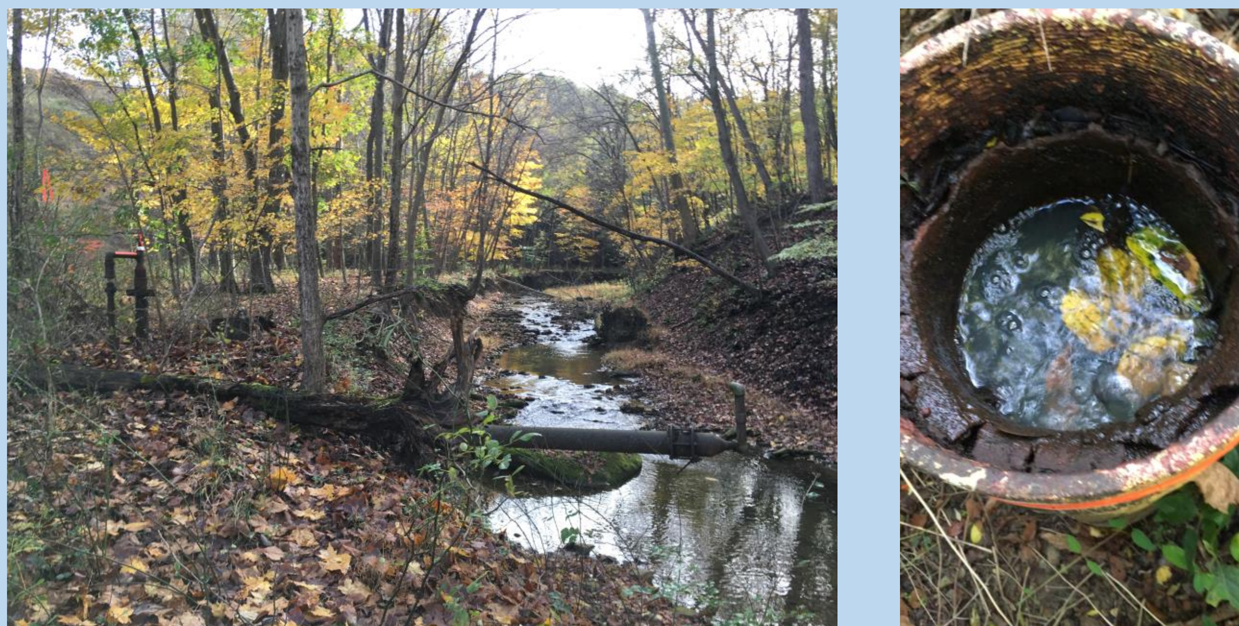
Finding Abandoned Wells

- Historical Records Search (e.g., state databases)
- Site Reconnaissance (e.g., physical structures)
- Aerial and Satellite Imagery Review (began in 1930s)
- Magnetic Surveys (e.g., aeromagnetic surveys)
- Ground Penetrating Radar



Magnetic anomalies from Oil Creek State Park, PA. From Saint-Vincent et al. (2020)

Photographs of abandoned well at Oil Creek State Park, PA (DiGiulio)



Photographs of abandoned well at western PA (DiGiulio)

Abandoned Wells in Pennsylvania


ACS OMEGA

http://pubs.acs.org/journal/acsodf Article

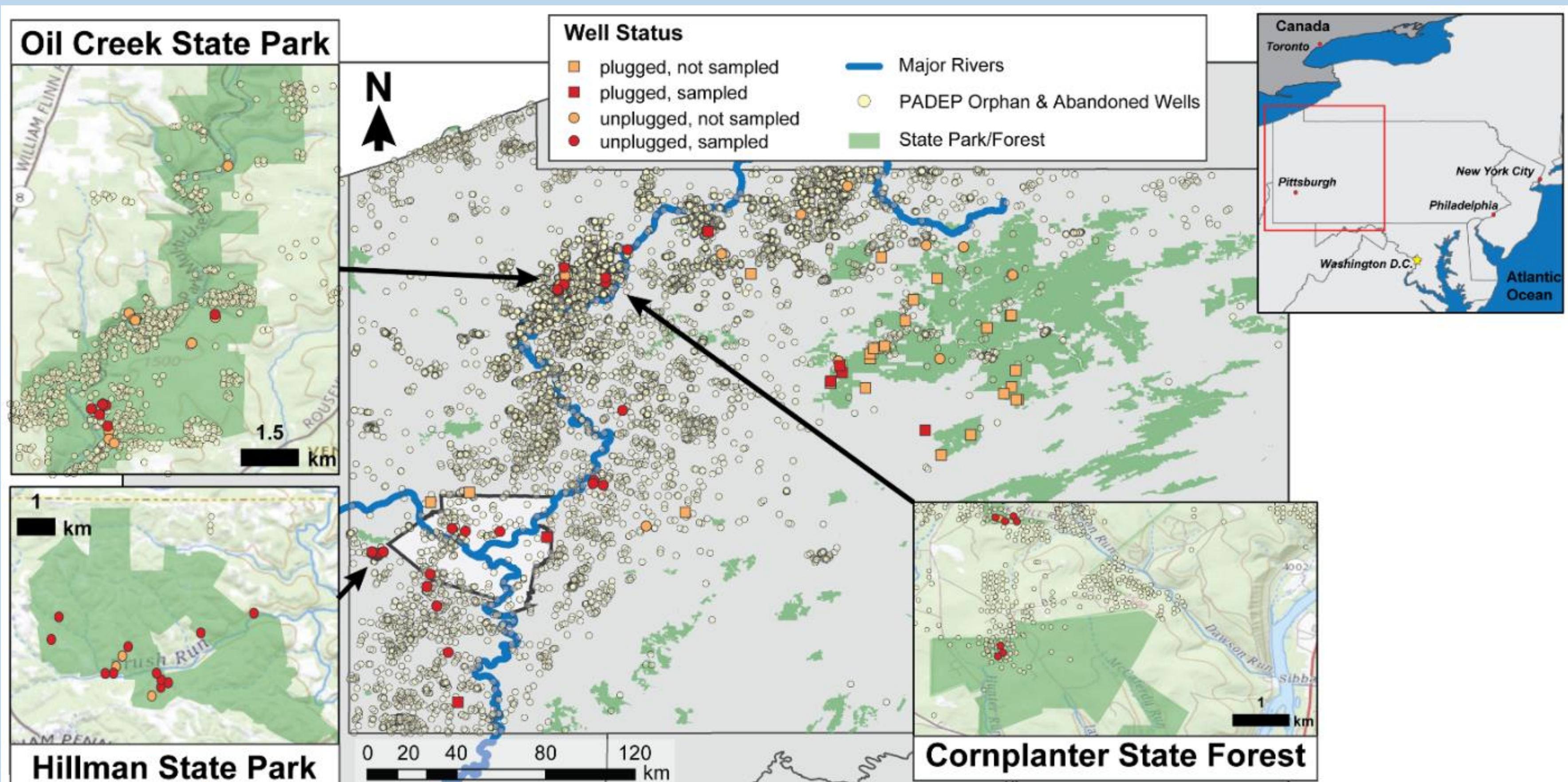
Chemical Characterization of Natural Gas Leaking from Abandoned Oil and Gas Wells in Western Pennsylvania

Dominic C. DiGiulio,* Robert J. Rossi, Eric D. Lebel, Kelsey R. Bilsback, Drew R. Michanowicz, and Seth B.C. Shonkoff

Cite This: https://doi.org/10.1021/acsomega.3c00676 Read Online

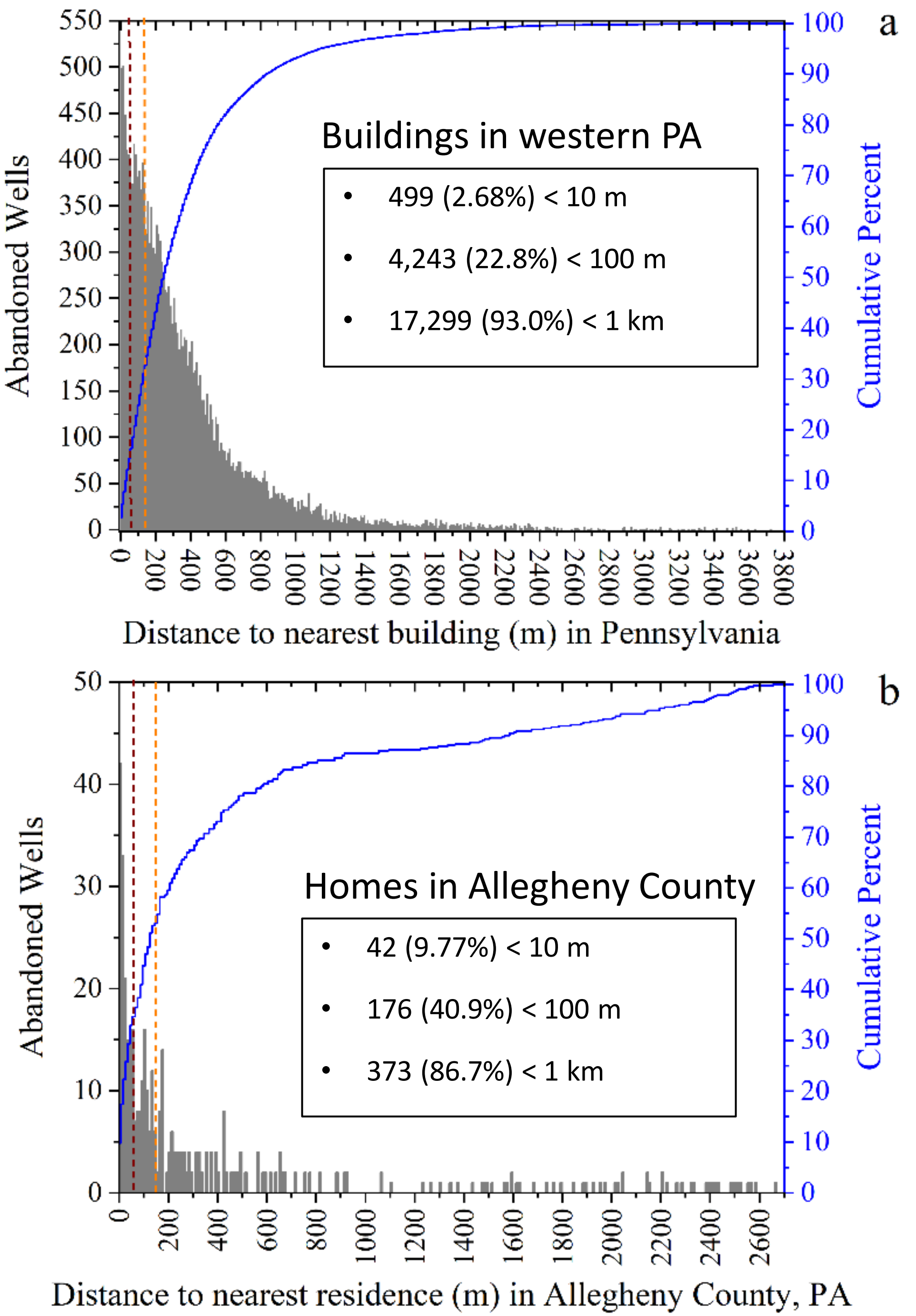
ACCESS | Metrics & More | Article Recommendations | Supporting Information

- 24,619 documented abandoned wells (18,608 having coordinates)
- PADEP estimates that over 200,000 abandoned wells exist in Pennsylvania that have not been located.



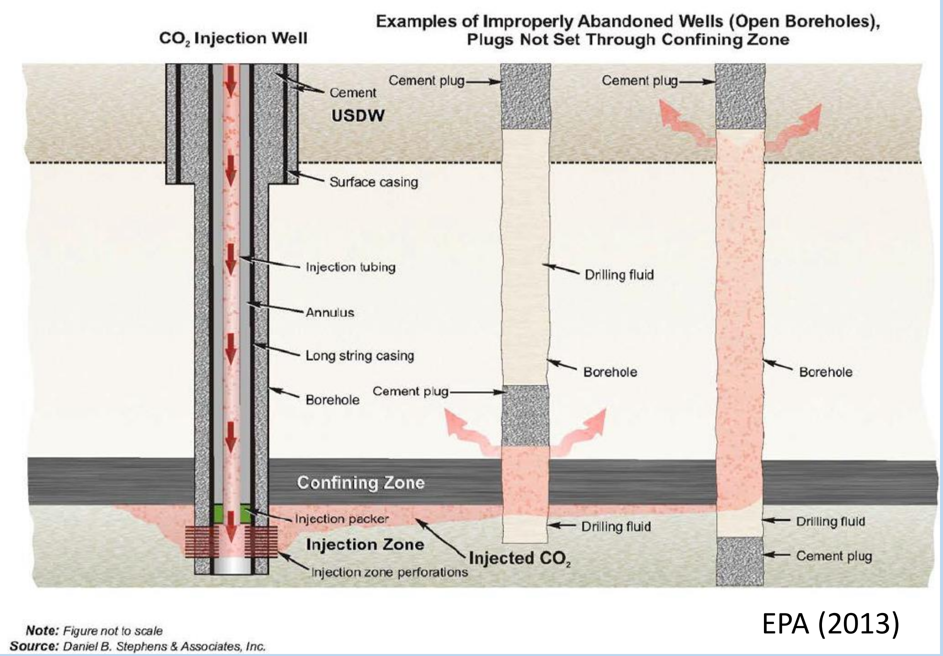
Proximity Analysis

Photograph sampling abandoned well near house in western PA (DiGiulio)



Actual numbers likely much higher since only a fraction of abandoned wells are located.

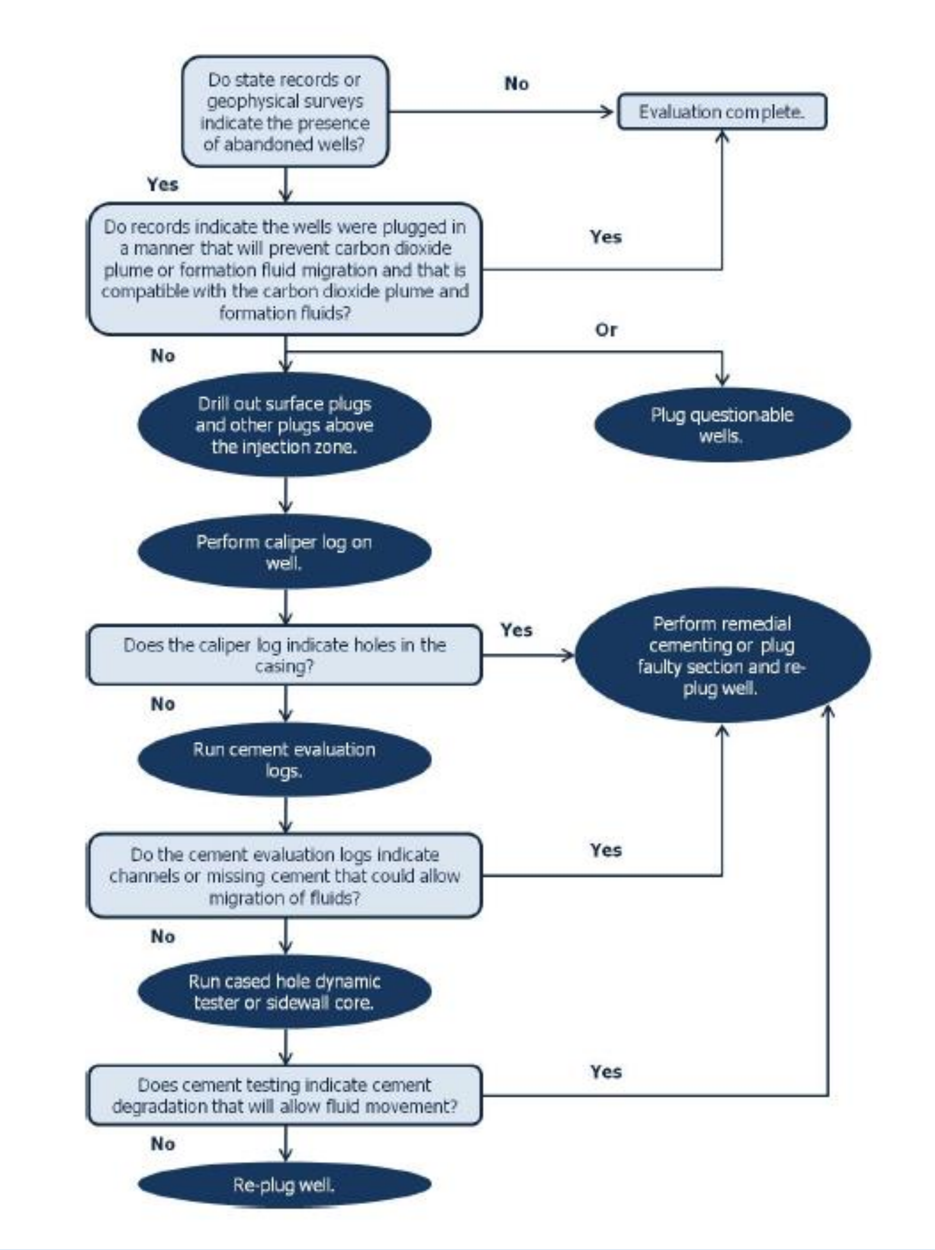
Evaluating Abandoned Wells



EPA (2013)

At a minimum, there should be a cement plug across the primary confining layer, the bottom of any casings, and across any USDWs.

- Well type, construction, date drilled (especially pre-1960), location, depth, record of plugging and/or completion.
- Open hole or cased hole, location of plugs.
- Drilling, casing and cementing records (deviation, loss of circulation, lack of the use of centralizers, improper removal of drilling mud before cementing).
- Compatibility of casing and cement materials.
- Records of MITs or logs performed (e.g., CBL/VDL).



EPA (2013)

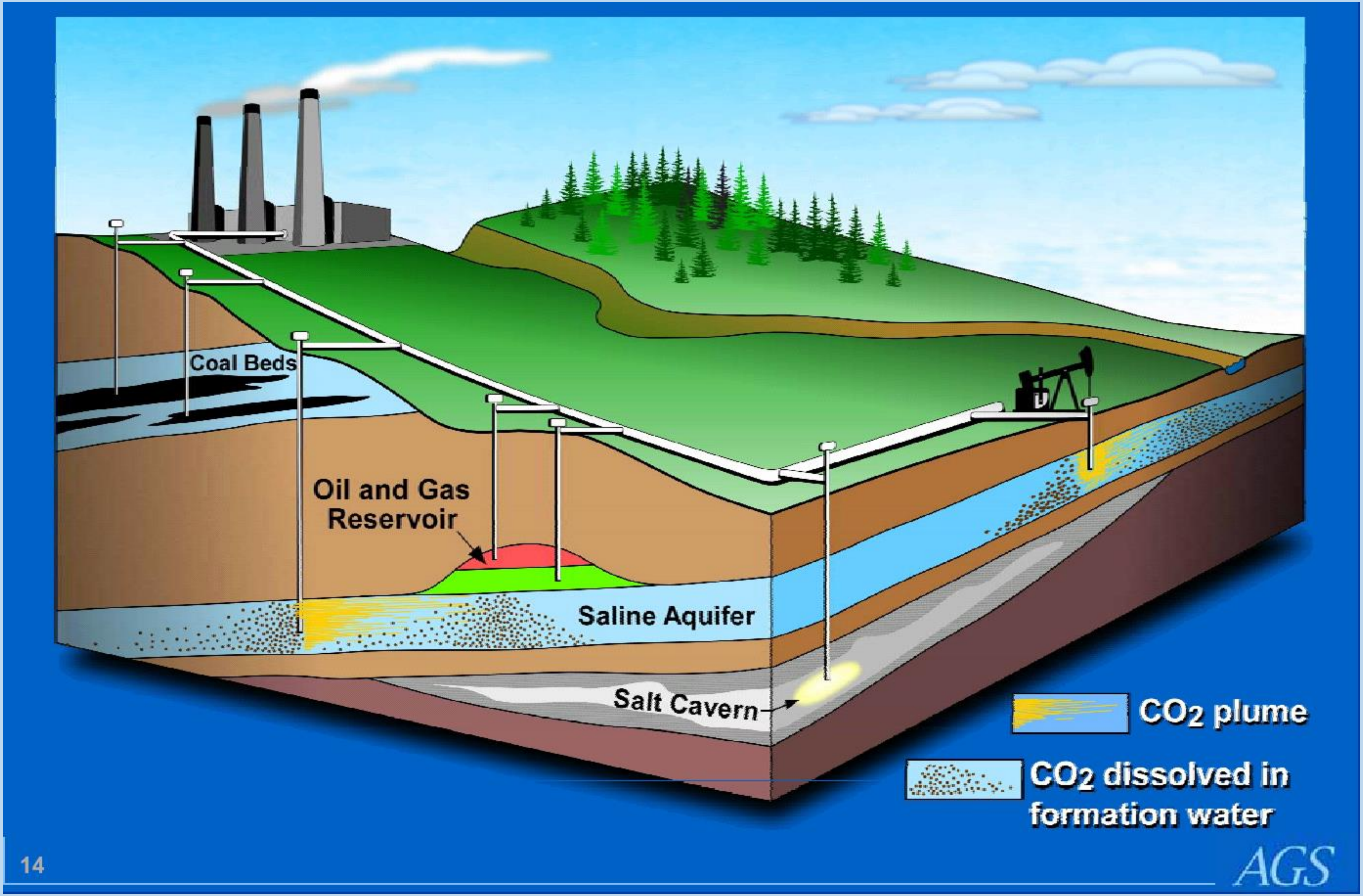
Thank You!

Contact Information

dom.c.digiulio@gmail.com

Supplemental Slides

Types of Geologic Storage Units

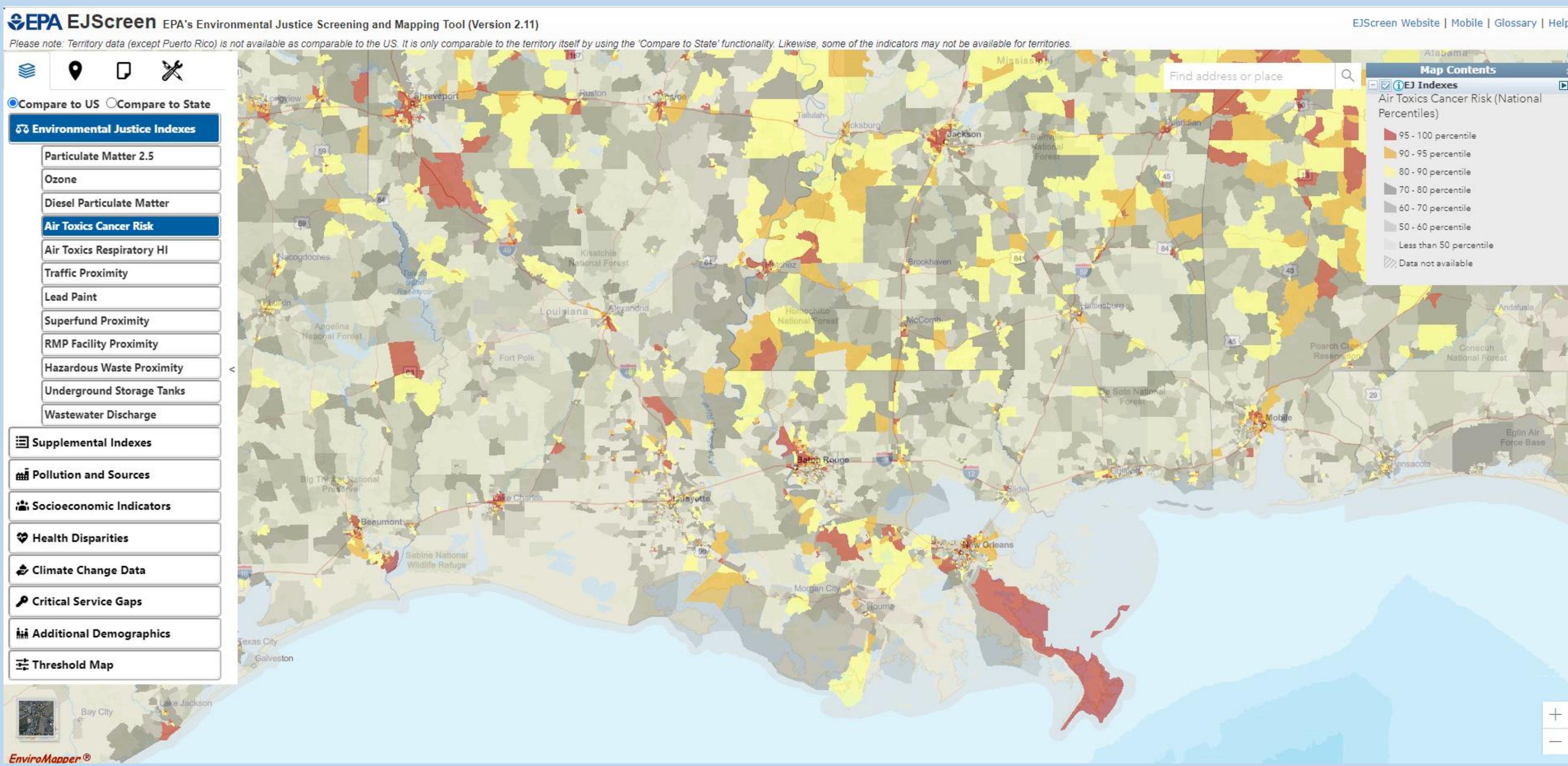


from Bachu (2007)

New Environmental Justice Requirement for Class VI Primacy (LA)

- EPA letter to governors (12/9/2022)
- Memorandum of Agreement between LA and EPA (3/3/2023)

- More inclusive public participation process
- Consideration of EJ impacts (EJ Screen)
- Enforce Class VI regulations
- Incorporate mitigation measures



Offshore Geographic Extent of Class VI Rule and Subpart RR Monitoring

- Bureau of Ocean Energy Management (BOEM) ongoing rulemaking is outer continental shelf (OCS) CO_2 Storage
- State seaward boundary equals 3 nautical miles for LA, MS, AL and 9 nautical miles for TX, FL, and Puerto Rico

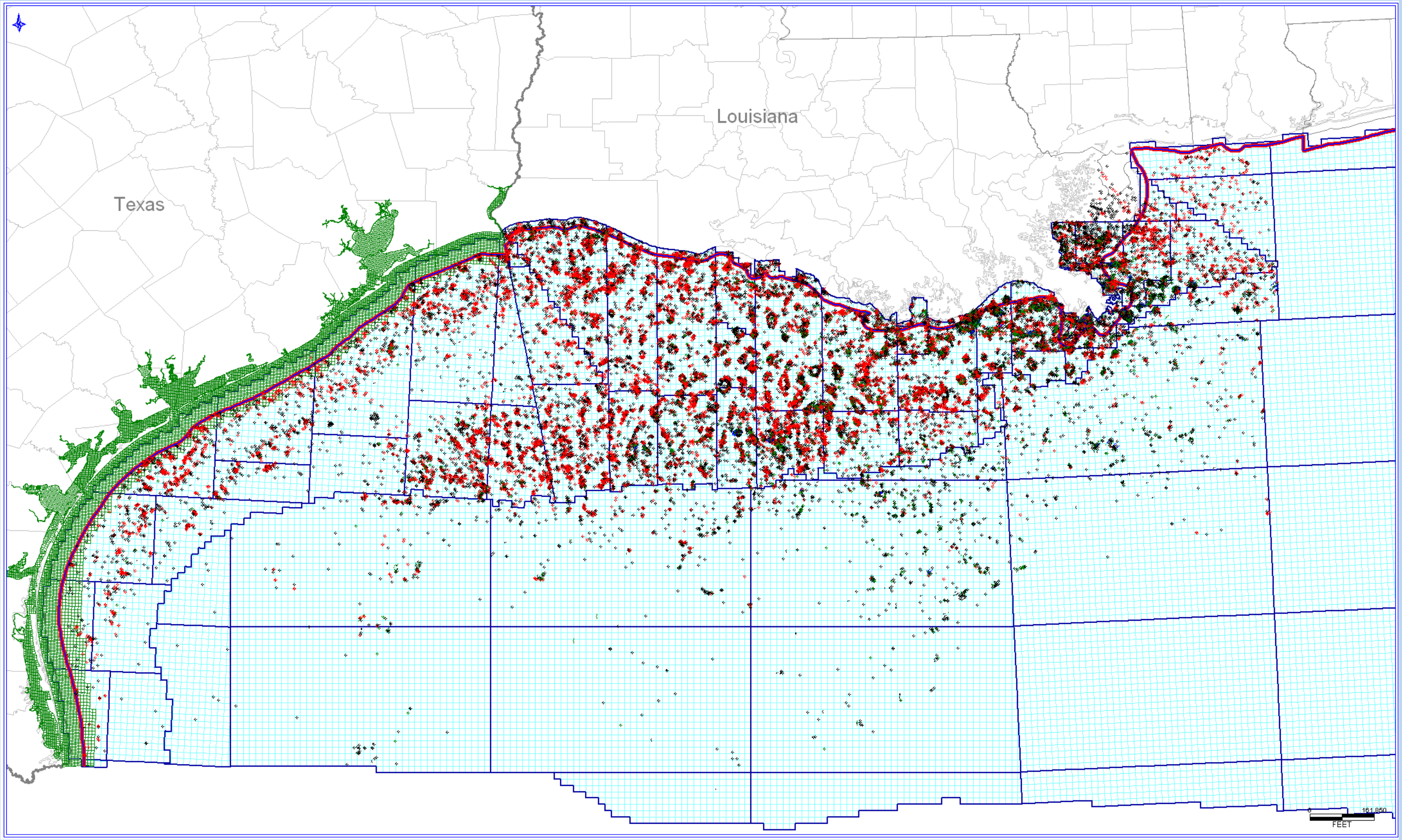


Figure from Smyth and Hovorka, 2017. Red dots = gas wells, green dots = oil wells, black dots = dry holes

Storage During Enhanced Oil and Gas Recovery

- ~ 80% of the CO_2 used in EOR is derived from naturally occurring underground reservoirs of CO_2.
- Eligible for 45Q tax credits
- Pressure buildup from CO_2 injection balanced by fluid withdrawal.
- Many abandoned wells.
- Regulated as Class II Wells
- Class VI closure requirements not applicable even if oil or gas recovery is no longer a significant aspect operation.

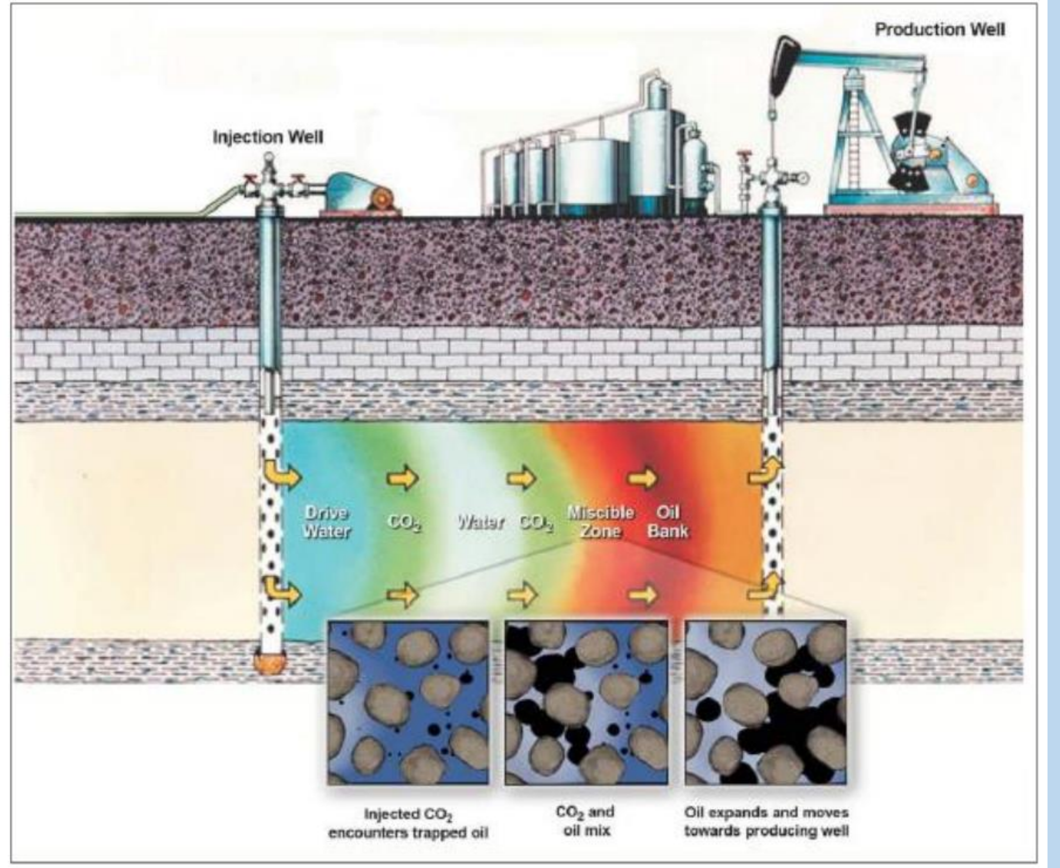
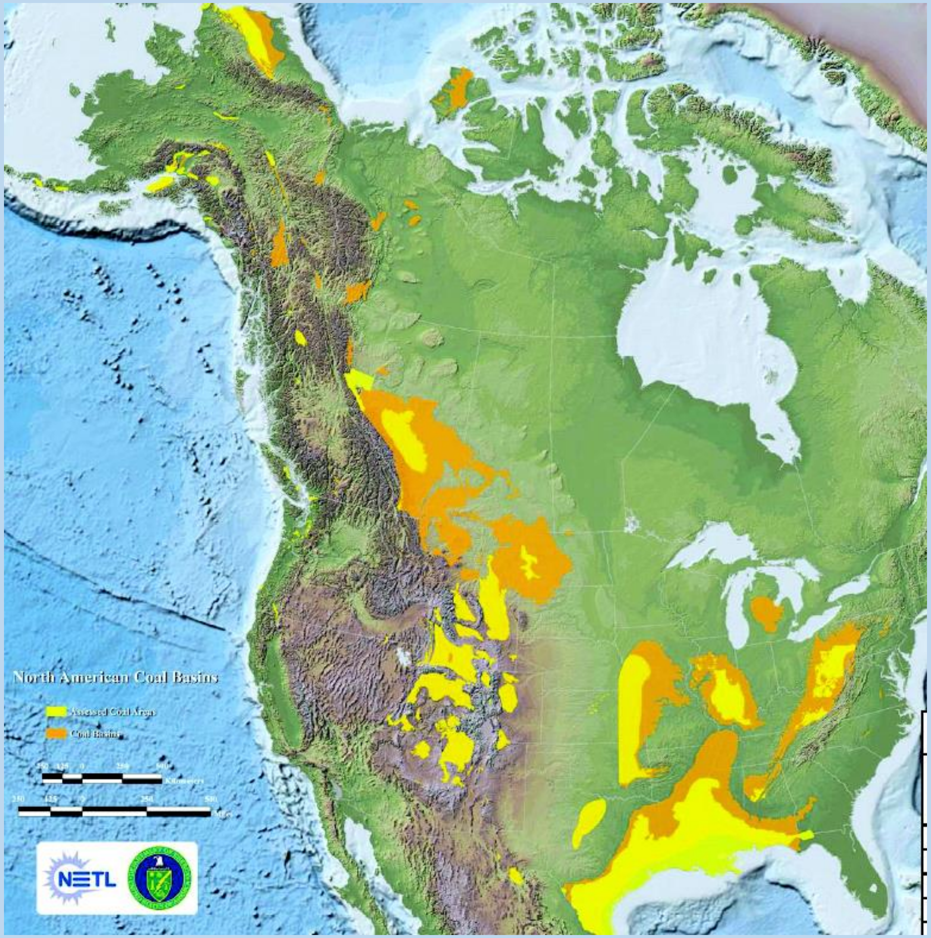


Figure from DOE, 2007

Conversion to a Class VI

- Increase in reservoir pressure within the injection zone indicates increased risk to USDWs.
- Increase in carbon dioxide injection rates.
- Decrease in reservoir production rates.
- Vertical distance between the injection zone(s) and USDWs.
- Suitability of the Class II area of review delineation.
- Quality of abandoned well plugs within the area of review.
- The owner's or operator's plan for recovery of CO_2 cessation of injection.
- The source and properties of injected CO_2.
- Any additional site-specific factors as determined by the Director.

Storage in Unmineable Coal Seams



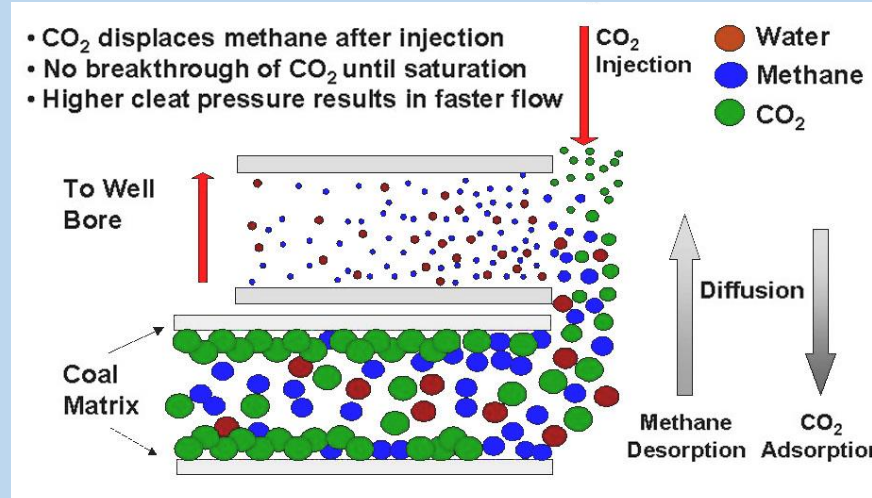


Figure from DOE, 2007

Figure from DOE, 2006

- Too deep or too thin to be economically mined. Value added incentive.
- DOE estimates that for every molecule of methane displaced three to 13 CO_2 molecules are adsorbed.

- Relatively minor storage capacity
- Swelling - reduction of permeability.
- May be too shallow for storage as supercritical fluid.
- Coal permeability decreases with depth.
- Injection below ~ 900 meters causes fracturing.
- May be close to or part of USDWs

Comparison of Storage Capacity

Estimates of CO_2 Stationary Source Emissions and Estimates of CO_2 Storage Resources for Geologic Storage Sites

RCSP or Geographic Region	CO_2 Stationary Sources		CO_2 Storage Resource Estimates (billion metric tons of CO_2)								
	CO_2 Emissions (million metric tons per year)	Number of Sources	Saline Formations			Oil and Gas Reservoirs			Unmineable Coal Areas		
			Low	Med***	High	Low	Med***	High	Low	Med***	High
BSCSP	115	301	211	805	2,152	<1	<1	1	<1	<1	<1
MGSC	267	380	41	163	421	<1	<1	<1	2	3	3
MRCSP	604	1,308	108	122	143	9	14	26	<1	<1	<1
PCOR*	522	946	305	583	1,012	2	4	9	7	7	7
SECARB	1,022	1,857	1,376	5,257	14,089	27	34	41	33	51	75
SWP	326	779	256	1,000	2,693	144	147	148	<1	1	2
WESTCARB*	162	555	82	398	1,124	4	5	7	11	17	25
Non-RCSP**	53	232	--	--	--	--	--	--	--	--	--
Total	3,071	6,358	2,379	8,328	21,633	186	205	232	54	80	113

Source: U.S. Carbon Storage Atlas –Fifth Edition (Atlas V); data current as of November 2014

* Totals include Canadian sources identified by the RCSP

** As of November 2014, "U.S. Non-RCSP" includes Connecticut, Delaware, Maine, Massachusetts, New Hampshire, Rhode Island, Vermont, and Puerto Rico

*** Medium = p50

From NETL, 2016

Iterative Nature of Site Characterization, Modeling, and Monitoring to Support Class VI Rule

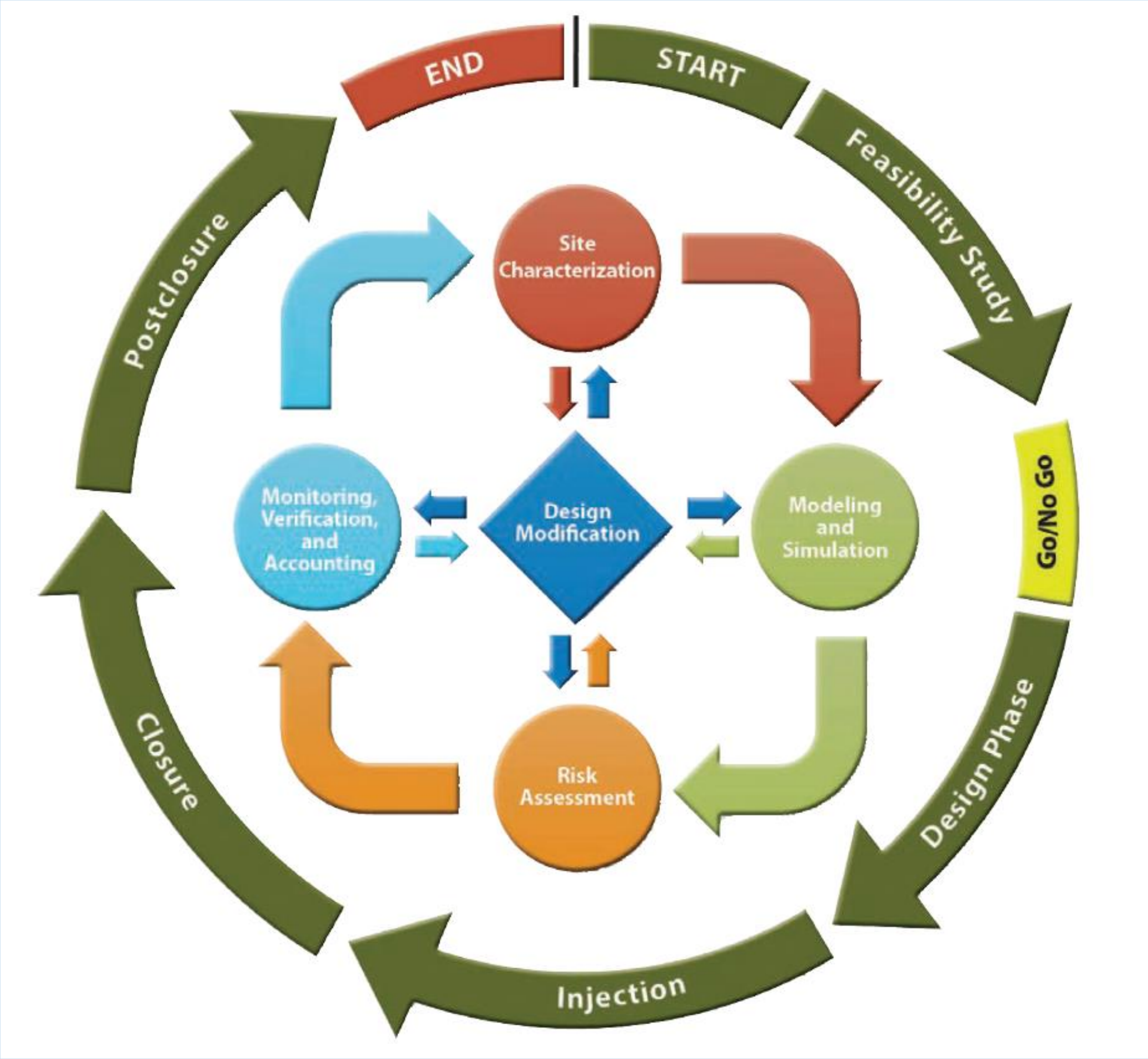


Figure Gorecki, 2012

Testing and Monitoring Plan

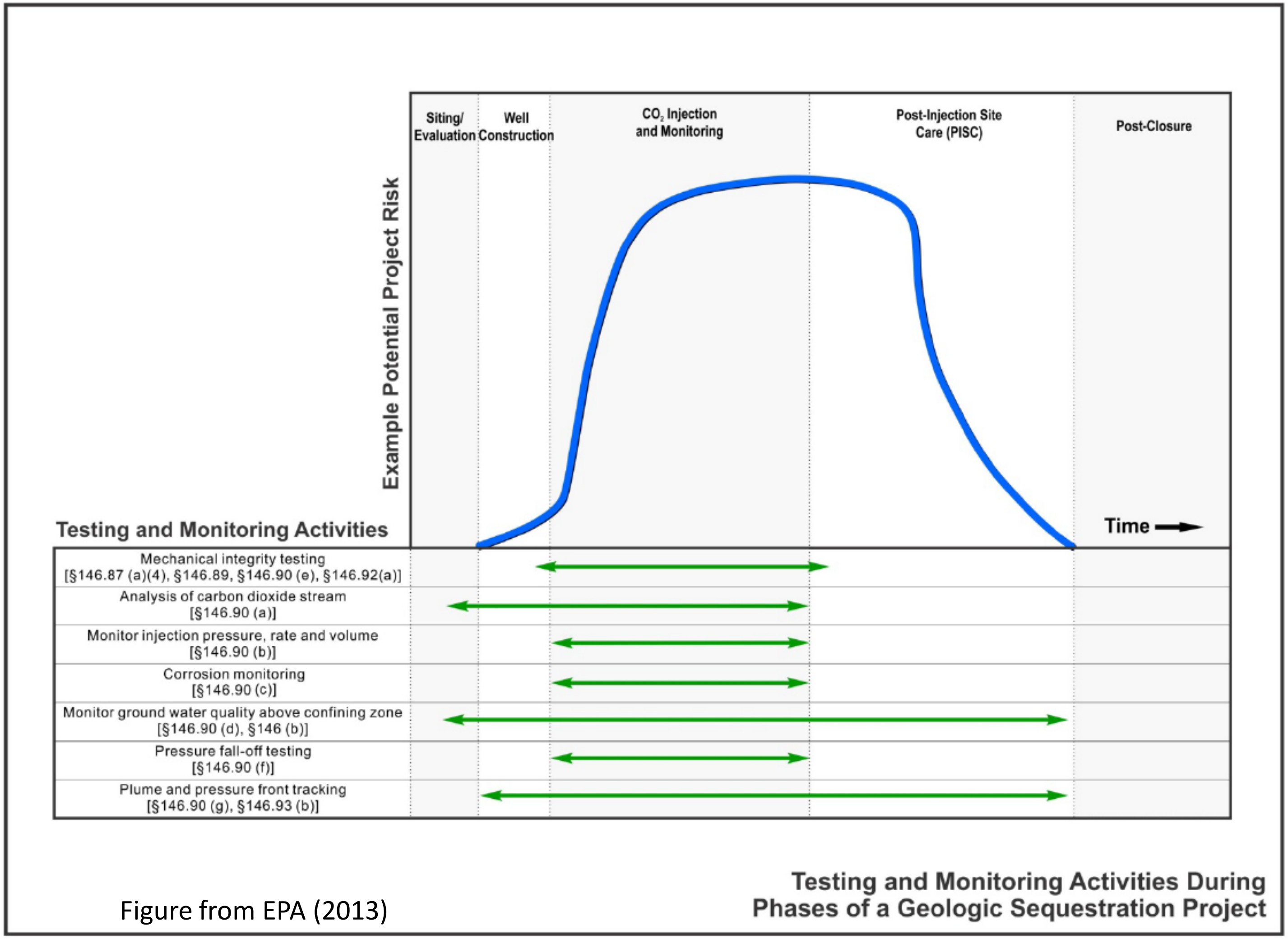


Figure from EPA (2013)

Testing and Monitoring Plan must be submitted with the initial permit application for and revised, if necessary, based on information collected during pre-injection logging and testing. The plan must be reviewed at least every five years to incorporate monitoring data and the results of AoR reevaluations to make necessary amendments or demonstrate that no amendments are needed.

Monitoring, Reporting, and Verification (MRV) Plan for Subpart RR Reporting

Mass Balance

- Mass of CO_2 received
- Mass of CO_2 injected into the subsurface
- Mass of CO_2 produced (mixed with produced oil, gas, or other fluids)
- Mass of CO_2 emitted by surface leakage
- Mass of CO_2 emitted as equipment leakage or vented from surface equipment
- Mass of CO_2 sequestered in subsurface geologic formations
- Cumulative mass of CO_2 sequestered since the start of required reporting.

Leakage

- Delineation of the maximum and active monitoring areas
- Identification of potential CO_2 leakage pathways in the maximum monitoring area and the likelihood, magnitude, and timing of surface leakage through these pathways
- Strategy to detect and quantify CO_2 surface leakage
- Strategy to establish the expected baselines for monitoring CO_2 surface leakage