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Live Webinar

Quantifying Formation and Fault Barrier Capacity: A Geomechanics-Based Framework for Safe Subsurface Operations

WEDNESDAY, 10 DECEMBER
1100 CST (UTC-6)

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SLB

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Quantifying Formation and Fault Barrier Capacity: A Geomechanics Based Framework for Safe Subsurface Operations

Uday Tare

December 10, 2025

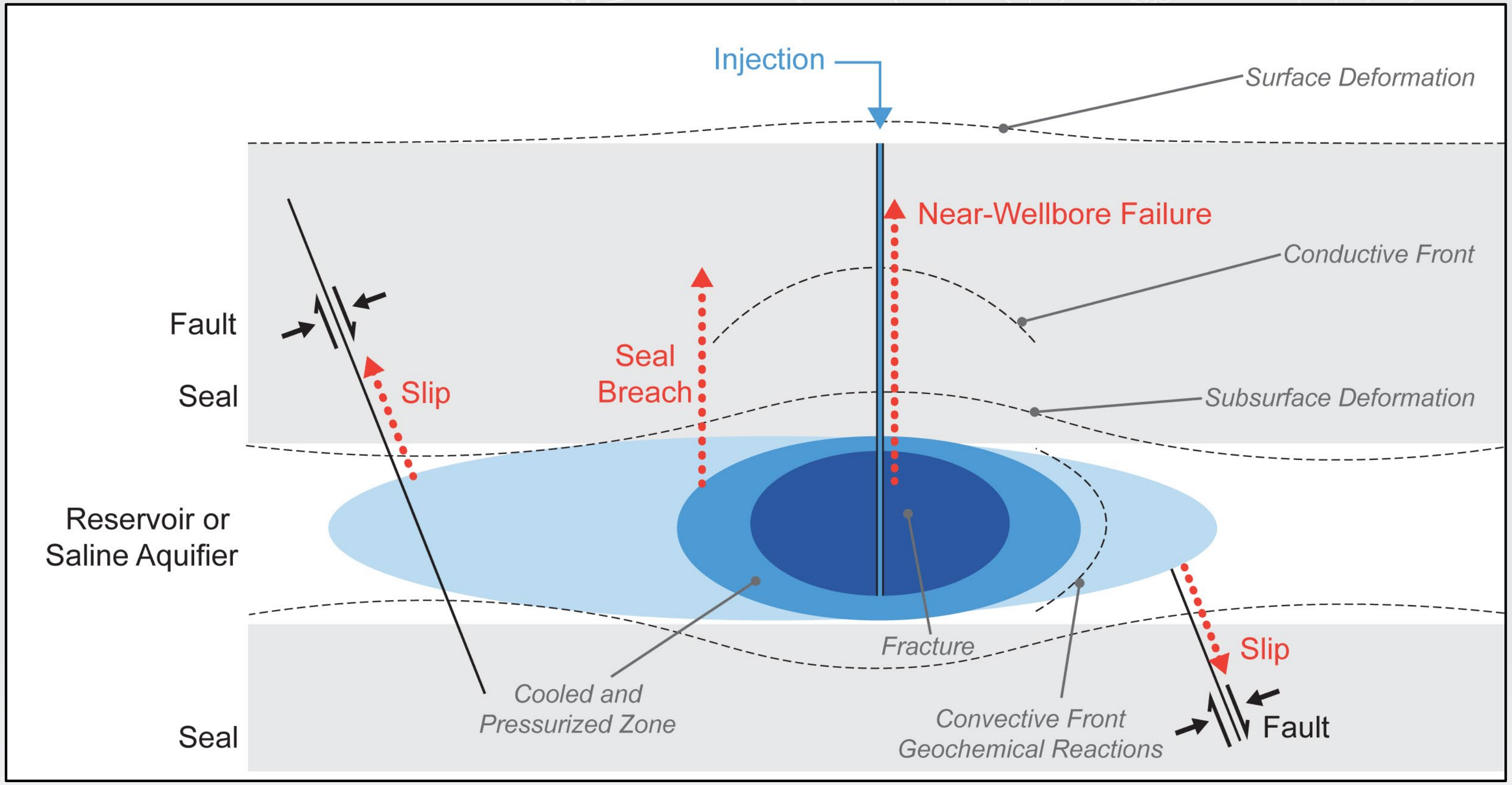
Presentation Outline

- **Introduction**
- **Geomechanics Concepts and Workflow**
- **Fracturing**
- **Seal Integrity**
- **Injection-Induced Fault Slip**
- **Remarks**

Introduction

Reservoir Containment Leak Paths

Injection and storage is a multi-physics problem.



Reservoir containment loss has multi-dimensional impact spanning environmental, safety, regulatory, financial, social, and infrastructure domains that necessitate robust barriers and proactive management.

Reservoir containment leak paths.

- Well and near wellbore
- Reservoir seal breach
- Injection-induced fault slip

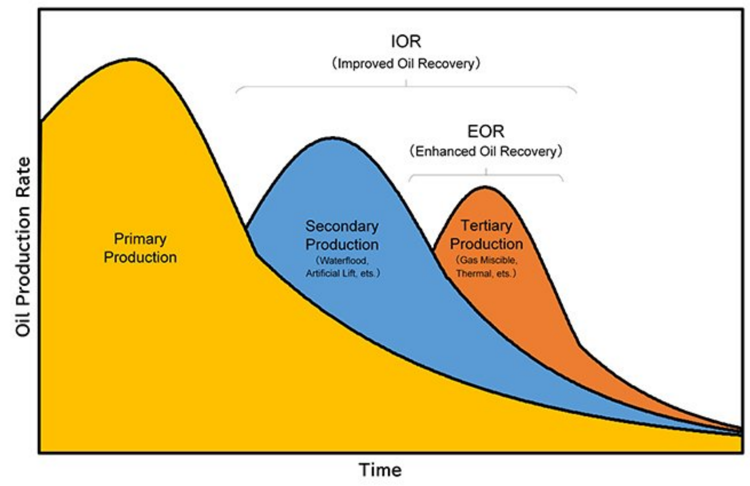
Barriers to ensure reservoir containment.

- Well design and zonal isolation elements
- Reservoir–seal system
- Life cycle planning
- Safe operations (pressure management)
- Monitoring and surveillance systems
- Contingency and emergence response planning

Why quantify leak path barrier capacity?

- Supports setting safe operational limits
- Required for regulatory approval
- Informs MMV/surveillance plans
- Critical to environmental safety

IOR and EOR Overview



Source: JAPEX, 2024

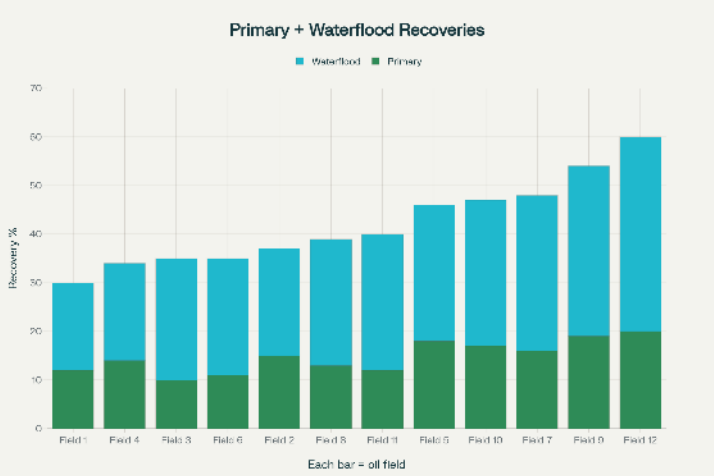
Industry Drivers – Shifting Oil and Gas Portfolios

- Less primary hydrocarbon production (natural decline)
- Portfolio diversification toward improved oil recovery (IOR)
- Enhanced oil recovery (EOR) opportunities
- Government recovery mandates and efficiency requirements
- License to operate depends on achieving recovery targets

Global Scope – All Major Basins: Conventional and unconventional resources across developed and developing provinces

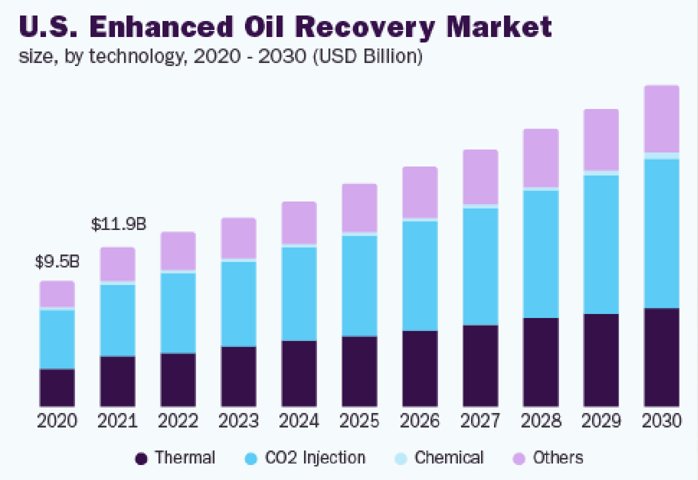
In conventional reservoirs waterflooding consistently adds 15%–30% additional recovery on top of primary production.

With "smart water" (low-salinity waterflooding) can increase oil recovery by 5%–30% of original oil in place beyond conventional waterflooding.



AAPG Explorer Article, Nash 2025

Towards 70% Recovery Factor, SPE 179586

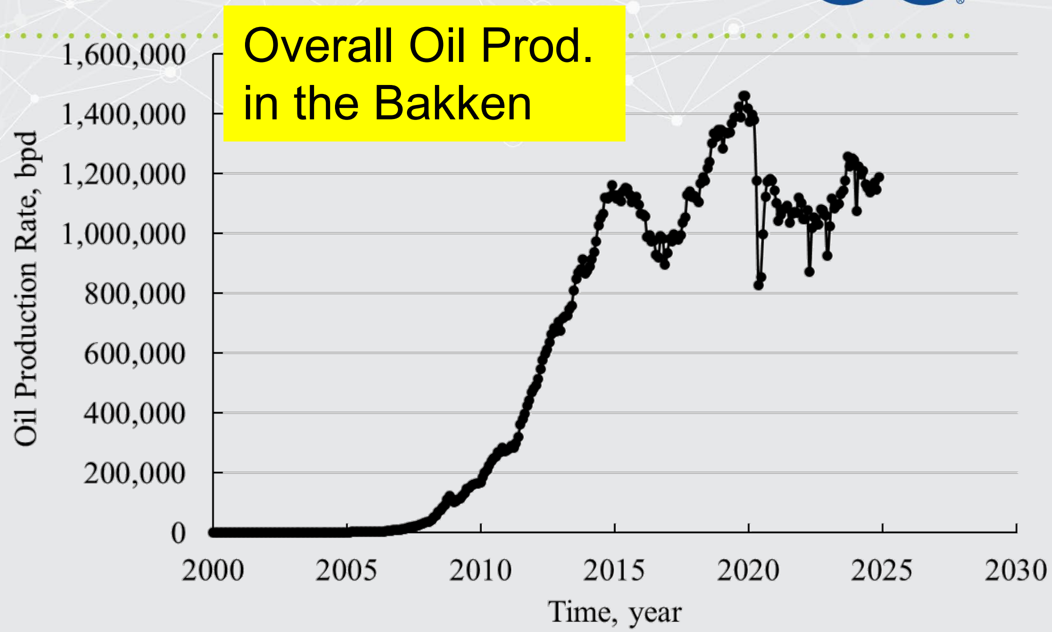


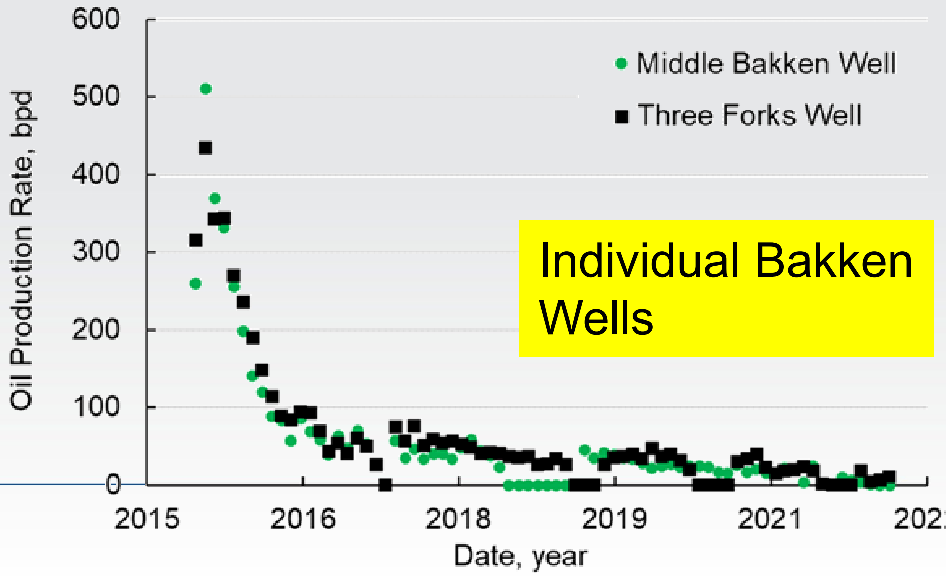
Source: Grand View Research, 2024

The EOR market in the United States is anticipated to increase in the next decade because of the growing development of unconventional resources.

Oil Production Overview for the Bakken

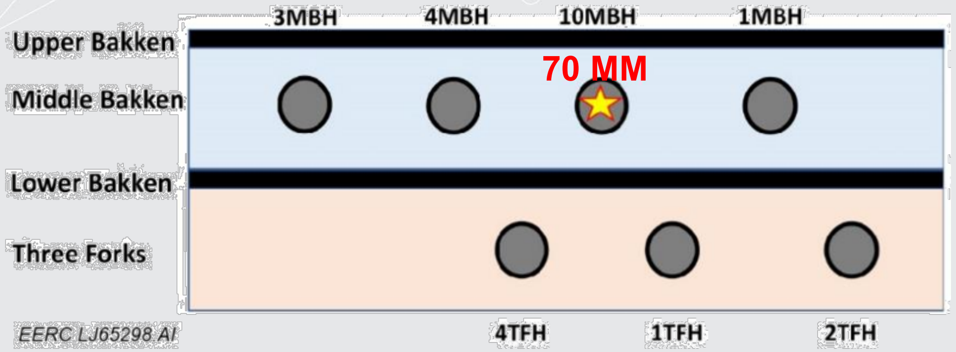
- The oil production in the Bakken has stabilized around 1 MMbpd for over 10 years.
- Oil production rate declines fast in most Bakken wells, leading to low oil recovery factors. More wells need to be drilled to maintain the overall production rate.
- With the continuous development of the Bakken, EOR is becoming increasingly important for operators in the area.
- EOR is still in an early stage for the Bakken, and many fundamental questions need to be answered.



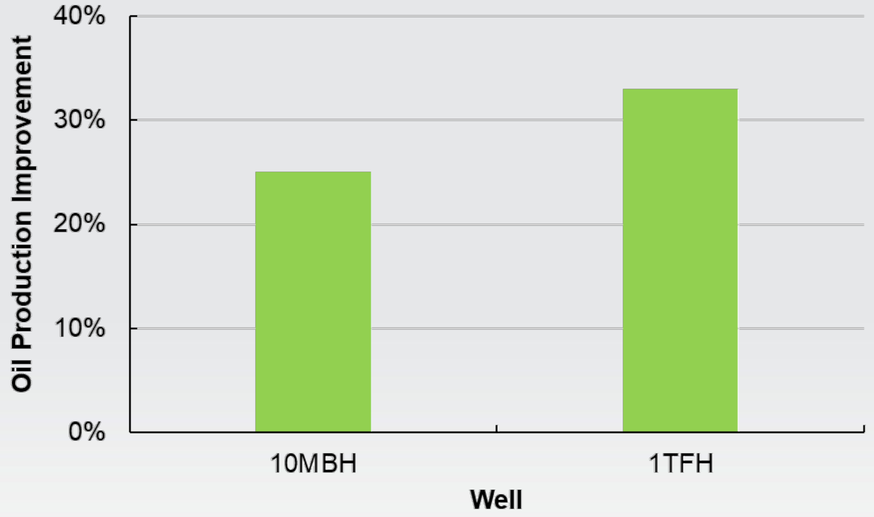


Three Gas EOR Pilot Tests in the Bakken

To better understand and control the EOR process in the Bakken, the EERC has worked with Liberty Resources LLC on three gas EOR pilots since 2018.



1. **Stomping Horse (2018)**: a multi-well HnP using produced gas (SPE-201471-MS).
2. **East Nesson 1 (2021)**: a single-well HnP using produced gas, fresh water, and surfactant (URTEC-3722974).
3. **East Nesson 2 (2023)**: a single-well HnP using produced water and produced gas (SPE-220889-MS).

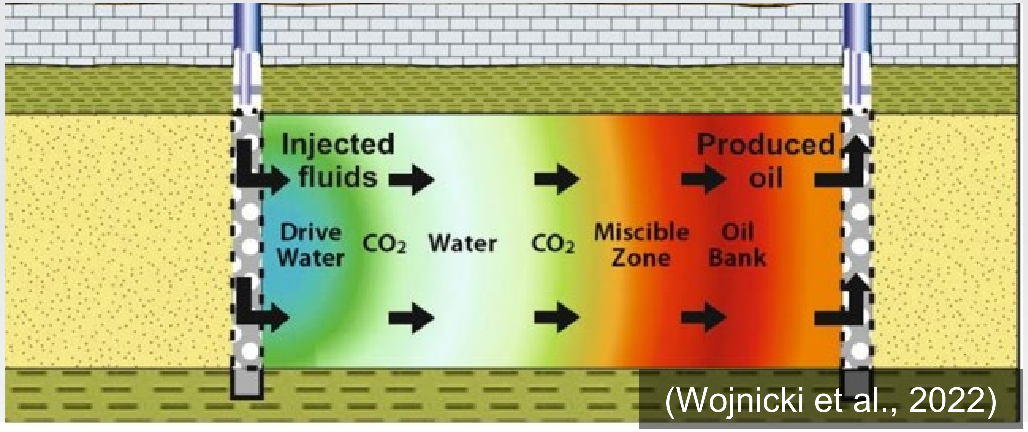


The 60-day average oil rate increased 24% and 33% in 10MBH and 1TFH, respectively.

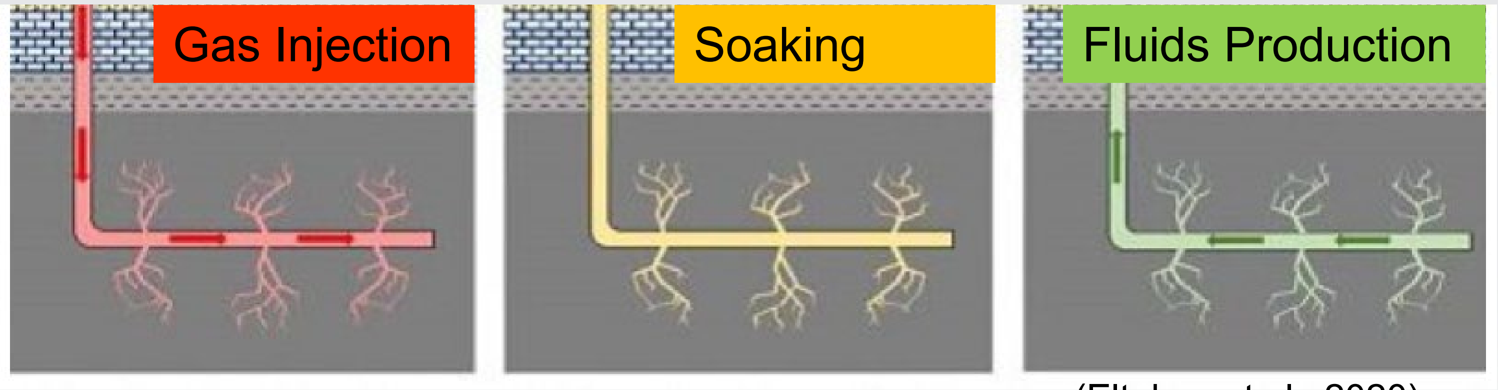
From: Jim Sorensen
Energy & Environmental Research Center
701.777.5287, jsorensen@undeerc.org

Comparison of Gas EOR in Conventional and Unconventional Reservoirs

- In conventional reservoirs, long-term miscible flooding is one of the most successful EOR methods. High sweep efficiency is achievable in these permeable formations.
- However, for unconventional reservoirs, gas flooding could be challenging due to the low sweep efficiency caused by the strong contrast between tight matrix and permeable fractures.
- HnP is the main EOR method in unconventional reservoirs, utilizing the same well for injection, soaking, and production.



(Wojnicki et al., 2022)



(Eltahan et al., 2020)

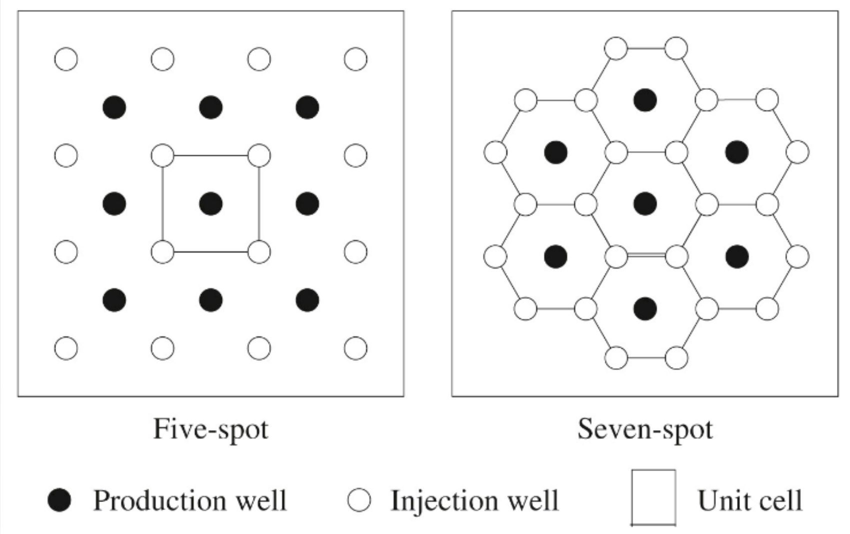
Miscible Gas Flooding in **Conventional Reservoirs**

Gas HnP in **Unconventional Reservoirs**

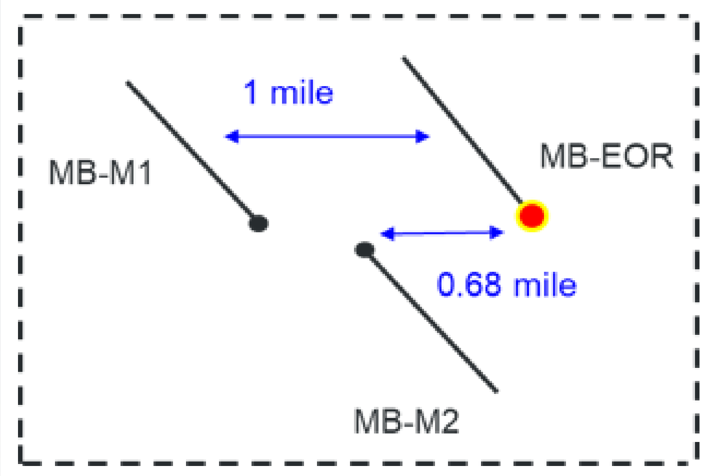
Zhao, J., Jin., L., Yu, X., Azzolina, N.A., Wan, X., Smith, S.A., Bosshart, N.W., and Sorensen, J.A., 2024, Field implementation and surveillance of gas injection enhanced oil recovery in the Bakken; Presentation for the Unconventional Resources Technology Conference, June 18, 2024.

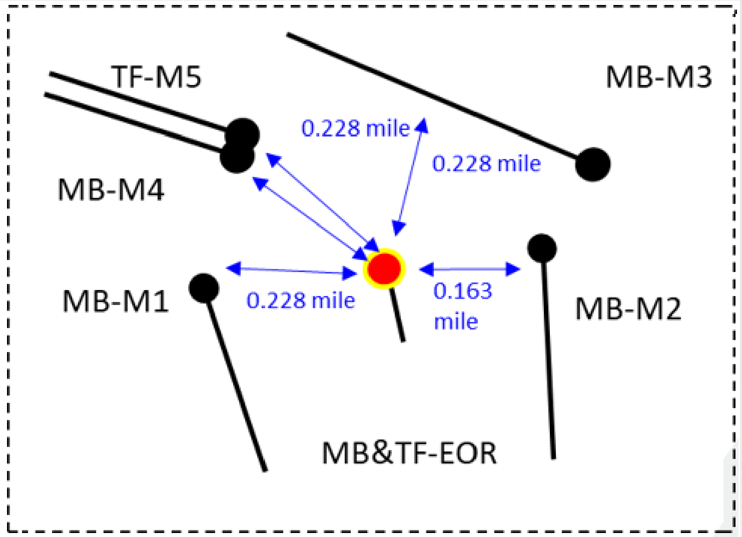
Well Distribution and EOR Patterns in Different Reservoirs

- **Conventional reservoirs onshore:** Well distribution can be regularized, and a variety of flooding patterns have been developed to maximize the EOR effect.
- **Unconventional reservoirs:** Well distribution can be irregular, and there is not a common pattern developed for EOR purposes.
- **Deepwater developments:** Few wells because wells are costly. common types of waterfloods are peripheral floods and producer/injector pairs.



Regular Well Distribution and Flooding Patterns in Conventional Reservoirs





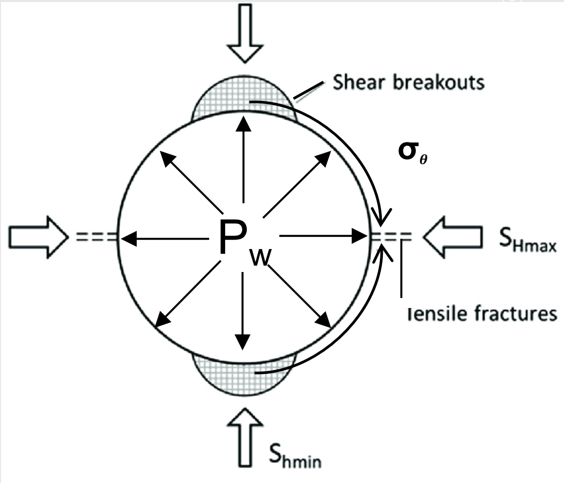
Irregular Well Distribution and EOR Patterns in Unconventional Reservoirs

Zhao, J., Jin., L., Yu, X., Azzolina, N.A., Wan, X., Smith, S.A., Bosshart, N.W., and Sorensen, J.A., 2024, Field implementation and surveillance of gas injection enhanced oil recovery in the Bakken; Presentation for the Unconventional Resources Technology Conference, June 18, 2024.

Geomechanics Concepts and Workflow

Geomechanics Concepts for Quantifying Barrier Integrity

Near Wellbore



Near Wellbore Induced Tensile Fracturing

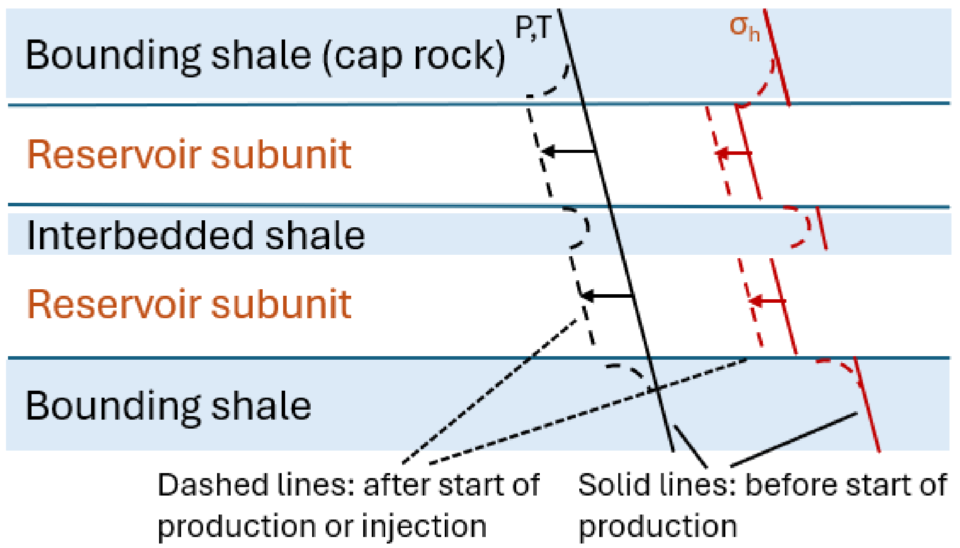
Fractures initiation at wellbore: **$\sigma_{\theta\ min} \leq 0$ psi**

Formation breakdown: **$P_w > \sigma_{\theta\ min} + \sigma_{Thermal} + T$**

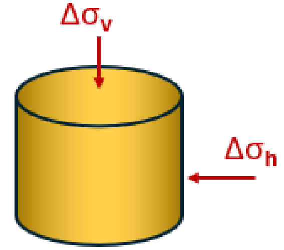
P_w – Bottom Hole Pressure
$\sigma_{\theta min}$ – Near wellbore minimum tangential stress
$\sigma_{Thermal}$ – Thermal Stress
T – Tensile Strength

Idle and Orphan Oil and Gas Wells: State and Provincial Regulatory Strategies
Supplemental Information on Orphan Well Plugging and Site Restoration, IOGCC 2024
https://oklahoma.gov/content/dam/ok/en/iogcc/documents/publications/Orphan%20Wells%20Revised.pdf

Reservoir–Seal System

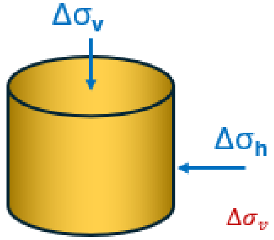


Poro-elastic



$$\Delta\sigma_h \approx a\frac{1-2v}{1-v}\Delta Pp$$

Thermo-elastic

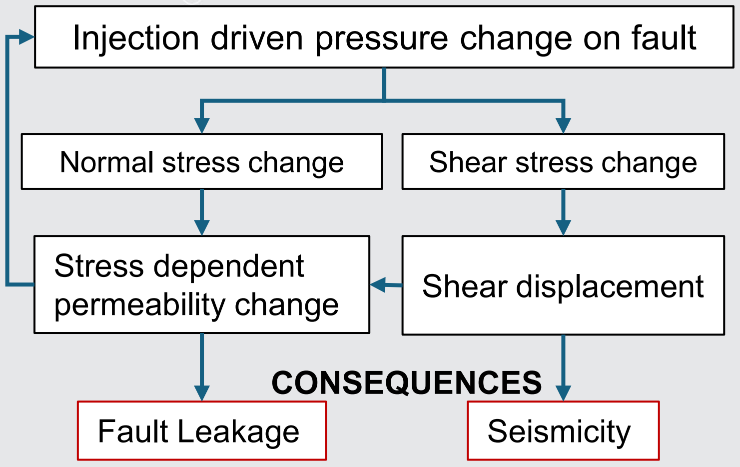


$\Delta\sigma_v \approx 0$

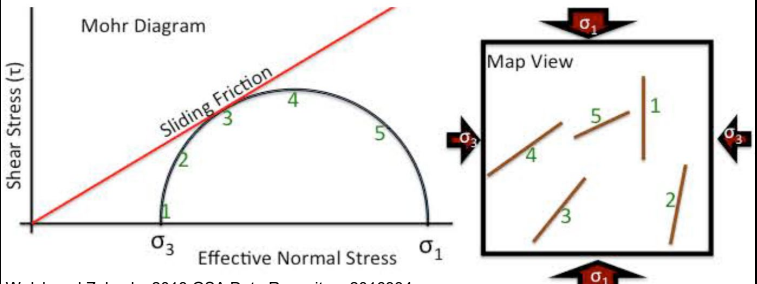
$$\Delta\sigma_h \approx \frac{E}{1-v}\beta\Delta T$$

a = Biot's poro-elastic constant
β = linear thermal expansion coefficient $\approx 0.6 - 1.2 * 10^{-5}/°C$

Faults



Changes in fault stress state potentially impact stress-dependent flow and reactivation potential of faults.



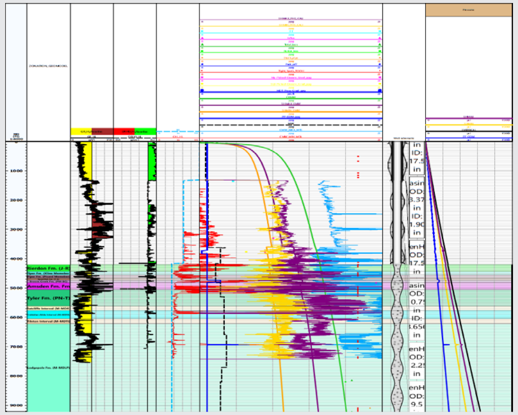
Walsh and Zoback., 2018 GSA Data Repository 2016334

Mohr-Coulomb slip criteria: $\tau \geq \mu (S_n - P_p)$

τ - resolved shear stress on fault
μ - coefficient of friction
S_n - normal (compressive) stress on fault
P_p - pore pressure

Geomechanics Workflow for Barrier Assessment

1D MEM

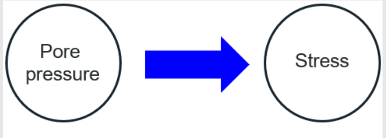


- In-situ stresses
- Pore pressure
- Rock mechanical properties (ρ, E, v, UCS, FA, TS)

- 3D Seismic Data

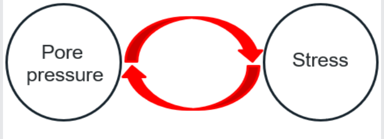
3D/4D MEM

- **Geomodel**
  - Geological structures & features (faults geometry and orientation)
  - 3D Mechanical properties (φ, ρ, E, v, UCS, FA, TS)
- **Reservoir model**
  - Formation pressure evolution (P)
  - Saturation evolution (S)
  - Temperature evolution (T)



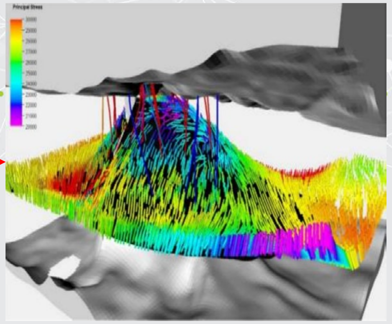
One-way coupling

OR



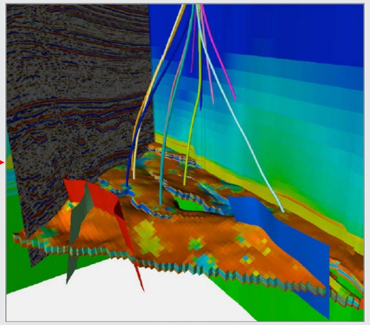
Two-way coupling

- 3D/4D stresses and 3D/4D strains (deformations)
- Identification and prediction of rock failure location and magnitude
- Faults stability analysis
- Near wellbore geomechanics

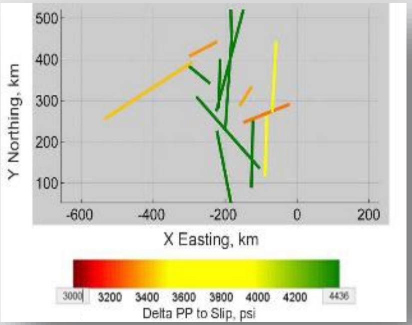


3D/4D Stresses and Strains

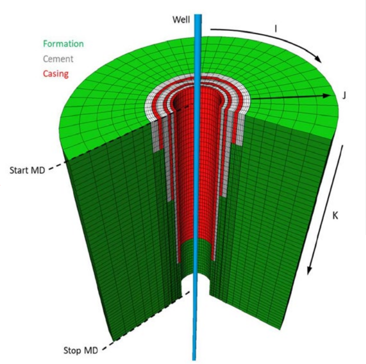
- InSAR feasibility
- Advanced AOR*
- Stress shadow
- Compaction table coupled with geomechanics



3D/4D Fault Stability Analysis



Stanford, Fault Slip Potential (2D Fault Stability analysis)



Near Wellbore Geomechanics

- Near wellbore injectivity
- Near wellbore leak prediction*
- Improve risk-based AOR*

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Hydraulic Fracturing

Stages of Fracturing

Fracture initiation

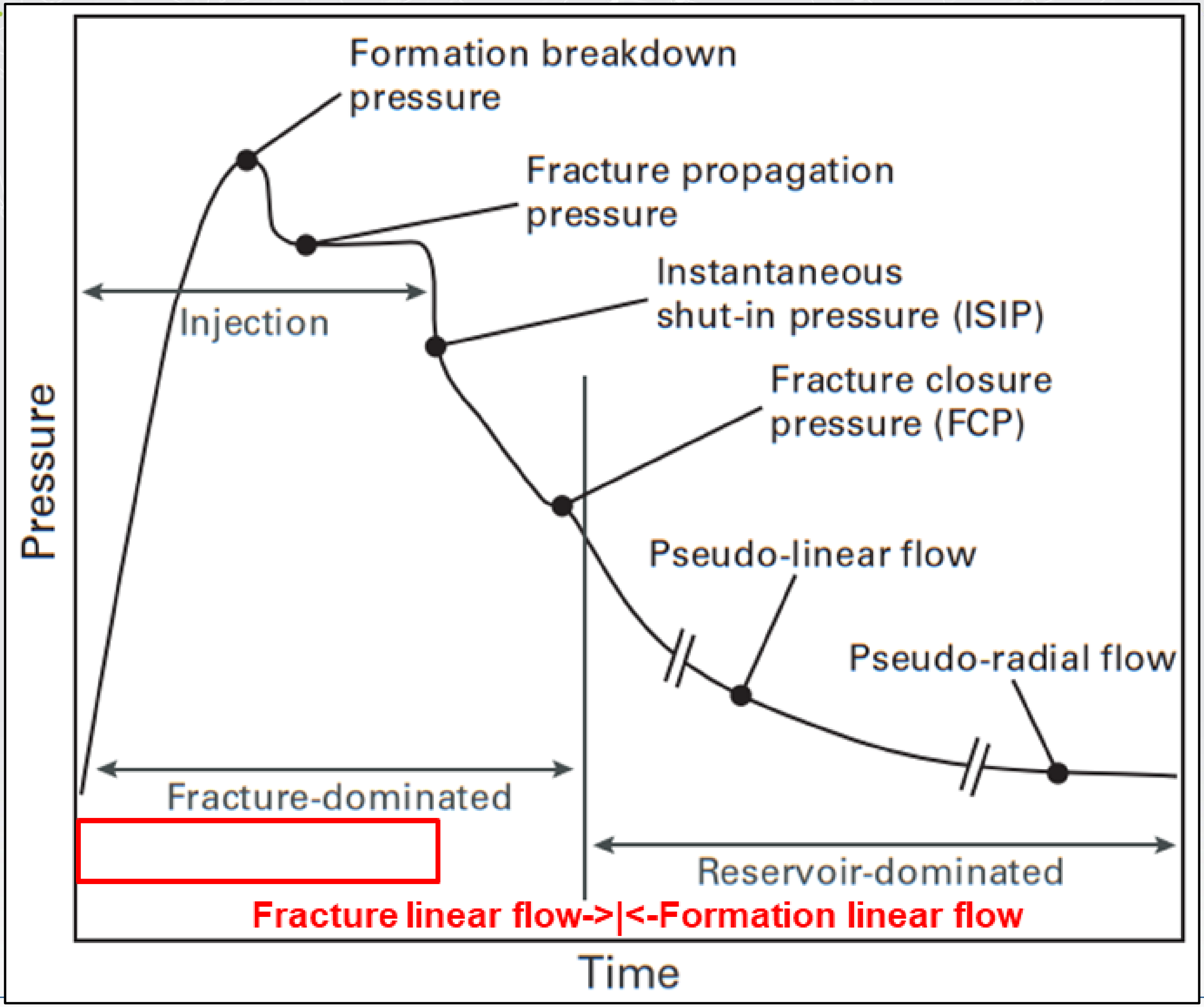
- Wellbore orientation
- Completion
- Near wellbore fracture geometry

Fracture propagation pressure (FPP)

- Bottom hole flowing pressure ~ FPP

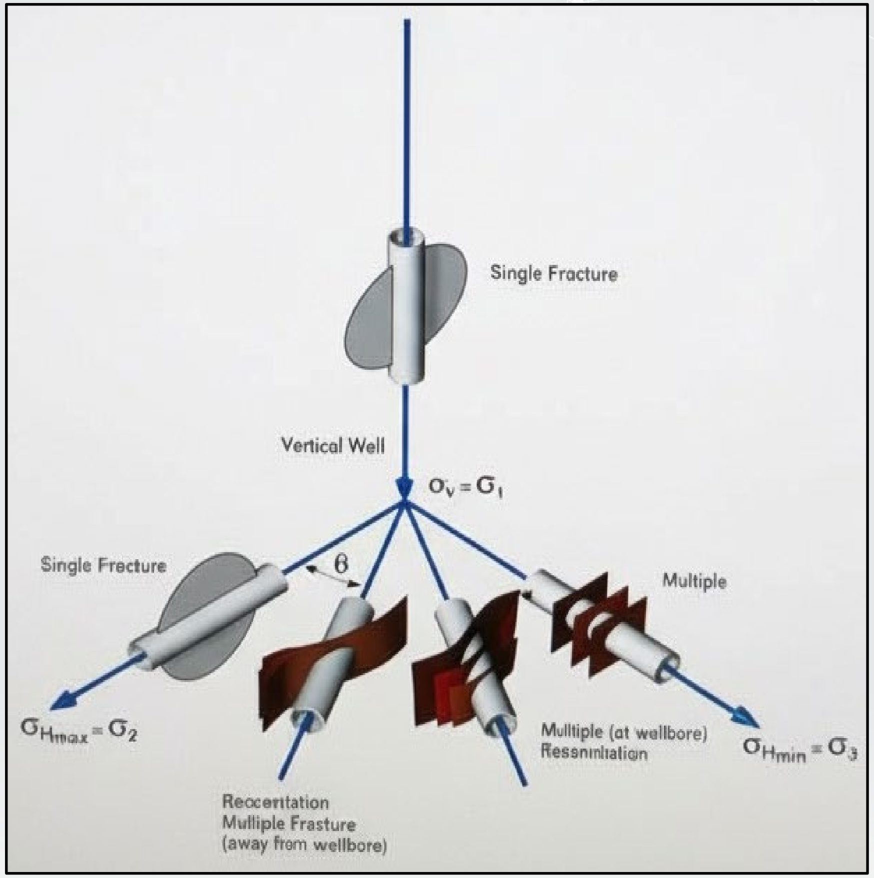
Fracture closure pressure (FCP)

- Shmin ~ FCP
- Data analysis: micro/minifrac tests
- Pressure fall-off (PFO)



Unconventioal Reservoir Geomechanics
By Mark Zoback, et al.

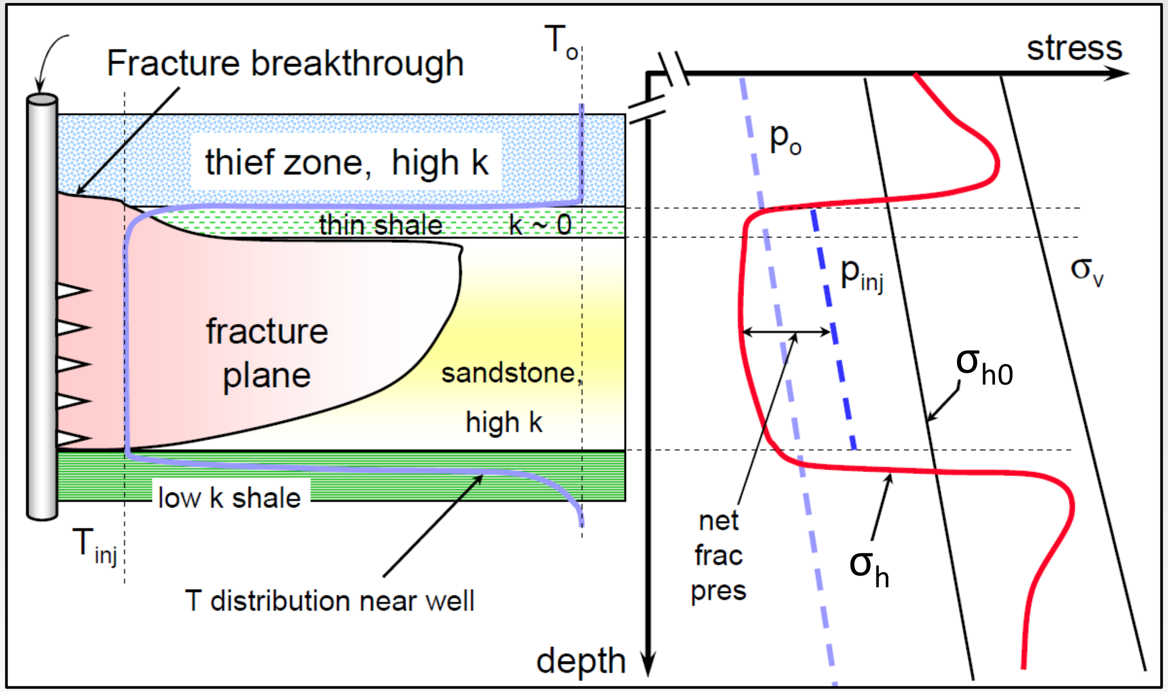
Near-Wellbore Fracture Geometry and Impact of Cooling



Effect of wellbore azimuth

Effect of temperature, heat transfer for cold injection:

- Diffusion dominated, radially around wellbore in overburden
- Convection dominated in flooded zone in reservoir
- Diffusion dominated, vertically and radially near reservoir/cap rock interface

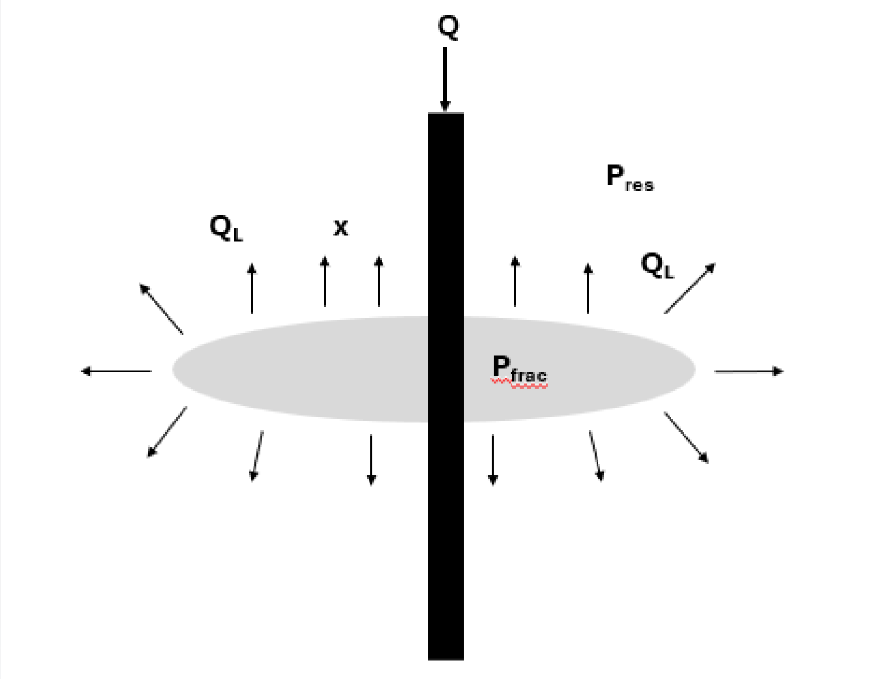


Basic Fracture Dynamics

Once a fracture has been initiated, its growth is determined by the following balance:

d(Fracture Volume)/dt = Injection Rate – Leak Off to Formation

$$= Q - Q_L$$



A few observations from above equation**:**

- Higher injection rate, Q, will lead to a larger fracture size.
- Higher formation leak off, Q_L, will lead to a small fracture size.

Leak Off Rate, Q_L , is given by Darcy's Law

$$\frac{Q_L}{A_{frac}} = \frac{P_{frac} - Pres}{x} \frac{k}{\mu}$$

A few observations:

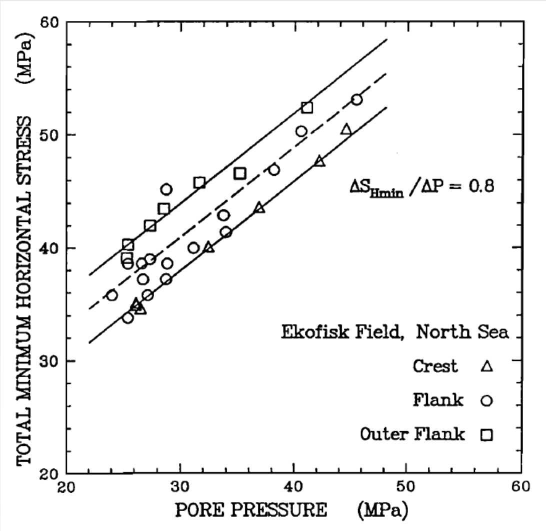
- Higher viscosity, μ, decreases leak off and hence leads to larger fractures.
- Higher permeability, k, increases leak off and leads to smaller fractures.
- Limited reservoir depletion leads to small $P_{frac} - P_{res}$, which leads to small leak off and large fractures.

- A_{frac} is the fracture surface area in contact with the formation
- P_{frac} is pressure in the fracture
- P_{res} is pressure in the surrounding reservoir
- k is formation permeability
- μ is fluid viscosity
- x is diffusion distance into the formation

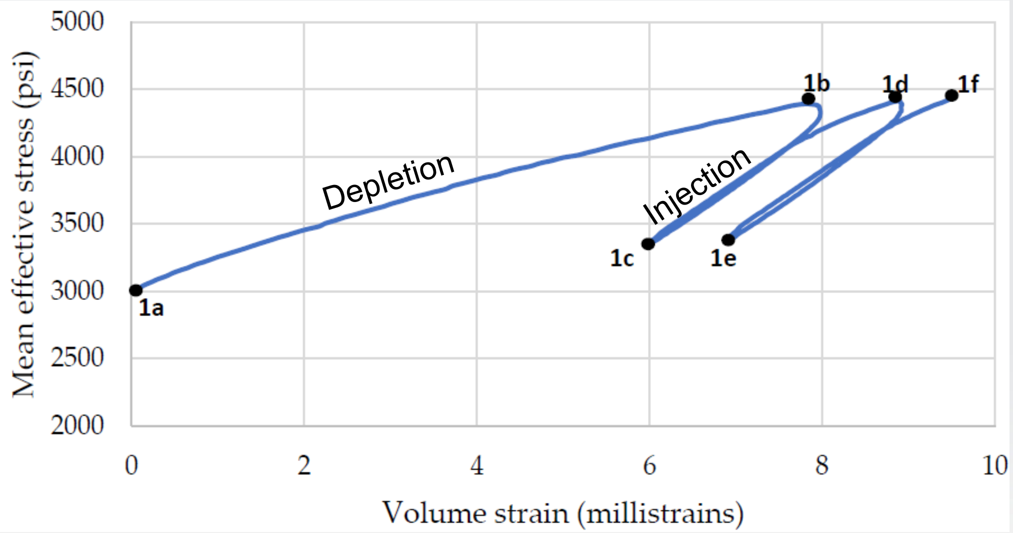
Seal Integrity

Effect of Depletion and Injection

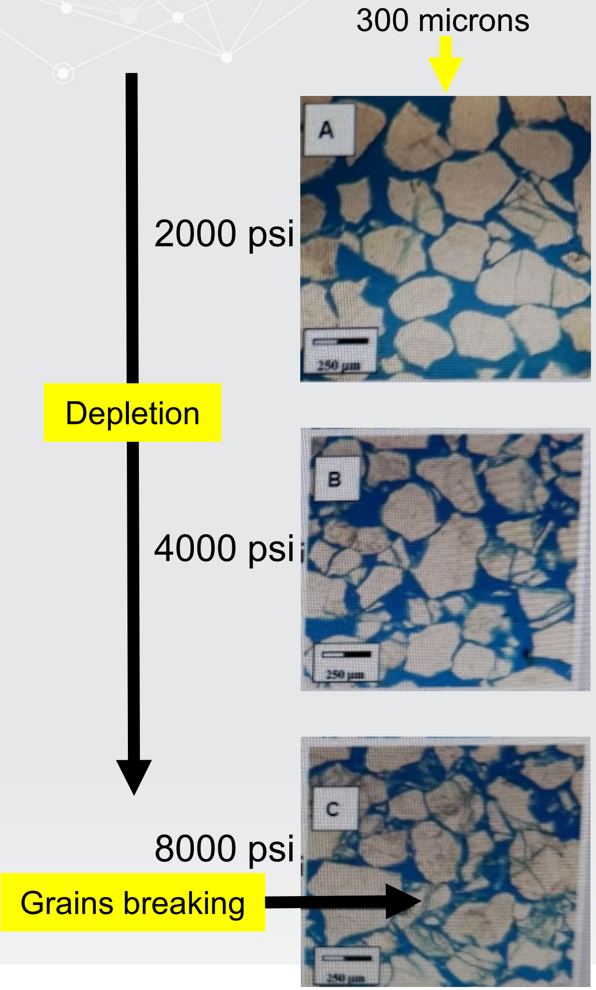
- Rocks often display hysteresis when moving through a stress cycle.
  - Deplete reservoir/reinflate by waterflooding is an example stress cycle.
- Grain breakage or grain rotation is an example of why hysteresis occurs.
- Pore volume compressibility (Cp) is one quantity that demonstrates hysteresis.
- Injection pressure limits should account for reduction in minimum stress due to depletion and spatial variations in min stress (e.g., arching).
- Excessive stress → rock breakage, fault movement, reservoir seals break.



Plot of total minimum horizontal stress versus pore pressure in the Ekofisk field (from Teufel et al., 1991).



Volume strain response of a sand pack with changing mean effective stress during depletion (1a–1b, 1c–1d, 1e–1f) and injection (1b–1c, 1d–1e) stress paths (Prakash et. al., Geosciences 2024, 14, 327)



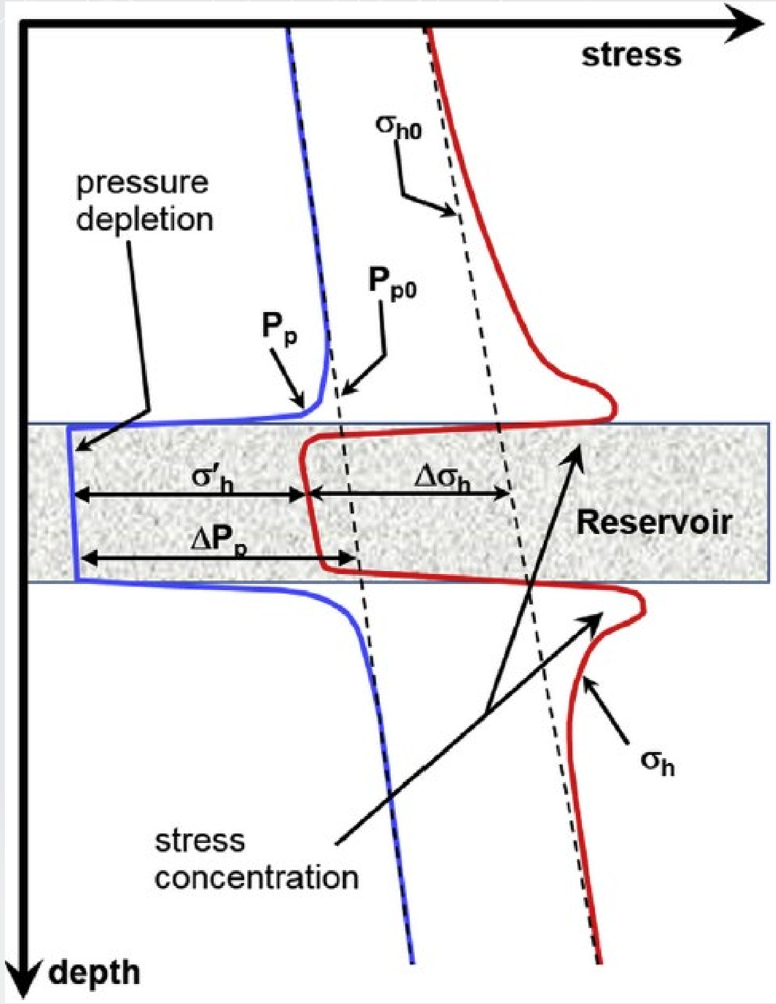
Effect of Depletion and Injection

- Pressure depletion in the reservoir leads to increase in vertical and minimum horizontal effective stresses ($\boldsymbol{\sigma'_v}$, $\boldsymbol{\sigma'_h}$), and a decrease in minimum horizontal total stress ($\boldsymbol{\sigma_h}$).
  - $\boldsymbol{\sigma_h}$ decrease in the reservoir must be redistributed above and below the reservoir.

- Fluid injection would result in opposite effects of reservoir depletion.
  - Pore pressure ($\mathbf{P_p}$) increases in the reservoir.
  - $\boldsymbol{\sigma_h}$ increases in the reservoir.
  - $\boldsymbol{\sigma_h}$ decreases in the caprock.
  - $\boldsymbol{\sigma'_v}$, $\boldsymbol{\sigma'_h}$ decreases in the reservoir.

- Injection of colder fluid can significantly cool the reservoir and modify the trends described above.

- The cap rock stress can also change due to thermal changes and needs to be considered in setting injection pressure limits.

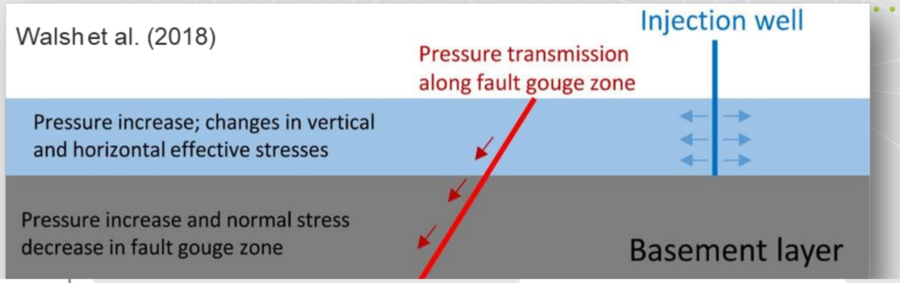


Maximum Injection Operating Pressure

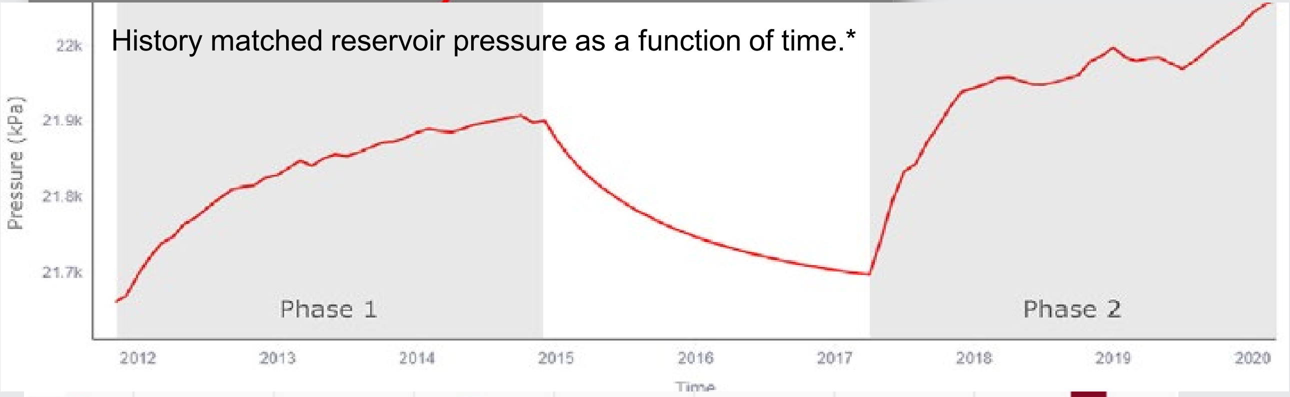
Well Name			
1	Cap rock definition depth (TVD KB)	17,000	
2	Estimated minimum horizontal stress (Sh) in cap rock (psi)	12,500	
3	Additional cap rock stress from hoop stress or tensile strength (psi)	0	Hoop stress is believed to be negligible in this case.
3	Stress change to prevent flow through nearby faults (psi)	0	
4	Stress change in cap rock for reaction to sand compaction (psi)	0	
5	Stress change in cap rock for temperature changes (psi)	-300	
6	Uncertainty in extrapolating gauge BHP to top perfs (psi)	0	Because the gauges are deep in the well this reduces the uncertainty.
7	Additional pressure drop from well center to sand face, e.g., due to well skin (psi)	0	
8	Additional safety margin (psi)	0	This level of conservatism has already been incorporated into multiple other places.
9	**Maximum injection pressure to prevent cap rock fracturing**	**12,200**	
11	Estimated minimum horizontal stress (Sh) in reservoir (psi)	9050	
12	Stress change for poroelastic effects (injection pressure increase)	700	
13	Stress change for temperature changes (psi)	-550	
10	**Anticipated sand fracture pressure**	**9200**	
14	Margin between max. injection pressure to prevent cap rock fracturing and sand fracture pressure (psi)	**3000**	
	Planned maximum injection pressure limit (psi)	**9050**	Could be lower to account for uncertainty

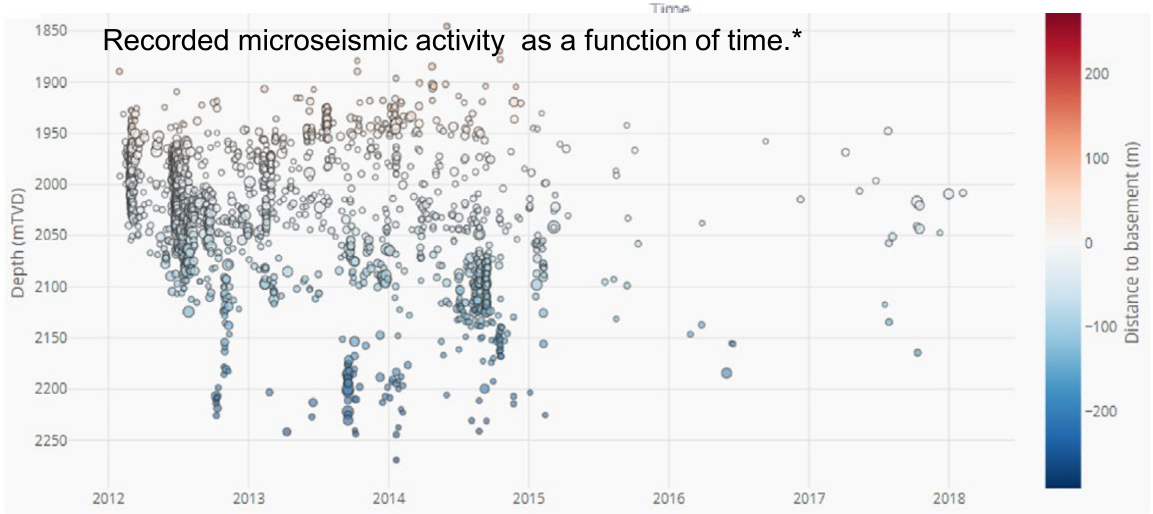
Injection-Induced Fault Slip

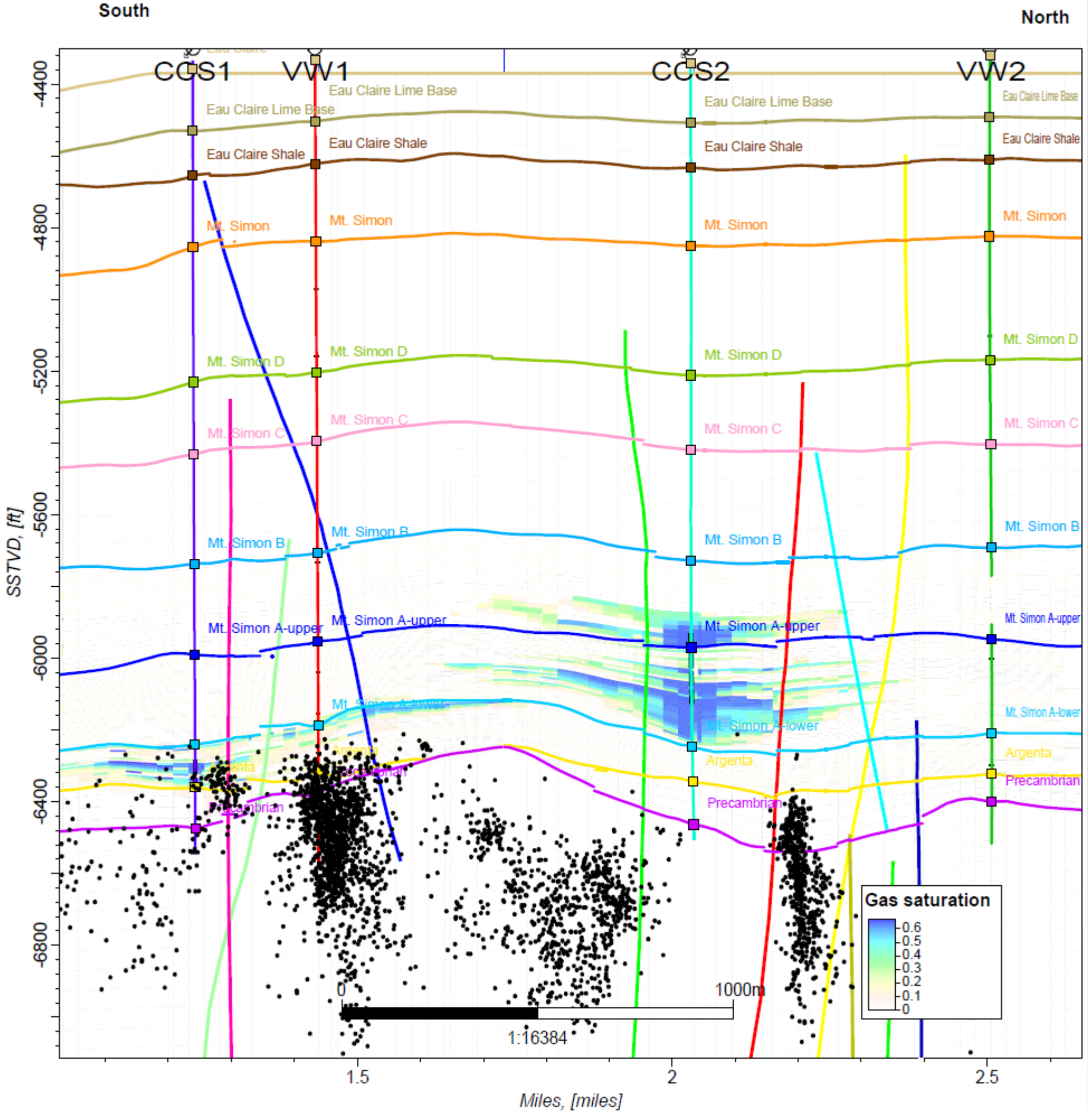
Illinois Basin – Decatur Project (IBDP) CO_2 Injection Monitoring



Pressure Transmission into Basement







N–S cross-section (3× vertical exaggeration) through the reservoir showing the CO_2 saturation at the end of the two injection phases in Jan 2020. *Bisdom & Chan, iScience 27, 109957, 2024 (Adapted from Zulaski and Lee 2020, IBDP Final Static Geological Model Development and Dynamic Modeling.)

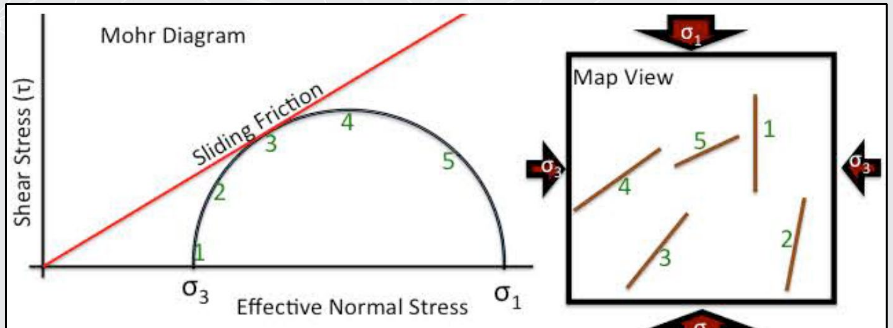
Illinois State Geological Survey (ISGS): Illinois Basin - Decatur Project (IBDP) CO2 Injection Monitoring Data, April 30, 2021 - Midwest Geological Sequestration Consortium (MGSC) phase III Data Sets - DOE Cooperative Agreement No. DE-FC26-05NT42588 (https://doi.org/10.11582/2022.00017)

Fault Slip Potential (FSP) Approach

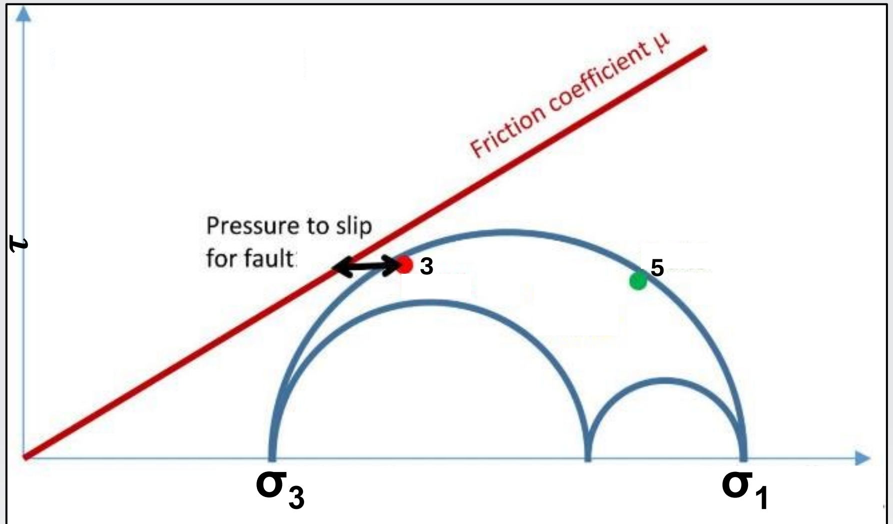
- **Based on Mohr–Coulomb Slip Criteria**: FSP calculates pore pressure to slip on each fault using deterministic geomechanical modeling.
- **Monte Carlo Analysis**: Runs probabilistic simulations to yield the probability of each fault slipping, given uncertainties in input parameters.
- **Hydrology Model**: Assesses specific injection scenario, providing pore pressure changes to be used in the fault slip analysis.
- FSP doesn't make a prediction that a fault is going to slip; it's giving you a probability that a fault is critically stressed.

Assumptions:
- Faults are planes of weakness. Zero cohesion.
- Single layer. Faults are in contact with the injection interval.
- Out-of-zone effects and poroelasticity are not considered.

Applications:
- Regional fault assessment.
- Injector placement and injection rate optimization.
- Hydraulic induced fault slip.



Walsh and Zoback., 2018 GSA Data Repository 2016334



Based on Walsh & Zoback 2018

Mohr-Coulomb slip criteria: $\tau \geq \mu \, (S_n - P_p)$

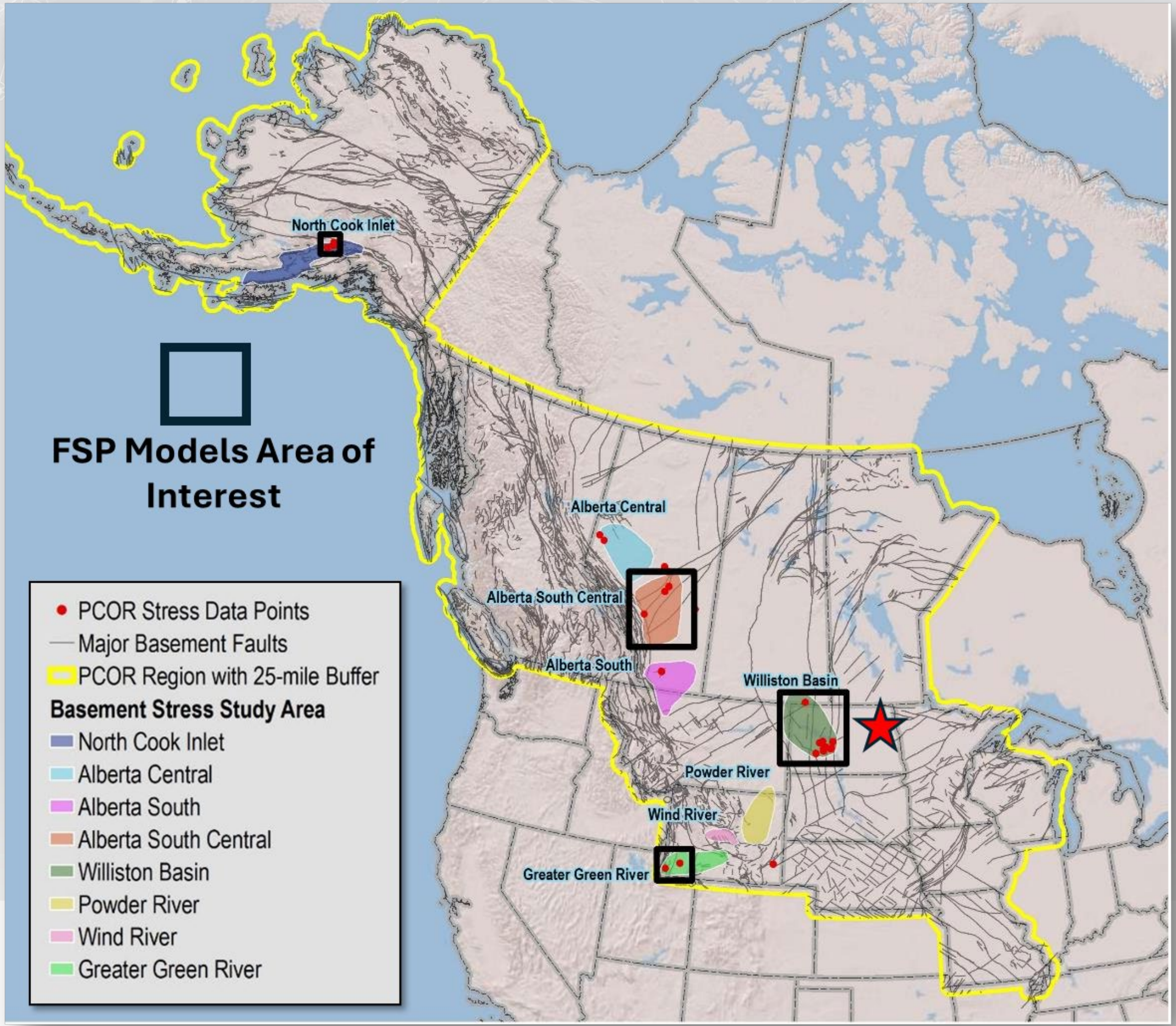
τ - resolved shear stress on fault
μ - coefficient of friction
S_n - normal (compressive) stress on fault
P_p - pore pressure

https://cisr.beg.utexas.edu/fsp

Basement Faulting and Stress Study, Plains CO2 Reduction (PCOR) Partnership Region

From: *Regional Subsurface Stress Assessment for CO2 storage in Candidate Basal Reservoirs Within the Plains CO2 Reduction Partnership Region of North America,* Fossum, B.J., Jo, T.H, Peck, W.D., & Livers-Douglas, A.J., Proceedings 03/2024 AAPG/SPE/SEG CCUS Conference.

- Screening level regional evaluation to assess potential of basement fault reactivation due to CO2 storage in candidate basal reservoirs in PCOR Region.
- Study selected eight representative basement stress areas; four areas were modeled using FSP v2.0.
- Demonstrated the application of a scalable and integrated structural interpretation and geomechanical workflow to conduct a critical stress analysis of selected faults to identify uncertainties and mitigate risk.

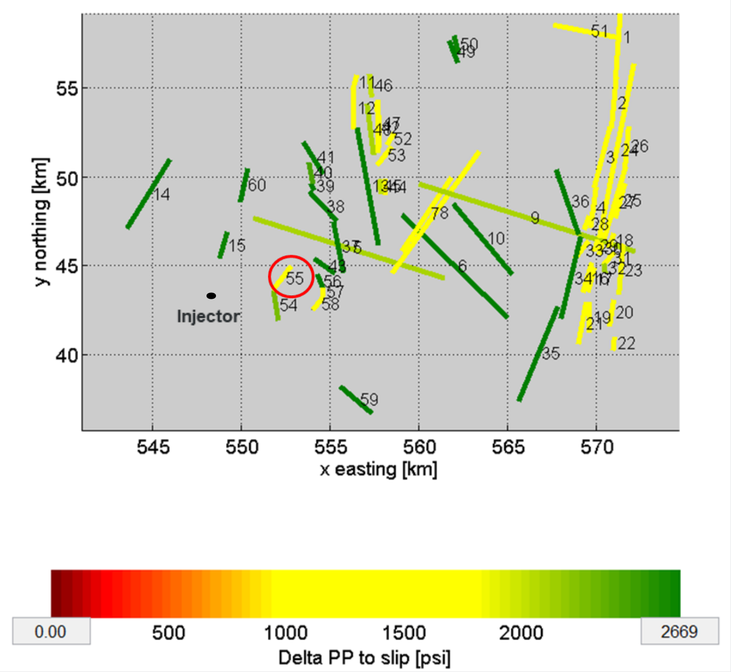


See Fossum et. al (2024) and Fossum et al. (2023) for stress data summaries and sources.

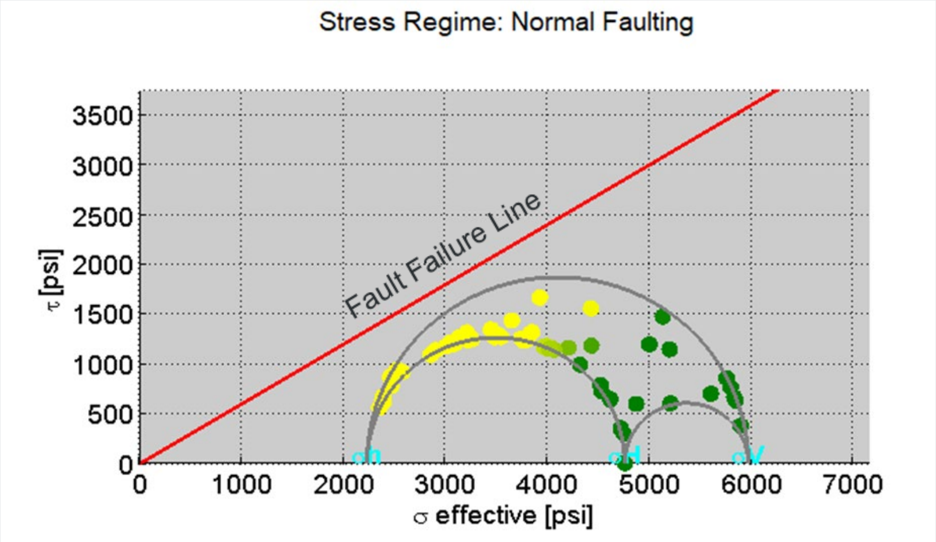
DOE Cooperative Agreement No. DE-FE0031838/North Dakota Industrial Commission under Contract Nos. FY20-XCI-226 and G-050-96

FSP Reference Case Input Data and Critical Stress Analysis

Input (units)	Value
Formation depth (TVD ft)	10,109
Stress regime, Shmax orientation (deg)	Normal, 50
Sv, SHmax, Shmin (psi/ft)	1.06, 0.94, 0.69
Initial res press gradient (psi/ft)	0.47
Nos. of injection wells	1
Injection period (yrs)	12
CO_2 avg injection rate (bbls/d)	23,400
CO_2 density (kg/m^3)	850
Fault friction coefficient	0.6



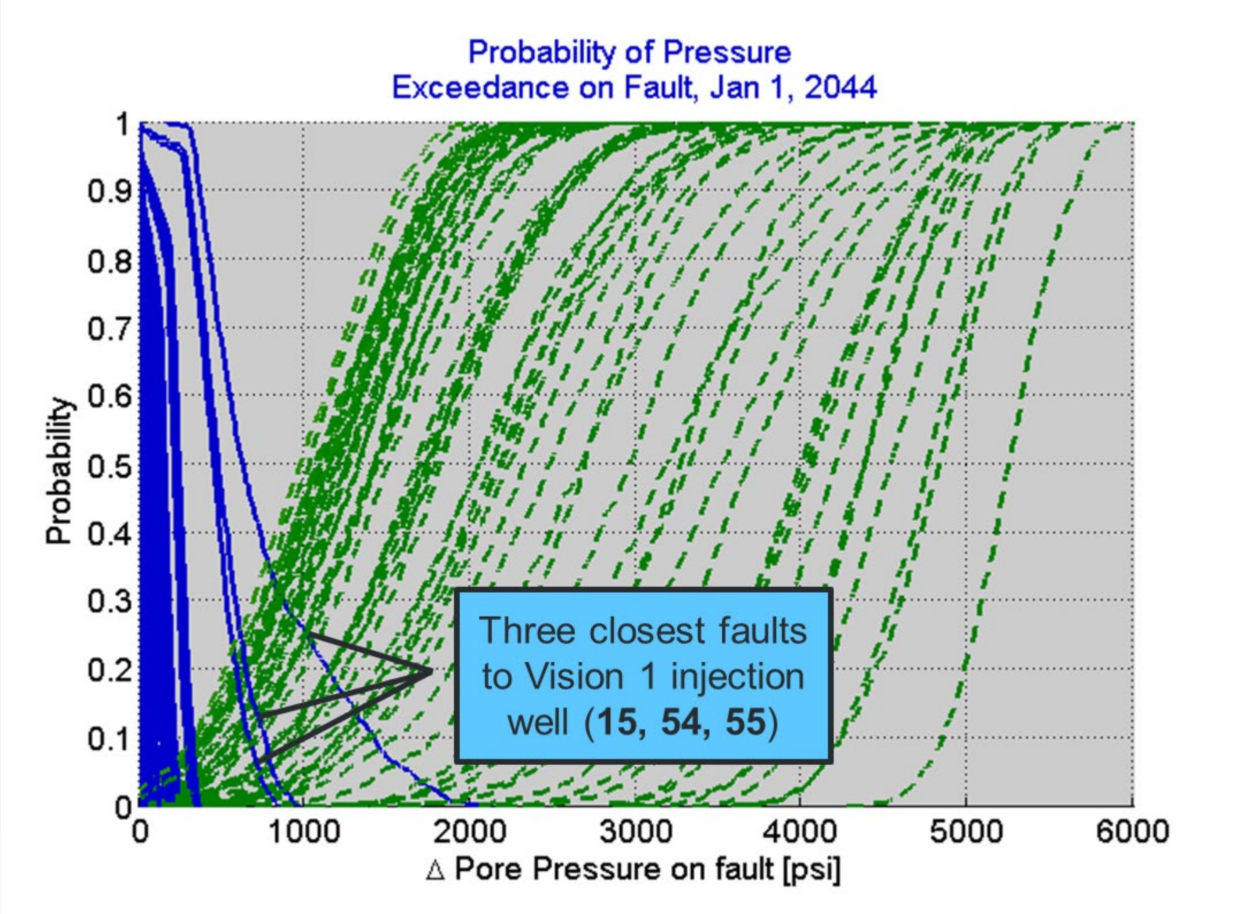
Critical Stress Analysis Results



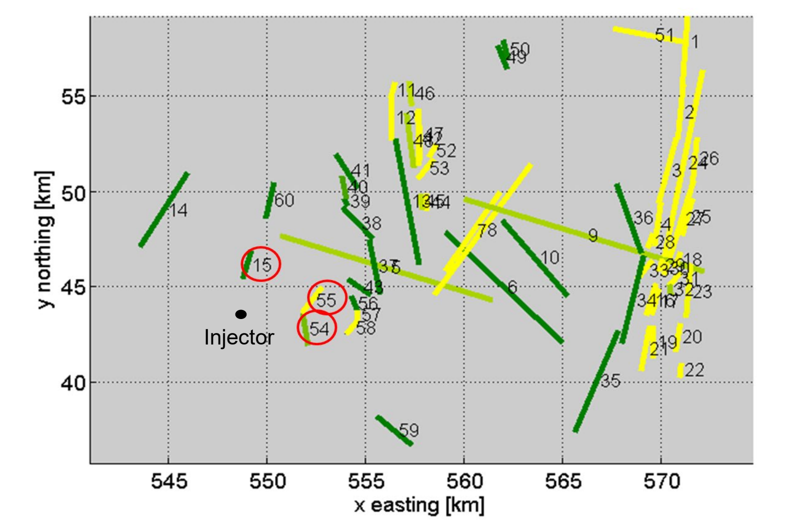
Mohr-Coulomb Failure Envelope

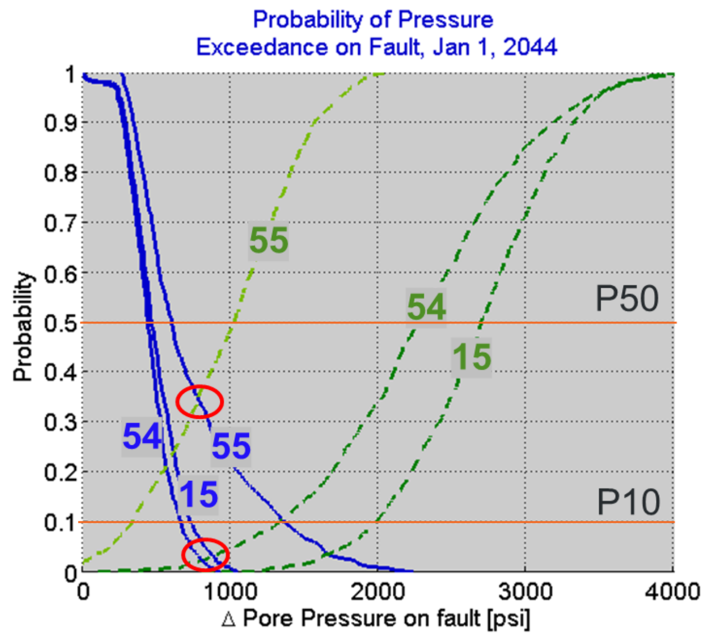
Faults at Formation are generally **not critically stressed** using deterministic Mohr-Coulomb failure criteria

FSP Hydrology All Faults Probabilistic Simulation after 12 years



Blue: Probability of pressure exceedance on fault after 12 years injection.
Green: Probability of Mohr-Coulomb fault slip.





Pressure Exceedance on Faults vs Mohr–Coulomb slip:

- Fault #55: 34% slip potential
- Fault #15: 0% slip potential
- Fault #54: 2% slip potential

Comments

- Basement fault reactivation risk increases in tectonically active regions with strong strata, elevating induced seismicity potential during CO_2 injection.

- **Critical orientation and throw control pressure thresholds**: Largest-throw faults determine maximum allowable pore pressure for containment; these faults are most readily mapped.

- **Numerical modeling challenges**: FE mesh resolution near faults is computationally expensive and limits sensitivity analysis; mesh-free methods offer limited computational benefit.

- **Offset distance scales with throw**: Larger-throw faults require greater setback from injection wells than similarly oriented small-throw faults; overlooking this underestimates reactivation risk.

- Application of **a scalable and integrated structural interpretation** and **geomechanical model workflows** to conduct a critical stress analysis of identified faults is necessary to identify uncertainties and mitigate risk.

Remarks

Barrier Capacity Assessment Framework

- Barrier capacity assessment integrates geomechanical concepts across three subsurface leak paths to define conservative operational limits.
- Three key applications:
  - **Design** basis (well placement, safe injection limits, rates)
  - **Operations** (planning and change management)
  - **Risk mitigation** (data prioritization via value of Information analysis)
- Tools: Analytical screening for fast approximations; numerical models for robustness validation.
- Proactive controls mitigate barrier events: out-of-zone injection, caprock integrity, induced seismicity management.

Geomechanics Assessment ➡ **Analytical Screening** ➡ **Operational Limits** ➡ **Decision Logic**

Thank you

Q&A

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