Strategies for Maximizing Secure Storage of CO2 in Deep Aquifers

Steven Bryant
Director, Geological CO2 Storage JIP
Center for Petroleum and Geosystems Engineering
The University of Texas at Austin
Original Motivation of JIP

- Identify key phenomena influencing aquifer storage
- Understand governing mechanisms
- Demonstrate feasibility of permanent storage in aquifers
- Founding membership
  - ChevronTexaco
  - ExxonMobil
  - ENI
  - CMG
People

- Faculty
  - Bryant
  - Pope
  - Lake
  - Sepehrnoori
  - Nguyen
  - Jablonowski
  - Minkoff (UMBC)

- Research Scientists
  - Srivatsan Lakshminarasimhan
  - Mojdeh Delshad
  - Aura Araque
  - Heather Pedraza

- Undergraduates
  - Sarah Dobbs
  - Nurhidayah Hutamin
  - Chris Irle
  - Archna Agrawal
  - Michael Boyle

- Grad Students
  - Vikas (MS 03)
  - Ajitabh Kumar (MS 04)
  - Myeong Noh (PhD 04)
  - Robin Ozah (MS 05)
  - Elizabeth Zuluaga (PhD 05)
  - Yousef Ghomian
  - Justin Ferrell
  - Derek Wood
  - Sang-Yeop Park
  - Kyung-won Chang
Key points

• Reservoir simulation is an important tool for **understanding** mechanisms in aquifer storage
• Augmented reservoir simulators essential for **design** and **risk assessment** of aquifer storage
• **Permanent** storage of CO2 feasible
  - Implications for probability of leakage
• Simulation-based optimization as guide to **future needs**
  - Petrophysical characterization
  - Laboratory experiments
  - History matching
  - New field measurement techniques/tools
  - Site selection & Risk assessment
Outline

• What we’re trying to do
  - Geological CO2 Storage Joint Industry Project
  - [www.cpge.utexas.edu/gcs](http://www.cpge.utexas.edu/gcs)
• How we’re trying to do it
  - which simulators
  - what kind of simulations
• What we’ve learned
• What’s next
**Approach**

- Simulate **prototypical** storage scheme
  - Inject 1 million tons/yr for 50 yrs
  - Shut in injection well
  - Simulate $10^3$-$10^4$ years of gravity-driven flow
- Examine **sensitivity** of behavior
  - Aquifer characteristics
  - Injection strategy
- Track CO2 fate
  - CO2-rich phase
    - **Mobile** saturation
    - **Residual** saturation
  - Brine phase
  - Carbonate **minerals**
Phase Densities: CO2-Saturated Brine

T = 140°F; P = 3000 psi

Salinity, ppm NaCl

Brine Density, lb / cu ft

CO2 Saturated Brine

Brine (Without CO2)
Key Petrophysical Properties

- Porosity
- Permeability
  - Magnitude
  - Anisotropy
- Residual gas saturation
- Property correlation (Holtz, 2002)
- Capillary pressure
- Relative permeability
- Hysteresis
  - Land model
Hysteresis in Relative Permeability

Injection stage: CO2 displacing water

Post-injection: water displacing CO2
**Permanent Storage of CO2 in Aquifers**

- CO2 is stored permanently when it will not escape from the aquifer **any faster** than the chemical species native to that aquifer.

\[ t_{\text{escape}} \geq t_{\text{residence}} \]

Condition for “permanence”
Simulators we have used

- Fully compositional (Peng-Robinson Equation of State)
  - UTCOMP
    - Research code
    - 20+ years development
  - GEM
    - Commercial reservoir simulator (CMG)
- Augmented reservoir simulator
  - GEM-GHG
    - Compositional + geochemistry
    - Intra-aqueous reactions
    - Mineral dissolution/precipitation
Example Simulation Results

- Injection along entire interval
- Injection in bottom half of aquifer
- Influence of buoyant fingers
- Frio pilot behavior
- Gravity-stable EOR/storage
Results – Influence of Well Completion (1)

- Injection across entire interval leads to extensive contact with seal

Saturation Profiles of CO$_2$-rich Phase (vertical slice through the injection well in X-Z direction)

\[ T = 10,000 \, \text{y} \]
Results – Influence of Well Completion (2)

- Injection across lower part of interval eliminates contact with seal

Saturation Profiles of CO$_2$-rich Phase (vertical slice through the injection well in X-Z direction)

Injection only into lower interval

50 Years

1000 Years

$S_{g,\text{residual}} = 0.25$
Horizontal wells increase aquifer utilization

- Well spacing and type
- Optimal volume as function of aquifer thickness, well type

**Vertical Well**
Perforation - 500 feet
48 million tons injected

**Vertical Well**
Perforation - 500 feet
338 million tons injected

**Horizontal Well**
Perforation - 5300 ft
338 million tons injected

Gas saturation at 1000 y
Mechanisms for permanence: residual phase

- CO2 phase is *nonwetting* relative to brine
- Size of pores in sedimentary rocks ~ 1-10 microns
  - Capillary forces dominant
- Origin of residual phase saturation (volume fraction of pore space)
  - Nonwetting phase spontaneously *disconnected* during flow
  - Disconnected blobs held by capillary forces
Residual saturation varies with rock type

Porosity (fraction)

Katz, 1966 Sgr
Chierici, et al, 1963
Fishlock, et al., 1886
Firoozabadi, et al, 1987
Keelan, 1976 Sgr (fraction)
Mulyadi H. et. al, 2000 (SS*) Sgr
Mulyadi H. et. al, 2000 (CoC*) Sgr
Mulyadi H. et. al, 2000 (CC*) Sgr
Geffen T. M. et. al 1952 Sgr
Crowell SgrM
Aissaoui, 1983 Sgr
Jerauld 1996 Sgr
Hamon et. al, 2001 Sgr
Kantzas et. al, 2000 SgrM
Moomba SgrM

Courtesy Mark Holtz, BEG
Results – Controlled buoyant flow enhances permanent storage

Saturation of CO2 phase

Mole fraction CO2 in brine

Saturation of mobile CO2 phase

Saturation of residual CO2 phase

50 years

1000 years
Contrast: gas cap storage minimizes permanence

- CO2 cannot move
- Brine cannot displace CO2
- Will not form residual saturation
- Mass transfer only at CO2/brine interface
Results – Controlled buoyant flow enhances permanent storage

- Residual
- Aquous
- Mobile

Time, years

CO₂ Stored in Various forms, %
Results – Mineralization contributes long term

- Key reaction: dissolution of aquifer mineral containing divalent cation
  \[ \text{Anorthite} + 2\text{H}^+ + \text{H}_2\text{O} \rightarrow \text{Ca}^{2+} + \text{Al}_2\text{Si}_2\text{O}_5(\text{OH})_4 \]

- Causes carbonate mineral precipitation

![Distribution of CO2 in Various Forms](chart)

Time, years

- Percentage CO2 as Residual Gas
- Percentage CO2 in Aqueous Phase
- Percentage CO2 as Free Gas
- Percentage CO2 as Minerals
Sample results for Frio Brine Pilot

- Collaboration with Bureau of Economic Geology at UT-Austin

Permeability Distribution
The graph shows the observed arrival at the monitoring well and the simulation of CO2 breakthrough time. The x-axis represents time (days) while the y-axis represents CO2 mass fraction rate in brine (lb/day). The observed arrival at the monitoring well indicates the point where the CO2 breakthrough is detected.
Comparison of Predicted Gas Saturation for Alternative Frio Injection Strategies

Injection at the top

Injection at the Bottom
Predicted CO2 Distribution in Frio Pilot

Injection at the top

Injection at the Bottom
Gravity Stable EOR/Storage

- Candidate Reservoirs Specification
  - Steeply Dipping Reservoirs in Gulf Coast
  - Mature Oil Fields with High Remaining Oil Saturation
  - Highly Faulted Around Salt Domes
  - Heterogeneous

Permeability Distribution
Frio Type Reservoir; Horizontal Producer, Vertical Injectors

Top Layer

Permeability Distribution

Oil Saturation
Frio Type Reservoir; Horizontal Producer, Vertical Injectors

Oil Saturation

Oil Recovery as % of OOIP = 31.8
Sequestered portion of injected CO2 = 43.6%
Cumulative gas injected = 81,000 MM SCF
Total CO2 Sequestered = 35,500 MM SCF
CO2 stored = 4.8 MSCF/STBO
O2 injected = 10.9 MSCF/STBO
Preliminary Simulations of Frio 2 CO2 Injection
Objectives of Study

- Very rapid “look-see”
- Illustrate “inject at the bottom” principle
  - maximize residual phase trapping
- Estimate whether CO2 reaches top of formation
  - Injected volumes between 1500 and 6000 ton
  - 3000 ton injected in Frio 1
- Examine two target sands:
  - “5400” sand
  - Lower ~100 ft of the “C” sand
    - Top part of “C” used in Frio 1
Simulation Approach

- GEM-GHG from CMG
- CO2/brine phase behavior from previous CPGE work
- Grid, wells, properties from Frio 1
  - Geological model from BEG
  - Model limited to top 60’ of “C” sand
- Assumptions for this study (quick look)
  - 5400 sand
    - Geometry (thickness, dip, etc) same as the top 60’ of “C” sand
    - All permeabilities adjusted based on logs in C and in 5400 (range 0.8 to 4 D)
  - Lower “C” sand
    - Rectangular box (layered) with same dip, 150’ thick
    - Porosity/permeability of top 60’ same as Frio 1
    - Porosity/permeability of bottom 90’ estimated from log (shaly sand)
Cases Tested

- Compare injection at top vs injection at bottom in Frio 1 (retrospective)
- Inject in bottom 35’ of 5400 sand
  - Different volumes of injection in 12 days
    - Rates of 125 tpd, 250 tpd, 500 tpd
    - Different values of residual saturation
      - Value for Frio 1 (Sgrmax = 0.276)
      - Sgrmax = 0.276/2 = 0.138
- Inject in bottom 30’ of extended C sand
  - Initial condition
    - Simulate Frio 1 to date, then continue simulation for 6 months
  - Inject 3000 tons, starting one year after Frio 1
    - Reduce injection rate to 50 tpd for 60 days
      - Keeps BHP < 2500 psi
      - ~50 mD formation in bottom of “C” sand
### Summary of input data for Frio 1 simulations.

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
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<tbody>
<tr>
<td>Length, ft</td>
<td>3520</td>
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<tr>
<td>Width, ft</td>
<td>2300</td>
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<tr>
<td>Dip, Degree</td>
<td>5-35</td>
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<tr>
<td>Thickness, ft</td>
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<tr>
<td>Number of blocks</td>
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<tr>
<td>Depth at top of formation at injection well, ft</td>
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<tr>
<td>Vertical to horizontal Perm. Ratio</td>
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<tr>
<td>Average horizontal permeability, md</td>
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<td>Average vertical permeability, md</td>
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<td>Average porosity</td>
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<td>Initial Pressure, psia</td>
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<tr>
<td>Residual Water Saturation</td>
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<tr>
<td>Residual Gas Saturation</td>
<td>0.25</td>
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<tr>
<td>Maximum Injection Pressure(psia)</td>
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<tr>
<td>Temperature, °F</td>
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<td>Salinity, ppm</td>
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### Summary of input data for base case Frio 2 simulations

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<th>Parameter</th>
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<th>5400 sand</th>
<th>Lower C sand</th>
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<td>Dip, Degree</td>
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<td>43<em>28</em>26</td>
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<tr>
<td>Depth at top of formation at injection well, ft</td>
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<td>5050</td>
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<td>Vertical to horizontal Perm. Ratio</td>
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<tr>
<td>Average horizontal permeability, md</td>
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<tr>
<td>Average vertical permeability, md</td>
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<td>Average porosity</td>
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<tr>
<td>Residual Water Saturation</td>
<td>0.25</td>
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<td>Temperature, °F</td>
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<tr>
<td>Salinity, ppm</td>
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</tr>
</tbody>
</table>

All cases held at constant pressure far field boundaries
5400 Sandstone Simulations: Effect of volume of discharge

Gas saturation along injection plane at t = 1 week

2.365 x 10^6 cu. ft./ day  Injection rate  4.73 x 10^6 cu. ft./ day
5400 Sandstone Simulations: Effect of volume of discharge

Gas saturation along injection plane at t = 1 week

4.73 \times 10^6 \text{ cu. ft./ day} \quad \text{Injection rate} \quad 9.46 \times 10^6 \text{ cu. ft. / day}
5400 Sandstone Simulations: Effect of volume of discharge

Gas saturation along injection plane at t = 2 weeks

2.365 x 10^6 cu. ft./ day  Injection rate  4.73 x 10^6 cu. ft. / day
5400 Sandstone Simulations: Effect of volume of discharge

Gas saturation along injection plane at $t = 2$ weeks

4.73 x $10^6$ cu. ft./ day  
Injection rate  
9.46 x $10^6$ cu. ft. / day
5400 Sandstone Simulations: Effect of volume of discharge

Gas saturation along injection plane at $t = 1$ month

2.365 x $10^6$ cu. ft./day \hspace{1cm} Injection rate \hspace{1cm} 4.73 x $10^6$ cu. ft./day
Pure Phase Properties Used to Model Mixed Gas/Brine System

Shown: CO\textsubscript{2} Solubility in Aqueous Phase at 140 °F
Overall Mole Fractions are 0.15 H\textsubscript{2}S, 0.35 CO\textsubscript{2} and 0.50 H\textsubscript{2}O
High resolution simulations indicate that buoyancy-driven instabilities do not dominate.

Pure CO$_2$ Injected for 50 Years in Bottom Half of Aquifer
Then 10000 y Gravity-Driven Flow
Gas Saturation Profile at 10,000 Years for Coarse Grid Case (Base Case)

Pure CO₂ Injected for 50 Years in Bottom Half of Aquifer
Conclusions

• Collaboration with CMG has been fruitful
  - **Augmented** reservoir simulation capability in place (GEM-GHG)
  - Tuned equation of state, transport properties, geochemistry
  - Full multiphase petrophysical properties necessary for aquifer storage simulations
  - Basis for coupling reservoir to compartment models of leakage

• Important tool for research, design
  - **Permanent** storage of CO2 in aquifers is feasible
  - Exploits buoyancy-driven flow
    • Residual saturation
    • Dissolution in brine
  - Evaluate tradeoffs for site selection, leakage risk assessment
Future Work (2)

- Structural traps within range of plume travel
  - Sealing faults
  - Anticlines
  - Criteria for avoiding gas cap accumulation
- Incorporate fine-scale behavior as needed
- Effect of background brine flow
Future Work (3)

• Optimize combined EOR/storage

Single stage injection/production well pair

Three stage injection/production well pair