Evaluation of CO2-EOR Performance and Storage Mechanisms: FWU Case Study

W. Ampomah, Qian Sun*, E.J. Kutsienyo and R. Balch
• Project Overview
• Reservoir Simulation & History Matching
• Storage Mechanisms Evaluation
  • Structural Trapping
  • Solubility Trapping
  • Geochemical Trapping
• Conclusive Remarks
CO₂ storage volume - February 2019

- 1,360,000 metric tons of CO₂ purchased
- 1,260,000 of purchased CO₂ stored within Morrow B sand
- ~93% of purchased CO₂ stored
  - Structural-stratigraphic Trapping
  - Residual Trapping
  - Solubility Trapping
  - Mineral Trapping
WEST-HALF INJECTIONS AND PRODUCTION PATTERN OF THE FWU FIELD THAT DESCRIBES THE HISTORY MATCHED PERIOD
Storage Modelling Workflow

- **Baseline Model (Adopted)**
  - Primary (1956 – 1964)
  - Secondary (1964 – 2010)

- **Parametrizations through Sensitivity Studies:**
  - Spatial permeability distributions
  - Relative permeability data

- **History Match (HM) Tertiary Flood**
  - \(\text{CO}_2\)-WAG (2010-2017)

- **Implementations of History-matched Model**
  - Development strategies evaluations
  - Storage mechanisms evaluations
  - \(\text{CO}_2\) long-term fate monitoring
PARAMETERIZATION THROUGH SENSITIVITY STUDIES

18 parameters were investigated

175 initial run training and verification points

236 total simulation experiment resulted in an acceptable R-Squared value
## Assisted History Matching Observations

<table>
<thead>
<tr>
<th>Parameterization with Sensitivity Studies</th>
<th>Optimized History Matching Results</th>
</tr>
</thead>
<tbody>
<tr>
<td>All Corey Correlations Parameters</td>
<td>9.58% in Global History Match Error</td>
</tr>
<tr>
<td>Permeability (I, J)</td>
<td>✓ 4.5% in cumulative Oil Production Error</td>
</tr>
<tr>
<td>Critical Saturation (e.g. Swcrit)</td>
<td>✓ 10% cumulative Gas Produce Error</td>
</tr>
<tr>
<td>Relative perm curve endpoints</td>
<td>✓ ~6.7% in Average Cumulative Injection Error</td>
</tr>
<tr>
<td>✓ Kr at Connate Water (krocw)</td>
<td></td>
</tr>
<tr>
<td>✓ Kr at Irreducible oil (krwiro)</td>
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</tbody>
</table>
Time series plot for all experiments

- Gas Rate Sc (ft³/day)
- Oil Rate Sc (ft³/day)
- Water Cut Sc
- Water Rate Sc (bbl/day)

Legend:
- General Solutions
- Field History
- Base Case
History Matching Results

Field Production Oil Rate (bbl/day)
- Field History
- HM PSO
- Baseline Model

Water Cut (stb/stb)
- HM PSO
- Field History
- Baseline Model

Field Production Gas Rate (Scf/day)
- Field History
- HM PSO
- Baseline Model

Field Injection Gas Rate (ft³/day)
- Field History
- HM PSO
- Baseline Model
Forecasting Models

- **Case A**: Current WAG patterns (15 wells) and adjacent water injectors (5 wells) with constant daily group target of 20 MMscf/d CO₂ purchase
- **Case B**: Convert all injectors to WAG wells (20 wells) with CO₂ purchase at constant daily group target of 20 MMscf/d CO₂ purchase
- The water-gas injection period ratio is 1:2.

<table>
<thead>
<tr>
<th></th>
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<th>Amount of substances of CO₂ (10⁹ g-moles)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td>Structural (Free gas)</td>
</tr>
<tr>
<td>Case A</td>
<td>10.61</td>
<td>155.4</td>
<td>4.78</td>
</tr>
<tr>
<td>Case B</td>
<td>12.14</td>
<td>155.4</td>
<td>4.67</td>
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</tbody>
</table>
Storage Mechanisms Modeling

1. GAS SOLUBILITY TRAPPING MODELING

• In this work CO$_2$ is considered to be soluble in aqueous and oleic phases.
• CO$_2$-Brine mixture modelled using Henry’s Law
• CO$_2$-Oil Mixture modelled using the Peng-Robison EOS

2. RESIDUAL AND STRUTURAL GAS TRAPPING MODELING

• CO$_2$ in free phase (supercritical/gaseous phases) is trapped by geological structure of the reservoir.
• Three phase relative permeability hysteresis model is employed to model the residual trapping.
Phase Storage of CO$_2$ in the Farnsworth Unit – Field

FIELD-SCALE STORAGE OF CO2

- Total CO2 Injected
- Structural Trapped CO2
- Oil Phase Trapped CO2
- Aqueous Phase Trapped CO2
- Residual Phase Trapped CO2
Geochemical Trapping

- Reactive surface areas of the minerals Pan et al., (2016).
- Initial volume fractions and the aqueous species concentrations are taken from Ahmed et al., (2016).
- The kinetic/activations energy and rate constant taken from Palandri and Kharaka, (2004)
  - At 25°C, using the pH medium of the minerals as described in Pan et al., (2016)
- Mineral volume fractions defined in terms of corresponding bulk volume fraction using the pore volume weighted average porosity (0.142) from the field.

<table>
<thead>
<tr>
<th>Intra-aqueous chemical equilibrium reactions</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. $\text{CO}_2\text{(aq)} + \text{H}_2\text{O} = \text{H}^+ + \text{HCO}_3^-$</td>
</tr>
<tr>
<td>2. $\text{CO}_3^{2-} + \text{H}^+ = \text{HCO}_3^-$</td>
</tr>
<tr>
<td>3. $\text{OH}^- + \text{H}^+ = \text{H}_2\text{O}$</td>
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</tbody>
</table>

<table>
<thead>
<tr>
<th>Mineral dissolution/precipitation reactions</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Calcite + $\text{H}^+ = \text{Ca}^{2+} + \text{HCO}_3^-$</td>
</tr>
<tr>
<td>2. Dolomite + 2$\text{H}^+$ = $\text{Ca}^{2+} + \text{Mg}^{2+} + 2\text{HCO}_3^-$</td>
</tr>
<tr>
<td>3. Quartz = $\text{SiO}_2\text{(aq)}$</td>
</tr>
<tr>
<td>4. Albite + 4 $\text{H}^+$ = 2 $\text{H}_2\text{O} + \text{Na}^+ + \text{Al}^{3+} + 3\text{SiO}_2\text{(aq)}$</td>
</tr>
<tr>
<td>5. Siderite + $\text{H}^+$ = $\text{HCO}_3^-$ + $\text{Fe}^{2+}$</td>
</tr>
<tr>
<td>6. Illite + 8 $\text{H}^+$ = 5 $\text{H}_2\text{O} + 0.6 \text{K}^+ + 0.25 \text{Mg}^{2+} + 2.3 \text{Al}^{3+} + 3.5 \text{SiO}_2\text{(aq)}$</td>
</tr>
<tr>
<td>7. Kaolinite + 6 $\text{H}^+$ = 5 $\text{H}_2\text{O} + 2 \text{Al}^{3+} + 2\text{SiO}_2\text{(aq)}$</td>
</tr>
<tr>
<td>8. Smectite + 7 $\text{H}^+$ = 0.29 $\text{Fe}^{2+} + 3.75 \text{SiO}_2\text{(aq)} + 0.16 \text{Fe}^{3+} + 4.5 \text{H}_2\text{O} + 1.25 \text{Al}^{3+} + 0.15 \text{Na}^+ + 0.02 \text{Ca}^{2+} + 0.2 \text{K}^+ + 0.9 \text{Mg}^{2+}$</td>
</tr>
<tr>
<td>9. Chamosite + 10 $\text{H}^+$ = 2 $\text{Fe}^{2+} + \text{SiO}_2\text{(aq)} + 2 \text{Al}^{3+} + 7 \text{H}_2\text{O}$</td>
</tr>
</tbody>
</table>
PILOT CASE - Prediction Summary on selected 13-10A pattern

- Mineralization study was performed as a pilot study to relate the chemo-mechanical laboratory experiments prior to field-scale evaluation.
  - Study concentrated around the 13-10A where most cores were collected.

- Mineralization occurs in two forms:
  - Intra-aqueous reactions
  - Dissolution/precipitation reactions

- The simulation model runs for 1,000 years to monitor the fate of the injected CO₂.
Aqueous Species Evolution

• Evolution of Aqueous Species:
  • $\text{Al}^{3+}$ initially increased but later decreased
  • $\text{K}^+$, $\text{CO}_3^{2-}$, $\text{Fe}^{3+}$, $\text{Na}^+$, $\text{HCO}_3^-$ increased gradually
  • $\text{Ca}^{2+}$, $\text{Mg}^{2+}$, $\text{Cl}^-$, $\text{Fe}^{2+}$ continuously decreased

• pH of the in-situ brine initially decreased and later increased relatively
Mineral Evolution in 13-10A area

- Dissolution observed in Ankerite-Calcite cements correspond to the chemo-mechanical experiments observed (Ampomah et al. 2016).

- Other Mineral Matrix dissolution and precipitation corresponds with previous studies (for example, Khan et al. 2017).

- Net precipitations is predicted in the reservoir which correspond to change in porosity.
Precipitation Heat maps

1000 years' impact in layer 7 (3037-Dec-01)

20 years' impact in layer 7 (2037-Dec-01)

1000 years' impact in layer 9 (3037-Dec-01)

1000 years' impact in layer 10 (3037-Dec-01)

20 years Impact in layers 10 (2037-Dec-01)

1000 years' impact in layer 10 (3037-Dec-01)

1000 years' impact in layer 7 (3037-Dec-01)

1000 years' impact in layer 9 (3037-Dec-01)

A: Quartz Precipitation

B: Kaolinite precipitations
Precipitation and pH value Heat maps

A: Siderite precipitations

B: pH of the reservoir medium
Concluding Remarks

1. A fully CO$_2$-WAG injection strategy guarantees safe storage medium for the injected CO$_2$ in the Morrow B. Thus, a significant CO$_2$ was observed to dissolve in the liquid phase as compared with the amount in the structural and residual phase trapping.

2. CO$_2$ dissolution that accounted for solubility trapping is known to depend on the flow mixture, the amount of the aqueous species, and salinity within the reservoir.

3. The results from the pattern studies also show that the Morrow B is an effective reservoir for CO$_2$ sequestration and suggest that geochemical storage is highly favorable in both short and long-term.

4. Current work was successfully conducted on the pattern-scale, thus, on a section of the field-scale reservoir. The result suggests ankerite group mineral, Dolomite, shows varying evolution during the study period, whiles calcite exhibited continuous dissolution. The observed result confirms the flow-through laboratory experiments.

5. The next stage of this work would focus on expanding the simulation work to full field scale.
References


Acknowledgements / Thank You / Questions

Funding for this project is provided by the U.S. Department of Energy's (DOE) National Energy Technology Laboratory (NETL) through the Southwest Regional Partnership on Carbon Sequestration (SWP) under Award No. DE-FC26-05NT42591.
The oil recovery results indicate that the case considering the mineral reactions yields lower oil production.

Such observation is due to the loss of injected CO$_2$ via chemical reactions with the insitu brine and formation rocks.
Effect of WAG Cycles on Storage

Prior to Prediction Studies different Injection cycles were tested:

- **WAG Cycle with high water injection fraction:**
  - Less CO$_2$ injection
  - Less Recovery
  - Better liquid phase storage

- **WAG Cycle of 1:3 yield**
  - Highest CO$_2$ injection
  - Best oil Phase CO$_2$ storage
  - Lowest Aqueous Phase Storage

- **WAG Cycle of 1:2 yield**
  - Best recovery, but less injection
  - Highest Storage volumes
  - Best secure storage mediums
  - Met most project objectives

<table>
<thead>
<tr>
<th>WAG Cycle</th>
<th>Oil Recovery (MM bbl.)</th>
<th>Amount of substances of CO$_2$ ($10^9$ g-moles)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Total CO$_2$ Injection</td>
<td>Structural Trapped gas (Free gas)</td>
</tr>
<tr>
<td>1:1</td>
<td>10.42</td>
<td>125.89</td>
</tr>
<tr>
<td>1:2</td>
<td>10.61</td>
<td>155.39</td>
</tr>
<tr>
<td>1:3</td>
<td>10.47</td>
<td>169.82</td>
</tr>
<tr>
<td>3:2</td>
<td>10.44</td>
<td>107.31</td>
</tr>
<tr>
<td>3:1</td>
<td>9.96</td>
<td>80.21</td>
</tr>
</tbody>
</table>
Salinity effects on storage

Sea Water
- Massive increase in Na⁺ & Cl⁻
- Lesser CO₂ storage in water

Produced water:
- Slight Increase in Na⁺ & Cl⁻
- Average Storage CO₂ in water
- Highest Oil recovery

Fresh Water:
- Decrease in Na⁺ & Cl⁻
- Highest storage of CO₂ in water
- Less oil recovery
- High water produce

- TDS affect the storage with other species added

### Table: Amount of substances of CO₂

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<tr>
<td></td>
<td></td>
<td>Structural Trapped Gas (Free gas)</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Seawater</td>
<td>11.815</td>
<td>3.21</td>
</tr>
<tr>
<td>Produced Water</td>
<td>12.095</td>
<td>2.83</td>
</tr>
<tr>
<td>Fresh Water</td>
<td>11.846</td>
<td>2.72</td>
</tr>
</tbody>
</table>
PERMEABILITY EFFECT FROM GEOCHEMICAL REACTION

\[ \hat{\phi}^* = \phi^* - \sum_{\beta=1}^{n_m} \left( \frac{N_\beta}{\rho_\beta} - \frac{N_\beta^0}{\rho_\beta} \right) \]

\[ \phi = \hat{\phi}^* [1 + c_\phi (p - p^*)] \]

\[ \frac{K_n}{K_k} = rf = \left( \frac{\phi}{\phi^0} \right)^3 \left( \frac{1 - \phi^0}{1 - \phi} \right)^2 \]

\( \phi = \) Porosity

\( \phi^* = \) Reference porosity without mineral precipitation/dissolution

\( \hat{\phi}^* = \) Reference porosity including mineral precipitation/dissolution

\( N_\beta = \) Total moles of mineral \( \beta \) per bulk volume at the current time

\( N_\beta^0 = \) Total moles of mineral \( \beta \) per bulk volume at time 0

\( \phi^0 = \) initial porosity at time 0

\( n_m = \) number of minerals

\( \rho_\beta = \) mineral molar density

\( c_\phi = \) rock compressibility

\( p^* = \) reference pressure.

\( k_n = \) permeability at current time steps

\( k_k = \) Initial permeability

\( rf = \) Resistance factor
Phase Storage of CO$_2$ in 13-10A Region

The gradual decrease in residual trapped gas promotes

- Mineralization
- Solubility trapping

- In the field-scale, CO$_2$ dissolution in oil phase is the predominant short-term storage in the FWU
<table>
<thead>
<tr>
<th>Components</th>
<th>During 20 years Operation</th>
<th>1000 years (After Shut-In)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. CO$_2$(aq)</td>
<td>1.1019E+08</td>
<td>1.6505E+08</td>
</tr>
<tr>
<td>2. CO$_3^{2-}$</td>
<td>3.20E+04</td>
<td>6.20E+04</td>
</tr>
<tr>
<td>3. HCO$_3^-$</td>
<td>1.1016E+08</td>
<td>1.64987E+08</td>
</tr>
<tr>
<td>4. Albite</td>
<td>-1.40E+07</td>
<td>-8.76E+07</td>
</tr>
<tr>
<td>5. Quartz</td>
<td>3.98E+07</td>
<td>1.78E+08</td>
</tr>
<tr>
<td>6. Calcite</td>
<td>-1.71E+06</td>
<td>-6.45E+06</td>
</tr>
<tr>
<td>7. Dolomite</td>
<td>9.66E+05</td>
<td>-2.05E+07</td>
</tr>
<tr>
<td>8. Siderite</td>
<td>3.43E+07</td>
<td>5.94E+07</td>
</tr>
<tr>
<td>9. Illite</td>
<td>9.51E+04</td>
<td>-7.08E+06</td>
</tr>
<tr>
<td>10. Kaolinite</td>
<td>1.30E+07</td>
<td>7.58E+07</td>
</tr>
<tr>
<td>11. Smectite</td>
<td>-2.02E+06</td>
<td>-2.89E+06</td>
</tr>
<tr>
<td>12. Chamosite</td>
<td>1.68E+07</td>
<td>2.06E+07</td>
</tr>
</tbody>
</table>
OIL PERMEABILITY RESISTANCE FACTOR

4 years Impact in most layer 7,8,9 (2014-Jan-01)

20 years’ impact in layer 7 (2037-Dec-01)

1000 years’ impact in layer 7 (3037-Dec-01)

4 years’ impact in layer 10 (2014-Jan-1)

20 years’ impact in layer 10 (2037-Dec-01)

1000 years’ impact in layer 10 (3037-Dec-01)