Investigation of Geochemical Interactions of Carbon Dioxide and a Carbonate Formation in the Northwest McGregor Oil Field after Enhanced Oil Recovery and CO_2 Storage

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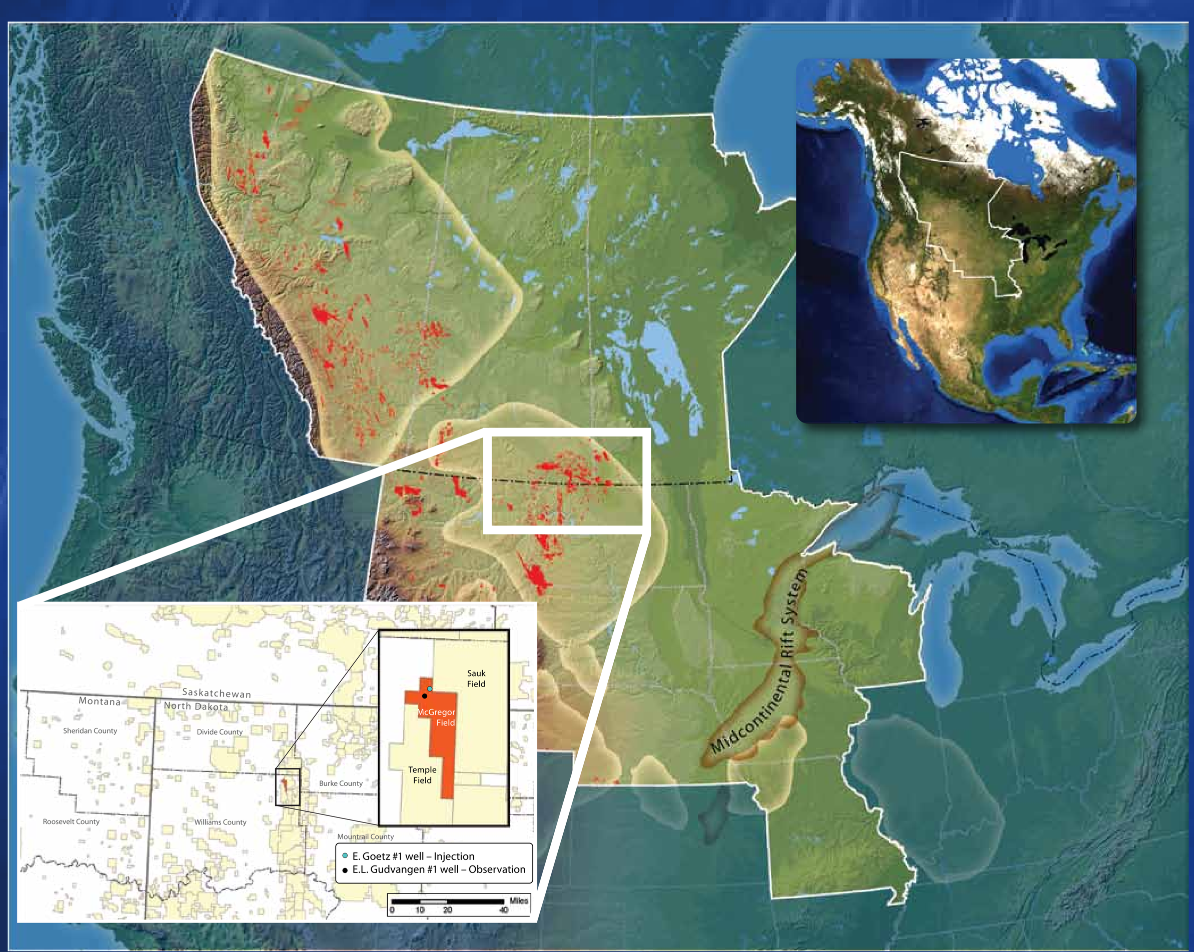
Abstract

Injection of carbon dioxide (CO_2) for the purpose of enhanced oil recovery is widely regarded as one of the key commercial applications of geological storage and provides valuable insight into other large-scale projects aimed at reducing CO_2 emissions to the atmosphere. The Plains CO_2 Reduction (PCOR) Partnership, one of the seven U.S. Department of Energy National Energy Technology Laboratory Regional Carbon Sequestration Partnerships, is conducting a project in the Northwest McGregor oil field in North Dakota to determine the effects CO_2 has on the productivity of the reservoir, wellbore integrity, and the carbonate formation into which the CO_2 was injected. The method used in this project was huff 'n' puff whereby 440 tons of supercritical CO_2 was injected into a well over a 2-day period and allowed to "soak" for a 2-week period. The well was subsequently put back into production to recover incremental oil. This paper outlines the approach and current observations derived from numerical modeling and laboratory simulations of potential geochemical reactions to evaluate the short-term risks for operations (e.g., porosity and permeability decrease) and long-term implications for CO_2 storage via mineralization. The integration of data obtained during mineralogical analyses, fluid sampling, and laboratory experiments proved to be a key for better understanding the dynamic geochemical processes which happen in the reservoir after CO_2 injection and was necessary for successful completion of the numerical modeling. Results of the numerical modeling suggest that the already acidic and highly saline environment (pH <4.5 and total dissolved solids ~300,000 mg/kg) of the Northwest McGregor oil field should not experience any significant changes in mineralogy as a result of CO_2 injection, especially in the near term, which correlates with the postinjection field geochemical analyses.

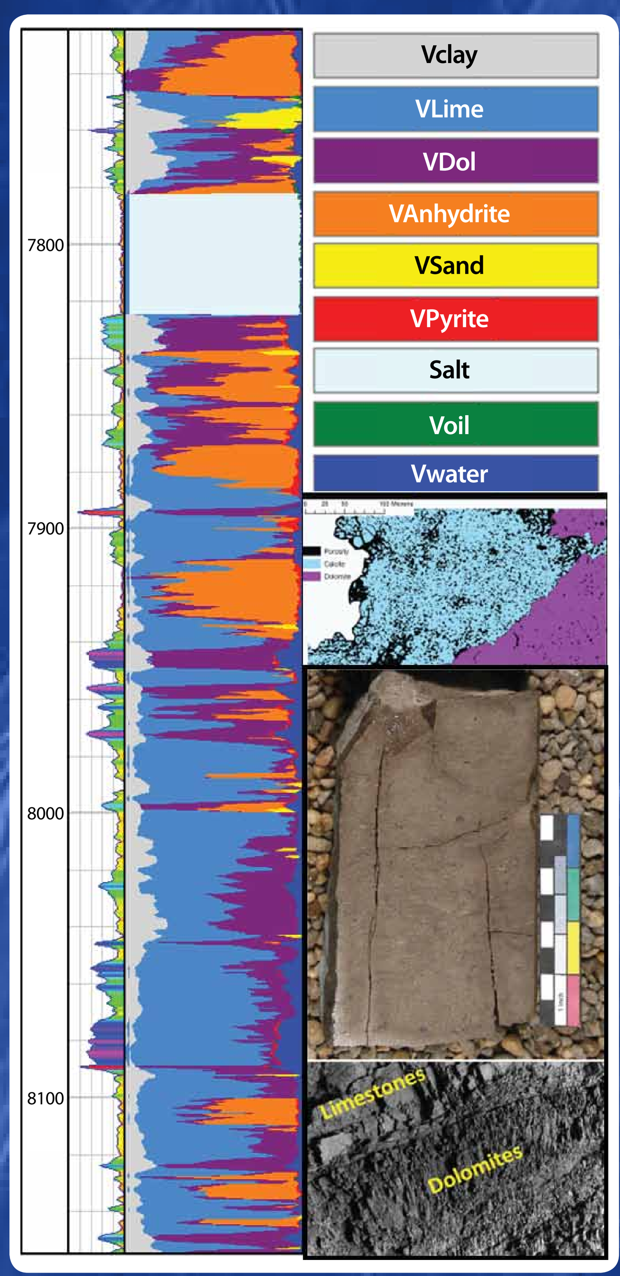
Location

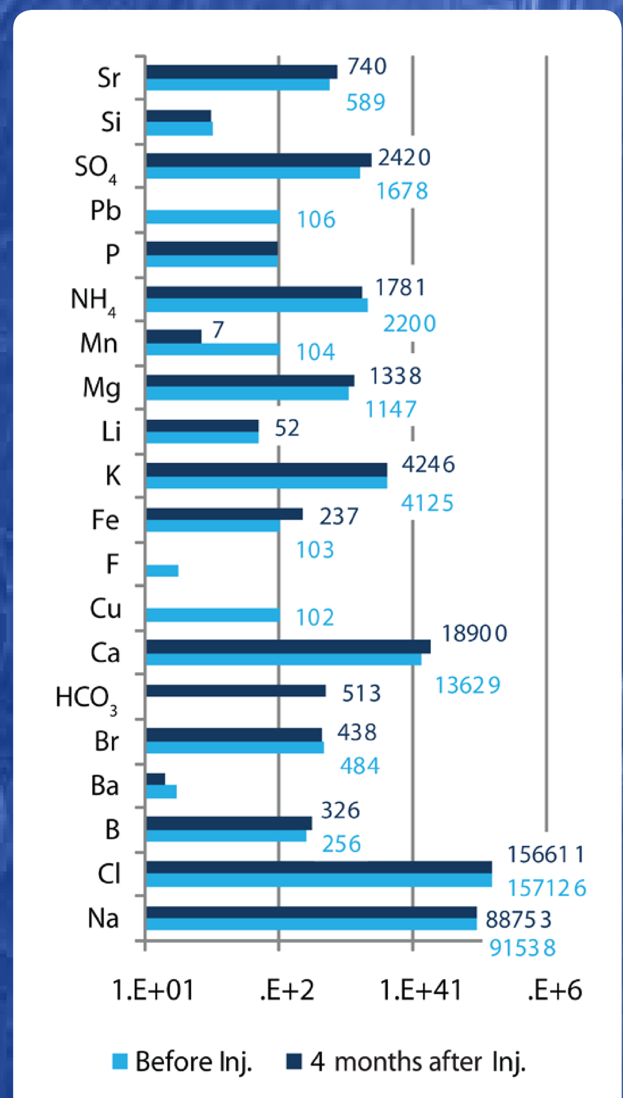


Reservoir Characteristics

Producing Formation	Mission Canyon
Lithology	Primarily limestone
Average Porosity	15%
Matrix Permeability	0.35 mD
Secondary Permeability	Fractures
Depth from Surface to Pay	8050 ft/2434 m
Average Temperature	216°F/102°C
Original Discovery Reservoir Pressure	3127 psig/216 bar
Preinjection Reservoir Pressure	2700 psig/186 bar
Oil Gravity (API)	41.7°
Cumulative Oil Production	2.2 million STB

Reservoir Geochemistry

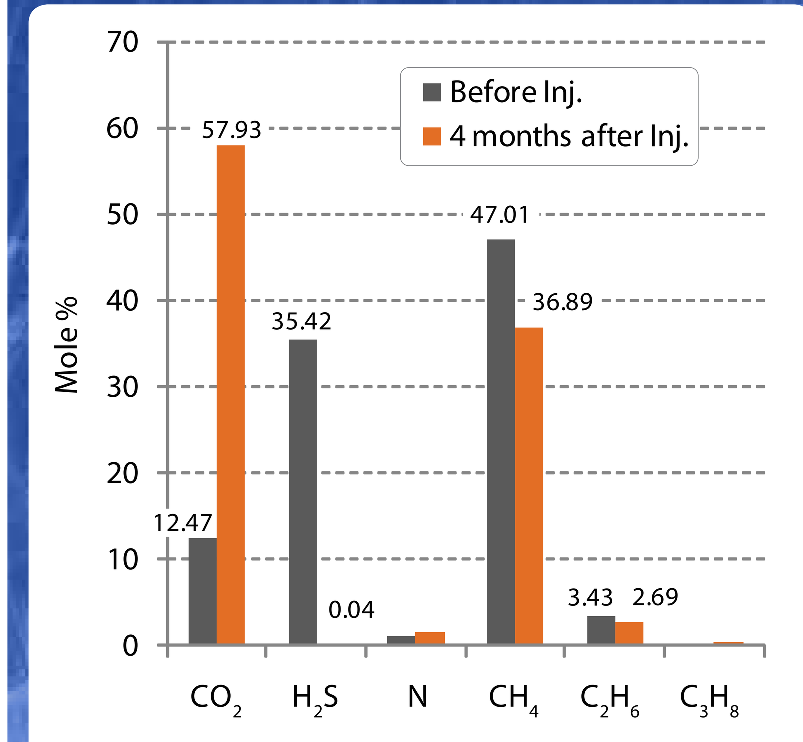




Reservoir fluid analysis performed with Schlumberger's E-line measured before stimulation, 4 months after stimulation, and numerical verification.

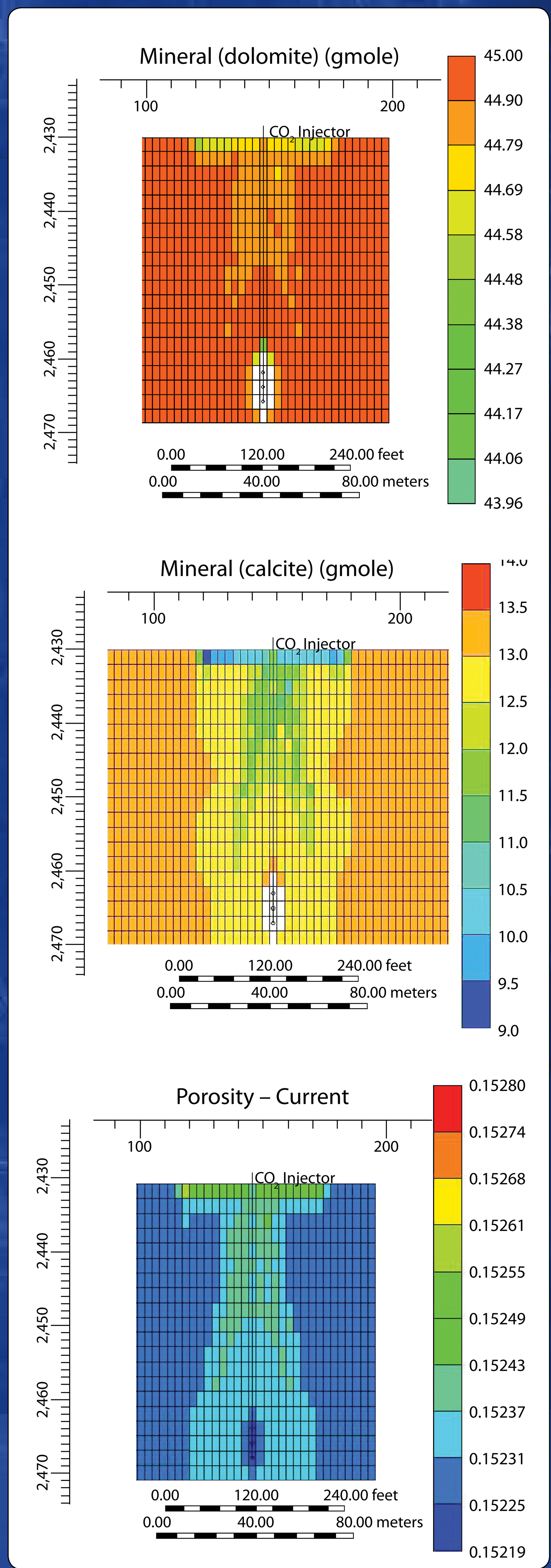
pH	Density g/cm³	Conductivity at 25°C, mS/cm	Resistivity at 77 °F	Salinity	TDS, mg/kg
5.55 (at 106°F) 4.50 (at 216°F – live pH) 4.23 (modeled)	1200	249	4.02	283,8552	92,863

The live water pH measurement service offered by Oilphase DBR was performed before the stimulation. On injection of dye into the sample at reservoir pressure and temperature, it was determined that the pH value of the sample is expected to be <4.5 units at 2600 psia and 225°F.



Measured concentration of some gases in the reservoir before and after stimulation.

Reservoir Modeling



Spatial 2-D distribution of the calcite and dolomite dissolution and insignificant porosity increase modeled 10 years after injection.

Conclusions

1. The fluid samples recovered before and after CO_2 injection with Schlumberger's E-line technique and analyzed by Oilphase-DBR and various geochemical modeling techniques illustrated:
   - Unusually low (< 4.5) pH readings
   - Very consistent dataset which proved to be viable and applicable for further modeling
   - Very high concentration of dissolved solids (around 300,000 mg/kg of water)
2. Results of the equilibrium modeling further indicated that the analyzed water is in equilibrium or near-equilibrium state with the Mississippian Formation minerals: anhydrite, calcite, dolomites, pyrite, and illite.
3. Modeling suggests low reactivity of the reservoir rocks with the injected CO_2 and in situ brine. However, minor mineralogical changes, such as minor dissolution of calcite and dolomite minerals, are predicted to occur. The kinetic and mass-transfer modeling illustrated the dynamics of the possible mineralogical changes. It was observed that the next thermodynamically stable point can be reached in nearly 7 years after the CO_2 injection.
4. The numerical modeling results are in agreement with the laboratory study. In addition, the low precipitation of hematite was observed in laboratory conditions, as a result of minor ankerite dissolution.

PCOR Partnership 2003 – Present

University of North Dakota Grand Forks