Geochemical Modeling of Carbon Dioxide Injection into a Carbonate Formation in the Northwest McGregor Oil Field for CO2 Storage and Enhanced Oil Recovery (EOR)

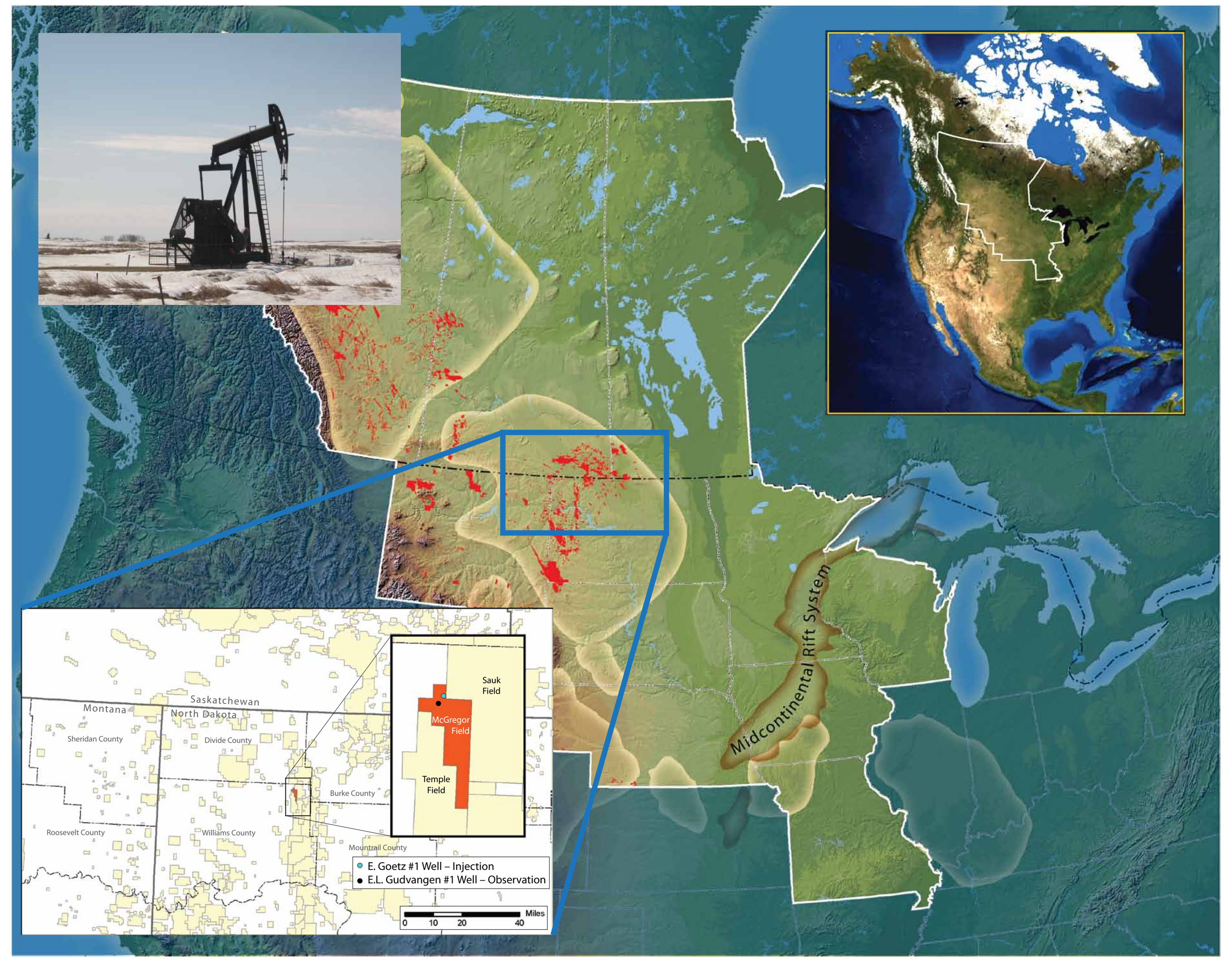
Yevhen I. Holubnyak, Damion J. Knudsen, Blaise A. Mibeck, Jordan M. Bremer, Steven A. Smith, James A. Sorensen, Charles D. Gorecki, Edward N. Steadman, and John A. Harju
Energy & Environmental Research Center, Grand Forks, ND 58203, USA

ABSTRACT

Injection of carbon dioxide (CO_2) for the purpose of enhanced oil recovery (EOR) is widely regarded as one of the key commercial applications of geological storage that will provide valuable insight into large-scale projects aimed at reducing CO_2 emissions to the atmosphere. The Plains CO_2 Reduction 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 will have on the productivity of the reservoir, wellbore integrity, and the carbonate formation into which CO_2 was injected. The method used in this project is huff 'n' puff whereby 400 tons of supercritical CO_2 was injected into a well over a 2-day period and allowed to "soak" for a 2-week period. Then the well was subsequently put back into production to recover incremental oil.

The purpose of this paper is to outline the approach and current observations for the numerical modeling of potential geochemical reactions in order to evaluate the short-term risks for operations (e.g., porosity and permeability decrease) and long-term implications for CO_2 storage via mineralization. Mineralogy of the reservoir was determined using well logs, traditional core sample analysis, x-ray diffraction, and QEMSCAN techniques. Using the results of these analyses, the mineral phases selected for model inputs were anhydrite, calcite, dolomite, illite, K-feldspar, and traces of pyrite. A pressurized bottom-hole fluid sample was also collected, and its composition was determined. The results of this fluid sample were also used as input parameters for the model.

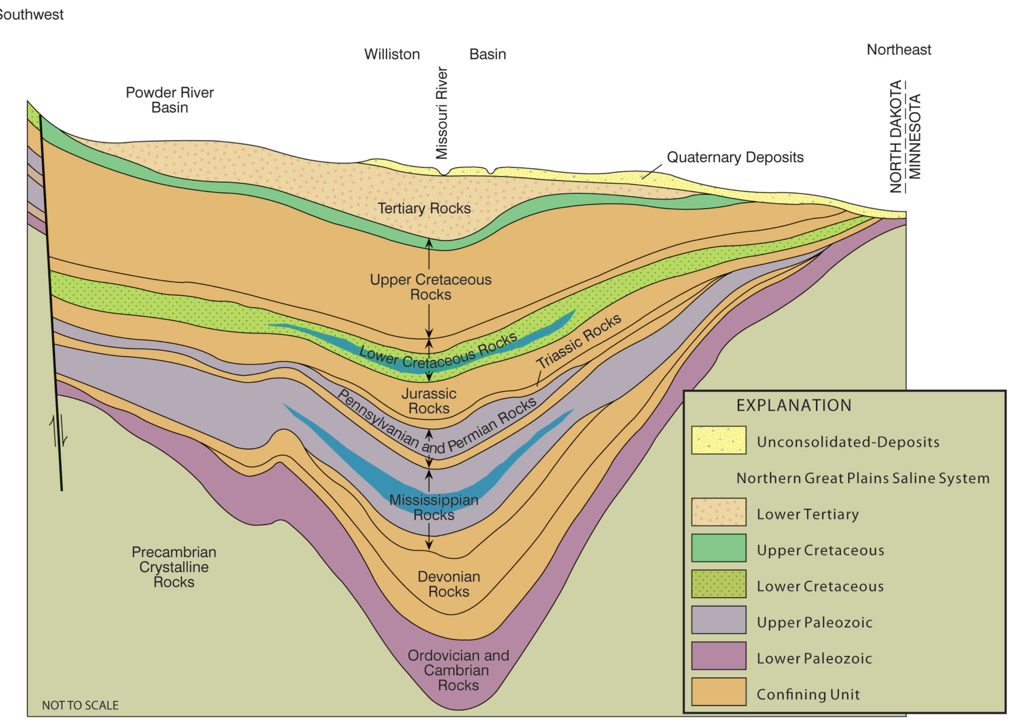
Modeling was performed using PHREEQC and Geochemist Workbench software in order to determine the most favorable geochemical interactions, evaluate in situ fluid properties, etc. The Computer Modelling Group Ltd. GEM simulator was utilized for the creation of a 2-D cross-section model for reactive transport evaluation. It was determined that the already-reducing environment of the Northwest McGregor oil field should not experience any significant changes in mineralogy, especially in the near term. This conclusion is also supported by a laboratory study, which is presented in this poster. Minor calcite and dolomite dissolution is predicted by both modeling and laboratory study.

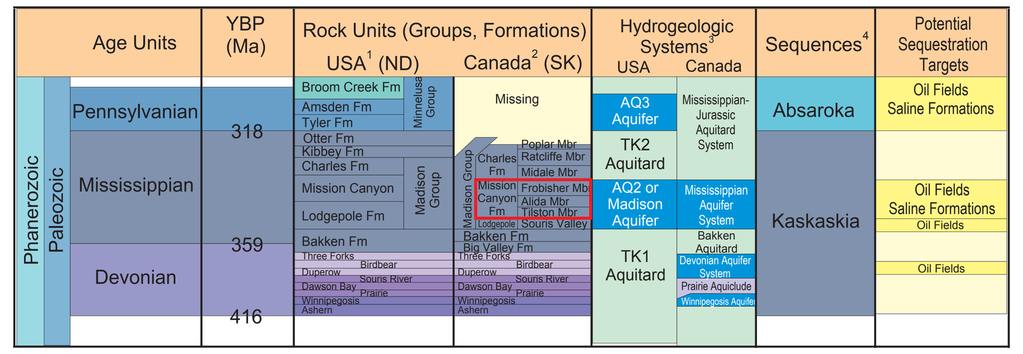


RESERVOIR CHARACTERISTICS

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 LOCATION



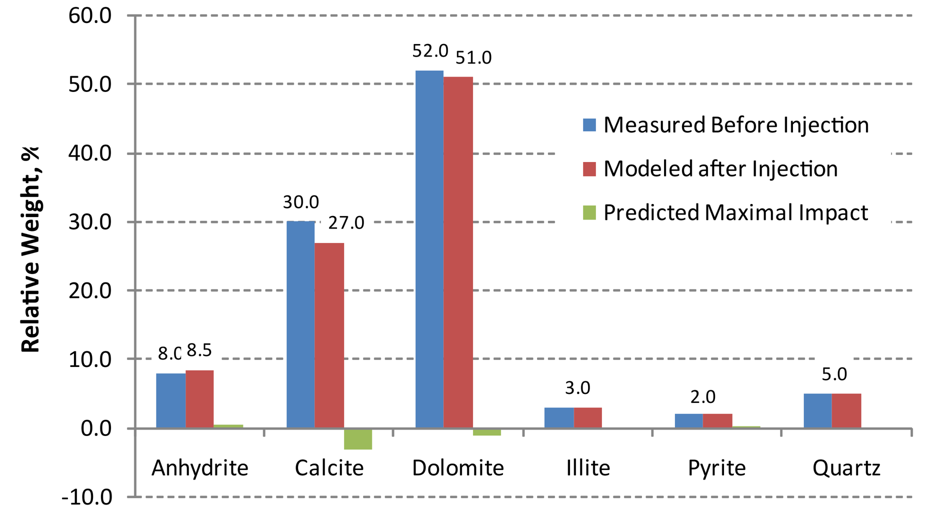


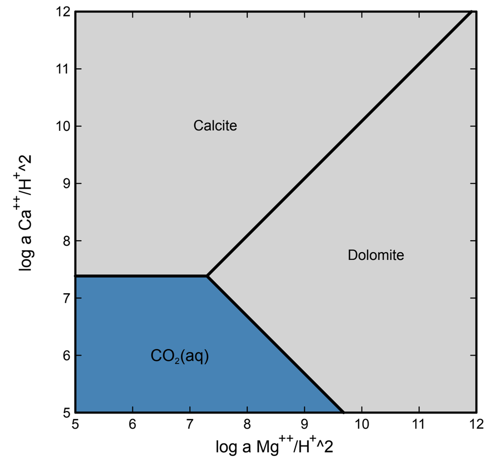
OPERATIONAL PARAMETERS

Total Mass of CO_2 Injected	440 tons
Maximum Allowable Injection Pressure Based on Fracture Gradient	5100 psig/352 bar
Average Injection Rate	12.2 tons/hour
Average Injection Pressure (surface)	2900 psig/200 bar
Average Injection Pressure (bottomhole)	5000 psig/345 bar
Average Injection Temperature (bottomhole)	190°F/88°C
Wellhead Pressure at End of Injection	3500 psig/341 bar
Length of Injection Period	36 hours

MINERALOGY ANALYSIS

The formation mineralogy, mineral composition, and the spatial variations at the Norwest McGregor site were determined using well logs, traditional core sample analysis with XRD, XRF, and QEMSCAN techniques. All utilized techniques have certain advantages and disadvantages. For instance, XRD diffraction is usually considered to be a semiquantitative technique, and it is unable to identify phases below 1 to 5 weight percent, and if solid solutions are present or amorphous phases exist, it is very difficult to interpret the mineral assemblage. Therefore, the integrative mineralogical analysis was performed utilizing linear program normative analysis (LpNORM). Using the results of these analyses, the mineral phases selected for model inputs were anhydrite, calcite, dolomite, illite, and traces of pyrite.



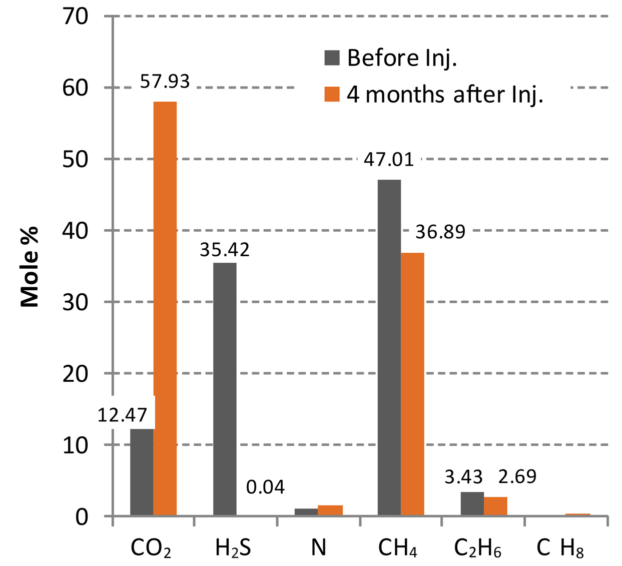


Log activity-activity diagram illustrating the stability of calcite and dolomite.

FLUID SAMPLE ANALYSIS

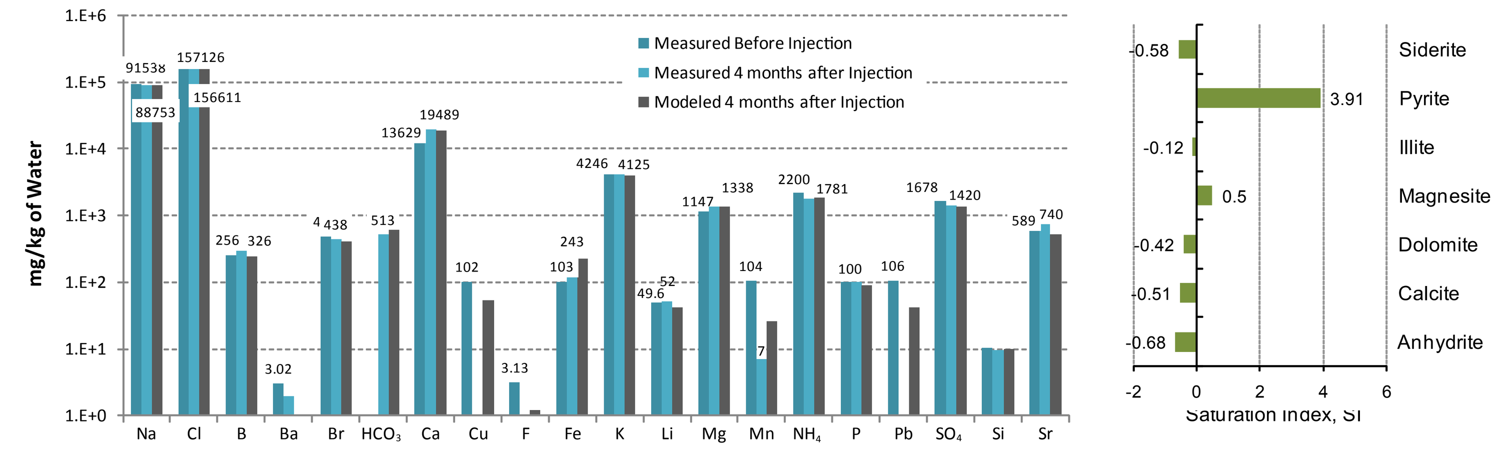
A single bottomhole sample collected using Schlumberger's E-line was transferred to Oilphase-DBR. The gas from zero flash was subjected to chromatography, and its composition was determined.

The live water pH measurement service offered by Oilphase DBR is an extension of the already-commercial downhole pH measurement service. Both the techniques overcome the limitations of the traditional practice of flashing high-temperature, high-pressure water (HTHP) to room temperature and conventional analysis of flashed gas and water at ambient conditions. These traditional analyses of flashed gas and water are used as inputs to calculate HTHP pH by chemical equilibrium modeling. This technique introduces errors in pH because of sample handling, precipitation of ionic solids from flashed water samples, and the modeling uncertainties of complex ionic equilibrium. By taking the measurements at the HTHP state, these errors are eliminated. 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.



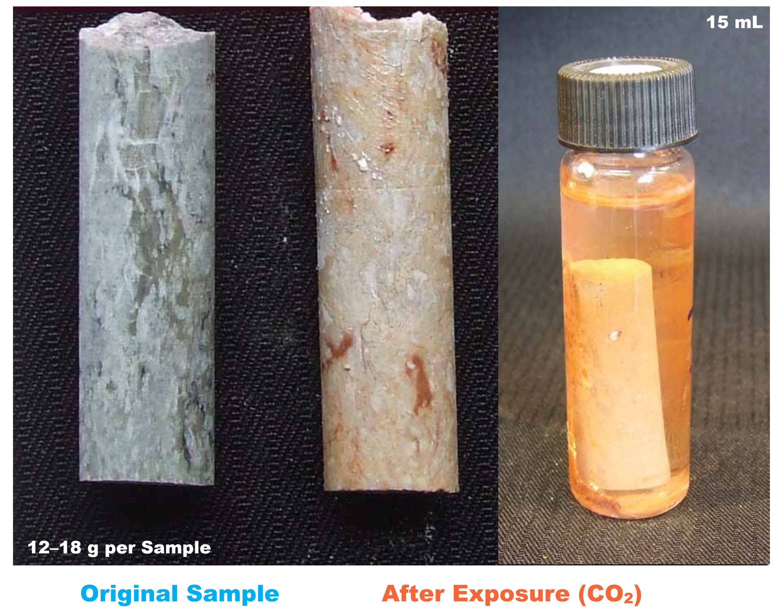
Measured concentration of some gases in the reservoir before and after stimulation

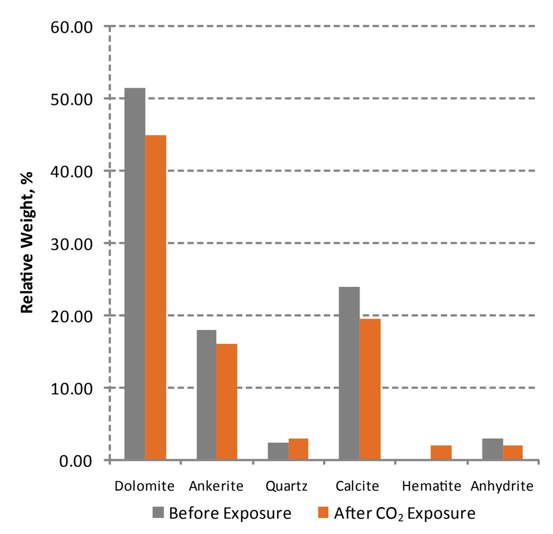
pH	Density, g/cm^3	Conductivity at 25°C, mS/cm	Resistivity at 77°F, ohm-m	Salinity, ppm	TDS, mg/kg
5.55 (at 106°F) 4.50 (at 216°F – live pH) 4.23 (modeled)	1200	249	4.02	283,855	292,863



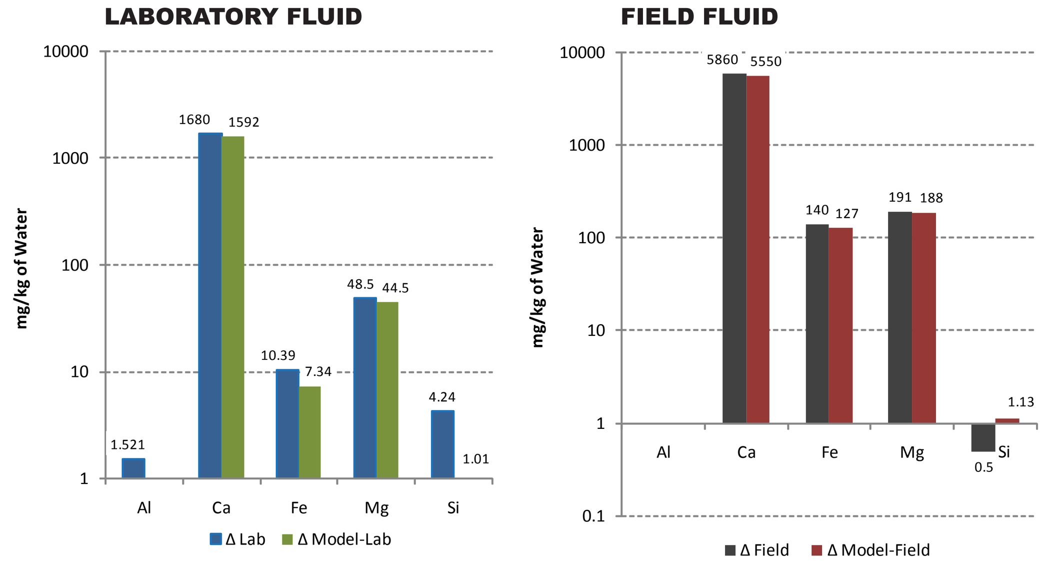
Reservoir fluid analysis measured before stimulation, measured 4 months after stimulation, and numerical verification.

EXPERIMENTAL RESULTS AND MODELING



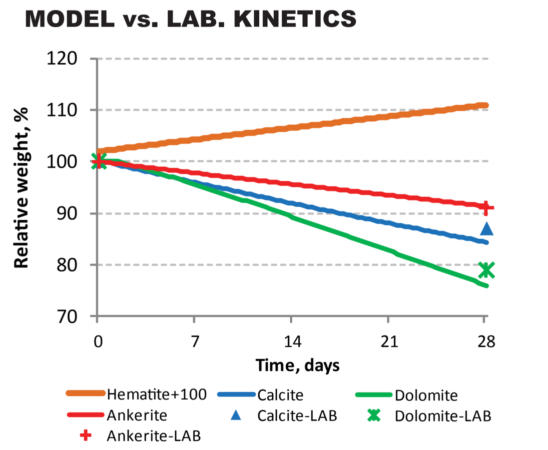


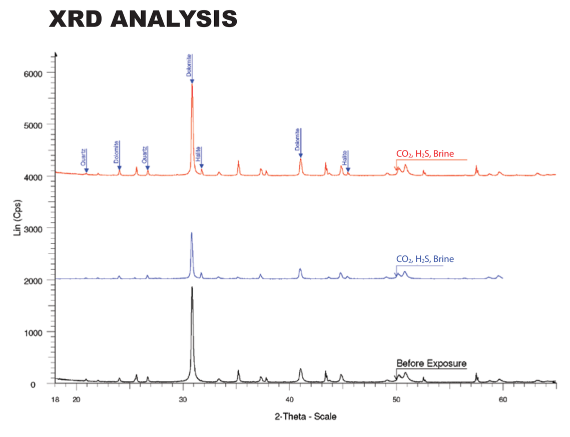
Normilized mineralogical analysis.



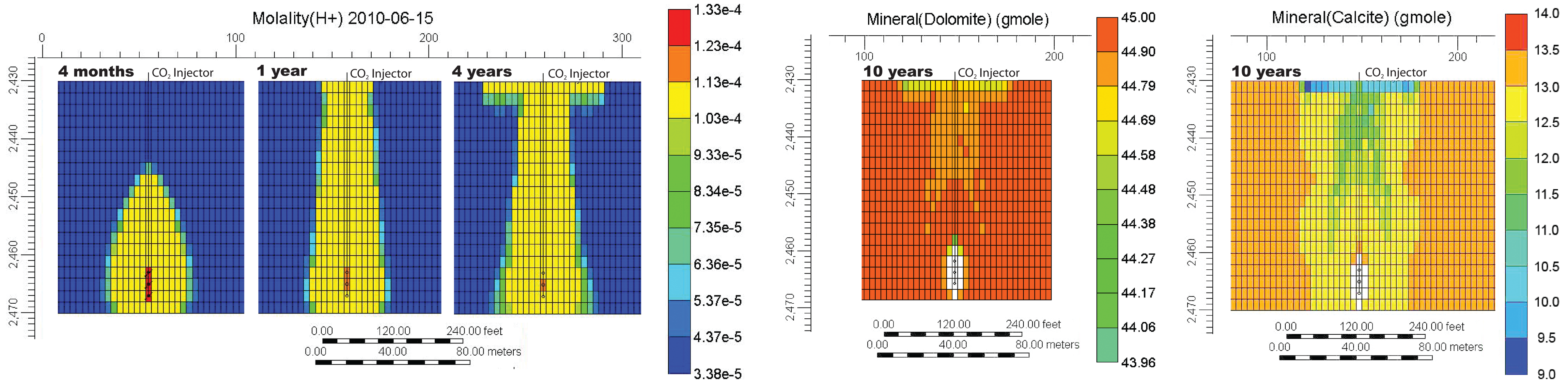
Comparison of changes in fluid compositions before and after stimulation.

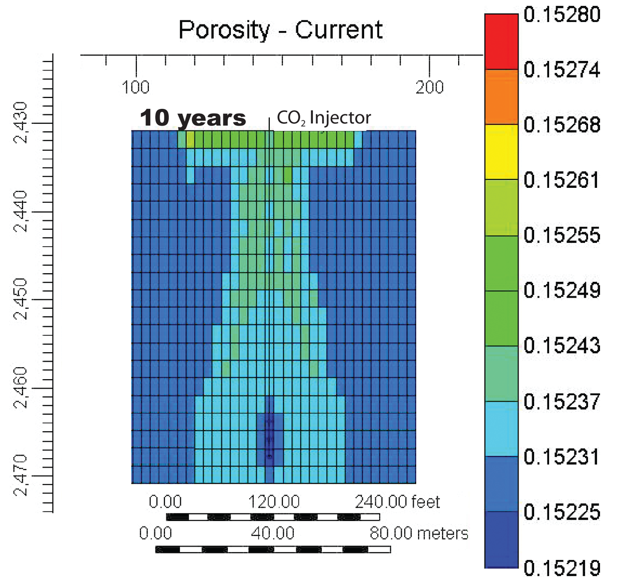
The experiments were designed to expose the selected rock/mineral samples to CO_2 under relatively high pressure and temperature, specifically 2100 psi or 145.4 bar and 176°F or 80°C, respectively.
The tests were conducted by placing core plug into a small (15-mL) scintillation vial and inserting the open vials into a chamber, which could be regulated for temperature and pressurized with CO_2. Each sample was simultaneously saturated with saline solution (sodium chloride – NaCl).
The samples were incubated in the testing chamber for a period of 4 weeks (28 days). The 4-week exposure time was conservatively selected after initial evaluation of the control sample (magnesium silicate) indicated that a complete reaction (carbonation reaction) was achieved after approximately 2 weeks. Comparative methodology using the XRD, XRF, and QEMSCAN techniques was utilized.





2-D RESERVOIR MODEL





CONCLUSIONS

1. The fluid samples recovered before and after CO_2 injection with the 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 assemblage
   - 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 Mississip pian 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 are predicted to occur: the dissolution of calcite and dolomite minerals. 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 almost 7 years after CO_2 injection.
4. The numerical modeling results are in agreement with laboratory studies. In addition, low precipitation of hematite was observed in laboratory conditions, as a result of minor ankerite dissolution.