

INTERIM FINAL TECHNICAL REPORT  
October 1, 2006, through September 30, 2007

Project Title: **AN ASSESSMENT OF GEOLOGICAL CARBON  
SEQUESTRATION OPTIONS IN THE ILLINOIS BASIN:  
PHASE II**

ICCI Project Number: DEV05-2  
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ABSTRACT

The primary focus of the four year, Phase II ICCI and DOE sponsored Midwest Geological Sequestration project is carbon dioxide (CO<sub>2</sub>) injection in six field pilots. The second year's objectives were to drill wells for the coalbed methane site, select the deep saline site, and conduct one oil reservoir pilot.

For the coal bed pilot, two wells were drilled and completed in July, 2007. Testing of these two well and drilling of up to two more wells will occur in the coming year with injection to occur in the summer of 2008.

For the first of four enhanced oil recovery (EOR) projects, a site in the Loudon oil field in Fayette County, Illinois was chosen. Injection occurred in the spring and the subsequent production briefly peaked at eight times the pre-injection rate before decreasing. Incremental oil production attributed to the CO<sub>2</sub> injection was 93 barrels. Site selection for the second oil reservoir pilot is in progress and will be selected from the list of nominated fields. Injection is scheduled for late 2007.

The site for the deep saline project has been selected and the scope of the Deep Saline Pilot has been amended to demonstrate the ability of the Mt. Simon Sandstone, a major regional saline-water bearing formation in the Illinois Basin, to accept and retain 1 million tons of carbon dioxide injected over a period of three years. The proposed site is on the property of Archer Daniels Midland (ADM) Company in Decatur, Illinois, and the proposed CO<sub>2</sub> source is ADM's ethanol fermentation operation at their Decatur facility. This well is scheduled to be drilled in April 2008.

The final report will be submitted within 90 days of the completion of this four-year project as required by the U.S. Department of Energy, the major funder of the project, and in coordination with ICCI.

## EXECUTIVE SUMMARY

The primary focus of the four year, Phase II ICCI and DOE sponsored Midwest Geological Sequestration project is active CO<sub>2</sub> injection in six pilots. The second year's objectives were to drill wells for the coalbed methane site, conduct one oil reservoir pilot, and select the deep saline site. The work to identify the site for each pilot includes screening, regional geologic studies, laboratory work, geologic and reservoir modeling, site visits, operational plans, and NEPA reports. Areas of accomplishment that are applicable to all pilots include surface injection equipment; data acquisition equipment; monitoring, mitigation, and verification (MMV) program; CO<sub>2</sub> capture; and outreach.

### **Coal Seam Pilot**

The coal field pilot is in Wabash County, between Albion and Mt. Carmel Illinois. Two wells, M-1 and I-A1, were drilled in July, 2007. Excellent core recovery from multiple seams was achieved ensuring that a broad spectrum of analyses can be completed prior to actual injection of CO<sub>2</sub> in May of 2008. The Springfield (main target) and the Seeleyville coals were over six feet thick. Coal samples have been delivered and analyses assigned to the Indiana Geological Survey and Southern Illinois University. Gas desorption measurements were initiated at the well site and will continue for several months at the Illinois State Geological Survey (ISGS). Gas samples from the coals were analyzed for their chemical composition. Drill stem tests (DST) in each coal indicated less permeability than anticipated; so drilling operations ceased until additional, more reliable pressure transient tests are conducted to confirm DST perm results. To better understand the sealing capacity of the shale to vertically migrating CO<sub>2</sub>, sections of the shale above the Springfield No. 5 Coal seam had indirect tensile strength testing and point-load index testing performed along with moisture content determinations.

Samples were prepared for sorption, moisture equilibration, and volumetric strain experiments. Methane adsorption was done at in situ temperature (~72.5°F) for the Springfield sample. Micropore and mesopore characteristics of the maceral concentrates after high pressure CO<sub>2</sub> adsorption isotherm analysis were determined and compared to those of the original (unaffected by CO<sub>2</sub>) samples. The micropore characteristics are not affected by the CO<sub>2</sub> isotherm analysis, whereas the effect on mesopores was varied for different coals. For the Lower Block coal, significant reduction in surface area and mesopore volume was noticed for all macerals (largest for vitrinite, smallest for fusinite), whereas only very small changes were noticed for the Springfield coal. Samples for which significant changes were observed were reanalyzed for mesopore characteristics to determine if the change is of permanent or temporary nature. Results indicate that surface area and mesopore volumes remain as they were immediately after treating them with CO<sub>2</sub> at high pressures. This indicates that the effect of CO<sub>2</sub> on the pore structure of coals is of long-term nature.

A geophysical well log was used to image the Springfield and Seelyville coals as well as the area 5 to 10 feet above and below the coals. Preliminary processing of data indicated mixed/inconclusive results, likely caused by borehole and/or fluid conditions within the hole. Increased viscosity of fluids and the presence of mud cake on borehole walls likely

diminished the contrast between the borehole fluid and wall interface such that a portion of the pulse echo generated by the imaging tool was not recovered. This initial data suggests that the mud rotary drilling procedure used to drill these boreholes likely complicated cleat orientation and location identification using this logging technique. A consulting firm (Weatherford) also logged these boreholes using full wave form sonic, spontaneous potential, resistivity, gamma, compensated density, and caliper probes to determine lithology, shale content, water content, density, porosity, and borehole integrity of the injection formation. Fluid samples that were collected appear to be drilling mud instead of formation fluids based on water quality parameters of the fluids such as pH and specific conductance. Little or no gas was collected from the DST.

Two color infrared (CIR) aerial images were acquired in June and August, 2007 to serve as background (pre-CO<sub>2</sub> injection) images of plant vigor around the pilot site. These images were collected during two stages of leaf development to provide background information related to both environmental and plant growth conditions. In addition, these images provide high resolution base maps that will be used to coordinate MMV efforts.

### **Oil Reservoir Pilots**

The first EOR pilot was a single well CO<sub>2</sub> injection planned to examine incremental oil recovery and CO<sub>2</sub> sequestration volume as well as to test injection equipment, pilot procedures and MMV techniques. During the spring, 43 tons of CO<sub>2</sub> were injected over five days at the Owens #1 oil producing well in the Loudon oilfield, Fayette County, Illinois. The injection equipment (storage tank, pump skid, and heater) was located 900 feet from the injection well and a 1200-foot, 1.5-inch pipeline was used to deliver CO<sub>2</sub> to the well. CO<sub>2</sub> was injected directly into the casing-tubing annulus without removing production tubing, rods or pump. To allow CO<sub>2</sub> to dissolve into the crude oil, the well was shut-in for eight days. Afterwards, oil production peaked at eight times the pre-CO<sub>2</sub> oil rate and the water rate dropped 33%. Post-injection production records show that the CO<sub>2</sub> treatment produced an additional 93 barrels of oil over the first two months of production following the soak period.

Four groundwater monitoring wells were installed at the pilot site. One was a deep well installed into bedrock to a depth of approximately 135 feet. Three additional shallow wells were installed at depths less than 30 feet. All of the wells are within 50 feet of the test well (Owens #1), and serve to monitor shallow groundwater quality and groundwater flow direction. Background (pre-CO<sub>2</sub> injection) groundwater samples were collected from the four monitoring wells and from three residential wells located within a half-mile of the injection well. Since the beginning of the pilot, 27 groundwater samples have been collected and analyzed and 18 brine samples have been collected from oil production wells (Owens 4, Coddington 4), the CO<sub>2</sub> injection well (Owens 1) and the test separator. Dissolved oxygen, pH, Eh (redox potential), electrical conductivity, alkalinity, and temperature parameters were measured in the field. Ammonia, alkalinity, and dissolved CO<sub>2</sub> concentrations were determined in the laboratory. Anions were determined by ion chromatography and cations were determined by inductively coupled argon spectroscopy.

Three nests of vadose zone soil gas samplers were installed at the pilot site consisting of three samplers at depths of 1.5, 4, and 8 feet. Piezometers were installed near each sample nest to monitor depth to shallow groundwater. Gas samplers allow for collection of soil gas to determine CO<sub>2</sub> and hydrocarbon concentrations. Additional gas samples were collected from the annular space at the oil production and CO<sub>2</sub> injection wells. Few samples have been collected from soil samplers because of saturated soil conditions. Generally, water levels were less than two feet below ground surface throughout the duration of the project. Gas samples collected from the injection well indicated CO<sub>2</sub> concentrations near 100% during the CO<sub>2</sub> injection period and slowly declining to approximately 70% CO<sub>2</sub> five months after injection was terminated.

Brine samples collected from Owens 1 and Owens 4 wells appeared to be in equilibrium with calcium carbonate as aragonite. Samples collected from Owens 1 and the test separator were supersaturated with respect to aragonite. Eighty-six days after the beginning of CO<sub>2</sub> injection, the saturation index of the sample collected from the test separator was 0.75. It appeared that the injection of carbon dioxide decreased the pH of the brine, and increased the concentration of bicarbonate and calcium ions. Mineralogical data from the cypress sandstone suggests that as much as 5% is made up of calcite, likely used to bind the sand grains. The increase in calcium concentrations in the brine samples would suggest the injection of CO<sub>2</sub> and subsequent decrease in brine pH has caused dissolution of the calcite. Hence, the brine is thermodynamically poised to precipitate solid-phase calcium carbonate because of the injection of CO<sub>2</sub>. It appeared that the Owens 4 brine samples were also impacted. The saturation index of the 86-day sample was 0.27. During late September 2007, breakthrough of CO<sub>2</sub> into the Owens 4 well confirms that changes in brine composition at this well were likely induced by CO<sub>2</sub>.

While the brine samples collected from the injection formation were altered by CO<sub>2</sub>, the water samples collected from groundwater monitoring wells were not altered. The aragonite saturation indices for both the Owens 1 Shallow and Owens 1 Deep well samples randomly varied from -0.11 to 0.11. Moreover the pH of the samples did not change significantly during the pilot study. Therefore, it appeared that the chemical composition and equilibria of shallow groundwater was not impacted by CO<sub>2</sub> leaks from either the Cypress Formation or from leaks associated with the injection well. Residential well groundwater samples generally do not appear impacted by CO<sub>2</sub> leakage although there have been changes in the groundwater chemistry that could be due to seasonal effects.

Electromagnetic terrain conductivity (EM), high resolution earth resistivity (HEER), and induced polarization (IP) surveys were conducted. Two grids were constructed around the Owens number 1 well: a 330-foot square grid oriented northwest to southeast with 33-foot spacing between grid nodes, and a larger 658 x 1315 ft. overlapping grid oriented northeast to southwest with 66-foot spacing between grid nodes. The EM instrument was set up to investigate depths of 25, 50, and 100 feet and resistivity measurements were collected up to 100 feet. Significant interferences from buried pipes and overhead power lines made interpretation of the survey data difficult. Results from EM and HEER

surveys complimented each other and did not indicate detectable leakage of CO<sub>2</sub> from the injection formation into the shallow geologic environment.

The Owens 1 and 4 wells and Coddington 4 well were logged by the ISGS prior to and post CO<sub>2</sub> injection using spontaneous potential, single point resistance, multi-electrode normal resistance, and gamma probes to determine the lithology, shale content, water contents, density and porosity of the injection formation. In addition, a three-arm caliper probe was used to determine casing integrity and open-hole dimensions. Schlumberger followed the ISGS logging efforts at the Owens 1 well using their Reservoir Saturation tool (RST), gamma, fluid density, temperature and pressure probes to log the hole. Data analysis is currently on going to determine any effects on well and formation integrity that could be attributed to CO<sub>2</sub> injection. Post-injection logging was completed the last week of September with subsequent analyses occurring in the next few months.

### **Deep Saline Pilot**

The scope of the Deep Saline Pilot has been amended to demonstrate the ability of the Mt. Simon Sandstone, a major regional saline-water bearing formation in the Illinois Basin, to accept and retain one million tons of CO<sub>2</sub> injected over a period of three years. The proposed site is on the property of Archer Daniels Midland (ADM) Company in Decatur, Illinois, and the proposed source of the CO<sub>2</sub> is ADM's ethanol fermentation operation. A detailed pre-injection site assessment and drilling of one well will take place under the saline reservoir task of the current Phase II effort to characterize the site and ensure its suitability. Expanded Phase III activities will overlap the Phase II effort to make the site suitable for a large-scale injection test. Linking Phase II and proposed Phase III tasks will reduce costs and test large-scale sequestration sooner than might otherwise be possible. This is an important objective given the increased costs for steel pipe, drilling, well logging, and other oil field services that have occurred since Phase II was proposed. The MGSC will initially characterize the site using orthogonal 2D seismic lines to confirm the geological structure at the site and to test for any seismically resolvable faults that may exist. A well will then be drilled through the entire Mt. Simon Sandstone to the underlying granitic basement and will include extensive logging, core sampling, and fluid sampling to build a comprehensive reservoir model at the site. This model will be used to approximate the distribution of the injected CO<sub>2</sub> and of the potential reactivity of the CO<sub>2</sub> and CO<sub>2</sub>-laden brine with the reservoir and the seals. The model will be expanded as more data are derived from a baseline 3D seismic survey and will be used to predict where additional geophysical surveys will be deployed as CO<sub>2</sub> is injected. Injection at a nominal daily rate of 1,000 tons per day will begin in October 2009. One of the injection zone targets is expected to be near the base of the Mt. Simon Sandstone based on regional geology and will be defined based on well logs and core samples taken from the initial well drilled on the site.

### **Capture, Outreach and MMV Plan Development and Deployment**

Two progress reports, entitled "Estimation Methodology and Inventory of Industrial Stationary CO<sub>2</sub> Emissions in the Illinois Basin" and "Energy and CO<sub>2</sub> Emissions in the Illinois Basin: Baseline Scenario" were submitted to DOE/NETL. The first report detailed the methodology used for estimating CO<sub>2</sub> emissions and included a complete list

of source data for each type of source. Emission data from eleven major industrial categories which included electricity, refineries, iron and steel, cement, ammonia, aluminum, lime, ethanol, compressor stations, autos and glass were presented. Total annual emissions from **stationary** sources within the Basin were estimated at 304 million tonnes (metric), 88.5% of which were from 126 power plants and 10.5% from 126 non-utility sources. The second report provides the baseline scenario of mid-term (2005-2030) energy use and CO<sub>2</sub> emissions in the Illinois Basin. A forecast for both primary energy and secondary energy demands in Illinois, Indiana and Kentucky was performed for five major sectors: residential, commercial, industrial, transportation and electricity. Results indicate that between 2005 and 2030, average annual growth rate of total energy use will average 1.27%. Total electricity generation will increase at an annual rate of 1.54%. Coal will continue to be the primary source for generating electricity and its share will increase from 72% to 76% of total electricity generation. From 2005 to 2030, the total annual CO<sub>2</sub> emissions from mobile and stationary sources (including residential) will increase from 700 to 1,056 million tons in these three states.

In May 2007, the ISGS filed a patent application (Appl. No. 60/798,489) that describes a novel Integrated Vacuum Carbonate Absorption Process (IVCAP). A preliminary process and economic analysis study indicates that the cost of CO<sub>2</sub> capture with the IVCAP is 20~40% less than the MEA-based processes.

In year two, posters, fact sheets, and a physical and portable sequestration model developed to demonstrate the general concept of CO<sub>2</sub> sequestration in oil reservoirs and saline formations were used with the general public and at teacher workshops. The model shows CO<sub>2</sub> moving through porous media and collecting below a vertical seal. Four professional development teacher workshops have been conducted in the past year educating 175 teachers on sequestration science and related energy issues. More than 35 presentations have been given at conferences, business leader organizations, schools, and other venues with more than 500 attendees and 1,300 sequestration posters have been distributed during the year.

A Health and Safety Plan (HASP) was created for three potential pilot projects: enhanced oil recovery (EOR) Huff and Puff (HNP) pilot at the Owens lease, EOR five-well pilot at the Hobbs Lease, and enhanced coal bed methane (ECBM) pilot at the Tanquary Farm lease. Staff involved with the Huff and Puff pilot participated in a safety meeting. This meeting reviewed the content of the HASP, allowed staff to watch a safety video on the properties and safe handling of carbon dioxide, and answered staff questions and concerns. Training was provided on GPS measurement procedures and data downloading and formatting, in anticipation of field work for the measurement of elevation and location of injection, monitoring, and other nearby wells near of HNP pilot area. National Environmental Protection Act (NEPA) questionnaires were approved by the US Department of Energy for the three pilot projects. Each of the pilots received a categorical exclusion allowing work to proceed at each site.