CO_2 Injectivity, Storage Capacity, Plume Size, and Reservoir and Seal Integrity of the Ordovician St. Peter Sandstone and the Cambrian Potosi Formation in the Illinois Basin

TOPICAL REPORT

December 8, 2009, through May 30, 2012

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Report Issued: May 30, 2012

Report Number: DOE/FE0002068-1

U.S. DOE Cooperative Agreement DE-FE0002068

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ABSTRACT
The Cambro-Ordovician strata of the Illinois and Michigan Basins underlie most of the states of Illinois, Indiana, Kentucky, and Michigan. This interval also extends through much of the Midwest of the United States and, for some areas, may be the only available target for geological sequestration of CO_2. We evaluated the Cambro-Ordovician strata above the basal Mt. Simon Sandstone reservoir for sequestration potential. The two targets were the Cambrian carbonate intervals in the Knox and the Ordovician St. Peter Sandstone.

The evaluation of these two formations was accomplished using wireline data, core data, pressure data, and seismic data from the USDOE-funded Illinois Basin – Decatur Project being conducted by the Midwest Geological Sequestration Consortium in Macon County, Illinois. Interpretations were completed using log analysis software, a reservoir flow simulator, and a finite element solver that determines rock stress and strain changes resulting from the pressure increase associated with CO_2 injection.

Results of this research suggest that both the St. Peter Sandstone and the Potosi Dolomite (a formation of the Knox) reservoirs may be capable of storing up to 2 million tonnes of CO_2 per year for a 20-year period. Reservoir simulation results for the St. Peter indicate good injectivity and a relatively small CO_2 plume. While a single St. Peter well is not likely to achieve the targeted injection rate of 2 million tonnes/year, results of this study indicate that development with three or four appropriately spaced wells may be sufficient. Reservoir simulation of the Potosi suggest that much of the CO_2 flows into and through relatively thin, high permeability intervals, resulting in a large plume diameter compared with the St. Peter.

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EXECUTIVE SUMMARY

The study objective was to evaluate the potential of formations within the Cambro-Ordovician strata above the Mt. Simon Sandstone as potential targets for carbon sequestration in the Illinois and Michigan Basins. This topical report evaluates the injectivity, storage capacity, plume size, and reservoir and seal integrity of the Ordovician St. Peter Sandstone and the Cambrian Potosi Formation. The evaluation of these two formations was accomplished using wireline data, core data, pressure data, and seismic data from the USDOE-funded Illinois Basin Decatur Project being conducted by the Midwest Geological Sequestration Consortium in Macon County, Illinois. Interpretations were completed using log analysis software, a reservoir flow simulator, and a finite element solver that determines rock stress and strain changes resulting from the pressure increase associated with CO_2 injection.

The St. Peter Sandstone interval exhibited good potential storage capacity and injectivity based on borehole analyses. Porosity values were in the low 20% range, while calculated permeability values were from the high 10s to the low 100s of mDs, establishing good flow potential for injecting CO_2. Reservoir simulation results for the St. Peter formation indicate good injectivity and a relatively small CO_2 plume. While a single well is not likely to achieve an injection rate of 2 million tonnes/year, results of this study indicate that a development with three or four appropriately spaced wells may be sufficient.

The Knox-Potosi dolomitic interval exhibited lower storage capacity and injectivity potential than the St. Peter interval based on borehole analyses. Porosity values were low, typically less than 5%. Calculated permeability values within the Potosi formation were also low and ranged from less than one mD to 10s of mDs. However, this analysis appears to be misleading since it is known that regionally this section has accepted large volumes of injected waste and was indicated as a high permeability zone at the study site by a large volume of lost drilling mud which occurred in each of the two wells at roughly the same stratigraphic and depth levels. Given that significant volumes of cement were pumped into the high permeability interval to stem drilling fluid losses prior to wireline measurements being taken, it is likely that the wireline log analysis was negatively impacted by the presence of cement in the formation pore space.

Reservoir simulation of the Potosi formation, based on the geological model created from seismic data calibrated to wellbore synthetics, did not achieve significant injectivity because of extremely low connectivity defined by the seismic attribute analysis. However, both homogenous and heterogeneous models developed from well log and field data indicated that the Potosi may be capable of accepting 2 million tonnes/year of CO_2 through a small number of wells. It should be noted, however, that much of the CO_2 flows into and through relatively thin, high permeability intervals, resulting in a large plume diameter. In considering a commercial-scale injection program into the Potosi, the impacts of an areally large CO_2 plume will need to be taken into account.

In reality, to inject 2 million tonnes/year of CO_2 through a single well may be challenging, considering hydraulic limitations. An analysis of wellbore deliverability coupled with a multi-well injection scenario would need to be carried out in order to determine an appropriate well count and spacing for a CO_2 injection project of this scale in the Potosi Formation.

This topical report is part of a larger project, United States Department of Energy (USDOE) under cooperative agreement DE-FE0002068 from 12/08/2009 through 9/31/2013.

OBJECTIVES

This research evaluated the carbon sequestration potential of the St. Peter Sandstone and the Knox Supergroup in the Cambro-Ordovician strata of the Illinois Basin by using data acquired from the Midwest Geological Sequestration Consortium's Illinois Basin – Decatur Project where the United States Department of Energy (USDOE) has funded the drilling of two deep wells to the granite basement and the acquisition of a high-resolution 3D seismic reflection data set. These data are used in this study to provide a framework for geologic interpretation.

Project tasks included:

1. Geology:
   a. Determine geologic and petrophysical attributes of St. Peter and Knox-Potosi formations near the Illinois Basin – Decatur Project.
   b. Use newly acquired well and seismic data to construct a geocellular earth model representing the potential spatial distribution of these attributes for use in both simulation and geomechanical response models to indicated (CO_2) injection volumes.

2. Simulations:
   a. Investigate the behavior of St. Peter and Knox-Potosi formations under an injection rate scenario of 2 million tonnes of CO_2 per year for a period of 20 years using predictive simulation models.
   b. Predict injectivity, corresponding plume development, and pressure plume development over the course of the injection period.

3. Geomechanics:
   a. Build a 3D mechanical earth model (MEM) for the St. Peter Sandstone using seismically derived rock properties.
   b. Model stress changes in St. Peter and Makoqueta formations related to CO_2 injection and associated pressure changes.
   c. Predict long-term integrity of the Makoqueta Formation as a result of CO_2 injection.

INTRODUCTION AND BACKGROUND

The Mt. Simon Sandstone is a significant sequestration reservoir in the Illinois Basin, but it is not a uniform blanket sandstone and there are areas where the Mt. Simon Sandstone is too deep to be a viable target because of limited porosity and permeability [1]. The USDOE-funded Illinois Basin – Decatur project in Decatur, Illinois (Figure 1) is evaluating the sequestration potential of the Mt. Simon Sandstone and, because of its thickness and excellent reservoir quality at that site, is not doing any detailed evaluation of the overlying Knox Dolomite and St. Peter Sandstone. Hence, this project evaluates the Cambro-Ordovician strata above the Mt. Simon Sandstone (Figure 2) for CO_2 sequestration potential. Target reservoirs in the Cambro-Ordovician are porous zones within the Knox Supergroup and the St. Peter Sandstone. In addition, the Knox Supergroup and the Maquoketa (Utica) Shale are seals for the Cambro-Ordovician interval and are considered secondary seals for the Mt. Simon.

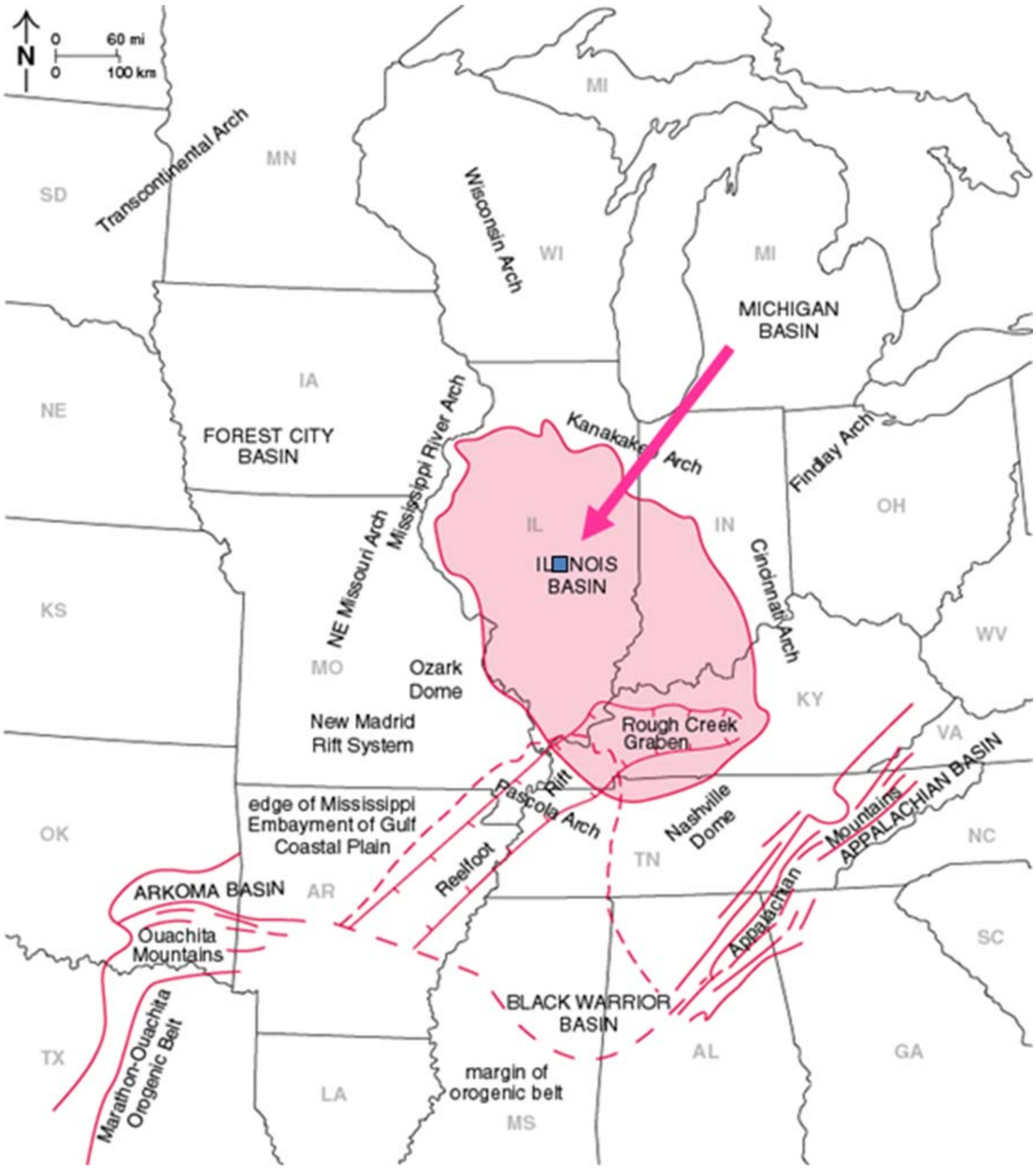

Figure 1. Location of the Illinois Basin – Decatur Project in Macon County, Illinois

The St Peter Sandstone has been used for natural gas storage in central Illinois [2] and is present in most areas of Illinois. At Decatur, Illinois, the St. Peter is at least 170 feet (52 meters) thick and reservoir properties suggest that it could represent a good target for CO_2 sequestration.

Knox carbonates are present in all areas of Illinois and can be over 7,000 feet (2134 meters) thick in the southern part of the state. Intervals within the Knox have been used for waste injection from industrial sites under the Underground Injection Control (UIC) program. For example, in Tuscola, Illinois, the Potosi has been a primary injection reservoir for hazardous waste for over 30 years and 157 million to 210 million gallons of liquid waste per year have been injected [3]. Lost circulation zones were encountered during drilling of deep wells at the Illinois Basin – Decatur Project that are analogous to intervals found at the Tuscola site.

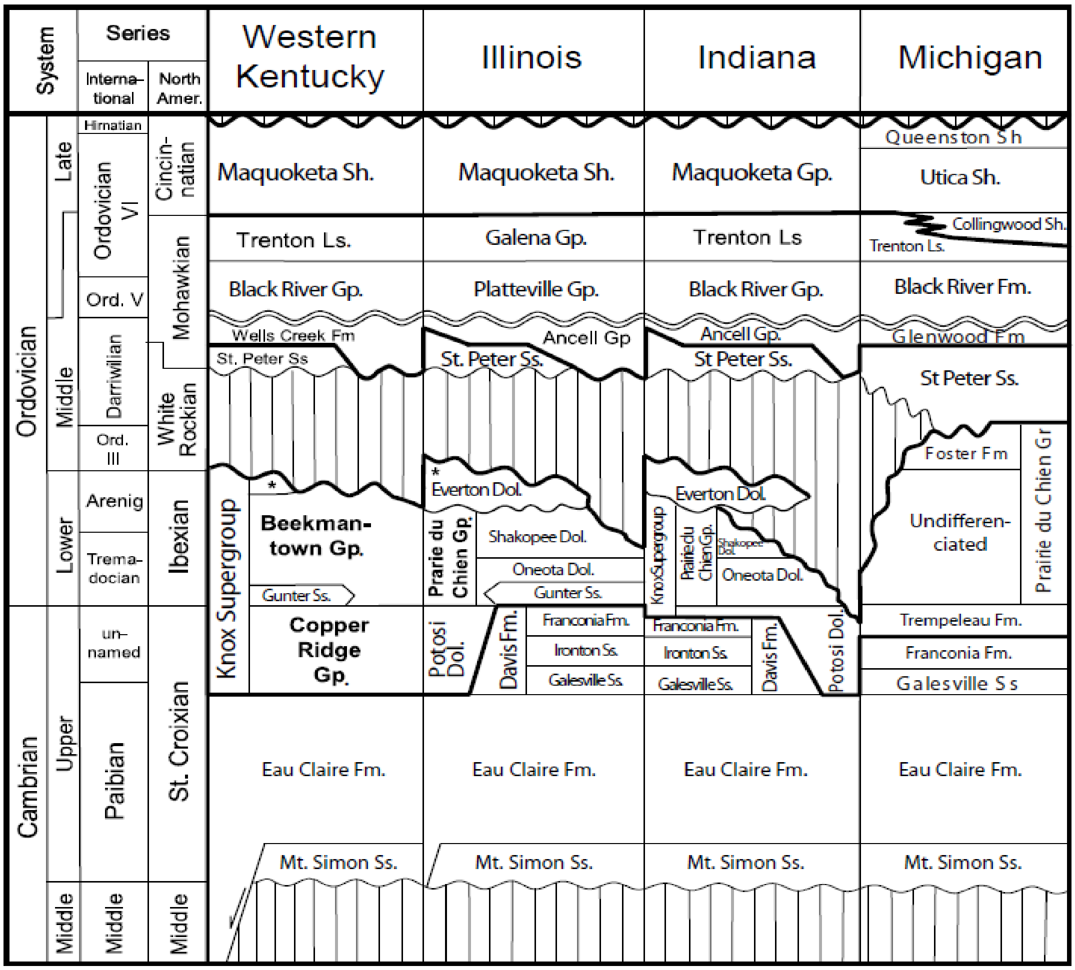

Figure 2. Stratigraphic column showing Ordovician and Cambrian stratigraphy

EXPERIMENTAL PROCEDURES

Evaluation of CO_2 storage potential of the St. Peter and Knox-Potosi subsurface intervals included the following major tasks:

- Borehole analyses of potential CO_2 storage reservoirs and associated seals.

- Seismic attribute analyses of potential CO_2 storage reservoirs and associated seals.
- Simulation of CO_2 injection performance potential of CO_2 storage reservoirs and associated seals.
- Geomechanical response of the rock framework of potential CO_2 storage reservoirs and associated seals to CO_2 injection.

Objectives and General Methodology for Borehole Analysis

Measurements taken from tools lowered into a borehole are referred to as wireline measurements defined by a specific 'logging program' that is associated with a specific group of combined measurement tools. Table 1 identifies logging runs made in the CCS #1 and Verification #1 deep wells drilled at the Illinois Basin – Decatur Project (Figure 3), tools included in each run, and primary reasons for running each logging tool.

Table 1. Wireline Logging Tools by Run

Logging Run	Logging Tools	Data Use
Platform Express*	Gamma Ray	Correlation
	Caliper	Hole size
	Resistivity	Correlation, Saturations
	Density	Porosity, Fluid Type
	Neutron	Porosity, Fluid Type
ECS*, HNGS, CMR (CMR-200* only on CCS #1)	Elemental Capture Spectroscopy Sonde	Lithology, Clay Minerals
	Combinable Magnetic Resonance Tool	Permeability, Bound Fluid Volume, Porosity
Sonic Scanner*, FMI*	Sonic Scanner acoustic scanning platform	Mechanical Rock Properties, Porosity
	FMI fullbore formation microimager	Structure, Depositional Environment, Fractures

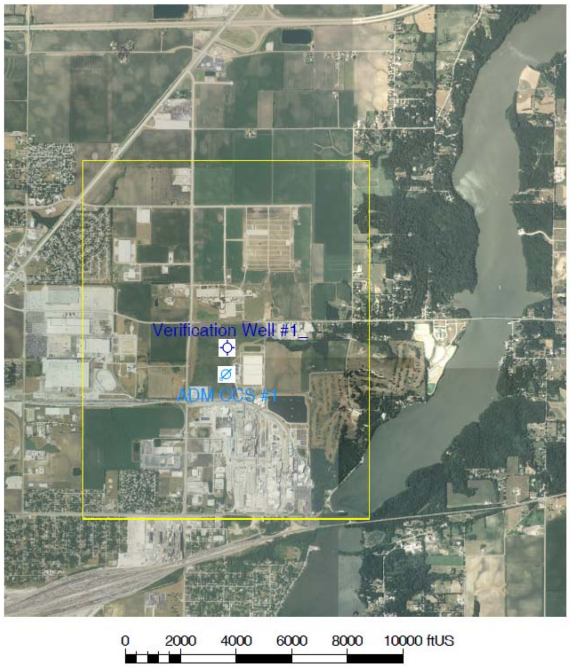

Figure 3. Base map of Decatur Project showing locations of deep wells and limits of 3D reflection seismic data (Yellow Outline)

Interpretation of Wireline Logging Data

The interpretation of wireline logging data was done using the ELANPlus* advanced multimineral log analysis within GeoFrame* reservoir characterization software. The Elemental Log Analysis (ELAN) evaluation is done by optimizing simultaneous equations described by one or more interpretation models. The resulting analysis provides key petrophysical answers that describe the reservoir. Interpretations derived from this analysis include but are not limited to porosity, lithology, and permeability. A brief description of data provided by the ELAN analysis presentation in Figures 4 and 5 follows.

<u>Depth Track</u>

- GR – Gamma Ray.
- Caliper – Hole Size.
- RSOZ – Resistivity Standoff: quality control indicating enlarged borehole.
- DSOZ – Density Standoff: quality control indicating enlarged borehole.
- Bad Hole Flag: quality control indicating hole is too large or rugose for measurement to be made.

<u>Track 1</u>

- RLA5 to RLA2 – Array laterolog resistivity measurements with different depths of investigation with RLA5 being the deepest.
- RXO_HRLT – Laterolog resistivity measurement with shallow depth of investigation indicating the resistivity of the invaded zone.

<u>Track 2</u>

- PEFZ – Photoelectric Effect: used for lithology identification.

- RHOZ – Measurement of bulk density of formation: used in combination with neutron and sonic for lithology identification as well as identification of fluids in the porosity.
- Neutron – Measurement of formation neutron porosity (lime): used in combination with density and sonic for lithology identification as well as identification of fluids in the porosity.
- Density Correction: correction applied to density measurement for borehole effects such as mudcake.
- DTCO – Delta T: sonic travel time of compressional mode from Sonic Scanner.

<u>Track 3</u>

- Kint ELAN – Permeability derived from the ELAN analysis.

<u>Track 4</u>

- Porosity – Effective porosity as calculated by ELAN analysis: analysis also includes vuggy porosity identified in carbonates.

<u>Track 5</u>

- Volumetric display of lithology and fluids solved for in the ELAN analysis.

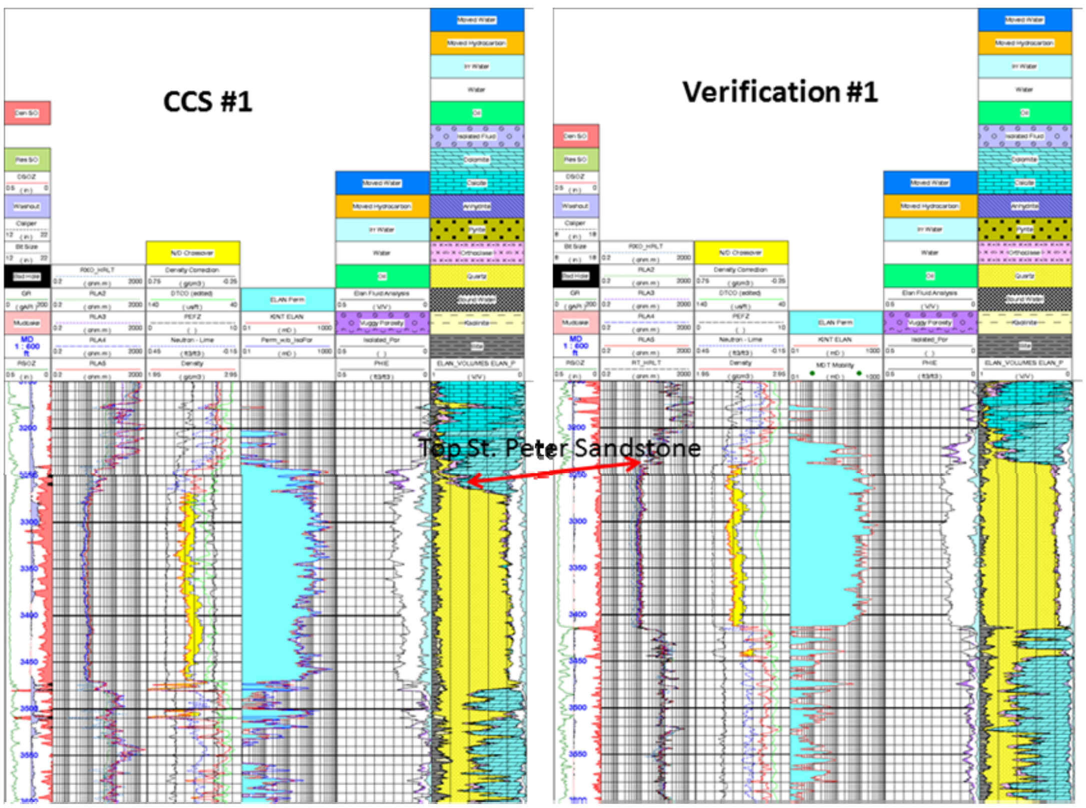

Figure 4. ELAN analysis of St. Peter Sandstone

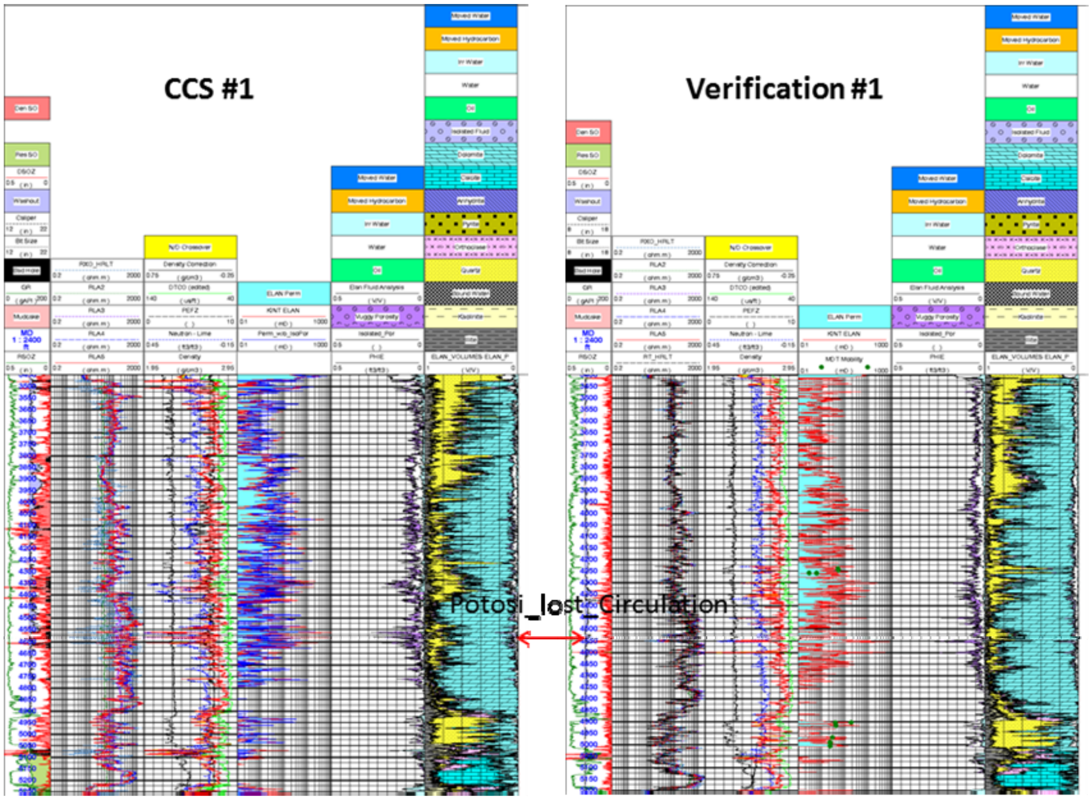

Figure 5. ELAN analysis of Potosi lost circulation interval

Objectives and General Methodology for Seismic Analysis

A three-dimensional (3D) seismic survey was acquired for the Illinois Basin – Decatur Project in early 2010 and results from analysis of seismic data were utilized in evaluating the St. Peter and Potosi intervals. Figure 3 delineates the areal extent of the seismic acquisition. The survey is relatively small at approximately 2.5 to 3 miles (4 km to 4.8 km) square; limitations from the adjacent Archer Daniels Midland Company (ADM) plant site would not allow extension to the south and other plant facilities limited westward acquisition.

After 3D seismic data are processed, analysis techniques such as amplitude-versus-offset (AVO) inversion and lithology analysis analysis can be performed to extract elastic and reservoir properties as well as formation lithologies from seismic data for specific geologic intervals. The inversion analysis was was calibrated to wireline logging and core data to aid in distributing key petrophysical features defined at a very fine scale at the wellbore out into the reservoir area covered by the seismic volume at a much coarser resolution. While the inversion results did not provide log-scale results, it did highlight the porosity and lithologic trends in the formations of interest that would not otherwise have been identified. Then, utilizing well-based data combined with that were spatially distributed using seismic attribute analysis, geocellular models were constructed focusing on the St. Peter and Potosi intervals. These geocellular models, or static geological models, were then utilized in reservoir simulation and geomechanical modeling to predict the performance of target reservoirs and seal units and their reactions to changes in pressure and fluid type as CO_2 was injected.

Objectives and General Methodology for Reservoir Simulation Modelling

Objectives of reservoir simulations were to:

- Develop two fine-scale reservoir simulation models to represent structure and geology of the St. Peter and Potosi intervals in the area surrounding the Illinois Basin - Decatur Project site, utilizing the static geologic model to distribute reservoir attributes spatially as accurately as possible with available data.
- Develop predictive simulation models for the two intervals to investigate the behavior of these target reservoirs.
- Predict injectivity and corresponding plume development during the course of CO_2 injection at a rate of 2 million tonnes/year over a period of 20 years.
- Define how many wells would be needed to inject the desired rate and quantity of CO_2.

Summary of Simulation Methodology for the St. Peter Interval

The ECLIPSE*300 reservoir simulation software was used to predict reservoir performance in the St. Peter interval. The geocellular model covered a 10 x 10 mile (16 x 16 kilometers) lateral area and a 320 feet (97 meters) thick interval. The reservoir was represented with a 118x115x30 foot grid (36x35x9 meters), resulting in a model containing 0.4 million cells. Around wellbores, each grid cell was 150x150 feet (46x46 meters) areally, whereas grid cells close to model boundaries were 1,500x1,500 feet (457x457 meters). Layer thickness in the model was 9 feet (2.7 meters) for the permeable section of the St. Peter Sandstone.

Porosity and permeability were populated based on CCS #1 well log data. Porosities were calculated using ELAN analysis and permeabilities were derived based on porosity and lithology. Permeability was upscaled from well logs to the simulation model using volume-weighted harmonic averaging, while porosity was upscaled using volume-weighted arithmetic averaging. Porosity and permeability information were propagated throughout the reservoir volume and a layer cake model was created (i.e. porosity and permeability values were constant in each layer areally). Vertical permeability was assumed to be 32% of horizontal permeability, based on the estimate for the deeper Mt. Simon Sandstone.

The reservoir was assumed to be 100% brine saturated based on wireline logs, with an initial formation salinity of 10,000 parts per million (ppm). For modeling purposes, the injected gas was assumed to have the behavior of pure CO_2. Residual water and CO_2 saturations were assumed to be 25% and 20%, respectively.

The model was equilibrated as an under-pressured reservoir (0.40 psi/ft based on MDT* (modular formation dynamics tester) data acquired during wireline logging of the CCS #1 well) with a reference pressure of 1,343 psia at 3,294 feet (1004 meters). Reservoir temperature was measured to be 85^{o}F (29^{o}C) at 3,180 feet (969 meters) by the Distributed Temperature System (DTS) deployed in the CCS #1 well and a 1^{o}F/100 feet gradient was assumed vertically in the reservoir. Infinite-acting conditions were assumed at model boundaries.

The CO_2 injection scenario was defined as a constant injection rate of 2 million tonnes/year of CO_2 for a 20-year period. A single injection well was controlled by a maximum bottomhole injection pressure of 1,980 psia at 3,470 feet (1058 meters) (equivalent to a 0.57 psi/ft gradient, which was estimated to be 80% of the fracture pressure gradient in the Mt. Simon formation). The entire 235 feet (72 meters) of the St. Peter formation was assumed to be perforated for simulating CO_2 injection.

Summary of Simulation Methodology for the Knox-Potosi Interval

As with the St. Peter simulation work, ECLIPSE 300 was used to run reservoir simulations in the Potosi interval. The Potosi geocellular reservoir model covered a 10x10 mile (16x16 kilometers) lateral area and a 430 feet (131 meters) thick formation. The reservoir was represented with a 112x112x70 grid (34x34x21 meters), resulting in a model containing 0.87 million cells. Around wellbores, each grid cell was 190x190 feet(58 meters) (areally, whereas grid cells close to model boundaries were 1,500 x 1,500 feet (457 meters). Layer thickness in the model ranged between 3 feet (1 meter) and 12 feet (3.6 meters).

Three different reservoir models were created using available data. The first simulation model was based primarily on interpreted seismic data calibrated to wireline log responses at the CCS #1 wellbore; the second set of simulations used well log and field performance data to generate two geostatistical models, one with a homogeneous and one with a heterogeneous reservoir property distribution. Formation injectivity and capacity were analyzed by simulating CO_2 injection into the CCS #1 well.

Porosity and permeability were populated based on CCS #1 and Verification #1 well log data, and upscaled in the same manner as described for the St. Peter formation. However, due to the vugular nature of the carbonate reservoir, log-derived permeability was modified for the second set of simulations utilizing Equation (1) in an attempt to approximate the behavior observed in the Illinois Potosi waste injection wells and during drilling of the CCS #1 well. Through this transform, the initially calculated permeability ($k_{initial}$), which responds primarily to matrix porosity, was modified to account for the proportion of porosity attributable to solution cavities.

$$k_{modified} = k_{initial} \text{ x } (1+2 \text{ x } \phi_{Total}) \qquad (1)$$

For the homogeneous model, porosity and permeability information from the CCS #1 well were propagated throughout the reservoir volume to create a layer cake (areally homogeneous) model. Information from both wells was propagated throughout the model with Sequential Gaussian Simulation (SGS) to create the heterogeneous model. No core or well test data were available to provide guidance on vertical permeability; hence, it was assumed to be 30% of horizontal permeability.

In all cases, the reservoir was assumed to be 100% brine saturated with an initial formation salinity of 10,000 ppm. For modeling purposes, the injected gas was assumed to have the behavior of pure CO_2. Residual water and CO_2 saturations were assumed to be 25% and 20%, respectively.

Models were equilibrated as a slightly under-pressured reservoir (0.42 psi/ft based on MDT data) with a reference pressure of 1,932 psia at 4,600 feet (1402 meters). A maximum bottomhole injection pressure was calculated using a gradient of 0.5 psi/ft in order to keep injection pressure below 80% of fracture pressure. Reservoir temperature was measured with DTS to be constant at 97F (36^{o}C) in the reservoir. Infinite-acting conditions were assumed at model boundaries. Finally, the entire 430 feet (131 meters) of the Potosi formation was assumed to be perforated for simulating CO_2 injection as shown in well section displays for CCS #1 and Verification #1 wells. Using these input parameters, an injection scenario was defined, targeting injection of 2 million tonnes/year of CO_2 at a constant rate over a 20-year period.

Objectives And General Methodology For Geomechanical Modeling

The geomechanical modeling was performed to model effects of CO_2 injection in the St. Peter Sandstone and sealing capacity of the Makoqueta Formations. Objectives of the geomechanical analysis included:

- Verification of cap rock integrity for the storage formation.
- Identification of seal fracture risk.

To achieve these objectives, the following approach was applied:

- Review existing 1D mechanical earth model (MEM) for CCS #1 and re-calibration using new data acquired since initial model construction.
- Combine 3D seismic inversion results and existing site geological interpretation to build and populate a 3D MEM with rock properties using calibrated equations developed from the 1D MEM.
- Combine 3D MEM and reservoir simulation pressure output through time and space in a Finite Element Model (FEM) to determine 3D stress properties and strain change due to injection.
- Examine result sensitivity to underdetermined parameters for seal failure risk.

Building and Calibration of 1D Mechanical Earth Model

Ideally, 3D geomechanical modeling requires calibration to one or more 1D models generated at individual wells within the prospect area. In this study, geomechanical modeling started with the CCS #1 wellbore where a 1D MEM was constructed and calibrated with available data using a 10-step workflow (Figure 6) described in the literature[4]. Each step provides information to describe the variation of rock properties and stress with depth along the wellbore. For example, Step 2 contains structural information of the study area critical for understanding the structural setting and its impact on the stress field, while Step 4 describes overburden stress by integrating formation density, typically measured by a formation density logging tool. Each workflow step uses available information for building and calibrating the 1D MEM. Calibration data for CCS #1 1D MEM included laboratory core test results for rock elastic properties, MDT pressure measurements for formation pore pressure, MDT packer injection for formation closure stress, mini-frac test for formation closure stress, FMI log for horizontal stress azimuth, and Sonic Scanner log for maximum horizontal stress. Results and equations from the calibrated 1D MEM on CCS #1 along with structural horizons and seismic inversion cubes were used to develop a 3D MEM for the injection site.

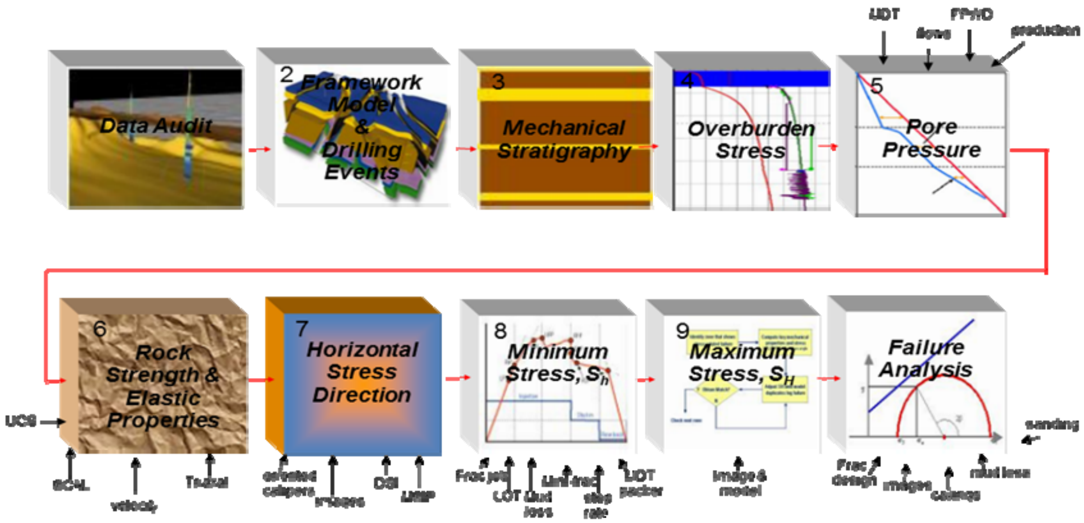

Figure 6. Required steps in building and calibrating a mechanical earth model

Construction of the 3D Mechanical Earth Model

A 3D MEM grid was constructed that laterally encompassed the seismic reflection survey and vertically extended from the Mt. Simon Granite Wash to the surface. Model accuracy is reduced outside the 3D seismic coverage area. The grid was rotated 70 degrees to align it with the maximum horizontal stress azimuth as determined from FMI image and Sonic Scanner fast shear azimuth. Model layering was coarse except at the St. Peter injection interval and the cap rock interval (see Table 2).

Table 2. 3D Mechanical Earth Model and ECLIPSE Reservoir Simulation Layers

Formation Top	**3D MEM Layers**	**Eclipse Layers**
Surface	5	-
Cypress	4	-
Base of New Albany	3	-
Galena	3	-
ECLIPSE Model Top	4	3

Injection Top	13	24
Injection Base	3	3
ECLIPSE Model Base	5	-
Eminence	1	
Potosi Dolomite	3	-
Top Eau Claire	2	-
Eau Claire Shale	3	-
Mt Simon	3	-
Granite Wash	2	-
Under burden	15	-

Density and VPVS ratio (ratio of compressional to shear velocity) seismic inversions of the 3D stacked seismic volume were used to propagate rock properties into the 3D model, and results were verified by comparing model results with log data at the CCS #1 wellbore. Average rock properties for each layer were used to complete model properties beyond the area covered by the seismic inversion data. Reservoir simulation model pressures were upscaled where models overlapped and combined with a pore pressure gradient derived from MDT pressure measurements outside the area included in the reservoir simulation model.

VISAGE Model Construction and Calibration

All 3D grid, rock properties, and simulation model pressures were loaded into VISAGE, a finite element solver that determines rock stress and strain changes resulting from the pressure increase associated with CO_2 injection.

Stress initialization of the VISAGE model occurs in two steps. In the first step, gravity loading is applied to determine the initial distribution of vertical stress in the model and reaction forces acting on the model sides and bottom. These forces are subtracted in the second step and side forces applied to load the model for simulation. Side force magnitudes were adjusted until the base case model minimum horizontal stress was in agreement with closure stress and the 1D MEM.

VISAGE Cases and Uncertainty

Three VISAGE cases were completed: a base case, a weak cap rock case, and a strike-slip stress case. The base case used all available data to build and calibrate model properties and stresses. For the weak cap rock and strike-slip stress cases, properties were varied to examine the sensitivity of the system.

Table 3. Comparison of Maquoketa Shale Rock Properties

Property	**Base Case Cap Rock**	**Weak Case Cap Rock**
Unconfined Compressive Strength	38,000 psi	3,000 psi
Tensile Strength	2,500 psi	119 psi
Friction Angle	45 deg	37 deg
Static Young's Modulus	5.1 Mpsi	1.36 Mpsi
Poisson's Ratio	0.31	0.16
Density	2.65 gm/cc	2.18 gm/cc

Uncertainty exists for all models, and for this study, one area of uncertainty resulted from the use of rock property and stress calibration data from the Mt. Simon and Eau Claire formations deeper in the stratigraphic section, These data were used because it was the only core data in the area that could be used for calibration. The resulting uncertainty in rock properties and stress was examined by varying properties within expected ranges and re-running the model. For the weak cap rock case, rock properties were decreased in the Makoqueta formation as shown in Table 3; this case was designed to test the vulnerability of the caprock to failure if the rock is weaker than modeled in the base case. Potential variation in the in-situ stress regime was investigated in the strike-slip stress case. The base case stress model has normal stress ordering of Sv > SH > Sh (see Appendix for definitions). To examine the impact on the model of an alternate stress regime, the maximum horizontal stress was increased above vertical stress for a strike-slip stress regime, SH > Sv > Sh. VISAGE calculated all components of stress and strain tensors for each cell, for all ten time steps and all three cases.

RESULTS AND DISCUSSION

Geology

Borehole Analysis: St. Peter Interval

The base of the St. Peter Sandstone is an erosional unconformity and, as a result of channel thickening, the Peter Sandstone is 36 feet (11 meters) thinner in the CCS #1 well than in the Verification #1 well.

Petrophysical analysis from both wells, delineates the general rock type for the St. Peter as quartz sandstone, shown in yellow in the rightmost track in each well log display (Figure 4). Porosity, which represents the potential storage capacity of the formation, is calculated to be in the low 20% range and is shown as the white zone in the 5th track from the left in each well log display. Permeability is defined as a measure of the section to allow fluids to flow, is not directly measured in wireline logs but is estimated from the CMR wireline log. The wireline calculated permeability of the St. Peter is estimated to range from 10 to 100 millidarcies (mD) and is shown in the cyan color on track 4.

Borehole Analysis: Knox-Potosi Interval

Within the thick Knox Supergroup, the Potosi interval was selected for detailed analysis as a potential CO_2 sequestration target. The Potosi is the primary injection zone for the Tuscola liquid waste injectors, and was a lost circulation zone during drilling of both CCS #1 and Verification #1 wells. FMI wireline logs suggest that lost circulation zones are composed of solution cavities that can be as much as 2 feet (0.6 meters) in diameter. Initial interpretations suggest that these solution cavities are a result of karst development with secondary solution enhancement by later hydrothermal fluids.

Petrophysical analysis from both wells delineates the general rock type for the Potosi interval as being highly dolomitized, shown in cyan in the rightmost track in each well log display (Figure 5). Porosity is calculated as low, generally less than 5%, which is not unusual in carbonates, even in productive zones. Porosity is shown as the white zone in track 5.

The permeability range in the Potosi interval is calculated to be from 1 to 10 mD and is shown in the cyan color on Track 4. However, since large volumes of mud were lost as this zone was drilled, the wireline measurements are not representative of the flow potential and storage capacity of the unit. This is likely a consequence of the cement pumped into the zone to control lost circulation; so the wireline log data is measuring cement and not actual porosity.

Cross-well Correlation

Spatially, CCS #1 and Verification #1 wells were correlatable along key tops identified from wireline and mudlog cuttings analysis. The St. Peter interval was slightly lower to the south with minor thickening but good lateral continuity between the two wells is inferred from log analysis. The Potosi interval was more difficult to correlate within the Knox Group, but key markers at the top and base of several stratigraphic members within the interval were identifiable and allowed gross interval confirmation. In general, there were only minor thickness variations in members of the Knox Group shown between the two wells. Within the Potosi interval, there were small identifiable responses at and within the lost circulation zone allowing for good estimation of the thickness of high permeability intervals.

Reservoir Simulation Analysis

St. Peter Formation Simulation Results

Reservoir simulation results for the St. Peter interval indicate that the plume diameter related to a single injector would be relatively small, with a radius of approximately one mile; however, the overall plume footprint with multiple wells may be quite large. During the 20-year simulation period, it was observed that an average injection rate of 990,000 tonnes/year was achieved at the maximum bottomhole injection pressure. During this period, the minimum injection rate was 660,000 tonnes/year (1st year) and the maximum injection rate was 1,164,000 tonnes/year (20th year). Although the well injected at maximum injection pressure throughout the injection period, injection rate increased as the saturation and mobility of CO_2 increased. Based on these results, , a rough estimate of the number of wells needed to inject 2 million tonnes/year into the St. Peter interval can be made; however, these results ignore potential well interference effects and possible limitations due to wellbore hydraulics. Keeping these assumptions in mind, the simulation results indicate that a minimum of two wells would be required; although three or four wells are more likely in order to allow for uncertainty in reservoir performance and to provide operational reliability.

In addition to the injectivity analysis, the corresponding pressure behavior of the reservoir due to the modeled injection from a single well was delivered for geomechanical analysis. The near-wellbore region experiences the largest pressure increase; the pressure disturbance decreases at increasing radial distance from the well, with an increase in formation pressure of 100 psi observed at a radius of approximately 20,000 feet (6,096 meters) from the injection wellbore at the end of the injection period.

Knox-Potosi Formation Simulation Results

As previously described, three reservoir simulation models were investigated for the Potosi interval. The first, in which the underlying static model was created by calibrating seismic attribute data to CCS #1 well logs, proved to have very low injection rate and storage capacity. Due to low connectivity between porous intervals, the model could only accept 90,000 tonnes/year at the maximum bottomhole injection pressure. This result, which is far below the target injection rate of 2 million tonnes/year, may have been influenced by low log porosity readings already reported. At any rate, the result was at odds with field evidence including large lost circulation events in both CCS #1 and Verification #1 wells and the high sustained injectivity recorded by Potosi liquid waste injectors in the region. These facts motivated the development of the second set of simulation models.

The homogeneous and heterogeneous models derived from well log and field data were similar models, with the primary difference being the spatial variation in reservoir properties in the heterogeneous model. These models obtained broadly similar results in terms of storage capacity, injectivity, and plume size, but differences are interesting from the standpoint of understanding the impact that heterogeneity can have on injectivity and CO_2 plume development.

In the homogenous simulation model, CO_2 preferentially flowed into and through high permeability solution cavities resulting in a relatively large plume radius of around 5 miles. In the homogeneous model, the CO_2 plume approximated a circle due to homogeneity within layers (Figure 7). The model was able to inject the targeted rate of CO_2 starting from day one. The maximum bottom hole injection pressure was never reached and as CO_2 saturations increased in the reservoir (increasing CO_2 mobility) the bottomhole injection pressure declined.

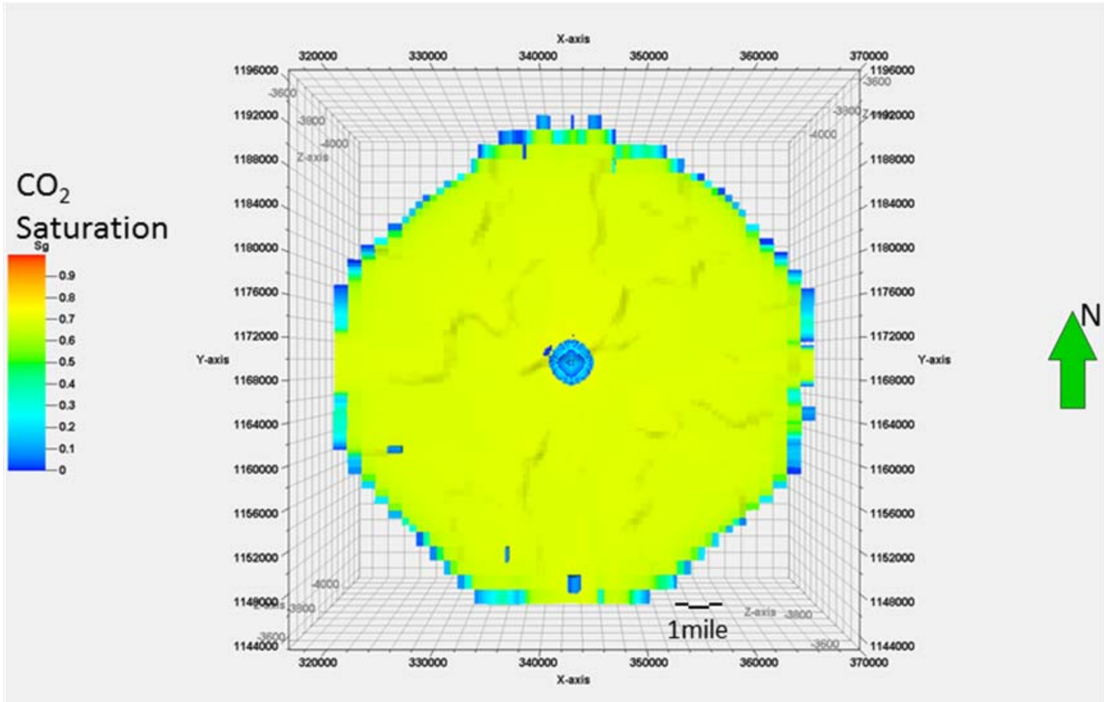

Figure 7. Potosi homogeneous reservoir model simulation results showing CO_2 plume plan view at the end of 20 Years of injection with an approximate radius of 5 miles (8 km)

In the heterogeneous simulation model, a similar result was observed. Again, CO_2 flowed preferentially into and through thin, high permeability intervals. In this case, the CO_2 plume shape was controlled by the modeled heterogeneity of the reservoir, resulting in a non-uniform plume shape and more mixing between reservoir layers (Figure 8). However, the overall area of the CO_2 plume was similar to the homogeneous case. A second difference from the homogeneous model was that the heterogeneous model had somewhat lower injectivity. For the first 5 years, injection occurred at the maximum bottomhole injection pressure and the target injection rate could not be reached. As in the homogeneous case, as the mobility of CO_2 increased and injectivity improved between year 5 and year 20, the target injection rate of 2 million tonnes/year was achieved.

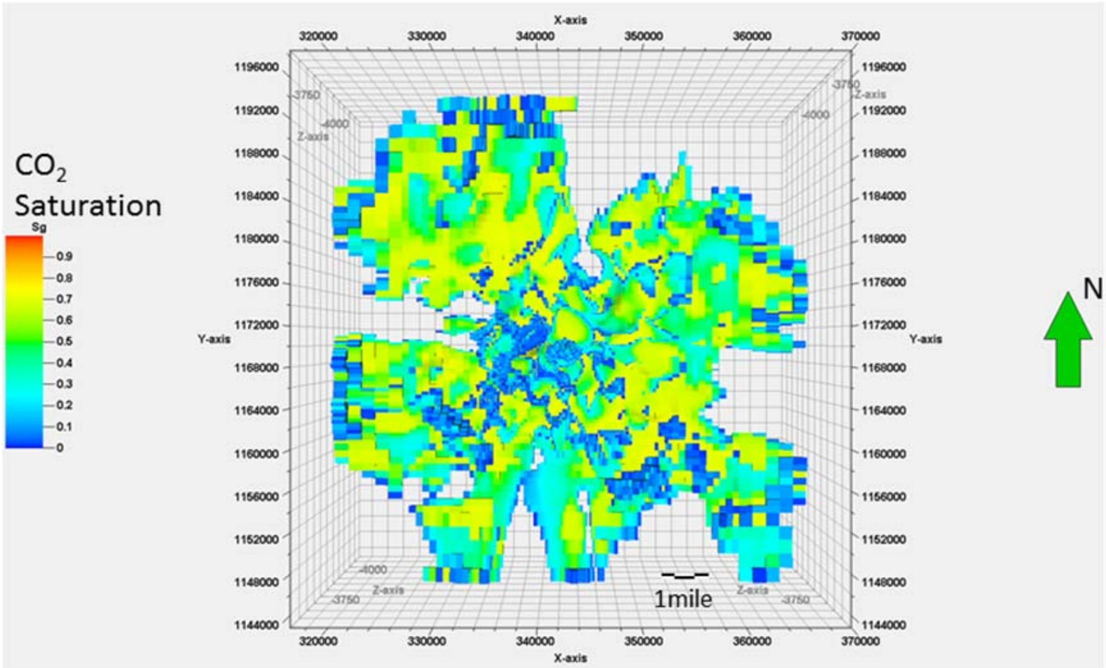

Figure 8. Potosi heterogeneous reservoir model simulation result showing CO_2 plume plan view at the end of 20 years of injection with an approximate "radius" of 5 Miles (8 km)

Both the homogenous and heterogeneous simulation models indicate that the Potosi formation may be capable of accepting 2 million tonnes/year of CO_2 through a small number of wells, but the resulting CO_2 plume may be relatively large due to the dominance of relatively thin, high-permeability intervals.

Geomechanical Analysis

VISAGE results for the three St. Peter Sandstone geomechanical simulation cases described earlier were examined to identify changes in rock properties after CO_2 injection. Effective minimum stress, plastic volumetric strain, q/p' ratio, and "dimensionless failure value" were used as failure indicators. These properties are well known in geomechanics and are often used to determine whether a rock under stress is close to failure. Low values of effective minimum stress are an indication that fracturing could potentially occur. Large positive values of plastic volumetric strain highlight locations where injection-driven dilation is occurring. Dilation is the enlargement or expansion of properties. High values of q/p' ratio are indications of areas which may be undergoing shear failure. Components of the q/p' ratio (q is mean effective stress and q is deviatoric stress) are defined in the Appendix. Dimensionless failure value (F) is the Mohr-Coulomb failure envelope normalized with respect to uniaxial compressive strength (UCS) such that when $F > 0$, shear failure of the rock is likely.

Base Case Results

Effective minimum stress decreased slightly in both the St. Peter and the cap rock during injection, but it still remained well above 0 psi and did not represent a fracturing risk. Lower stress was more evident around the seismic boundary in cap rock layers. Total volumetric strain increase was contained within the injection interval and was only 0.025% in the reservoir for the highest injection pressure and 0.002% for the cap rock. There was no plastic volumetric strain and therefore the rock was far from failure. The q/p' ratio showed a decrease between initial conditions and the final injection pressure state. As the stress state of the rock changes with injection, the rock will follow a "stress path" defined by rock properties. This decrease is seen when the stress path slope of the rock has a higher slope than the failure envelope slope; hence, as injection pressure increases, the rock moves toward a more stable state (see Figure 9). Dimensionless failure values were all below zero, and far from shear failure. Taking all these indications together, results from 3D MEM and VISAGE™ modeling show the base case was stable, and this is low risk of cap rock fracture.

Figure 9. Injection reservoir stress path in q-p' space with higher slope than the failure line

Weak Cap Rock Results

Effective stress for the weak cap rock case was lower than the base case (between 625 and 550 psi), but still above 0 psi and therefore far from failure. Total volumetric strain increased to 0.035% in the weak cap rock while in the reservoir it remained at 0.023%. Both of these are very low values. Plastic strain remained at 0.0. The q/p' ratio increased to 1.25 in the cap rock and still exhibited a decrease (1.15) with injection pressure indicating stability. Dimensionless failure values were higher than the base case, but remained below zero and far from shear failure. Thus, this investigation of a weaker than expected cap rock showed no failure, but it did have a higher risk of cap rock failure.

Strike-Slip Stress Regime Results

For the strike-slip stress regime case, maximum horizontal stress was increased above vertical stress for the top six layers of the injection interval. Effective stress showed slightly lower values than the base case, but was still above 0 psi and far from failure. Total volumetric strain decreased from the base case with a high of 0.017% in the cap rock and 0.022% in the injection zone with no plastic strain. The q/p' ratio was slightly higher than the base case with the same decrease in ratio between the initial state and the final reservoir pressure. Dimensionless failure values remained below zero and far from shear failure. The strike-slip stress case again showed no failure and had a low risk of cap rock fracture risk.

Stress Path Consolidation

The stress path for a representative cap rock cell was examined for each of the three cases and consolidated in Figure 10 as a q-p' plot. Each stress path in q-p' space showed movement toward increasing stability with injection. However, the slope in the weak cap rock case was much lower and may move toward shear failure with increasing reservoir pressure.

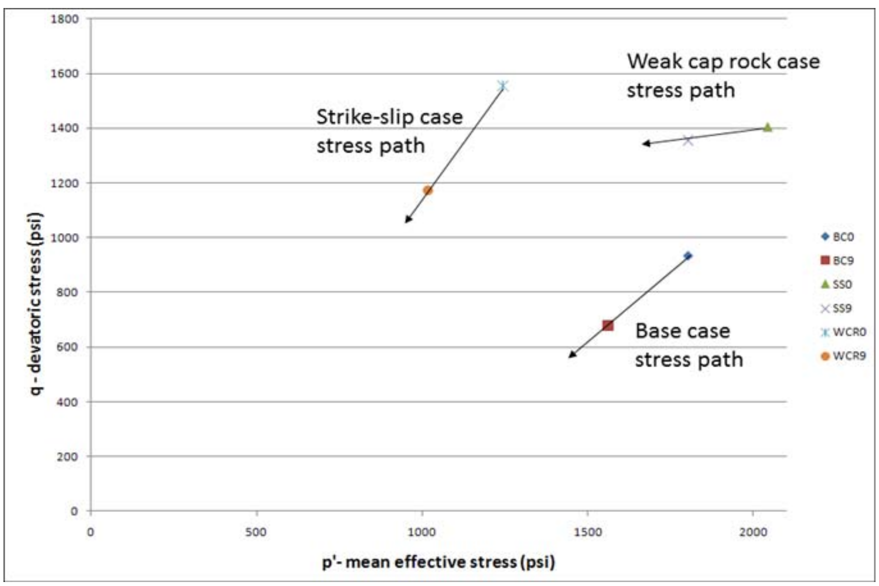

Figure 10. Stress path consolidation plots for VISAGE models

CONCLUSIONS AND RECOMMENDATIONS

Geology

Results from borehole measurements and analyses in the CCS #1 and Verification #1 wells established strong relationships between lateral and vertical reservoir attributes of the St. Peter and Knox-Potosi intervals investigated in this study.

The St. Peter Sandstone interval exhibited good potential storage capacity and injectivity based on borehole analyses. Porosity values were in the low 20% range, while calculated permeability values were from the high 10s to the low 100s of mDs, establishing good flow potential for injecting CO_2.

The Knox-Potosi dolomitic interval exhibited lower storage capacity and injectivity potential than the St. Peter interval based on borehole analyses. Porosity values were typically less than 5%. Calculated permeability values within the Potosi formation were also low and ranged from one mD to 10s of mDs. However, this analysis appears to be misleading since it is known that regionally this section has accepted large volumes of injected waste and was indicated as a high permeability zone at the study site by a large volume of lost drilling mud, which occurred in each of the two wells at roughly the same stratigraphic and depth levels. Given that significant volumes of cement were pumped into the high permeability interval to stem drilling fluid losses prior to wireline measurements being taken, it is suspected that the wireline log analysis was negatively impacted by the presence of cement in the formation pore space.

Reservoir Simulation Analysis

Reservoir simulation results for the St. Peter Sandstone indicate good injectivity and a relatively small CO_2 plume. While a single well is not likely to achieve the targeted injection rate of 2 million tonnes/year, results of this study indicate that a development with three or four appropriately spaced wells may be sufficient. In designing a multi-well injection scheme for the St. Peter interval, consideration will need to be given to the extent of the pressure plumes, as they can be expected to extend significantly beyond the radius of the CO_2 plume.

Reservoir simulation of the Potosi formation based on the geological model created using seismic data calibrated to wellbore synthetics did not achieve significant injectivity because of extremely low connectivity defined by the seismic attribute analysis. However, both the homogenous and heterogeneous models developed from well log and field data indicated that the Potosi may be capable of accepting 2 million tonnes/year of CO_2 through a small number of wells. It should be noted, however, that much of the CO_2 flows into and through relatively thin, high permeability intervals, resulting in a large plume diameter. In considering a commercial-scale injection program into the Potosi, impacts of a potentially large CO_2 plume will need to be taken into account.

In reality, to inject 2 million tonnes/year of CO_2 through a single well may be challenging, considering hydraulic limitations. An analysis of wellbore deliverability coupled with a multi-well injection scenario would need to be carried out in order to determine an appropriate well count and spacing for a CO_2 injection project of this scale in the Potosi formation.

Geomechanical Analysis

A 3D MEM was built for the St. Peter formation at the Illinois Decatur Project site using data and equations calibrated to core and stress measurements at the CCS #1 well. Data quality was good, though additional calibration data from the St. Peter formation and cap rock would reduce calibration uncertainty. VISAGE modeling was used to calculate stress and strain changes in the St. Peter and cap rock from increased pressure associated with CO_2 injection. Results from 3D MEM and VISAGE modeling show that the cap rock for the St. Peter formation is far from failure when injecting CO_2 at pressures modeled by ECLIPSE reservoir simulations. Uncertainty in VISAGE model results were examined by lowering cap rock properties and increasing maximum horizontal stress within expected ranges in two additional cases. A consolidation plot of the rock stress path shows movement toward more stability with pressure increase for all cases, though the weak cap rock case has a much lower slope and would likely move toward the shear failure surface with continued pressure increase.

To further constrain modeling results, it is recommended that core from the St. Peter sandstone and the cap rock be tested in the laboratory for elastic and strength properties. Although it is not likely that rock properties are lower than the weak cap rock case, this will reduce uncertainty in model results. Core from the St. Peter formation was obtained when the Verification #1 well was drilled at the project site. Unfortunately, attempts to core the Makoqueta formation during drilling failed, so caprock core will not be immediately available for mechanical testing. Additional testing is recommended to determine Biot's constant and properties for defining the complete failure surface. This will more accurately define the rock stress path relation to the failure surface for failure risk quantification. Stress measurements in the cap rock from mini-fracs or using the MDT packer injection technique are recommended to verify minimum horizontal stress magnitude.

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APPENDIX: DEFINITIONS AND SYMBOLS

Sv - Vertical stress

SH - Maximum horizontal stress

Sh - Minimum horizontal stress

q - Deviatoric stress $$q = \frac{1}{\sqrt{2}}\sqrt{(\sigma_1-\sigma_2)^2+(\sigma_2-\sigma_3)^2+(\sigma_3-\sigma_1)^2}$$

p' - Mean effective stress $$p' = \frac{\sigma_1+\sigma_2+\sigma_3}{3} - p_p$$

q/p' ratio - Ratio of deviatoric stress to mean effective stress

Acknowledgments

This report was prepared with support, in part, by grants made possible by the US Deparment of Energy under Award Number DE-FE0002068 and the Illinois Department of Commerce and Economic Opportunity through the Office of Coal Development and the Illinois Clean Coal Institute.

*Mark of Schlumberger