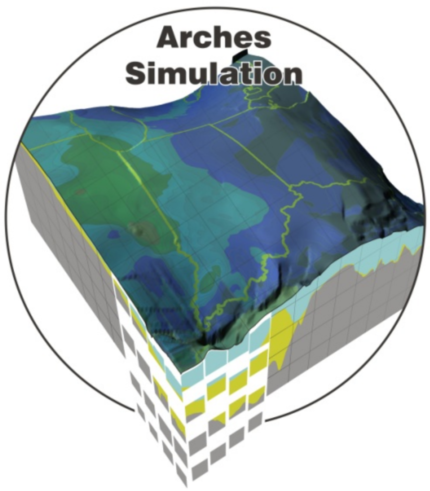
SIMULATION FRAMEWORK FOR REGIONAL GEOLOGIC CO_2 STORAGE ALONG ARCHES PROVINCE OF MIDWESTERN UNITED STATES

FINAL TECHNICAL REPORT



Reporting Period: October 1, 2009 - September 30, 2012

Principal Investigator: Joel Sminchak

December 2012

DOE Award Number: DE-FE0001034

Ohio Coal Development Office of the Ohio Development Service Agency,
Office of Energy Grant Agreement: CDO/D-10-03

Battelle Memorial Institute
Energy Systems & Carbon Management
505 King Avenue
Columbus, OH 43201

ABSTRACT

This report presents final technical results for the project *Simulation Framework for Regional Geologic CO_2 Storage Infrastructure along Arches Province of the Midwest United States*. The Arches Simulation project was a three year effort designed to develop a simulation framework for regional geologic carbon dioxide (CO_2) storage infrastructure along the Arches Province through development of a geologic model and advanced reservoir simulations of large-scale CO_2 storage. The project included five major technical tasks: (1) compilation of geologic, hydraulic and injection data on Mount Simon, (2) development of model framework and parameters, (3) preliminary variable density flow simulations, (4) multi-phase model runs of regional storage scenarios, and (5) implications for regional storage feasibility. The Arches Province is an informal region in northeastern Indiana, northern Kentucky, western Ohio, and southern Michigan where sedimentary rock formations form broad arch and platform structures. In the province, the Mount Simon sandstone is an appealing deep saline formation for CO_2 storage because of the intersection of reservoir thickness and permeability. Many CO_2 sources are located in proximity to the Arches Province, and the area is adjacent to coal fired power plants along the Ohio River Valley corridor.

Geophysical well logs, rock samples, drilling logs, and geotechnical tests were evaluated for a 500,000 km^2 study area centered on the Arches Province. Hydraulic parameters and historical operational information was also compiled from Mount Simon wastewater injection wells in the region. This information was integrated into a geocellular model that depicts the parameters and conditions in a numerical array. The geologic and hydraulic data were integrated into a three-dimensional grid of porosity and permeability, which are key parameters regarding fluid flow and pressure buildup due to CO_2 injection. Permeability data were corrected in locations where reservoir tests have been performed in Mount Simon injection wells.

The geocellular model was used to develop a series of numerical simulations designed to support CO_2 storage applications in the Arches Province. Variable density fluid flow simulations were initially run to evaluate model sensitivity to input parameters. Two dimensional, multiple-phase simulations were completed to evaluate issues related to arranging injection fields in the study area. A basin-scale, multiple-phase model was developed to evaluate large scale injection effects across the region. Finally, local scale simulations were also completed with more detailed depiction of the Eau Claire formation to investigate to the potential for upward migration of CO_2.

Overall, the technical work on the project concluded that injection large-scale injection may be achieved with proper field design, operation, siting, and monitoring. Records from Mount Simon injection wells were compiled, documenting more than 20 billion gallons of injection into the Mount Simon formation in the Arches Province over the past 40 years, equivalent to approximately 60 million metric tons CO_2. The multi-state team effort was useful in delineating the geographic variability in the Mount Simon reservoir properties. Simulations better defined potential well fields, well field arrangement, CO_2 pipeline distribution system, and operational parameters for large-scale injection in the Arches Province. Multi-phase scoping level simulations suggest that injection fields with arrays of 9 to 50+ wells may be used to accommodate large injection volumes. Individual wells may need to be separated by 3 to 10 km. Injection fields may require spacing of 25 to 40 km to limit pressure and saturation front interference. Basin-scale multiple-phase simulations in STOMP reflect variability in the Mount Simon. While simulations suggest a total injection rate of 100 million metric tons per year (approximately to a 40% reduction of CO_2 emissions from large point sources across the Arches Province) may be feasible, some areas are more suitable due to favorable geology. Sustainable injection rates were higher in areas where there was higher thickness and reservoir permeability. Distribution of injection across well fields is an effective method to reduce pressure and CO_2 saturation front interference.

CONTENTS

FIGURES

TABLES

EXECUTIVE SUMMARY

This document presents the final technical report for the project *Simulation Framework for Regional Geologic CO_2 Storage Infrastructure along Arches Province of the Midwest United States*. The Arches Simulation project was designed to develop a simulation framework for regional geologic carbon dioxide (CO_2) storage infrastructure along the Arches Province through: (1) development of a geologic model, and (2) advanced reservoir simulations of large-scale CO_2 storage along the province. This report presents final technical results covering the five major technical tasks:

- Compilation of geologic, hydraulic and injection data on Mount Simon
- Development of model framework and parameters
- Preliminary variable density flow simulations
- Multi-phase model runs of regional storage scenarios
- Implications for regional storage feasibility.

The Arches Province in the Midwestern U.S. has been identified as a major area for CO_2 sequestration because of the intersection of reservoir thickness and permeability along the province. The province includes areas of Indiana, Kentucky, Michigan, and Ohio along several arch structures between the Appalachian, Illinois, and Michigan sedimentary basins. The main injection target is the Mount Simon sandstone due to its depth, thickness, hydraulic properties, and brine salinity.

The Arches Simulation project is a three-year effort and part of the U.S. Department of Energy (DOE)/National Energy Technology Laboratory (NETL) program on monitoring/verification/accounting (MVA), simulation, and risk assessment of CO_2 sequestration in geologic formations. The project is supported by U.S. DOE/NETL under agreement DE-FE0001034 and The Ohio Coal Development Office of the Ohio Development Services Agency, Office Energy under agreement CDO/D-10-03. The project research team consists of Battelle Memorial Institute, Battelle Pacific Northwest Division, Geological Surveys of Ohio, Indiana, and Kentucky, and Western Michigan University.

Model Limitations

The model has several inherent assumptions and limitations related to depicting the nature of deep rock formations. This is a basin-scale simulation study, and many trends in geology and input parameters were generalized. In addition, some maps and parameter distributions were adjusted to facilitate numerical models. Research was focused on the Arches Province, and areas outside this region were not reviewed in detail. The project plan was intended to provide general guidance for a large region of the Midwestern U.S. A CO_2 storage project would require field work such as seismic surveys, drilling, geophysical logging, reservoir tests, detailed reservoir modeling, and system design. The results of this report shall not be viewed or interpreted as a definitive assessment of suitability of candidate geologic CO_2 storage formations, the presence of suitable caprocks, or sufficient injectivity to allow CO_2 sequestration to be carried out in an economic manner.

Compilation of Geologic, Hydraulic and Injection Data on Mount Simon

Initial work on the project involved compiling and interpreting information on the deep rock formations, Mount Simon injection well operations, and geotechnical data. Geotechnical data included wireline logs, rock core tests, structure maps, thin sections, geologic reports, and other test data related to the Mount Simon and Eau Claire formations in the study area. Operational data from Mount Simon injection wells were also compiled. A summary of the information collected in the data collection task is summarized as follows:

- Information from over 500 wells that penetrate the deeper rock zones in the Midwestern U.S.
- Geophysical well logs from 496 wells
- Approximately 4,000 rock core test results in Eau Claire or Mount Simon intervals
- 105 additional standard permeability and porosity tests on Mount Simon/Eau Claire rock samples
- Completion of geomechanical tests on 11 rock samples
- 16 mercury injection capillary pressure tests on rock samples
- 10 other advanced saturation tests on rock core samples
- Deep well injection operational data from 48 wells in the study area
- Pressure fall-off reservoir test data from 31 wells
- Compilation and analysis of a total of 960,000 porosity data from geophysical logs
- Geological maps, research, and publications.

Based on this information, nine geologic cross sections were generated across the Arches Province. Maps of the Mount Simon structure and thickness were completed based on the cross sections and well logs. A major new finding of the project was remapping the southern boundary of the Mount Simon in northern Kentucky based on structural control. The Eau Claire caprock formation was also better delineated with Geologic Analysis via Maximum Likelihood System (GAMLS) according to dominant facies.

Records from 42 Mount Simon injection wells were collected, documenting over 20 billion gallons of fluid injection into the Mount Simon over the past 40 years, which is equivalent to approximately 60 million metric tons (MMT) CO_2. Maximum injection rates generally ranged from 30 to 268 gallons per minute. Maximum wellhead injection pressures ranged from approximately 400 to 1600 pounds per square inch (psi). Based on maximum wellhead injection pressures, most wells operated on maximum bottomhole pressure gradient of approximately 0.5 to 0.7 psi/ft, or 10 to 55% above background reservoir pressures. Review of temporal pressure data from the injection wells suggests that most wells reach a steady-state balance where pressure is steady up to some maximum injection rate. These data were used to update a pressure field map for the Mount Simon reservoir.

Major conclusions of the data collection task are summarized as follows:

- The multi-state project approach was effective in delineating the Mount Simon across state boundaries in the region.

- The southern boundary of the Mount Simon sandstone in Kentucky and southern Indiana was re-interpreted based on structures associated with Cambrian rifting in the Rough Creek Graben and Rome Trough. The revision reduced the overall extent of the Mount Simon south of the Ohio River, where many power plants are located.

- Geologic structure maps were revised for the Mount Simon in the Arches Province to better define formation continuity across state lines.

- Records from Class I Mount Simon injection wells were compiled, documenting more than 20 billion gallons of injection into the Mount Simon formation in the Arches Province over the past 40 years. This volume is equivalent to approximately 60 MMT CO_2. Injection rates were generally 30 to 268 gallons per minute (gpm). Maximum wellhead injection pressures ranged from approximately 400 to 1600 psi.
- Reservoir tests (pressure fall-off tests) were compiled for 31 injection wells. Review of the tests indicated 21 tests were acceptable. Average reservoir permeability from these tests was 62 mD.

Development of Model Framework and Parameters

Information from the data collection task was used to develop a conceptual model that describes the geologic setting, stratigraphy, geologic structures, hydrologic features, and distribution of key hydraulic parameters (Figure ES-1). The data were integrated into a three-dimensional (3D) grid of porosity and permeability, which are key parameters regarding fluid flow and pressure buildup due to CO_2 injection. Permeability data were corrected in locations where reservoir tests have been performed in Mount Simon injection wells.

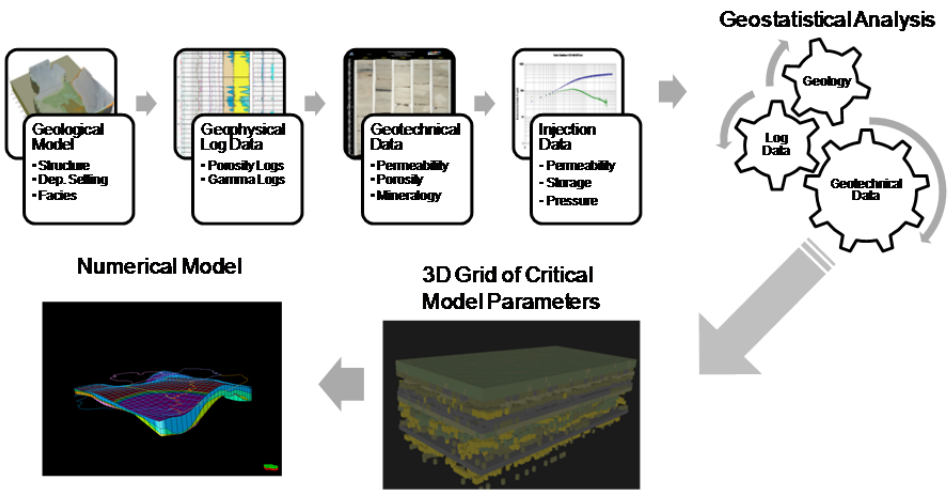


Figure ES-1. Geocellular Model Development Process

The final geocellular model covers an area of 600 km by 600 km centered on the Arches Province. The geocellular model includes a total of 49,000,000 cells representing estimated porosity and permeability distribution (Figure ES-2). Injection scenarios were developed based on survey of CO_2 point sources in the Arches Province. These sources have combined emissions of 286 MMT CO_2 per year, and 53 point sources have emissions over 1 MMT per year which have total emissions of 262 MMT CO_2 per year. To reduce greenhouse gas emissions in the Arches Province by 25 to 50%, CO_2 storage projects with total storage rates of 70 to 140 MMT CO_2 per year would be necessary. A pipeline distribution system would likely be required to access the Arches Province, since few sources are located in the central portion of the study area.

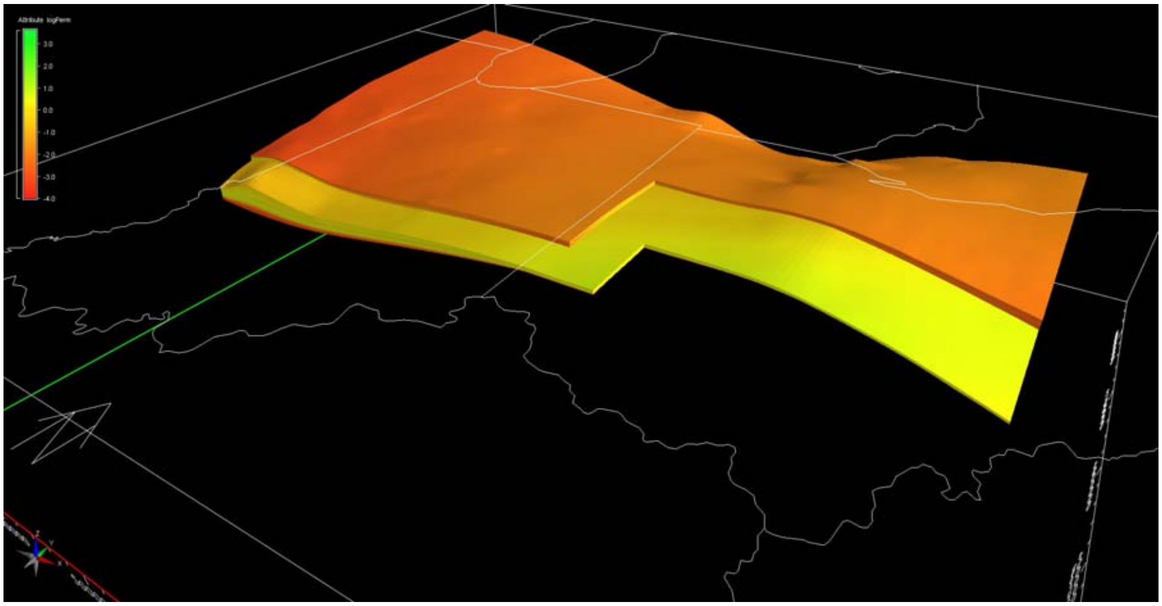


Figure ES-2. Geocellular Porosity Model (log mD)

Development of the conceptual model revealed several key conclusions regarding the geologic framework for CO_2 storage in the Arches Province:

- The Arches Province is located along the east-central extent of the overall Mount Simon, and the formation exhibits facies changes into the Appalachian Basin. These trends were exhibited in maps of hydraulic and geotechnical parameters.
- Geostatistical analysis for the Mount Simon wireline porosity data showed a fairly erratic dataset, but subsampling methods indicated a lateral correlation range of 50 to 60 km. Indicator analysis for the Eau Claire showed an area of mostly shale content extending for much of the north-south extent in the middle of the region.
- 131 large CO_2 point sources are present in the Arches Province with combined emissions of approximately 286 MMT CO_2 per year. Fifty-three sources greater than 1 MMT CO_2 per year account for over 90% of total emissions.
- Sources are clustered around the Ohio River Valley and Great Lakes, so a CO_2 pipeline distribution system would be necessary to access the central portion of the Arches Province.
- A 49 million node geocellular model for the Arches Province reflects regional trends in the Mount Simon. The model tends to predict average porosity and permeability where no data are available.
- Correction factors were a valuable method to normalize the permeability grid to pressure fall-off data from injection wells. Initial average permeability from the wireline log porosity data was 49.1 mD, and the corrected average permeability was 69 mD.
- Areas in southern Indiana, northwestern Kentucky, and several other areas have sparse well control with well spacing of 50 to 100+ km. The geocellular model tended to predict average data in these areas since there were few control points nearby.

Preliminary Variable Density Flow Simulations

The information in the geocellular model was translated into a series of numerical simulations designed to evaluate infrastructure to accommodate large-scale CO_2 storage applications. Initial simulations were completed with the single phase groundwater flow computer codes MODFLOW (McDonald and Harbaugh, 1988) and SEAWAT (Langevin et al., 2007). This model was used to develop grid spacing, model layers, input parameters, and boundary conditions. The model was calibrated to the pressure field in the Mount Simon formation. Sensitivity analysis showed the model was sensitive to increases in permeability. Regional storage scenarios were also analyzed with on-site versus storage field radius calculations, which showed it would be difficult to complete storage projects in areas along the Ohio River and Great Lakes where many large sources are clustered. Overall, major conclusions determined in the preliminary variable density flow simulations included the following:

- The variable density simulations indicate background fluid flow rates in the Mount Simon of approximately 67 cm/year.
- Simulation of regional versus on-site injection suggests that there are some advantages to distributing injection across many on-site sources. However, areas where large sources are clustered along the Ohio River and Great Lakes coast would have large volumes of CO_2, which would create significant pressure increases.
- The model setup was calibrated to the reservoir pressure field in the Mount Simon. Flow budgets were also comparable to other research.
- Sensitivity analysis on model input parameters indicates that the model error was more sensitive to increases in overall permeability.

Multi-Phase Model Runs of Regional Storage Scenarios

Based on the geocellular model, a basin-scale multiple-phase simulation was developed in Subsurface Transport Over Multiple Phases (STOMP) numerical code. The porosity and permeability distributions used in the basin-scale model were upscaled from the 3D geocellular model. The final basin-scale model contained 19 layers: 15 layers in the Mount Simon plus four layers in the Eau Claire. The 19-layer model contained 1,404,708 nodes. The simulation grid has variable grid spacing in the horizontal direction with finer resolution (500 m) in the regions near potential regional storage fields. The model was run in baseline mode with no injection to establish steady-state conditions.

A model validation exercise was also completed to evaluate the ability of the model to accurately simulate CO_2 storage. The validation involved simulation of an 11-hour CO_2 injection test completed by the Midwestern Regional Carbon Sequestration Partnership (MRCSP) at the East Bend Generating Station in Rabbit Hash, Kentucky. In the validation exercise, output from the Arches Simulations geocellular model was directly ported to a two-dimensional (2D) radial STOMP model. The model matched observed downhole pressures from the field, providing more confidence in the simulation approach used for the project.

Caprock simulations were performed to better understand the potential for CO_2 to migrate into the Eau Claire caprock. Separate simulations were completed with more detailed representation of the Eau Claire interval. Two well sites (Allen County, Indiana and Warren County, Ohio) with distinct Eau Claire character were selected for simulation. 2D radial models were developed for each site. Higher layer resolution was included across the Eau Claire based on facies analysis of the unit. CO_2 injection was simulated into the Mount Simon at 500,000 metric tons per year for 10 years. Then the upward migration of CO_2 was simulated for 1,000 years. The simulations provide a more accurate depiction of upward migration into the Eau Claire. Overall, these simulations showed no upward migration of CO_2.

A geomechanical simulation was also completed for a site-specific location near Holland, Michigan. The simulation was completed with the GEM geomechanical module and used geomechanical parameters from the Arches Simulation project. The reservoir simulations were completed to evaluate fracture pressures, rock deformation effects, and heterogeneity for the Mount Simon. Simulation results suggested the caprock is very unlikely to fracture due to high thickness and permeability of the reservoir.

Finally, a monitoring comparison study was completed for wireline saturation pulsed neutron capture logs and seismic monitoring techniques. The analysis was based on substitution analysis of simulated CO_2 saturation and rock properties. Results suggest saturation logs would be effective in the Mount Simon, but seismic methods may be sensitive to lower CO_2 saturation levels and the high rock compressive strength for the Mount Simon.

Major conclusions developed in the model runs of regional storage scenarios include:

- A model validation exercise matched observed bottomhole pressures observed for a CO_2 injection test at the MRCSP East Bend test site, which provides confidence in the simulation methodology and geocellular model.
- Site-specific caprock simulations based on GAMLS analysis of the Eau Claire formation showed minimal CO_2 movement into the Eau Claire formation, highlighting the importance of including detail for caprock units in CO_2 storage simulations.
- Substitution analysis of pulsed neutron capture (PNC) and seismic monitoring technologies suggests that PNC logs would be effective for detecting CO_2 saturation in a well but seismic monitoring in the Mount Simon formation in the Arches Province may be challenging due to lower CO_2 saturation levels in the reservoir and geomechanical properties of the rock matrix.

Implications for Regional Storage Feasibility

To better define large-scale storage applications in the Arches Province, infrastructure analysis was completed through a pipeline routing study, scoping level simulations, basin-scale simulations, and regional upscaling analysis. A pipeline routing study was completed using a CO_2 pipeline transport cost estimation tool, which determined least-cost pipeline routes from large sources to central areas of the Arches Province. This analysis suggests there are some central pipeline corridors where regional storage fields may be located. Next, scoping level simulations were completed with the multi-phase code STOMP in 2D mode. A matrix of simulations was completed based on general conditions in the model domain for 5 by 5, 6 by 6, and 7 by 7 well clusters at several injection rates. Simulation results were run to examine well field spacing and distance between fields. The second set of simulations was based on site-specific conditions at seven potential regional storage sites identified in the pipeline routing study. These simulations were used to examine injection rates, pressure buildup, and CO_2 saturation fronts. The effect of relative permeability parameters on the model were also analyzed with these simulations.

Based on results of the scoping simulations, a full basin-scale multiple-phase simulation was developed in STOMP for the Arches Province. CO_2 was injected in seven storage fields across 63 wells with a pressure limit of 0.675 psi/ft. Results from the basin-scale simulation reflect variability in the Mount Simon. Fields located in areas where the Mount Simon is thickest have better injection potential than other locations. A scenario where regional storage fields were located along pipeline routes had fairly low injection potential due to the shallow, thin nature of the Mount Simon limiting injection pressures. However, a scenario where injection fields were located in areas with thicker reservoir indicated total injection rates over 100 MMT/yr may be sustained. Simulation results showed that distributing injection across multiple wells in injection fields may limit the overall pressure fields created by deep well injection. Overall, basin-scale simulation results suggest that large-scale injection may be achieved with proper field design, operation, siting, and monitoring. Lastly, parametric analysis was completed to delineate CO_2 storage capacity based on parametric analysis of scoping simulations.

Based on the analysis of regional storage feasibility, several conclusions were determined:

- A source-sink least-cost pipeline routing analysis suggests there are central areas where CO_2 pipeline routes intersect or blend together which may be practical potential regional storage fields.
- Multi-phase scoping level simulations suggest that injection fields with arrays of 9 to 50+ wells may be used to accommodate large injection volumes. Individual wells may need to be separated by 3 to 10 km. Injection fields may require spacing of 25 to 40 km to limit pressure and saturation front interference.
- Basin-scale multiple-phase simulations in STOMP reflect variability in the Mount Simon. While simulations suggest a total injection rate of 100 MMT/yr (approximately to a 40% reduction of CO_2 emissions from large point sources across the Arches Province) may be feasible, some areas are more suitable due to favorable geology. Sustainable injection rates were higher in areas where there was higher thickness and reservoir permeability.
- Distribution of injection across well fields is an effective method to reduce pressure and CO_2 saturation front interference.

Section 1.0: INTRODUCTION

The Arches Simulation project was designed to develop a simulation framework for regional geologic carbon dioxide (CO_2) storage infrastructure along the Arches Province through development of a geologic model and advanced reservoir simulations of large-scale CO_2 storage along the province. This report presents final technical results covering the five major technical tasks:

- Compilation of geologic, hydraulic and injection data on Mount Simon
- Development of model framework and parameters
- Preliminary variable density flow simulations
- Multi-phase model runs of regional storage scenarios
- Implications for regional storage feasibility.

Overall, several useful products were developed in association with the project. Over 18 billion gallons of fluid injection was documented for the Mount Simon Sandstone. A database of geotechnical information was compiled for the Mount Simon and Eau Claire formations. Additional geotechnical tests were completed on rock cores. A series of numerical simulations was applied to better define CO_2 storage potential in the Arches Province. This report focuses on results of the technical tasks. For more detail on methodology and analysis, readers are referred to the following topical reports:

- *Data Package Summary Report- Simulation Framework for Regional Geologic CO_2 Storage along Arches Province of Midwest United States*, July 2010
- *Conceptual Model Summary Report Simulation Framework for Regional Geologic CO_2 Storage Infrastructure along Arches Province of Midwestern United States,* August 2011
- *Variable Density Flow Modeling for Simulation Framework for Regional Geologic CO_2 Storage along Arches Province of Midwestern United States*, October 2011.

In addition, much of the technical effort is described in the 12 quarterly progress reports prepared for the project.

1.1 Background

The Arches Province in the Midwestern U.S. has been identified as a major area for CO_2 sequestration because of the intersection of reservoir thickness and permeability along the province (Gupta et al., 2002; Gupta et al., 2004; Midwestern Regional Carbon Sequestration Partnership [MRCSP], 2005; Barnes et al., 2009). The province includes areas of Indiana, Kentucky, Michigan, and Ohio along several arch structures between the Appalachian, Illinois, and Michigan sedimentary basins. The main injection target is the Mount Simon sandstone due to its depth, thickness, hydraulic properties, and brine salinity. There are many existing CO_2 sources in proximity to the Arches Province, and the area is adjacent to the Ohio River Valley corridor of coal-fired power plants such that it may be feasible to access the area with a pipeline network.

The Arches Simulation project was a three-year effort and part of the United States Department of Energy (U.S. DOE)/National Energy Technology Laboratory (NETL) program on innovative and advanced technologies and protocols for monitoring/verification/accounting (MVA), simulation, and risk assessment of CO_2 sequestration in geologic formations. The project was supported by U.S. DOE/NETL under agreement DE-FE0001034 and Ohio Coal Development Office of the Ohio Development Agency, Office of Energy under agreement CDO/D-10-03. The work included five main technical tasks aimed at compiling hydrogeological information on the Mount Simon sandstone and confining layers, development of model framework, preliminary variable density flow simulations, multiple-phase model runs of regional storage infrastructure scenarios, and analyzing implications for regional storage feasibility. The research team consisted of Battelle Memorial Institute, Battelle Pacific Northwest Division, Geological Surveys of Ohio, Indiana, and Kentucky, and Michigan/Western Michigan University.

This report focuses on results concluded in these technical tasks. Initial work on the project involved compiling and interpreting information on the deep rock formations, Mount Simon injection well operations, and geotechnical data. This information was integrated into the conceptual model. The conceptual model was utilized to develop a series of numerical simulations of large-scale CO_2 storage in the Arches Province region. As with any modeling effort for geological environments, many items discussed in the report are subject to change based on evolution of the understanding of the deep rock formations and advancement of the numerical simulations.

1.2 Objectives

The overall objective of this project was to develop a simulation framework for regional geologic CO_2 storage infrastructure along the Arches Province of the Midwestern U.S. The project had two main goals: (1) development of a geologic model for the Arches Province integrating geologic information, Mount Simon injection data, and geotechnical data, and (2) completion of advanced reservoir simulations examining infrastructure requirements for large-scale CO_2 storage in the study area. The project was divided into five main technical tasks. Table 1-1 summarizes the task objectives. Over the course of the project, some task objectives were updated and more effort was input into tasks that offered more value to the project.

Table 1-1. Summary of Technical Task Objectives

Task Name	Objective
Task 2: Compilation of Geologic, Hydraulic, and Data on Mount Simon Sandstone	
Geotechnical Data Compilation	Compilation of core tests, logs, maps, reports
Mapping and GIS of Mount Simon	Structure maps for key formations
Eau Claire/Caprock Evaluation	Review of geotechnical and facies information on Eau Claire
Class I Data Analysis	Compilation of operational data for Mount Simon injection
Mount Simon Pressure Field Mapping	Reservoir pressure maps and pressure gradients
Task 3: Development of Model Framework and Parameters	
Conceptual Model	Analysis & integration of geotechnical data
Model Framework/Descretization	Translation of data into geocellular model
Code Modification & Debugging	Update simulation code to run basin-scale model
Code Verification/Comparison	Review CO_2 storage models, verify model against other research
Task 4: Preliminary variable density flow model simulations	
Variable Density Model Setup	Set up basin-scale groundwater flow model to analyze parameters
Model Runs	Complete variable density simulations
Flow Analysis	Analyze model results for flow budgets, flow vectors, pressure
Task 5: Multi-phase model runs of regional storage infrastructure scenarios	
Base Simulation	Complete baseline basin-scale multi-phase model in Subsurface Transport Over Multiple Phases (STOMP)

Table 1-1. Summary of Technical Task Objectives (Continued)

Task Name	Objective
Model Validation to Class I/MRCSP Data	Validate model by simulating MRCSP East Bend CO_2 injection
Regional Storage Scenarios	Analysis of injection field rates, well spacing, pressure, saturation
Data Analysis and Visualization	Visualize maps, geocellular model, and project results
Structure Simulations	Geomechanical simulations to asses fracture limits, caprock
Caprock Simulations	Simulate migration potential for Eau Claire Caprock
MVA Comparison	Evaluate feasibility of seismic, pulsed neutron capture (PNC) methods for CO_2 MVA
Task 6: Implications for Regional Storage Feasibility	
Infrastructure Analysis	Assess pipeline system, injection field arrangements for basin
Regional Upscaling Analysis	Analyze storage capacity, injection limits for regional storage

Section 2.0: COMPILATION OF GEOLOGIC, HYDRAULIC, AND INJECTION DATA FOR THE MOUNT SIMON FORMATION

The first task of the project was to compile information on geotechnical, hydraulic, and injection data for the Mount Simon formation. Geotechnical data included wireline logs, rock core tests, structure maps, thin sections, geologic reports, and other test data related the Mount Simon formation in the study area. This information was used to develop and refine maps of key formations and geotechnical parameters. A similar set of information was compiled for the Eau Claire caprock. Injection records for Class I Underground Injection Control (UIC) wells were compiled for the study area. This information included reservoir testing, which was used to update pressure field maps for the Mount Simon. More detail on data compilation is provided in the *Data Package Summary Report Simulation Framework for Regional Geologic CO_2 Storage along Arches Province of Midwest United States* topical report submitted in July 20, 2010.

2.1 Geotechnical Data Compilation

The data compilation effort involved reviewing state databases for oil and gas wells and Environmental Protection Agency (EPA) records on deep well injection. Deep well data were screened for wells penetrating the Eau Claire shale or deeper. Information for the wells was then tabulated in a database summarizing well construction, owner, location, logging methods, geotechnical testing, formation depths, and status. The database to support this modeling project was compiled by Battelle and the four state government organizations participating in the project: Indiana Geological Survey, Kentucky Geological Survey, Ohio Geological Survey, and the Michigan Geological Repository for Research and Education (Western Michigan University). Information was gathered from the records maintained by the state agencies and EPA. Records included original logs as well as digital data. The main sources of detailed, site-specific information were the Class I (hazardous waste) and Class II (saline waters produced by oil and gas exploration) injection wells. Government (state and federal EPA) regulations require extensive geologic and engineering studies for the permitting of these sites, especially Class I sites. Previous research from the MRCSP (Wickstrom et al., 2006) and Midwest Geological Sequestration Consortium (MGSC, 2005) provided a valuable basis for the database. In addition, several other sources (Bond, 1972; Brower et al., 1989; Gupta, 1993; Warner, 1988) were reviewed for input data.

Data were put in a PETRA database and tables. The data were updated with additional rock core tests completed for the Arches Simulation project. A summary of the data compiled is provided as follows:

- Information from over 500 wells that penetrate the Knox or deeper formations in the general region
- Geophysical well logs from 496 wells
- Approximately 4,000 rock core test results in Eau Claire or Mount Simon intervals
- 105 additional standard permeability and porosity tests on Mount Simon/Eau Claire rock samples
- Completion of geomechanical tests on 11 rock samples
- 16 mercury injection capillary pressure tests on rock samples
- 10 other advanced saturation tests on rock core samples
- Deep well injection operational data from 48 wells in the study area
- Pressure fall-off reservoir test data from 31 wells

- Compilation and analysis of a total of 960,000 porosity data points from geophysical logs
- Many other geological maps, research, and publications.

This information was used to develop the conceptual model and as a basis for simulation input parameters. Interpretation of the data is discussed in more detail in the following sections.

2.2 Mapping and GIS of Mount Simon

Based on items amassed in the data compilation task, maps of rock formation structure and parameters were completed. Wireline logs were analyzed to determine the depth of key formations, including the Knox, Eau Claire, Mount Simon, and Precambrian. These logs were integrated into a PETRA geological model that outlines the three-dimensional (3D) distribution of the rock formations and geotechnical rock properties. Based on this information, geologic cross sections through the Arches Province were constructed to better understand the distribution of the rock formations. As shown in Figure 2-1, these cross sections provide comprehensive coverage across the study area. Together, these cross sections define the structural framework of the model. The cross sections were utilized to delineate formation tops and variations in lithology. Cross sections were developed with a combination of geophysical log data, rock core examination, rock cuttings, and well logs (Figure 2-2).

The cross sections were developed by project team members for their respective states. Thus, they represent consensus interpretation of Mount Simon and Eau Claire distribution. The work represents a continuation of efforts initiated in MRCSP Phase I (MRCSP, 2005) and Phase II research (Medina and Rupp, 2010). Several areas evaluated as part of the initial MRCSP research were re-examined and the interpretation of Mount Simon and Eau Claire formation tops was revised. Overall, the layer tops used in this research were selected by each respective state geological survey. Data for Illinois, Pennsylvania, and West Virginia were retained from the MRCSP database. Some supplemental information in Wisconsin and Ottawa Province was obtained from previous modeling studies (Gupta, 1993).

A major result of this task was revision to the southern margin of the Mount Simon sandstone into Kentucky. This area is important for the Arches Province because many large CO_2 sources are located along the Ohio River. New seismic interpretations and well data collected from recent CO_2 injection tests were used to re-interpret the southern boundary of the Mount Simon sandstone and examine the manner in which the sandstone thins south- and eastward. Structures associated with Cambrian rifting in the Rough Creek Graben (western Kentucky, Illinois basin) and Rome Trough (eastern Kentucky, Appalachian basin) influence the southern limit of the sandstone, causing thinning or absence on structural highs. The sandstone deepens to more than 8,000 ft west of the Owensboro Graben in Hancock County, Kentucky, where reservoir quality appears to decrease based on depth-porosity relationships in the basin. Figure 2-3 illustrates the new interpretation of the southern limit of the Mount Simon. Based on these results, the structure maps for the Precambrian and Mount Simon were revised in the southern portion of the model. In addition, some data from the area south of the Mount Simon limit were removed from some data analysis because these points suggested inaccurate reservoir quality/capacity.

Based on cross sections and well log analysis results, structure maps for the Knox, Eau Claire, Mount Simon, and Precambrian formations were completed. These maps reflect data from 496 deep wells in the general study area (Medina and Rupp, 2010). The maps build on MRCSP maps for similar intervals, but include updates in some areas where the relationship between the Mount Simon and the Eau Claire formations were re-evaluated. The maps also match regional cross sections generated as part of the project. To ensure the geological model accuracy, a quality assurance/quality control (QA/QC) check was completed. Formation tops for all wells in the Arches Province were independently collected for each state and verified against the PETRA model.

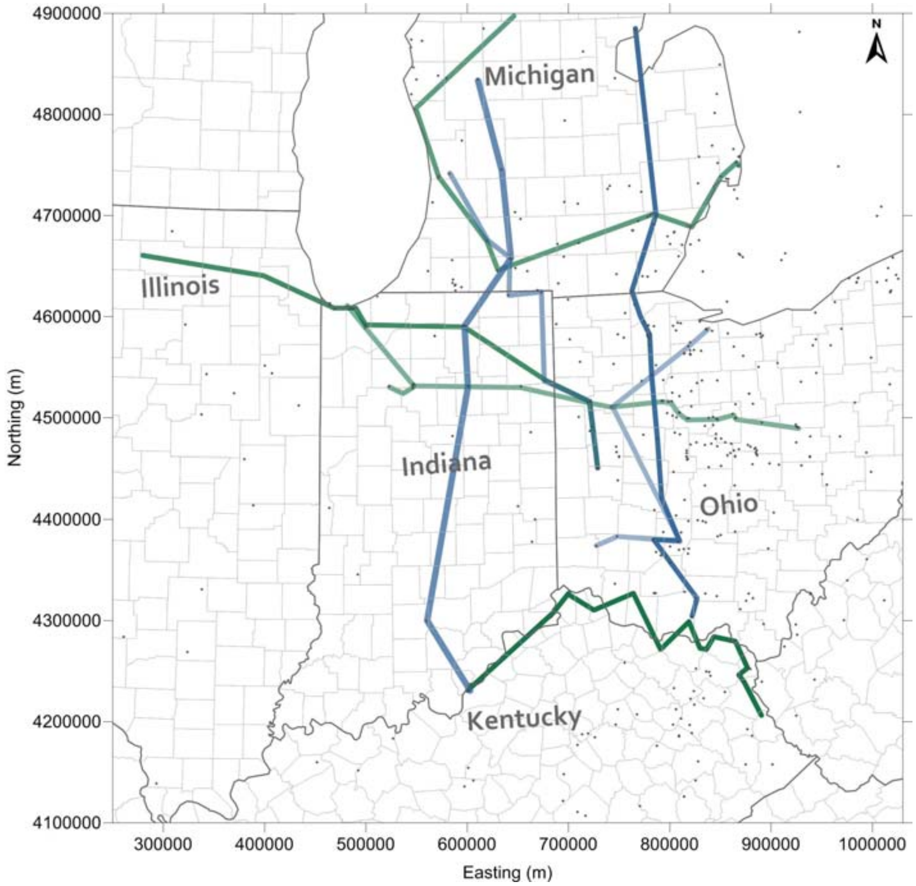


Figure 2-1. Location Map of Geological Cross Sections Prepared for Arches Province

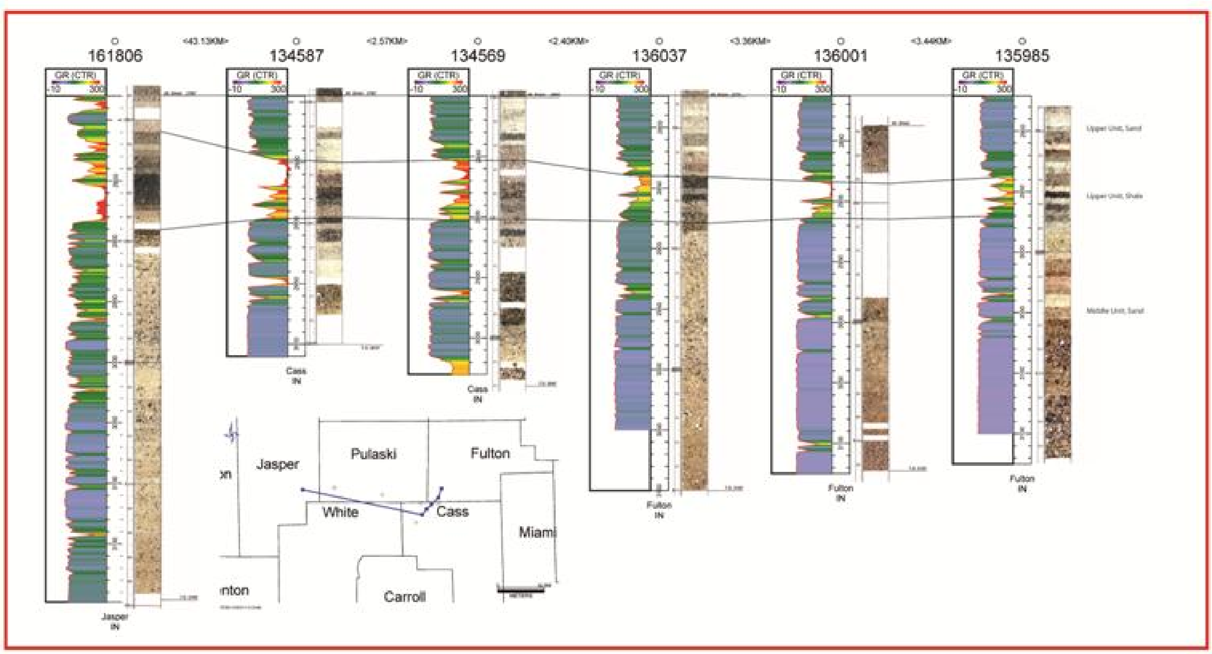


Figure 2-2. Example Geologic Cross Section in Northern Indiana

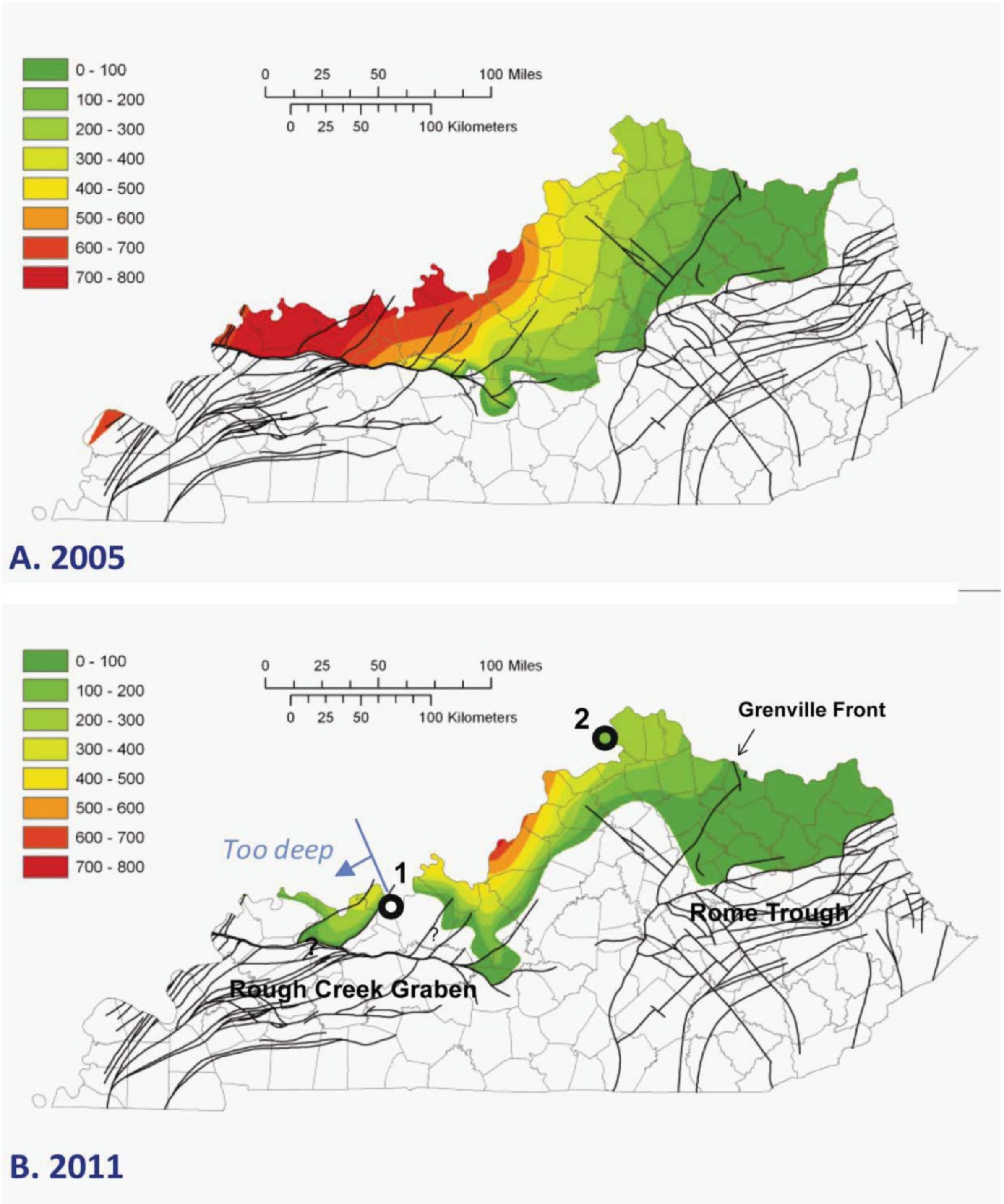


Figure 2-3. Comparison of Isopach Maps for the Mount Simon Sandstone in Kentucky (from (A) 2005 with the (B) new map updated for this study. Label 1 is the Kentucky Geological Survey No. 1 Blan well. Label 2 is the Battelle No. 1 Duke Energy well)

Information concerning the stratigraphic tops for the Cambro-Ordovician units in the Arches Region was collected for existing subsurface well records. Using stratigraphic information for the Knox Supergroup, Eau Claire formation, Mount Simon sandstone, and Precambrian basement, structure and isopach maps for each of these units were generated for the region. These maps were generated in geographic information system (GIS) software with interpolation methods that interpolate a raster surface from point, line, and polygon data. Figure 2-4 illustrates the resulting rasterized surfaces for the top (structure) and thickness (isopach) of each unit. These data were then exported as ASCII files, representing a finite-difference grid that can be used as input in numerical simulations. Maps were exported into GIS format at 4,000 m grid spacing.

2.3 Eau Claire/Caprock Evaluation

Along with data compilation on the Mount Simon formation, Eau Claire geotechnical data were reviewed for the study area. Wireline log data were collected in association with the development of the geocellular model. In addition, approximately 300 core test porosity and permeability data were evaluated from the Eau Claire formation for this study. Rock core tests indicated limited correlation of porosity to permeability for the unit. Many of the tests were below detection limits for permeability, which makes interpretation difficult. Overall, these data suggest an average porosity of 4.3% and permeability of 1.2 mD. However, the median permeability was 7.6E-5, suggesting several high outliers in the Eau Claire dataset. To supplement information on the Eau Claire, several rock core tests were included in the project. These tests included mercury injection capillary pressure, threshold entry pressure, and routine permeability tests.

In association with other research on the Eau Claire (Lahnn et al., 2012; Nuefelder, 2011), analysis was expanded into the Arches Province to portray the formation in the numerical model. Description of the Eau Claire in the model was based on research by Nuefelder (2011). In this research, the depositional fabric, mineralogy, and the resultant petrophysical characteristics of the Eau Claire formation were examined both stratigraphically and spatially. Intervals were classified with the Geologic Analysis via Maximum Likelihood System (GAMLS) according to dominant facies based on the following units: shale, silty-shale, silt, dolomitic shale, dolomite, and sand. The GAMLS classification process involved correlating petrographic analysis with well logs to classify the Eau Claire into different facies. The classification system was then applied to other well logs where rock samples were not available.

Figure 2-5 shows results of the GAMLS analysis based on the total percentage of each facies within the wells included in the study. As shown, there appear to be spatial trends in the predominant facies in the Eau Claire, with the formation exhibiting more dolomitic character into the basins. Figure 2-6 shows an Eau Claire cross section through the Arches Province illustrating the trends within wells.

2.4 Class I Mount Simon Injection Well Data Analysis

Operational data from Class I UIC injection wells were compiled to document historical injection in the Mount Simon in the Arches Province. Operational data were obtained for the 2005-2010 time period, or longer if possible. Many of the injection sites were closed or had operated prior to when injection records were necessary. Some of the data were summarized on a monthly basis because there was too much information to realistically address with the model. For example, EPA provided 3,500 pages of double-sided bottomhole pressure data for a site. While this is useful information, the model would never be calibrated to this level. Information from annual mechanical integrity tests was also tabulated as this provides a controlled test for model calibration.

Injection site data for the Class I disposal wells described in this report were gathered mainly from EPA UIC programs through various online and federal/state/local government sources.

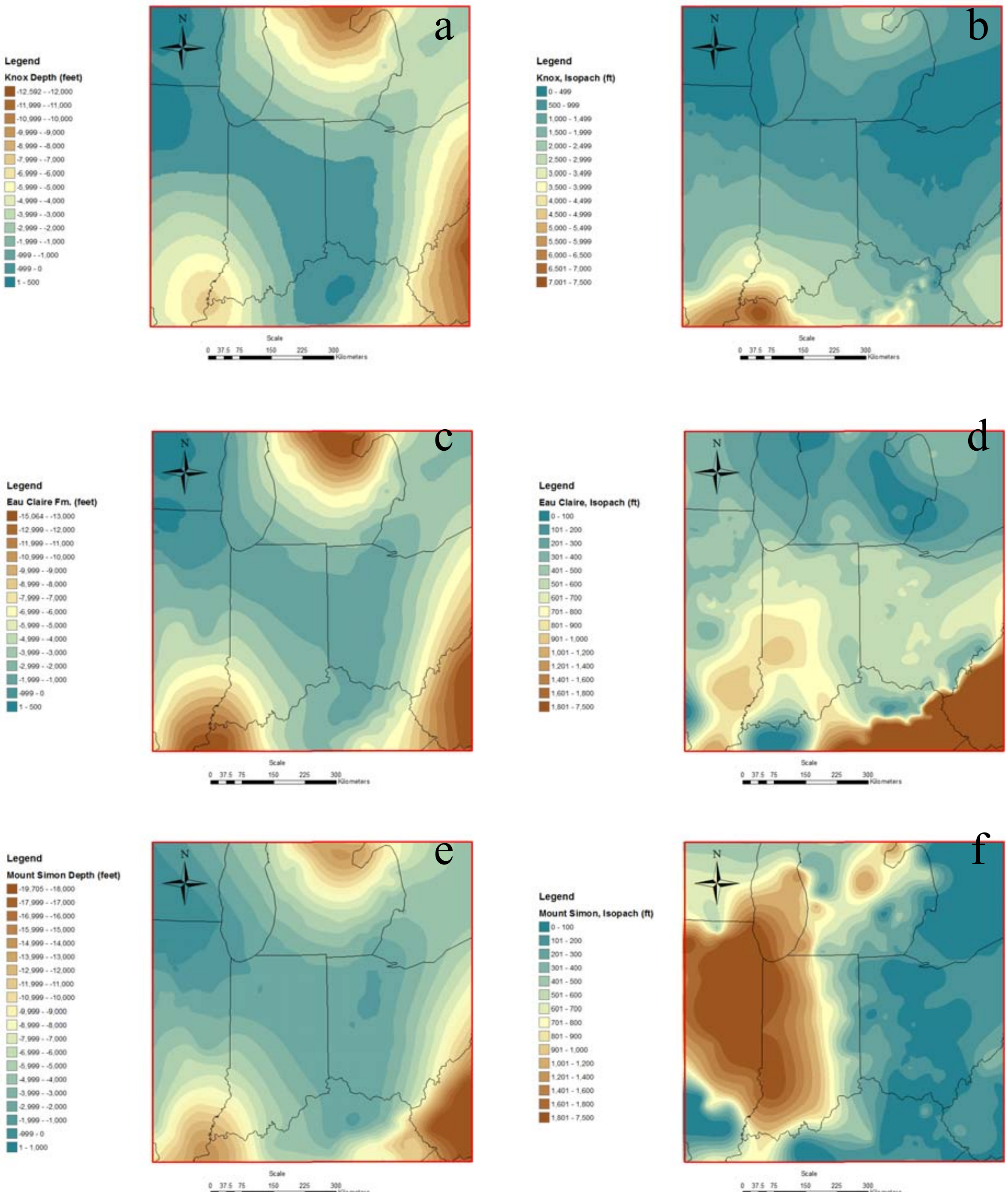


Figure 2-4. Study Area Showing Structure and Isopach Maps Respectively for the Knox (a, b), Eau Claire Formation (c, d), and Mount Simon Sandstone (e, f)

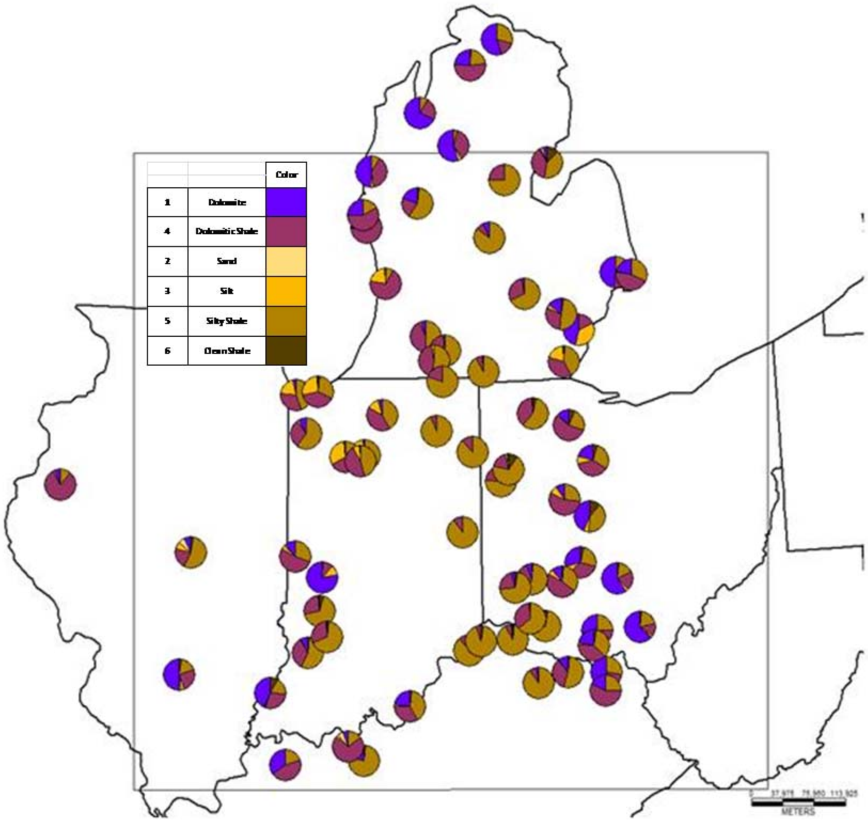


Figure 2-5. GAMLS Facies Analysis for the Eau Claire

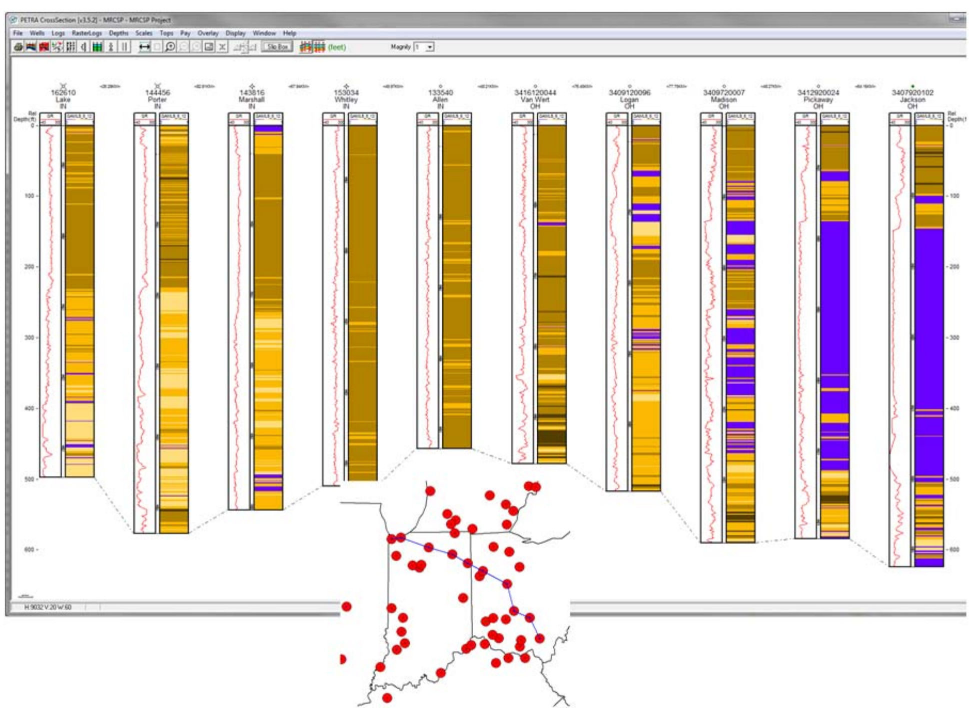


Figure 2-6. GAMLS Facies Cross Section for the Eau Claire

UIC regulations require injection sites to monitor injection and describe operations in monthly and annual reports. Well data in the state of Ohio were collected with the help of the Ohio EPA, who delivered the requested well information. EPA Region 5, along with aid from Western Michigan University developed the pertinent Class I well list for the state of Michigan. EPA Region 5, aided by Indiana University and the Petroleum Database Management System (PDMS), also helped to collect pertinent Class I well data in the state of Indiana. The only well data gathered from Kentucky were those from a CO_2 sequestration test well drilled by MRCSP, an effort led by Battelle. Class II UIC injection sites were also reviewed for operational data. Six Class II Mount Simon injection wells were identified in Ohio, but only two were active and located in the study area. It should be noted that more than 10 Mount Simon injection wells were permitted in Ohio after 2008, but were not addressed in the study since they were not available at the time. One Class II Mount Simon well was identified in Michigan outside the study area. Summary injection pressure data were available from some Class II wells but total injection was not available.

Table 2-1 summarizes injections documented in the study. A total of 42 Mount Simon injection wells were identified in the survey. Over 20 billion gallons of fluid injection into the Mount Simon were documented over the past 40 years. This volume is equivalent to approximately 60 million metric tons (MMT) CO_2. The largest single well injection volume was 2.9 billion gallons injected into the Innovene Lima #2 injection well, which is equivalent to approximately 8 MMT CO_2.

Surface/injection pressure, bottomhole pressure, flow rates, and amounts of fluid injected were compiled where available from UIC Class I sites. Additional parameters including annulus pressure, differential pressure, injection temperature, and/or fluid density were opportunistically gathered from a few sites. Figure 2-7 shows an example graph of data from a well illustrating nearly 40 years of injection. As shown, injection rates vary over time. Many wells operate during working hours or on an as-needed basis. Maximum injection rates ranged from approximately 30 to 268 gallons per minute, with a few unsuccessful well less than 10 gallons per minute. Wellhead injection pressures ranged from approximately 400 to 1600 pounds per square inch (psi). Based on maximum wellhead injection pressures, most wells operated on maximum bottomhole pressure gradients of approximately 0.5 to 0.7 psi/ft, or 10 to 55% above background reservoir pressures. Review of temporal pressure data from the injection wells suggests that most wells reach a steady-state balance where pressure is steady up to some maximum injection rate. However, some sites (such as the Vickery, Ohio site) have to alternate injection into multiple wells because of pressure buildup issues. All sites show a fairly rapid pressure decline after injection is stopped. Some sites had a nearly immediate pressure fall-off.

Where available, pressure fall-off data and/or reservoir tests were also collected. Reservoir test analysis completed by operators was evaluated for accuracy as part of the injection record collection task. Figure 2-8 shows an example pressure fall-off reservoir test. As shown, the test provides analysis of the test for transmissivity, permeability, and storage parameters. Quality of the reservoir tests varied, and some tests were designated as unacceptable due to poor quality.

2.5 Mount Simon Pressure Field Mapping

Available Mount Simon reservoir pressure data were compiled for the study area. These data reflect drill stem tests, pressure fall-off tests, and shut-in tests performed in the Mount Simon over the past 40 years. Tests were completed in different depth intervals in the Mount Simon. Many different methods were also used to measure reservoir pressure. Therefore, there is variation in quality of these measurements. To help resolve these variations, pressure fall-off test data were reviewed from Mount Simon injection wells. These tests were run under controlled conditions where the test interval is isolated with a packer assembly. The tests are also run until reservoir pressure stabilizes to a background level. In general, the pressure-fall-off data provided better definition to the nature of reservoir pressure. Review of the Mount Simon pressure data shows a clear trend with depth, as may be expected (Figure 2-9). Consequently, pressure gradients (pressure/depth) were also examined. The pressure gradients are generally 0.43 to 0.48

psi/ft in the Arches Province area and increase into the deeper geologic basins where formation fluid is denser. Given this trend, a uniform pressure gradient of 0.45 psi/ft was considered for the model.

Table 2-1. Summary of Mount Simon Injection Parameters

Site/ Permit #	State	UIC Class	Operator/Lease	Total Depth (ft)	Total Injection (gallons)	Injection Period	Max. Inj. Pressure (psi)	Max. Inj. Rate (gpm)
127-1W-003	IN	I	ArcMit. Burns Hrb. WAL1	4298	2,073,773,736	1968-2012	NA	NA
127-1W-004	IN	I	ArcMit. Burns Hrb. WAL2	4301	1,449,430,497	1968-2012	NA	NA
127-1I-009	IN	I	IN DOT #1	4558	1,145,407,000	1999-2012	NA	NA
127-11-C007	IN	I	Cathay Deepwell Disp.	4538	1,038,498,287	1969-2012	500*	NA
03-02-003	OH	I	Ineos Lima #1	3125	1,900,000,000	1968-2008	843*	257
03-02-004	OH	I	Ineos Lima #2	3158	2,900,000,000	1969-2008	815*	266
03-02-005	OH	I	Ineos Lima #3	3157	2,200,000,000	1972-2008	800*	257
03-02-006	OH	I	Ineos Lima #4	3150	934,000,000	1991-2008	790*	257
M0002	MI	I	E.I.DuPontdeNemours #1	6514	47,211,266	1972-1982	NA	8.5
M0051	MI	I	Heinz N. Am. WDW#1	5915	956,606,100	1974-2007	1220	268
M0052	MI	I	Heinz N. Am. WDW#2	6189	1,029,360,211	1975-2007	1130	248
M0053	MI	I	Heinz N. Am. WDW#3	5913	653,436,009	1975-2007	1200*	184
M0069	MI	I	Detroit Coke Corp.#1	4112	257,774,260	1973-1995	1060	117
M0070	MI	I	Chemetron Corp.#1	5895	110,739,844	1966-1994	NA	122
M0071	MI	I	BASF Chemetron D-2	5910	205,063,274	1973-1994	NA	241
M0217	MI	I	BASF Chemetron D-3	9500	65,218,954	1979-1994	NA	NA
M0129	MI	I	Pfizer, Inc. #3	5945	452,816,909	1975-2007	1007	176
M0130	MI	I	Pfizer, Inc. #4	5946	450,746,358	1975-2007	671	94
M0373	MI	I	Pfizer, Inc. Park-Davis #5	6027	204,956,496	1992-2007	1180	236
M0137	MI	I	Pharmacia & Upjohn #3	5615	222,021,758	1977-2007	464	247
M0327	MI	I	Pharmacia & Upjohn #4	5600	119,562,178	1981-2007	718	31
M0155	MI	I	Honeywell Semet-Solvay#2	4112	169,429,102	1979-2007	860	101
M0226	MI	I	Honeywell Semet-Solvay#3	4127	75,334,789	1977-2007	920	106
M0184	MI	I	Ford Motor Company D-2	4308	81,525,102	1976-1987	NA	41
M0328	MI	I	Gelman Sci. StoferMarsh.1	5804	150,324,076	1982-2004	1405	133
M0357	MI	I	Bio-Lab, Inc IW#1	4856	266,164,922	1989-2007	624	48
M0430	MI	I	Bio-Lab, Inc IW#2	4850	70,014,896	1998-2007	NA	44
M0462	MI	I	Env. Disp. Sys. 1-12	4645	1,372,379	2005-2007	747	9.7
M0463	MI	I	Env. Disp. Sys. 2-12	4550	715,730	2005-2007	631	3.7
M0509	MI	I	Mirant Zeeland IW1	6775	68,904,979	2002-2008	1158	129
M0510	MI	I	Mirant Zeeland IW2	6632	58,583,483	2002-2008	1227	88
05-09-001	OH	I	AK Steel #1	3288	567,000,000	1967-2008	510*	100
05-09-002	OH	I	AK Steel #2	3281		1968-2008	550*	118
03-72-009	OH	I	Vickery Env. #2	2952	357,700,000	1977-2008	472*	68.6
03-72-011	OH	I	Vickery Env. #4	2902	189,800,000	1977-2008	677*	35.4
03-72-012	OH	I	Vickery Env. #5	2938	380,500,000	1981-2008	644*	90.5
03-72-013	OH	I	Vickery Env. #6	2922	319,200,000	1981-2008	401*	87.4
156	MI	II	Alto Propane Storage Fee	8205	NA	NA	NA	NA
4517 4	OH	II	OOGC Disp. Killbuck #1	6532	NA	1985-2012	1470*	NA
139 2	OH	II	Second Oil Shidler #3-4	3600	NA	2005-2012	940*	NA
339 7	OH	II	N. Morrison #4	4607	NA	1986-?	1205*	NA
1591 3	OH	II	Moore Well Serv. KST #5	7202	NA	1985-?	1600*	NA
				TOTAL	21,173,192,595			

*Approximate value based on limited data.
NA = not available

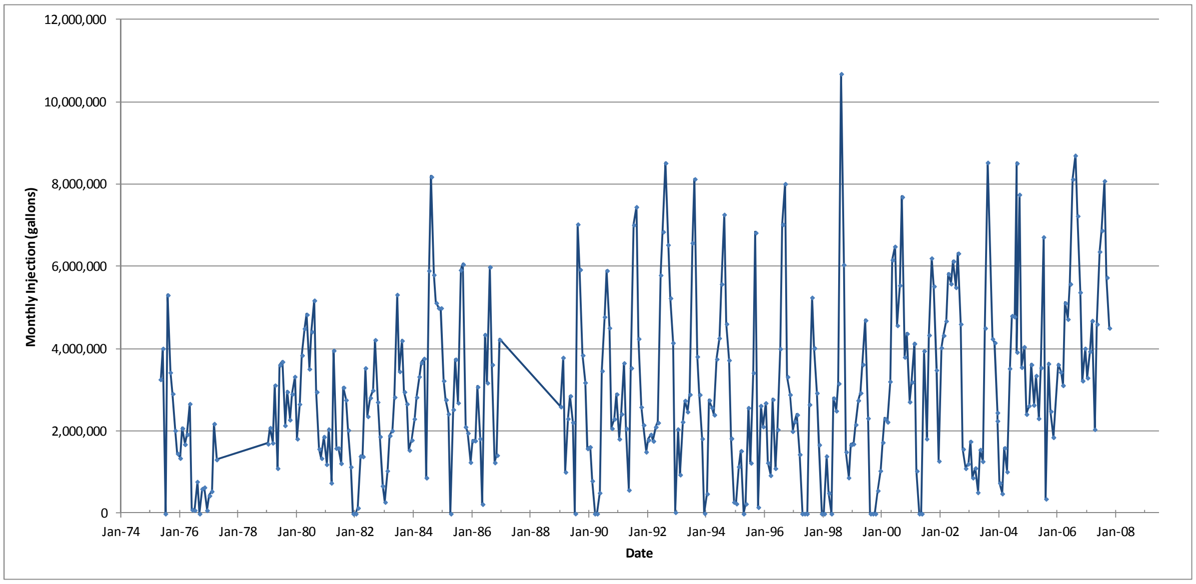


Figure 2-7. Injection History for Heinz #2 Injection Well, Holland, MI

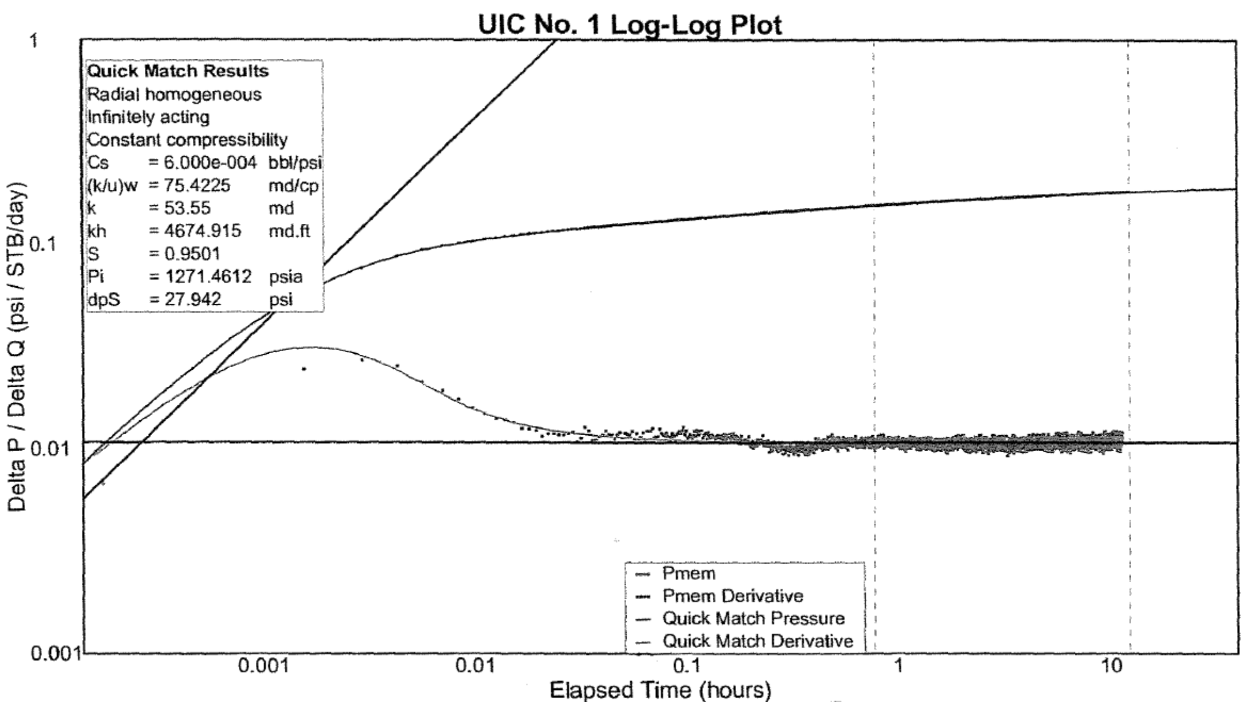


Figure 2-8. Reservoir Pressure Fall-Off Test from AK Steel UIC #1 Well, Middletown, OH

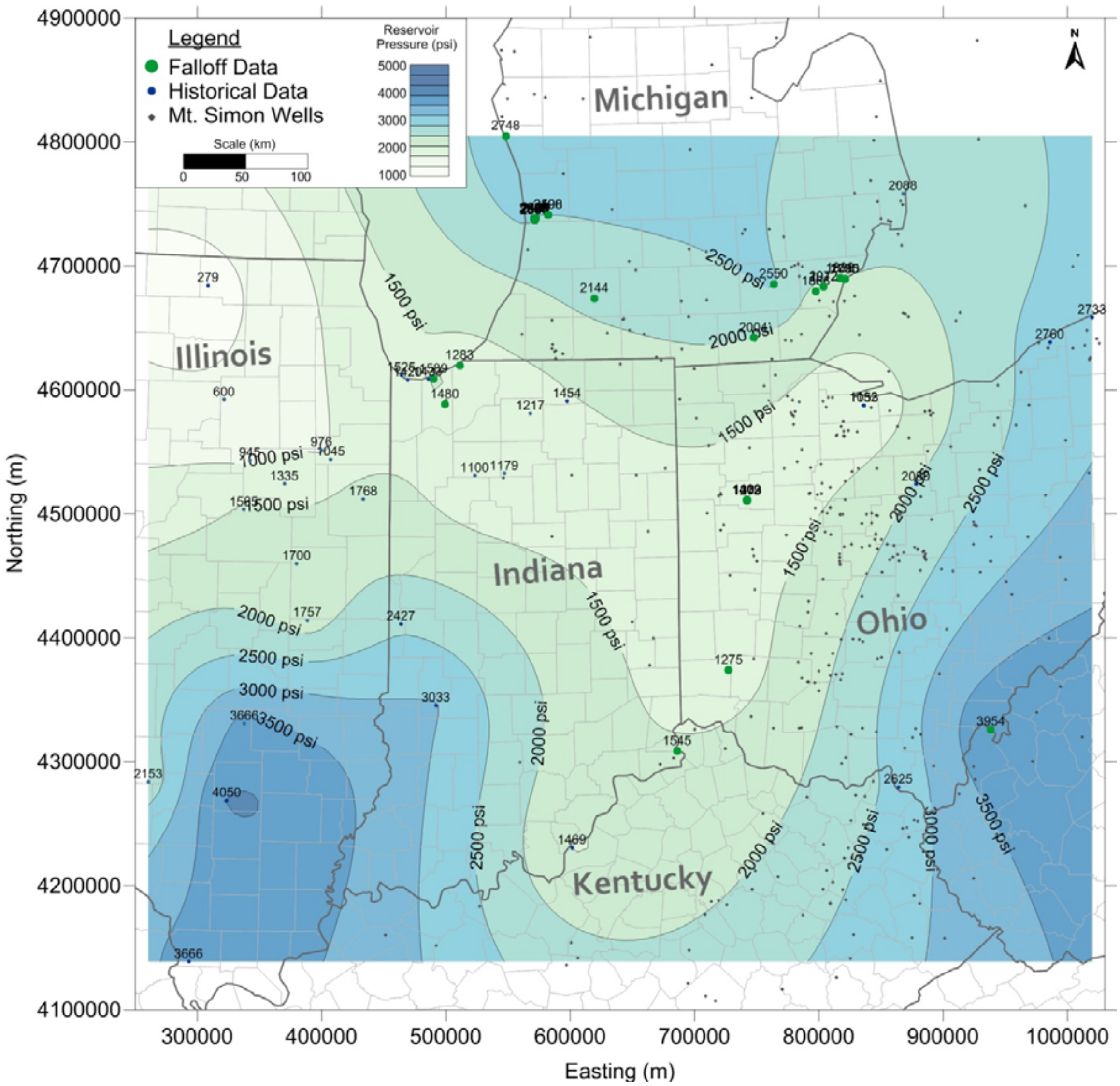


Figure 2-9. Mount Simon Reservoir Pressure (psi)

Section 3.0: DEVELOPMENT OF MODEL FRAMEWORK AND PARAMETERS

Development of model framework and parameters involved integration of the various geologic and hydrologic information into a geocellular model, which comprises the basis for the numerical model. Geologic information included general geologic setting, stratigraphy, structure of the rock formations, hydrologic features, and description of the hydrostratigraphic units. Hydraulic parameters were also reviewed that describe the physical conditions and controls in the rock formations being considered for CO_2 storage. Together, this information was translated into a geocellular model that represents the parameters and conditions in a numerical array, or regularly spaced grid, that may be imported into the numerical model.

3.1 Conceptual Model

Development of the conceptual model was a large effort involving the whole project team. Research was focused on the Mount Simon sandstone and the Eau Claire formation because these are the main rock formations suitable for CO_2 storage in the Arches Province. Analysis of the geologic information required review of geophysical well logs, rock samples, drilling logs, geotechnical test results, and reservoir tests. Data were tabulated and integrated into geologic interpretation software. Geologic cross sections and maps were prepared to aid in description of the geologic setting. Hydrologic information was compiled from geophysical well logs, rock core tests, reservoir tests, and other sources. To expand the database on geotechnical information regarding the Mount Simon sandstone and Eau Claire formation, additional rock core testing was completed on previously untested rock core available at the state core repositories. Once compiled, the geologic and hydraulic data were integrated into a geocellular model. Data were extrapolated into a 3D grid of porosity and permeability, which are key parameters regarding fluid flow and pressure buildup due to CO_2 injection. A method was also employed to correct permeability data where reservoir tests have been performed in Mount Simon injection wells. The geocellular model was translated into a numerical array of parameters with geologic interpretation and visualization software.

3.1.1 Geologic Setting. The Arches Province is an informal term to describe a geographical area in Illinois, Indiana, Kentucky, Michigan, Ohio, Ontario, and Wisconsin along several regional geologic structures: the Cincinnati Arch, Indiana-Ohio Platform, Kankakee Arch, and the Findlay Arch (Figure 3-1). Thick sequences of sedimentary rocks overlie Precambrian age crystalline basement rock in the region. The sedimentary rocks consist of layers of shale, anhydrite, siltstone, dolomite, limestone, and sandstone deposited in the Paleozoic Era approximately 250 to 570 million years ago. Cambrian System rocks are thought to have been deposited when the Laurentian continental plate separated from the Baltica plate and the Iapetus Ocean formed 505 to 570 million years ago. The rock formations have subsequently undergone periods of deformation and diagenesis that defines their current character. Below the sedimentary rock layers are very old crystalline and dense sedimentary Precambrian rocks more than 1 billion years old. Relatively thin, unconsolidated alluvial and glacial sediments are present on the surface in the region.

Rock units have been identified based on their age and character as determined in oil and gas wells drilled throughout the region. In general, these borings are more concentrated in areas where oil and gas are present. In addition, there have been more penetrations in shallower zones. The focus of the Arches Simulation project is the lower Cambrian age rocks because these have the most suitable pressure/temperature conditions for CO_2 storage in supercritical fluid or liquid state. Specifically, the Mount Simon sandstone is considered the most appealing zone for CO_2 storage in the Arches Province. The Eau Claire-Conasauga formations are considered the main containment unit above the Mount Simon. Younger formations in the Knox supergroup overlie the Eau-Claire-Conasauga. These rock formations

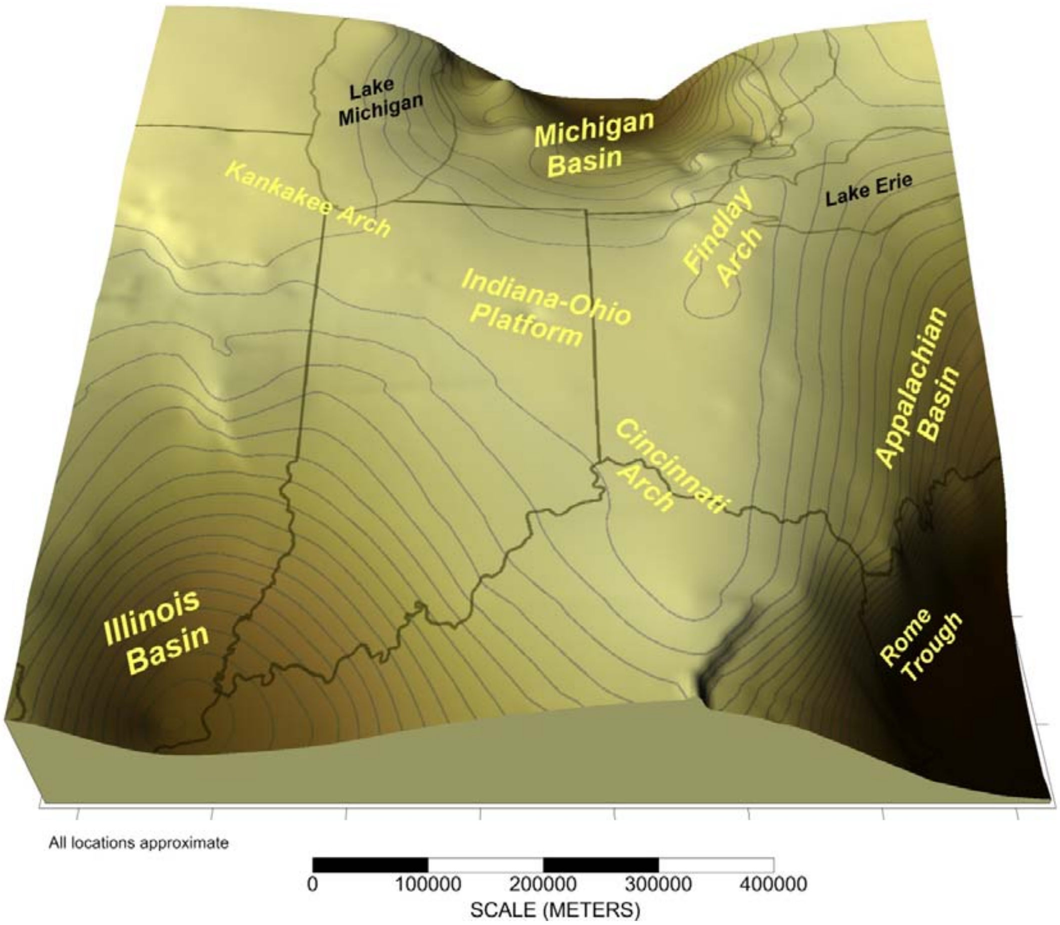


Figure 3-1. 3D Surface Image of the Mount Simon Sandstone Illustrating Major Geologic Structures in the Region

were not studied as part of this project, but may contain promising zones for CO_2 storage in some areas (Greb et al., 2009). Precambrian rocks are generally considered impermeable in much of the region, and comprise the lowermost unit addressed in the conceptual model.

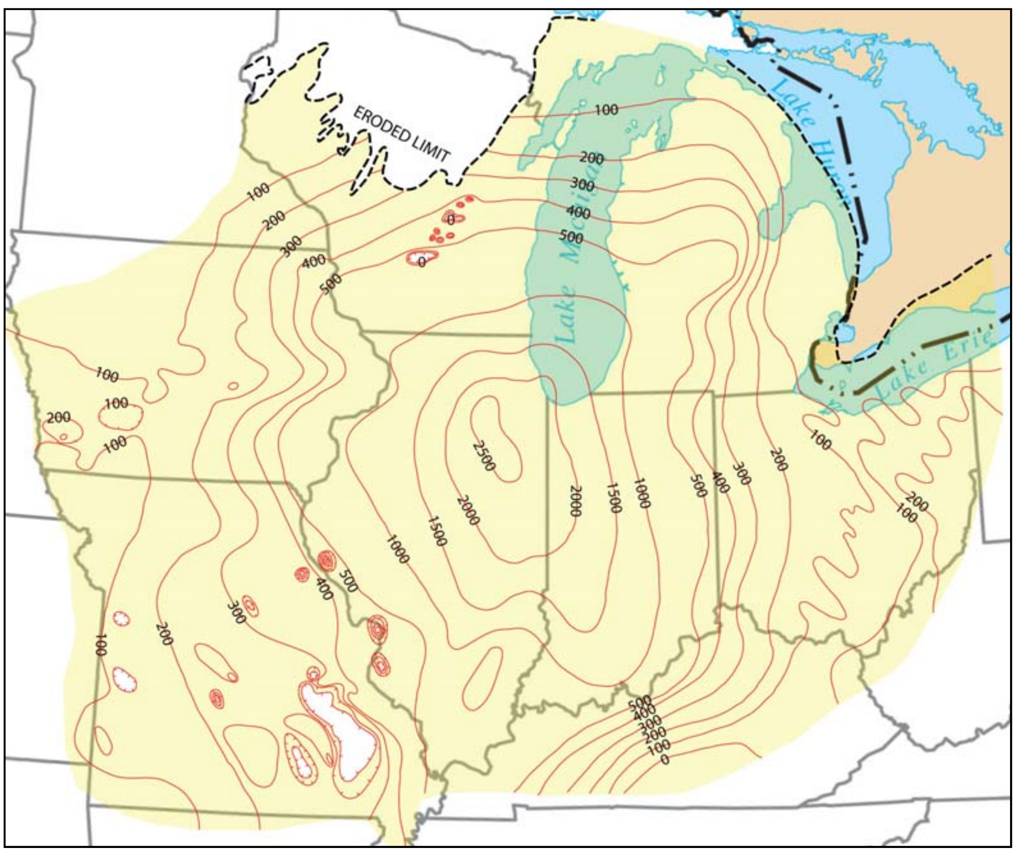
Rock formations form broad arch and basin structures in the Midwestern U.S. Sedimentary strata thicken to over 5,000 m in the Appalachian Basin, Illinois Basin, and Michigan Basin. These deep basins form major boundaries to fluid flow because fluids are limited from migrating across the deeper zones of the basins. In the northwest portion of the study area (Wisconsin and Minnesota), Paleozoic formations become shallower and outcrop at the surface or are truncated in the subsurface along the Canadian Shield (Mossier, 1992). In the northeastern portion of the study area (Ontario Province), the Findlay Arch continues into the Algonquin Arch. Paleozoic rock formations also shallow along the western St. Lawrence Platform to the erosional limit of Paleozoic rocks (Shafeen et al., 2004). Cambrian age rock formations are truncated in the subsurface in this area.

While the features in the Arches Province are notable from a regional perspective, the structures cover tens of thousands square kilometers. On a local basis, rock layers are nearly flat with very little dip. The center of the study area is the Indiana-Ohio Platform, where rock formations are essentially flat lying.

Even along the arch structures, dip is very low, on the order of 10 to 20 ft per mile. Formations dip more steeply into the basins, where total sedimentary thickness exceeds 5,000 m.

Studies have identified several rock formations that may be associated with Cambrian basal sandstones, including the Mount Simon formation, Conasauga Sandstones, Potsdam Sandstone, Rome Trough Sandstones, Maryville formation, and Rome formation. Together, the Cambrian basal sandstones may be correlated across a very large area of the U.S. As mentioned earlier, the arch structures are more the result of subsidence along the surrounding basins. Isopach maps of Cambrian basal sandstones better illustrate the depositional center of the rock formations. As shown in Figure 3-2, the depositional center of the Cambrian basal sandstones is located in what is currently northeastern Illinois, where the unit is over 2,000 ft thick. As shown, the thickness of the Cambrian basal sandstones thins away from this depocenter. The depositional environment across the interval varied substantially during the period of deposition. The rocks were then subjected to several hundred million years of diagenesis and alteration. The current nature of these rocks reflects these developments.

This total thickness is now superimposed on the current geologic structures. As such, the depositional center of the Cambrian basal sandstone interval does not coincide with the center of the basins. The Arches Province covers the east-central portion of the total extent of the Cambrian basal sandstone interval. In this area, the interval generally thickens from 100 ft on the edge of the Appalachian basin to over 2,000 ft in the northern portion of the Illinois basin.



All locations approximate

Figure 3-2. Isopach Map (ft) of Cambrian Basal Sandstones in the Midwestern United States Hydrologic Features

3.1.2 Hydrologic Features. Fluid flow in the deep rock formations is influenced by several factors, including topography, geologic structure, fluid density, rock permeability, tectonic forces, compaction, temperature variations, surface water bodies, and freshwater infiltration. Deep rock formations are fairly isolated and saturated with dense saline fluid throughout much of the Arches Province. As described in fundamental theory (Tóth, 1963), fluid flow cycles in these deeper zones are very slow, on the order of hundreds of thousands to millions of years (Figure 3-3). In addition, deep wells may disturb hydrologic conditions with introduced drilling fluids. As such, flow directions and velocities are difficult to determine. Hydraulic gradients created by large-scale CO_2 injection would probably be much greater than any pre-existing conditions. Consequently, these pre-existing gradients were not considered a major factor in the conceptual model.

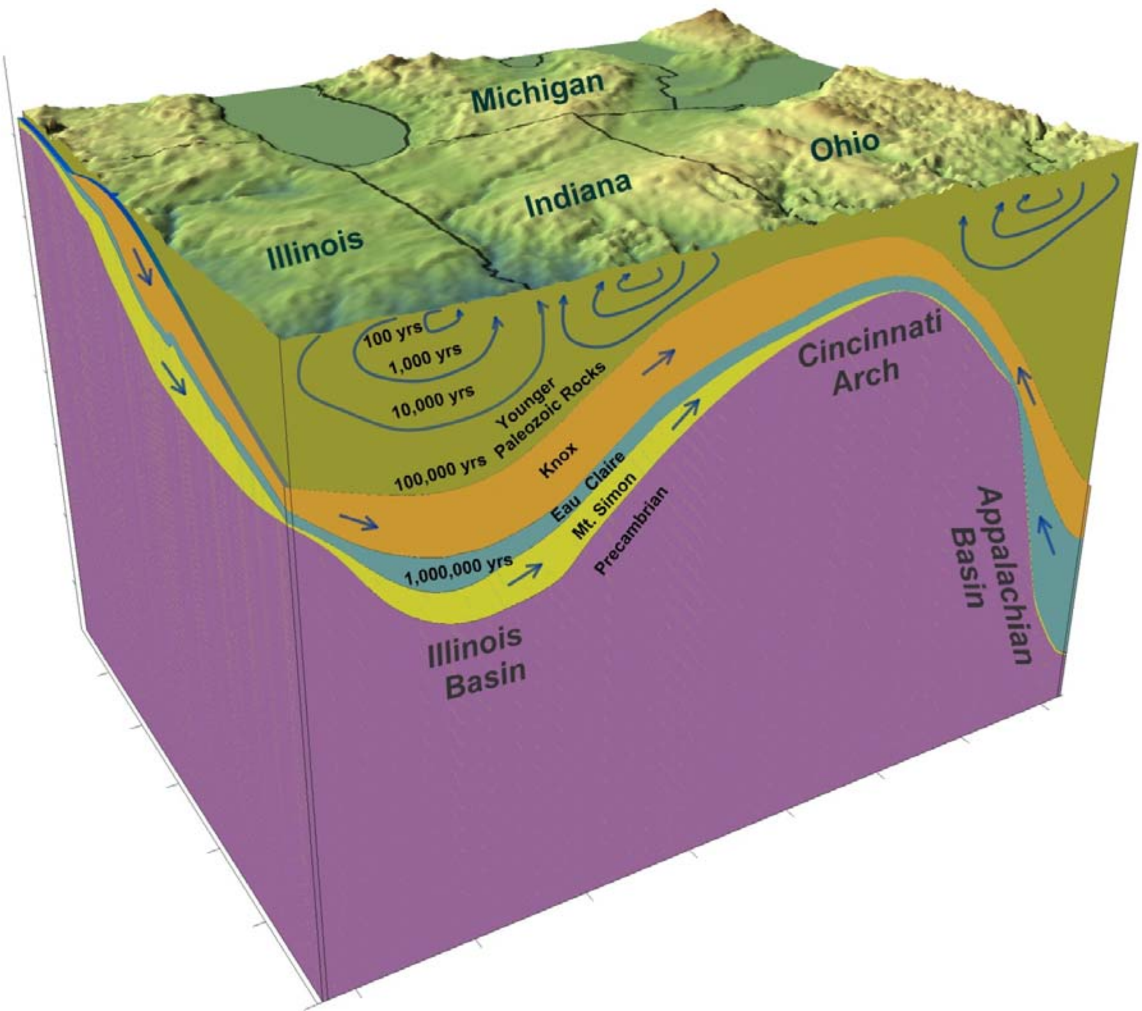


Figure 3-3. Geologic Block Diagram Illustrating Hydrologic Features and Flow Cycles in Arches Province

The basin and arch structures in the study area are major hydrologic features. Fluid density generally increases substantially into the basins, reaching levels over 1.3 kg/L at depths in some areas. Conversely, fluid density is generally lower along the arch structures. Fluid density in northern Illinois and Wisconsin is near 1.0, and the Mount Simon formation is considered a freshwater aquifer in these areas. Reservoir pressures reflect these density variations along with depth. Reservoir pressures are near freshwater gradients (0.433 psi/ft) in shallow zones, while the deeper basins may have a pressure gradient of 0.48 psi/ft or greater. These pressure gradients may be a result of fluid density and/or trapped fluids in the deeper portions of the basins.

Studies on potentiometric surface maps of equivalent freshwater heads in the Mount Simon suggested flow directions converging toward northwest Ohio (Clifford, 1973; Warner, 1988). This research matches other hypotheses that suggest fluids are migrating out of basins into arches due to tectonic forces compressing the basins. However, other research has indicated flow directions from the arches into the basins, possibly due to surface water infiltration along arch structures (Gupta, 1993). Lake Michigan is present in the northwestern portion of the study area, and Lake Erie is present in the northwestern portion of the study area. However, the lakes are relatively recent features and not directly connected to the Mount Simon or Eau Claire.

Permeability of rock formations is a large control on flow in the study area. The Cambrian basal sandstone has a variable distribution across the Arches Province. The formation transitions from a clastic sandstone in the western portion of the study area into the carbonate Conasauga formation into the Appalachian Basin. The Conasauga formation generally has much lower permeability than the Mount Simon sandstone. Other trends in permeability are present in the basin. In addition, vertical variations in permeability are present within the Cambrian basal sandstones. Recent research on the Mount Simon sandstone suggests that the porosity of the formation decreases with depth into the basins (Medina et al., 2008). Similar variations are present in the Eau Claire formation, which may have dominant sandstone, carbonate, or shale lithology depending on location and depth.

Other hydrologic features in the Arches Province include faults and other structural limits. In northern Kentucky, Cambrian rock formations are abruptly faulted several hundred feet, essentially marking a limit to the extent of the Mount Simon. In the far northeastern and northwestern portions of the study area, Cambrian rock formations are truncated by underlying Precambrian basement rocks.

3.1.3 Hydrostratigraphic Units. The geologic model covers Knox through Precambrian rock formations, but it is focused on the Eau Claire and Mount Simon formations (Figure 3-4). Precambrian rocks include crystalline metamorphic and igneous rocks along with some areas of dense sedimentary sandstones. Rocks include the crystalline Grenville Complex east of the Grenville Front. West of the front, basement rock reflects the East Continent rift basin, Eastern Granite-Rhyolite province, the mid-continent rift system, the Middle Run Formation, and Penokean Province. Few wells have penetrated these deeper Precambrian rocks, so they are not well understood. Some boring logs indicate weathered zones or washouts at the contact of Precambrian rocks and overlying sedimentary strata.

The Cambrian basal sandstone interval includes a complex distribution (Bowen et al., 2011) of Mount Simon sandstone in Michigan, Indiana, western Kentucky, Illinois, and western Ohio and dolomitic sandstones of the Conasauga Group in eastern Ohio and eastern Kentucky (Figure 3-5). The unit may be correlated with the Potsdam sandstone into New York and Pennsylvania and sandstone units in the Rome Trough in West Virginia, eastern Kentucky, and Pennsylvania (Wickstrom et al., 2005). The eastern portion of the study area includes a region where the basal Conasauga sandstones have been delineated. The Mount Simon is considered the main CO_2 storage interval in the Arches Province. The area in eastern Ohio and Kentucky was included in the model to provide coverage along the Findlay arch and to accommodate numerical boundary conditions.

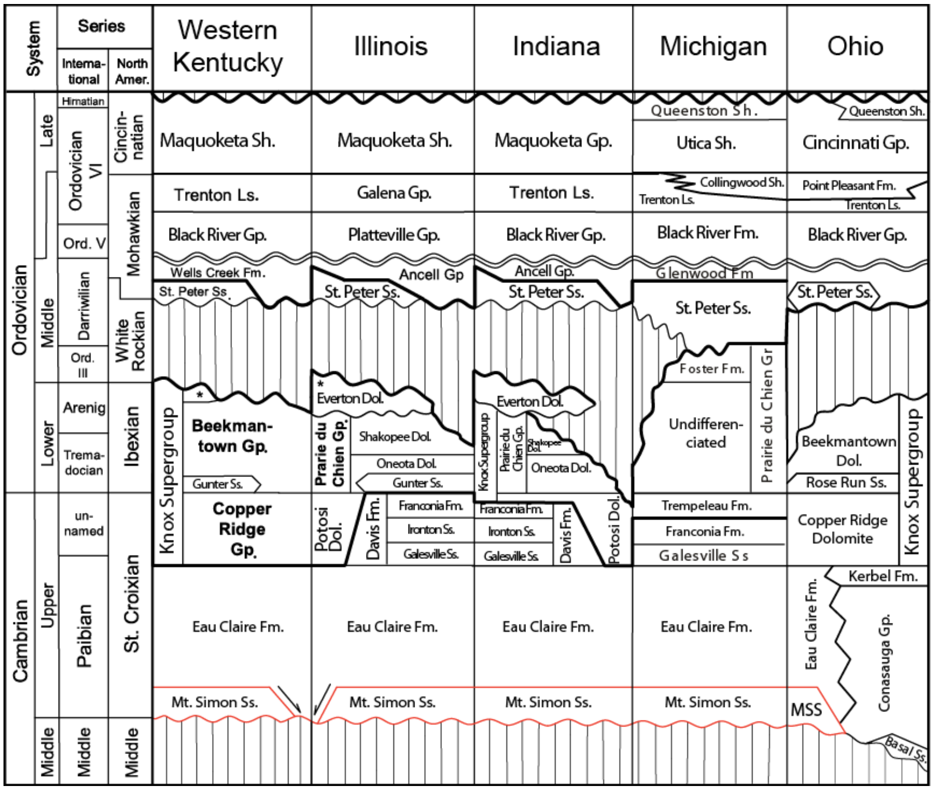


Figure 3-4. Cambrian Basal Sandstone Distribution in Midwestern U.S.

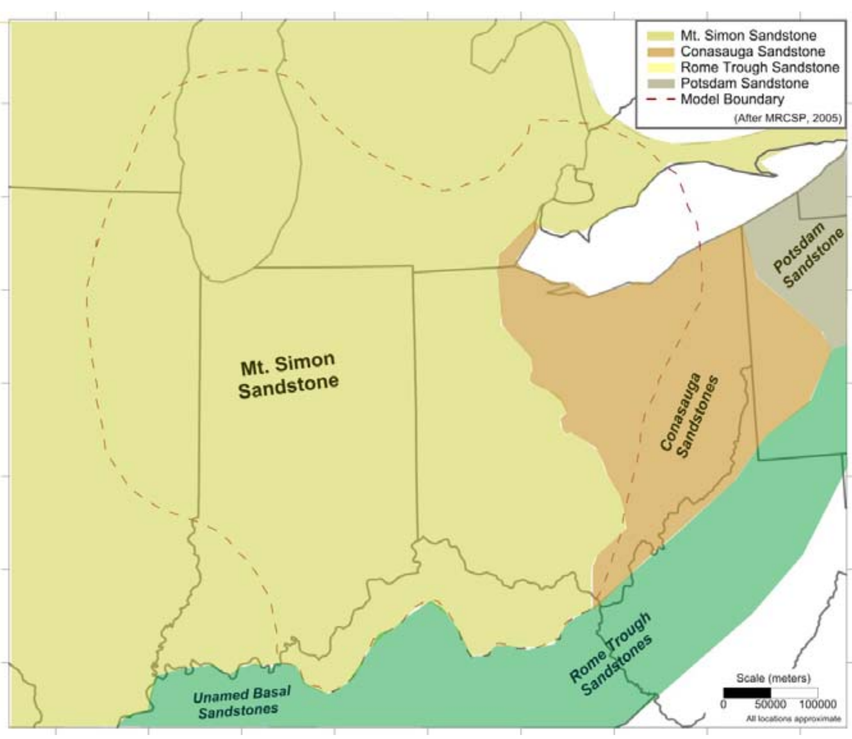


Figure 3-5. Cambrian Basal Sandstone Distribution in Midwestern U.S.

The Eau Claire conformably overlies the Cambrian basal sandstone and consists of "dark gray, red and green shales; dolomitic, feldspathic, and partly glauconitic siltstone; very fine-grained to fine-grained, well-sorted sandstone (often feldspathic and lithic); silty to sandy dolostone; and oolitic limestone" (Wickstrom et al., 2005). The Eau Claire formation is classified in the lower part of the Munising group. The formation has been identified in Illinois, Indiana, lower Michigan, western Ohio, northern Kentucky, and southwestern Ontario province. The Eau Claire transitions into the Conasauga Group from central Ohio eastward into the Appalachian Basin.

The Knox interval includes a variety of carbonate units unconformably overlying the Eau Claire. The upper limit of the interval is defined by the Knox Unconformity, a major erosional unconformity between lower and upper Ordovician rocks. The interval includes the Beekmantown, Copper Ridge, Prairie Du Chien, Potosi, Davis, Franconia, Ironton, Galesville, Trempealeau, and many other regional or driller-named formations. In general, the lower Knox is characterized by dense dolomite or limestone carbonate lithology, and the upper Knox is characterized by a series of thick shale units.

3.1.4 Model Input Parameters. Input parameters were assembled for the numerical simulation based on geophysical well logs, rock core test results, reservoir tests, and other geotechnical methods. These parameters include the various geotechnical, hydraulic, and physical information necessary to run the simulations. The main input necessary for the model is related to rock properties and initial physical conditions in the Mount Simon formation and adjacent formations. Since the model covers a 600 × 600 km area, smaller scale variability may not be fully portrayed in the numerical model. Other parameters follow relatively consistent trends across the model area, so a uniform value or gradient may be applied.

To supplement existing test data, additional rock core tests were completed as part of the Arches Simulation project. Each state survey reviewed existing Mount Simon and Eau Claire rock in their repositories and identified core that had not been tested. Based on this review, rock core was selected and sent to a geotechnical laboratory for testing.

Routine porosity/permeability core analysis was conducted as part of the Arches Simulation Project on 105 samples from eight wells in the study area. Table 3-1 gives the average permeability and porosity values from the new/Arches Project core dataset. Mercury injection capillary pressure tests were also completed on 11 samples as part of the project (Table 3-2). Geomechanical tests were completed on 11 samples (Table 3-3 and 3-4).

Table 3-1. Summary of Average Permeability, Average Porosity, and Average Grain Density Measured in Core Samples from New/Arches Project Samples (by well)

Formation	Number of Wells	Number of Samples	Average Permeability to Air (mD)	Average Porosity - NCS (%)	Average Grain Density (g/cc)
Eau Claire	3	27	127	14.9	2.67
Mount Simon	7	78	280	11.9	2.63

Table 3-2. Summary of Test Results from MICP

Sample Number	Well	Formation	Permeability to Air (mD)	Porosity (fraction)	Grain Density (g/cc)	Median Pore Throat Radius (µm)
1	Vistron #1	Mount Simon	65.870	0.192	2.565	3.9269
2	Vistron #1	Mount Simon	97.321	0.157	2.632	5.5207
3	Lloyd Cupp #1-11	Mount Simon	0.138	0.117	2.660	0.0865
4	Kalamazoo	Mount Simon	0.005	0.022	2.691	0.0306
5	Kalamazoo	Mount Simon	182.695	0.108	2.640	12.4511
6	Ottawa	Mount Simon	78.878	0.106	2.640	6.9670
7	Ottawa	Mount Simon	145.415	0.114	2.628	10.5600
8	Montague #1	Eau Claire	0.001	0.012	2.805	0.0702
9	Montague #1	Eau Claire	0.254	0.087	2.631	0.3007
10	Midwest #2	Mount Simon	55.355	0.125	2.648	1.4311
11	Midwest #2	Mount Simon	146.711	0.116	2.626	10.3852
12	NIPSCO - Wakeland #1	Mount Simon	4.194	0.100	2.646	1.4740
13	Duke East Bend	Mount Simon	0.0001	0.017	2.84	0.0186
14	Duke East Bend	Mount Simon	1.07	0.110	2.62	0.5131
15	Inland Steel	Mount Simon	0.0005	0.025	2.68	0.0044
16	US Steel	Mount Simon	0.00003	0.015	2.69	0.0046

Table 3-3. Summary of Triaxial Compressive Test

Sample Number	Well	Formation	Compressive Strength (psi)	Static Young's Modulus ($\times 10^6$ psi)	Static Poisson's Ration
1	Vistron #1	Mount Simon	15202	3.027	0.362
2	Vistron #1	Mount Simon	15729	3.338	0.32
3	Lloyd Cupp #1-11	Mount Simon	17259	2.334	0.308
4	Kalamazoo	Mount Simon	36729	6.451	0.288
5	Kalamazoo	Mount Simon	31557	5.546	0.208
6	Ottawa	Mount Simon	32376	4.957	0.347
7	Ottawa	Mount Simon	28477	4.54	0.173
8	Montague #1	Mount Simon	41184	7.862	0.253
9	Montague #1	Mount Simon	30082	4.647	0.3
10	Midwest #2	Eau Claire	15161	3.634	0.282
11	Midwest #2	Eau Claire	24259	4.148	0.169

Table 3-4. Summary of Brazilian Indirect Tensile Test

Sample Number	Well	Formation	Density (g/cc)	Max. Load (lb)	Brazilian Tensile Strength (psi)
1	Vistron #1	Mount Simon	2.05	2286	622.6
2	Lloyd Cupp #1-11	Mount Simon	2.29	975	278.6
3	Kalamazoo	Mount Simon	2.55	1220	391.1
4	Kalamazoo	Mount Simon	2.38	2369	736.1
5	Ottawa	Mount Simon	2.36	1761	507.1
6	Ottawa	Mount Simon	2.40	2082	578.4
7	Montague #1	Mount Simon	2.75	3087	900.3
8	Midwest #2	Eau Claire	2.31	2751	697.5
9	Midwest #2	Eau Claire	2.27	2843	743.9

Initial conditions were also specified for reservoir fluid pressure, reservoir temperature, and salinity. Available Mount Simon reservoir pressure data were compiled for the study area. Review of the Mount Simon pressure data showed a clear trend with depth, as may be expected (Figure 3-6). The pressure gradients were generally 0.43 to 0.48 psi/ft in the Arches Province area and increased into the deeper geologic basins where formation fluid is denser. Given this trend, a uniform pressure gradient of 0.45 psi/ft may be suitable for the Mount Simon formation. Fluid density information was also compiled for the Mount Simon. Fluid density shows a similar trend to pressure, with density increasing into the basins. Downhole temperature data were also compiled for the study area to evaluate reservoir temperature variations in the Mount Simon sandstone. Within the study area, data from Indiana, Illinois, Ohio, and Kentucky were analyzed and screened for temperature gradient calculations. Data were evaluated to determine an average temperature gradient for the Arches Province for subsequent application to the regional model. The dataset was comprised of 123 wells which included wells deeper than 2,000 feet located in the established study area. A high degree of data scatter existed within the dataset and therefore the 20 most extreme outliers were removed. Wells that showed the 10 lowest and highest temperature gradients were also removed from the final dataset to account for possible errant data collection. The average temperature gradient of the final dataset was calculated to be 1.02 °F/100 ft.

3.2 Model Framework/Discretization

In the early stages of the project, a general study area was defined that encompassed the Arches Province (Figure 3-7). This large, rectangular area included much of the surrounding geologic basins to delineate regional trends. Consequently, information was collected from areas outside of the final active model area. As the project progressed, the project team decided to delineate the model domain based on a depth to Mount Simon criteria of approximately 2,000 m below ground surface. This effectively eliminated the deeper portions of the basin. High points along the Findlay and Kankakee arches were designated as the approximate limits to the northeast and northwest model domain. The southern limit of the model domain was updated based on mapping completed by the Kentucky Geological Survey, which revised the interpretation of the Mount Simon in Kentucky. The model includes areas in eastern Ohio where the basal sandstone transitions to Conasauga sandstone facies. The model is not meant to indicate the presence of the Mount Simon in eastern Ohio, but the hydrologic interconnection between the Mount Simon formation and the Conasauga sandstones is not well understood. In the end the model showed a general decrease in permeability into eastern Ohio so the facies transition was represented in model parameters.

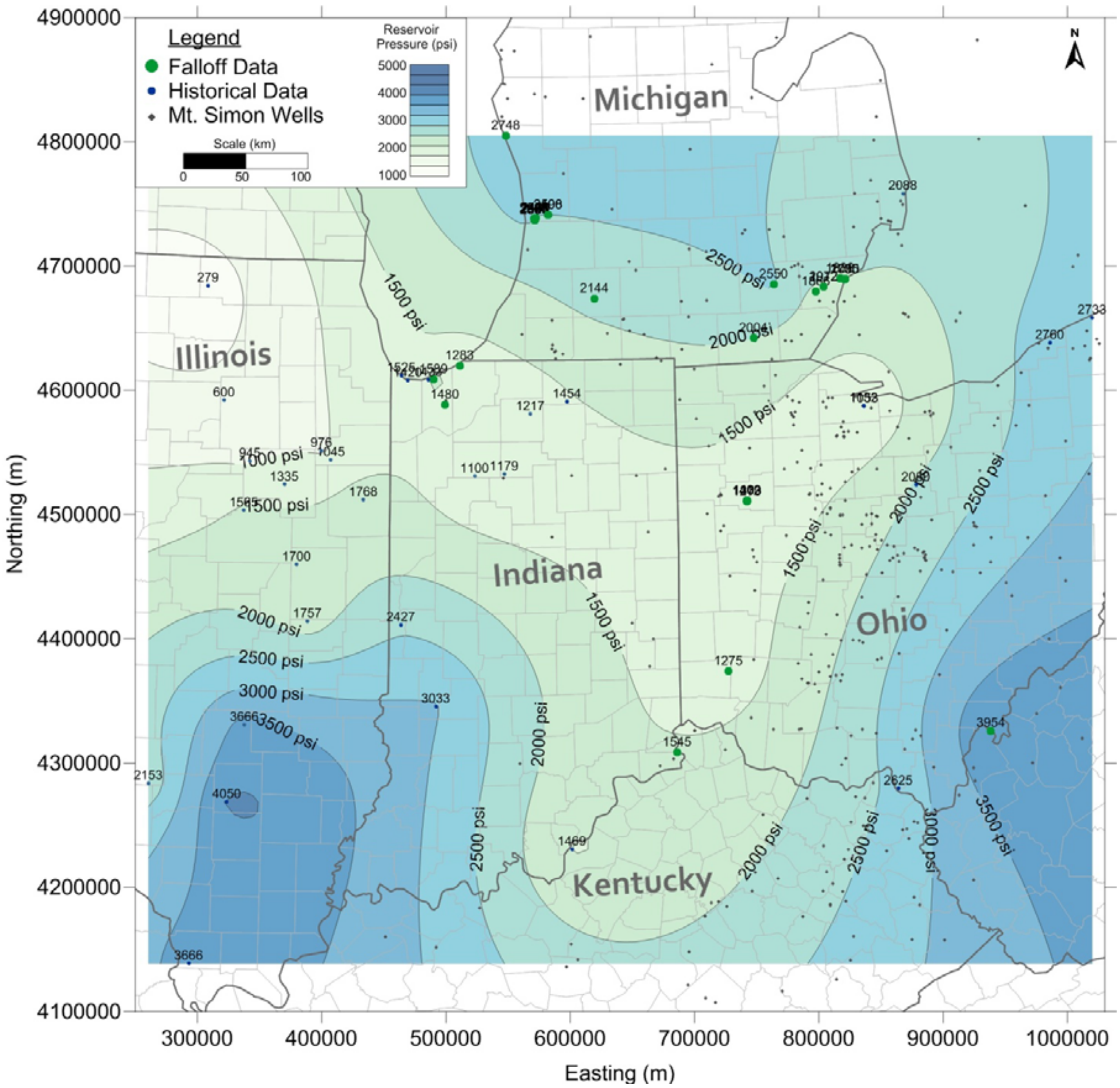


Figure 3-6. Mount Simon Reservoir Pressure (psi)

In the geologic mapping, grid spacing of 5,000 m by 5,000 m was utilized. Total model domain was 700 by 700 km. The 3D porosity grid for the geocellular model was finalized in EarthVision® geologic interpretation and visualization software. The 3D block contains porosity data for the Eau Claire and Mount Simon rock formations. The 3D block was based on 3D gridding of 360,000 porosity data from geophysical log data. The data were gridded in EarthVision® geologic interpretation and visualization software with conformal gridding methods. Conformal gridding is a specialized variation of the minimum tension gridding technique available in EarthVision®. Conformal gridding is designed for cases where a parameter's spatial distribution is related to variations in a surface. The conformal gridding was set to mimic the shape of the top surface grid for the Eau Claire and the bottom surface grid for the Mount Simon. The geocellular model grid covers a total area of 700 by 700 km. X,Y spacing was 5,000 m by 5,000 m in a 140 by 140 grid arrangement. Z-spacing was set at 2 m from 0 to -2,500 elevation. Total grid size was 24,500,000 cells.

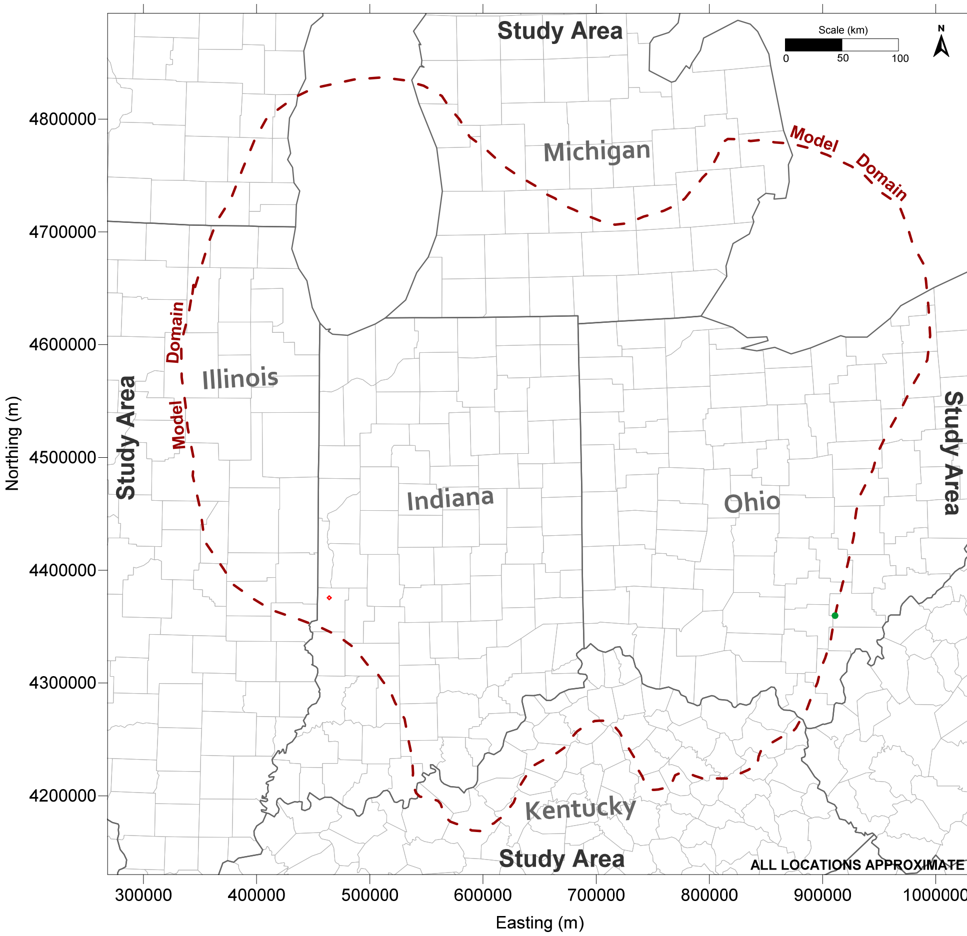


Figure 3-7. Map Showing General Study Area for Arches Simulation Project

3.2.1 Geocellular Model. As part of the conceptual model, a geocellular model was developed for the study area. The geocellular model includes structure, permeability, and porosity distribution for the key hydrostratigraphic units in the model. The geocellular model was based on a combination of geophysical logs, rock core test data, pressure fall-off testing in Mount Simon injection wells, and other geotechnical data (Figure 3-8). These data were analyzed with geostatistics and processed to a 3D grid. The 3D grid contains regularly spaced porosity and permeability values in the study area. These parameters are the primary control on fluid flow and are considered the main input for the numerical simulations. Data for the geocellular model are provided in Appendix C in digital format.

Porosity logs for wells in the Arches Province were compiled to better define hydraulic conditions in the model domain. Best available geophysical porosity logs were compiled for 186 wells that penetrate the Eau Claire and Mount Simon in the study area. Data were compiled into a "X,Y,Z, n" format based on well x-location, y-location, elevation, and logged porosity value. Porosity was based on either sonic, neutron, or density geophysical log data based on the best available data for each well. Logs were analyzed with histograms for each porosity log in a preliminary quality assessment. When the histogram data were anomalous, the log was discarded if no other source of information was available. In those wells with core analyses, logs were calibrated versus porosity from core and corrected for the log value accordingly. If more than one porosity log was available in a well, the best available log was selected based on the hierarchic order as follows: neutron porosity, then sonic, and then density logs. Neutron

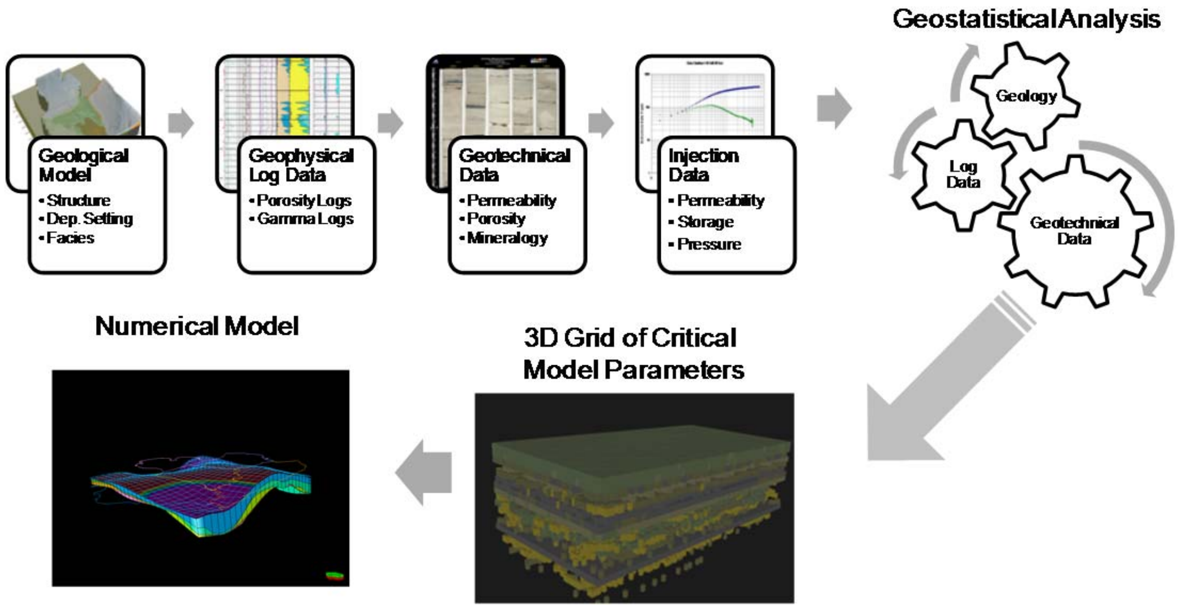


Figure 3-8. Schematic Diagram Showing Geocellular Model Development Process

porosity was estimated as a function of neutron porosity equivalence relationships established for different rock types (Schlumberger, 1972). Porosity was estimated from sonic logs using methods relating transit time (Δt) values to sonic porosity, using charts developed by Asquith and Gibson (1982). Bulk density was transformed to porosity (φ) using a density-porosity formula (Asquith and Gibson, 1982) for matrix densities of common lithologies after Schlumberger (1972). Due to the large number of wells included in the assessment, these methods were not as detailed as more rigorous petrophysical analyses that may be completed on an individual well basis.

The logs provide a fairly continuous estimate on rock porosity with depth. Data were compiled in digital format from the Knox formation to total depth. A total of over 950,000 porosity data points were collected. The data were screened for outliers and classified with indicator parameters based on formation (Knox, Eau Claire, Upper Mount Simon, Middle Mount Simon, Lower Mount Simon, or Precambrian). The porosity data supplement the ~3,700 core test data and 31 injection well pressure fall-off tests. As shown on the map, there are large areas where no data are available because no wells have been drilled into the Eau Claire or Mount Simon.

Porosity data were evaluated with two-dimensional (2D) maps of average porosity in the Mount Simon sandstone interval. Based on evaluation of these data, several wells outside the southern and eastern limit of the Mount Simon sandstone were removed from the dataset because these wells resulted in false indications of reservoir quality in these areas. In addition, some outliers were removed from the dataset because these wells had anomalous porosity values. Figure 3-9 shows estimated average porosity in the Mount Simon sandstone based on the porosity log data. Large portions of the model domain have porosity in the range of 10 to 15%, which matches the central tendency of Mount Simon rock core test results. Porosity generally decreases to less than 5% into the Michigan and Appalachian Basins.

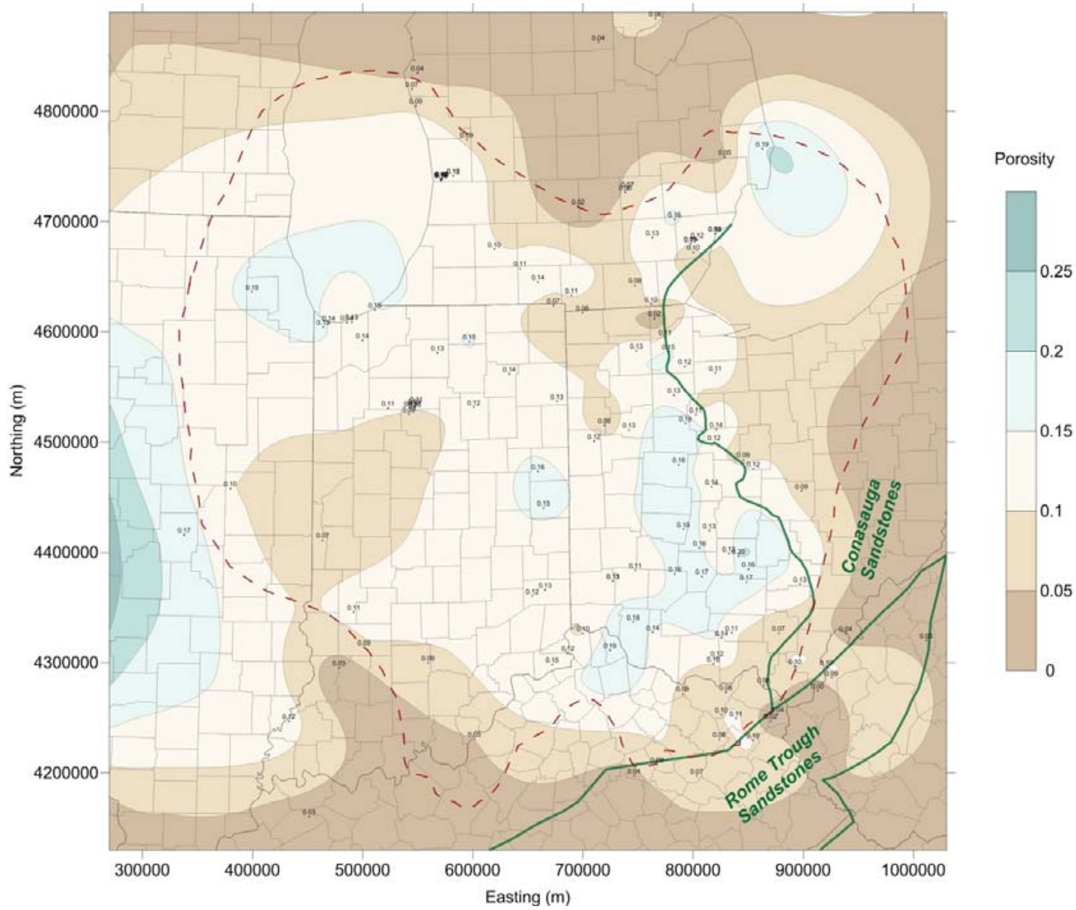


Figure 3-9. Average Porosity in Mount Simon Sandstone Based on Log Data

Geostatistical analysis was completed on the porosity data from the Mount Simon and the Eau Claire rock formations. The goal of the geostatistical analysis was to determine any valid spatial trends in porosity that may reflect reservoir quality in the study area. Analysis was also completed on the Eau Claire formation to determine caprock quality in the Arches Province. Based on porosity log data, geostatistical parameters, and structural boundaries, a 3D grid of porosity was developed throughout the model domain.

The 3D porosity grid for the study area was finalized in EarthVision® geologic interpretation and visualization software. The 3D block contains porosity data for the Eau Claire and Mount Simon rock formations. The 3D block was based on 3D gridding of 360,000 porosity data from geophysical log data. The data were gridded in EarthVision® geologic interpretation and visualization software with conformal gridding methods. Conformal gridding is a specialized variation of the minimum tension gridding technique available in EarthVision®. Conformal gridding is designed for cases where a parameter's spatial distribution is related to variations in a surface. The conformal gridding was set to mimic the shape of the top surface grid for the Eau Claire and the bottom surface grid for the Mount Simon.

The grid covers a total area of 700 by 700 km. X,Y spacing was 5,000 m by 5,000 m in a 140 by 140 grid arrangement. Z-spacing was set at 2 m from 0 to -2,500 elevation. Total grid size was 49,000,000 cells over the Eau Clair-Mount Simon interval. Figure 3-10 shows the porosity model. The Eau Claire is generally lower in porosity, but there are zones where higher porosity is present. This demonstrates that the geocellular model has captured variations within the unit so the Eau Claire is not portrayed as a

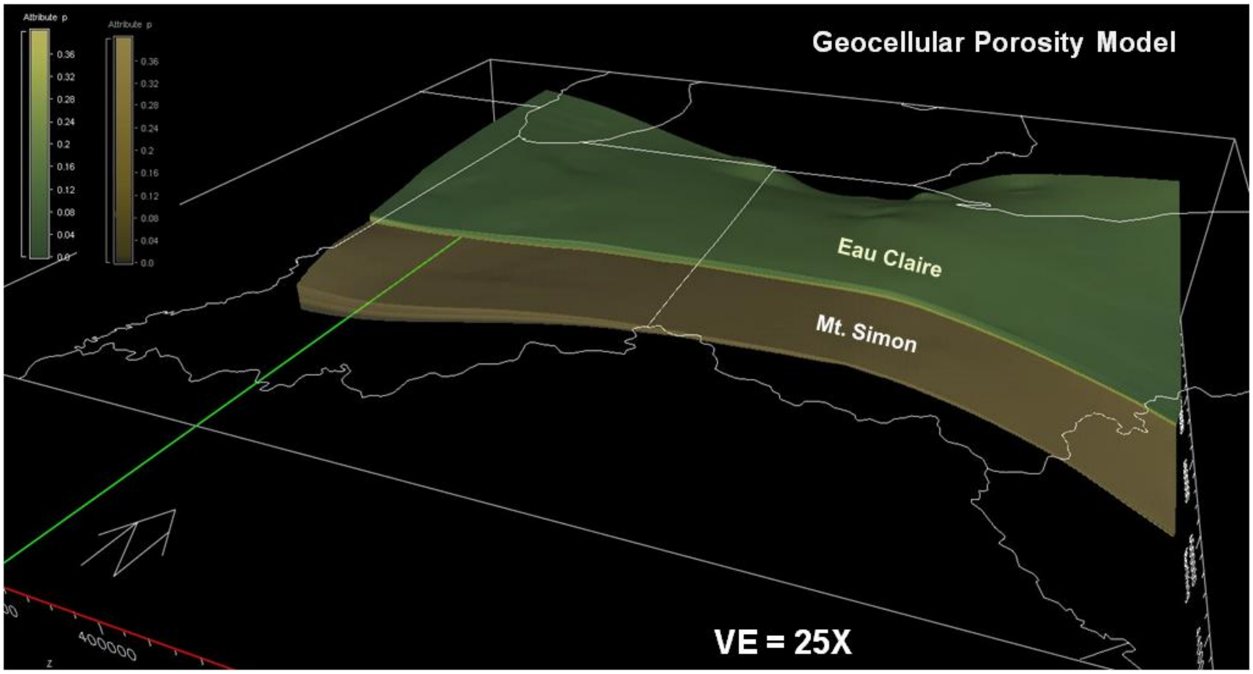


Figure 3-10. Diagram Illustrating 3D Porosity Distribution for Model

uniform confining layer. Average absolute error in the Eau Claire model was 1.8%, indicating suitable prediction of porosity. The Mount Simon includes zones of higher porosity. Some indication of grouping into upper, middle, and lower intervals is apparent. Average porosity of the scattered data for the Mount Simon was 0.14 and the gridded data average was 0.12, suggesting the Mount Simon grid model slightly underestimates porosity. Average absolute error in the Mount Simon model was 1.6%, indicating suitable prediction of porosity.

Porosity–Permeability Transform Estimate

Core data analyses combined with wireline logs for porosity were used to determine if there is a regional trend in porosity and permeability and how these values vary with depth within the reservoir (Medina et al., 2011). This published work along with other studies (i.e., Birkholzer et al., 2008) constitutes the basis for populating the 3D mesh with values according to published data. Vertical variations within the Mount Simon were also evaluated by isolating different trends in porosity/permeability with depth interval. Lateral variations and dividing of the study area into 'subregions' were also assessed to determine if there were regional trends in petrophysical properties of the Mount Simon. This subdivision was based on a shaley unit within the upper unit of the Mount Simon sandstone, which was originally defined in northwestern Indiana as the "B-Cap" (Becker et al., 1978).

The properties assigned to the conceptual geological model for use in the flow simulator were based on the relationship with the properties of the geologic material occurring at the location of each grid cell and porosity and permeability from rock core tests. Several different approaches have been used to represent permeability distribution of the Mount Simon (Figure 3-11). The k-Ø relationship used in this study was described by the exponential equation determined by Medina et al. (2008):

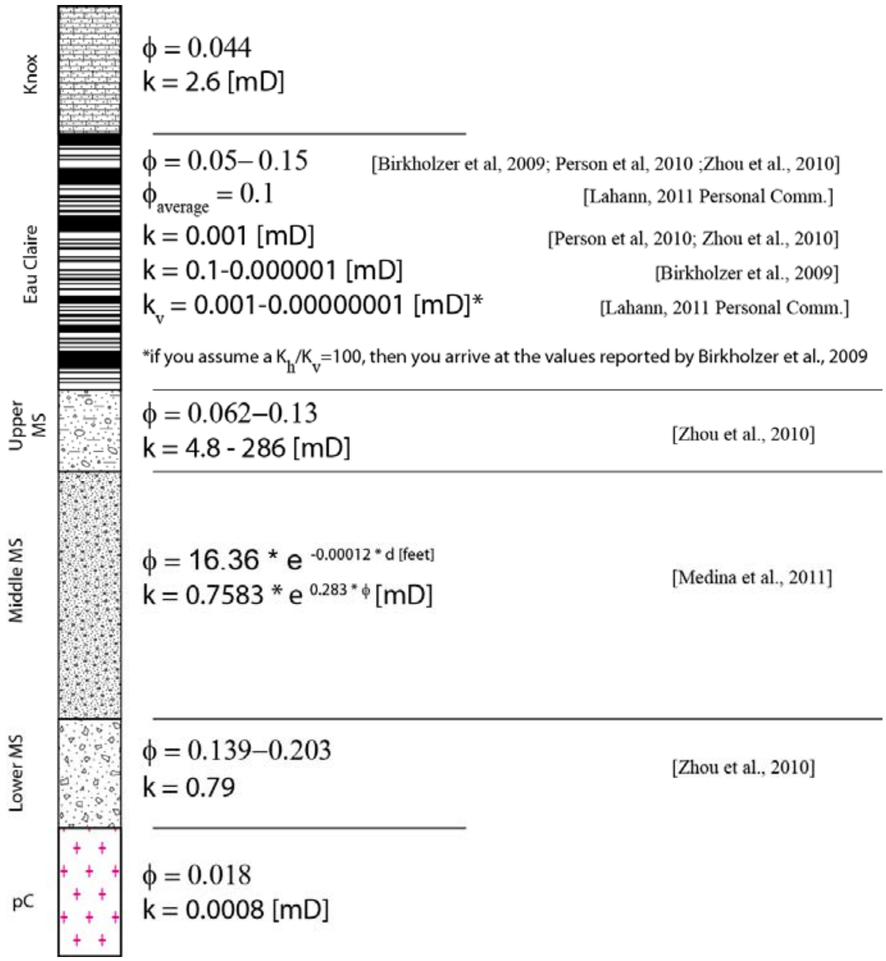


Figure 3-11. Ranges of Values for Porosity and Permeability Within the Eau Claire and Mount Simon Formations (pC=Precambrian; MS=Mount Simon sandstone)

$$k(\emptyset) = 0.7583 * e^{0.283*\emptyset}$$

where k is permeability in millidarcies (mD) and Ø is porosity (percent). This equation was based on the curve fit of 3,800 rock core porosity and permeability results from the Mount Simon. Since permeability can vary across many orders of magnitude, there is a fair amount of uncertainty in these types of equations. However, as described earlier, much of the 3D porosity model has a porosity of 15%. As such, most of the resulting permeability transform model is near 70 mD.

Eau Claire permeability distribution is even more problematic because shale lithology may have relatively high porosity but very low permeability. Approximately 300 core test porosity and permeability data were evaluated from the Eau Claire formation for this study. Rock core tests show very poor correlation of porosity to permeability for the unit. Many of the tests were below detection limits for permeability, which makes interpretation difficult. Overall, these data suggest average porosity of 4.3% and permeability of 1.2 mD. However, the median permeability is 7.6E-5, suggesting there are several high outliers in the Eau Claire dataset. Based on the k-Ø relationship of this Eau Claire data, the following exponential equation was used for porosity-permeability transform for the Eau Claire interval:

$$k(\emptyset) = 0.000226 * e^{37.27*\emptyset}$$

where k is permeability in millidarcies (mD) and ∅ is porosity (percent). This equation is a very general relationship. A more detailed evaluation of Eau Claire confining layer properties should be completed for site-specific CO_2 storage applications.

Injection Well Reservoir Test Permeability Correction Factors

A method was developed to normalize 3D permeability grid to pressure fall-off and rock core test data. The method involves transforming the 3D porosity grid to a permeability 3D grid, based on the best available method for estimating permeability from porosity (Patterson, 2011). The preliminary 3D permeability grid was then normalized by multiplying the initial permeability data by a correction factor. The correction factor basically normalizes data to the pressure fall-off and core test data, thereby providing the most accurate permeability distribution.

The availability of wireline log data (i.e., porosity data) for the Mount Simon in the Arches Province far surpasses that of available pressure fall-off data, which determine the bulk reservoir permeability. However, the log-derived (i.e., transformed) permeability data often under represented permeability values throughout the study area, with respect to fall-off data. For this reason, a correction factor was used to calibrate the log-derived permeability dataset to create a 3D permeability block. Reservoir permeability is a key input in the geocellular model for controlling darcy flow in a porous system. The permeability transform equation used to transform log porosity data into permeability is discussed in the previous section.

Unfortunately, the accuracy of a simple transformation of porosity to permeability decreases over large geographic distances and larger datasets with more scatter. For this reason, the 3D permeability block derived from wireline logs (i.e., transformed) was corrected using the correction factor f_{corr}, which is the ratio of permeability data derived from pressure fall-off data to those derived from the porosity-permeability transform. The result is a corrected 3D permeability volume throughout the study area that reflects the completeness of the wireline log data as well as the operational accuracy of the fall-off data.

$$f_{corr} = k_{PFO}/k_{LOG}$$

where k_{PFO} = pressure falloff permeability value

k_{LOG} = permeability transform (from porosity) value

$$k_{corr} = k_{LOG} * f_{corr}$$

Table 3-5 provides the number of wells used in determining the correction factor for both the pressure fall-off and log porosity data. Core data analyzed in the Arches Simulation Project were used to determine the maximum permeability cutoff for the corrected porosity-permeability transform data. That is, the maximum measured permeability from core was 1710 mD; therefore, the upper permeability limit for the corrected data was designed not to exceed this threshold. A total of 137 wells existed in the study area, the Mount Simon, and the average corrected permeability, by well, for these data was 69.1 mD.

To develop the final 3D permeability grid, the geophysical log porosity dataset was transformed to initial permeability values. These data were then corrected with correction factors extracted from the injection well reservoir test permeability correction factor grid. This final set of permeability data represents permeability corrected with injection well information. The permeability data were capped at 1710 mD because this represents the maximum observed permeability from rock core tests and reservoir tests in the

Table 3-5. Type of Data and Number of Wells Used to Determine the Permeability Correction Factor (f_{corr})

Data Type	Number of Wells	Average Permeability Value (mD)
Pressure Falloff	21	61.9
Log Porosity	172	49.5

Mount Simon. Consequently, it is unrealistic to include permeability zones greater than this value in the permeability model. The corrected permeability data were transformed into log values and gridded in EarthVision® with conformal gridding methods. The conformal gridding was set to mimic the shape of the top surface grid for the Eau Claire and the bottom surface grid for the Mount Simon.

Figure 3-12 shows the 3D permeability model visualization in EarthVision®. Similar to the porosity grid, the model exhibits vertical layering and broad lateral trends in permeability. However, permeability varies across several orders of magnitude. For the final Eau Claire grid, the average absolute error in the model was 1.6%, indicating suitable prediction of permeability. The Log average of the scattered permeability input data was -1.3 and the gridded mean was -1.6, indicating the grid slightly underestimates Eau Claire permeability. Average absolute error in the Mount Simon model was 1.6%. The Log average of the scattered permeability input data was 1.6 and the gridded mean was 1.2, indicating the grid also underestimates Mount Simon permeability. However, this variation is the result of some large areas in the corners of the model where permeability is low but few data points are present.

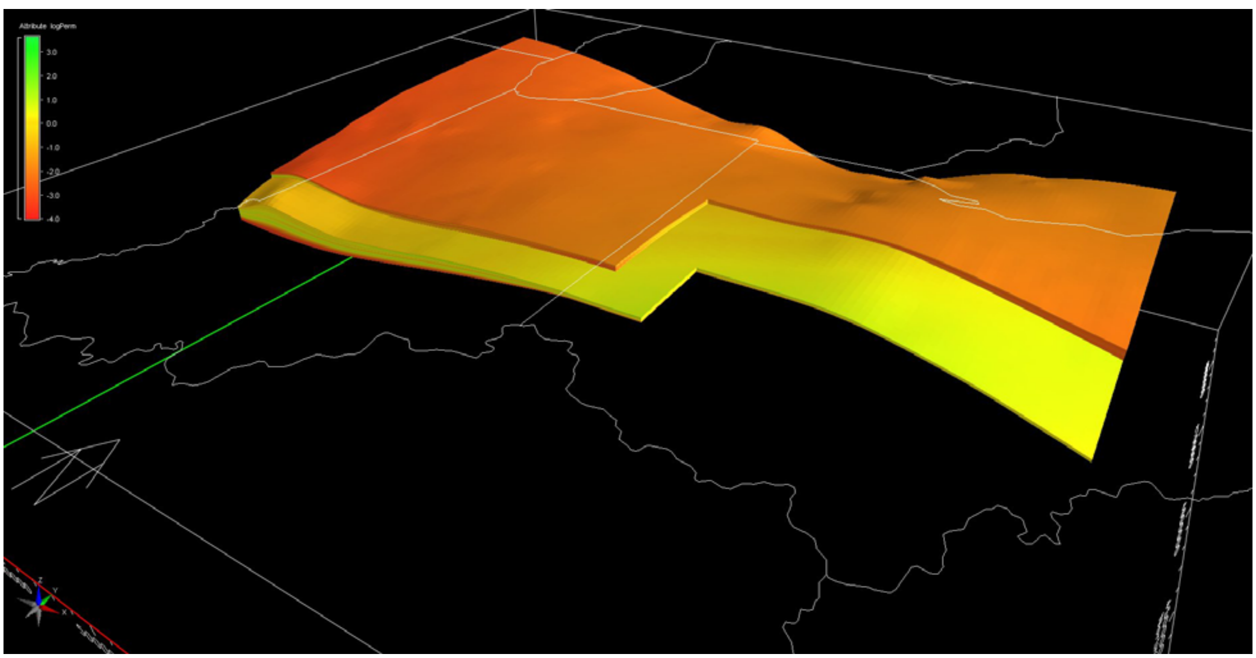


Figure 3-12. 3D Permeability Model (log K [mD]

3.2.2 Model Scenarios. CO_2 injection scenarios were developed for the numerical simulations. These scenarios include injection locations, rates, and schedules. The scenarios were based on review of CO2 sources in the Arches Province region and pipeline routing analysis.

Model scenarios were based on large CO_2 point sources in the study area and a pipeline routing study. The distribution of large CO_2 point sources was analyzed for the Arches Province. Data on CO_2 point sources were obtained from the U.S. DOE Carbon Atlas database (2008). Review of these sources suggests that there are approximately 131 point sources in the area with emissions greater than 100,000 metric tons CO_2 per year (Figure 3-13). These sources have combined emissions of 286 MMT CO_2 per year. There are 53 point sources with emissions over 1 MMT per year which have total emissions of 262 MMT CO_2 per year. To reduce greenhouse gas emissions in the Arches Province by 25 to 50%, CO_2 storage projects with total storage rates of 70 to 140 MMT CO_2 per year would be necessary. The study also suggests that a pipeline distribution system would be required, since few sources are located in the central portion of the Arches Province.

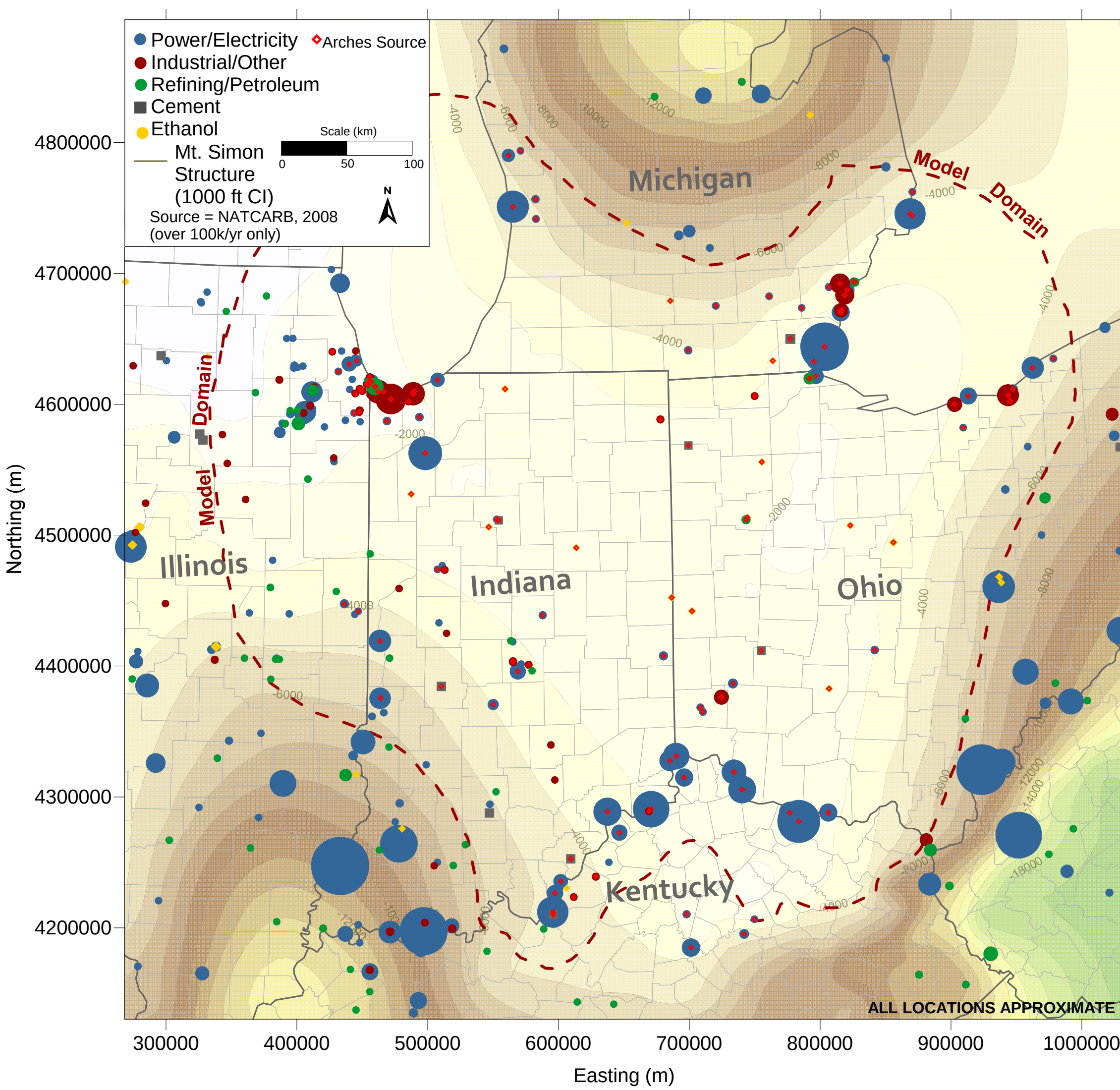


Figure 3-13. Distribution of Large CO_2 Point Sources in the Arches Province

Based on this source distribution, it was determined that on-site injection and regional storage field injection would be most useful for evaluating CO_2 storage potential in the Arches Province. The on-site scenario addresses whether it is feasible to implement CO_2 storage at the source locations, which is generally considered the most cost effective option for facilities. The regional storage scenario assumes a pipeline distribution system to transport CO_2 to regional storage fields with more suitable geology. Based on 25% to 50% reduction in emissions, or injection rates of approximately 70 to 140 MMT CO_2 per year, seven regional storage fields were considered for model scenarios. Each field would need to inject at a nominal rate of 10-20 MMT CO_2 per year.

The regional storage field scenario assumes that a pipeline distribution system will be constructed to transport CO_2 from sources to regional CO_2 storage fields. The regional scenario considered seven storage fields, each injecting at total rates of 10 to 20 MMT CO_2 per year. These fields will contain several wells to facilitate these injection rates. Separate scoping level simulations were completed to determine the most appropriate arrangement of injection wells in the storage fields. To determine geographical location of potential storage fields, a pipeline routing analysis was completed for the sources in the Arches Province.

3.3 Code Modification & Debugging

Most of the code modification and debugging was performed in association with STOMP model runs. STOMP is an evolving code maintained by Pacific Northwest National Laboratory. There are several versions of the program for different applications. During the Arches Province project, the parallel version of the code was developed, which allowed faster model runs for large problems. The Arches Simulation basin-scale model provided a test bed for the parallel version of the code. Most other code debugging was focused on addressing input data and numerical solution issues.

3.4 Code Verification/Comparison

A code verification/comparison exercise was performed assessing options for improving numerical performance for model runs. TOUGH2-MP/ECO2N, CMG-GEM, STOMP, MODFLOW-SEAWAT, ECLIPSE simulation models were evaluated for capabilities to simulate basin-scale CO_2 storage. TOUGH2, CMG-GEM, STOMP, and ECLIPSE were all verified in a model intercomparison study (Pruess et al., 2002). At the time the project started, STOMP had been applied to several CO_2 storage field sites and appeared the most flexible for evaluating basin-scale processes. MODFLOW-SEAWAT appeared to offer the quickest computational solutions, but it did not simulate multiple phase processes. In the end a combination of models was selected for the project. MODFLOW-SEAWAT was selected for preliminary, variable density, single phase simulations aimed at evaluating model input parameters and boundary conditions. STOMP-CO2 was selected for a series of 2D radial scoping level simulations with the purpose of investigating injection field arrangements. CMG-GEM was selected to assess geomechanical issues. Finally, STOMP-CO2 was also selected for the basin-scale simulations.

Adaptive mesh geometry, massively parallel processing, and other numerical solution schemes were evaluated for the code comparison. The exercise determined that Carter-Tracy boundary conditions would be the most feasible option for increasing numerical efficiency in STOMP. Based on convolution of unit-step response functions, Carter-Tracy boundary conditions offer a simple but approximate method for embedding an inner region of flow simulation within a much larger aquifer region where flow can be treated in an approximate fashion. This approach is used in many reservoir simulators for modeling water movement across an external boundary in response to pressure perturbations. It was determined that this option would be useful for reducing the size of the model domain in CO_2 storage related simulations (since no numerical simulation of far-field pressure changes and brine displacement would be required any more). However, it was not possible to incorporate Carter-Tracy conditions into STOMP-CO2 code in time for the project.

Model input parameters used for other simulations of the Mount Simon (Wiese, 2010; Person et al., 2010; Birkholzer et al., 2008; Zhou et al., 2009; Ghaderi et al., 2009; Eberts and George, 2000; Gupta, 1993) were tabulated. These previous modeling efforts provide a range of typical parameters necessary for simulations. They also provide guidance on model setup and numerical solution issues.

Flow budgets were reviewed to provide additional calibration on model results. Flow budgets were calculated with the variable density MODFLOW-SEAWAT model discussed in Chapter 3. Results of the flow budget calculations were compared with work by Eberts and George (2000). Eberts and George present a hydraulic budget analysis based on groundwater flow modeling for an area similar to the Arches Province. Their study included surficial aquifer, surface water bodies, and the carbonate-rock aquifer. The carbonate-rock aquifer includes Mississippian-Silurian age rocks. While it is not directly equivalent to the layers simulated in the Arches Province model, the Eberts and George analysis does provide a measure for comparison on flow budgets. In general, the models should have somewhat comparable flow budgets. Table 3-6 summarizes the simulated flow budgets from the Arches Province baseline simulation (with no pumping) and the carbonate-rock aquifer regional flow system from the Eberts and George study. The Arches Province baseline SEAWAT simulation indicates total flow in and out of the system of 372 million gallons per day (gpd), which compares to Eberts and George's budget of 386 million gpd for the bedrock-carbonate aquifer. Given the uncertainty on fluid flow in these deep environments, the flow budget analysis provides additional confidence in model setup.

Table 3-6. Comparison of Flow Budgets for Arches Province Simulation and Eberts and George Regional Aquifer System Analysis for Midwestern Basins and Arches

Simulation	Interval	Model Domain	Total Flow (Mgal/d)
Arches Simulations (no injection)	Knox-Precambrian	700 x 700 km	372
Regional Groundwater Flow in the Basins and Arches Aquifer System (Eberts and George, 2000)	Bedrock-Carbonate Aquifer (Mississippian-Silurian)	400 x 440 km	386

Mgal/d = million gpd

Flow vectors were also used to verify and compare simulation results. Flow vectors represent the simulated direction and magnitude of flow within model cells. The flow vectors were determined in the SEAWAT model. Flow vector directions suggest flow from the basins into the center of the Arches Province. The model generally suggests very minor flow in the Eau Claire and the Precambrian layers. Model results show the average simulated flow velocity in the Mount Simon is 67 cm/yr. In general, this flow rate agrees with previous studies on the Mount Simon (Gupta and Bair, 1997), which suggest flow rates in the formation are on the order of 1 meter per year or less. The model suggests the flow rate in the Eau Claire and Precambrian layers is less than 1 cm/yr.

Section 4.0: PRELIMINARY VARIABLE DENSITY FLOW MODEL SIMULATIONS

The objective of the variable density modeling task was to evaluate model input for the full basin-scale simulations. Overall, the variable density modeling was intended as an intermediate step to more complex simulations. The single-phase simulations were performed with variable density groundwater flow computer codes. These codes simulate brine flow and variable density effects. The models do not account for multi-phase behavior related to supercritical CO_2. Therefore, the models have limitations. However, the models allow rapid numerical solutions, and many different model iterations can be evaluated to determine a suitable model setup. By porting the single-phase flow simulation results to the multi-phase model, the modeling process will be streamlined and more effective. The initial models were designed to assess boundary conditions, calibrate to reservoir conditions, examine grid dimensions, evaluate upscaling items, and develop regional storage field scenarios. The models also allowed review of the translation of the geocellular model into numerical flow models. The task also provided practical information on items related to CO_2 storage applications in the Arches Province such as pressure buildup estimates, well spacing limitations, and injection field arrangements.

4.1 Variable Density Model Setup

The single-phase flow simulations were completed with the computer codes MODFLOW (McDonald and Harbaugh, 1988) and SEAWAT (Langevin et al., 2007). MODFLOW is a modular finite-difference flow model computer code designed to simulate the flow of groundwater through aquifers. The code was developed by the Unites States Geological Survey (USGS) and is well accepted for scientific and industrial applications. The code is based on solution of the partial differential equation for fluid flow in three dimensions. The modular nature of the program has allowed addition of many specialized modules. Because the code does not simulate multiple-phase behavior of CO_2, MODFLOW has not been frequently used to simulate CO_2 sequestration. However, the code solves the same fundamental Darcy equation of fluid flow as other computer codes. Nicot et al. (2009) applied MODFLOW to investigate pressure buildup and fluid migration issues related to CO_2 sequestration operations in aquifer systems in the Texas Gulf Coast. The single-phase flow simulations in this project follow a similar process and objectives.

SEAWAT is a MODFLOW-based computer program designed to simulate variable density groundwater flow and solute transport. The program has been used to assess issues related to brine migration in aquifers and saltwater intrusion. The SEAWAT code simulates variable density flow processes based on numerical equations which account for relative density difference terms, solute mass accumulation terms, and conservation of mass. The main advantage of the SEAWAT code is that it provides a proxy for upward migration of CO_2. The code may also provide some indication of the CO_2 injection plume by way of solute proxy.

There are limitations related to simulating CO_2 storage with the SEAWAT program. The program does not address multiple-phase processes related to supercritical CO_2 and brine mixtures. The program does not address the low viscosity properties of super critical CO_2 injected into the rock formations. CO_2 dissolution into brine is also not accounted for in the code. The models do not have the capacity to completely model density changes of CO_2 related to temperature/pressure conditions. However, pressure and flow away from the CO_2/brine interface may be accurately portrayed by the codes. In addition, the model has the capability to accommodate complex arrangements of permeability, fluid density, boundary conditions, and other parameters. Consequently, the single-phase SEAWAT simulations are useful for examining overall model input and setup.

The MODFLOW/SEAWAT codes represent fluid heads in terms of head elevation because aquifers are typically monitored in relation to water level elevation. Conditions in deep reservoirs are typically measured in pressure units of psi. To allow easier comparison with observed pressure in the Mount Simon sandstone, the results of the MODFLOW/SEAWAT simulations were converted into pressure based on average pressure gradient in the Mount Simon. This conversion equates 70 m head to approximately 100 psi.

The numerical model was developed in MODFLOW/SEAWAT using a modeling package. Table 4-1 summarizes the final model input parameters. The model was specified with six layers from the Knox to the Precambrian formations (Figure 4-1). The Knox layer was included as a blank layer to assist in analysis of flux across layers. The Mount Simon was represented by three layers to depict upward migration of low density fluid. The model was run in transient mode for 36,500 days, which allows for injection and post-injection periods. To facilitate numerical solution, cells in areas where the Mount Simon is greater than approximately 2,100 m deep were designated as inactive (Figure 4-2). Several model iterations were completed to determine appropriate model setup. During model development, it was determined that higher grid resolution around injection wells was necessary to facilitate accurate model solution near the injection wells.

The Knox and Precambrian layers were specified as homogeneous permeability distributions. The Eau Claire was specified as a variable permeability distribution based on the average values across the formation in the geocellular model. The Mount Simon layers were also given a variable permeability distribution based on average values across the formation in the geocellular model. The same permeability distribution was assigned for all three Mount Simon layers in the model. Uniform porosity and storage parameters were input for each model layer.

Several different boundary condition arrangements were evaluated during model development. Overall, the boundary conditions were assigned based on the reservoir pressure map for the Mount Simon prepared as part of the conceptual model. The boundary conditions were input to match this pressure distribution and limit their influence in the central portion of the model. The effects of several different boundary condition arrangements were examined in the SEAWAT model. The final model was calibrated to Mount Simon pressures based on specified heads in the western and eastern edges of the model. The model was set up with no flow boundaries in the northeast and southern areas. A zone of specified heads was also assigned in the central portion of the study area in the Knox layer to allow calibration. These boundary conditions were generally similar to previous work by Gupta and Bair (1997) and other simulation projects for the Illinois basin (Clifford, 1973; Person et al., 2010; Zou et al., 2010).

Three main scenarios were simulated with the SEAWAT model: (1) no injection baseline, (2) seven regional injection sites, and on-site injection (Figure 4-3). The regional storage field scenario was based on the seven sites identified in the pipeline routing study completed in earlier portions of the project. The scenario assumes that a pipeline distribution system will be constructed to transport CO_2 from sources to seven regional CO_2 storage fields. These locations are fairly arbitrary. Several other locations may be feasible for regional storage fields. However, the seven locations do represent coverage across the Arches Province. The on-site injection scenario addresses point sources with emissions greater than 1 MMT CO_2 per year. These 53 sources account for 91.6% of point source emissions in the Arches Province. The sources are mostly clustered along the Great Lakes coastline and Ohio River Valley, which generally do not have the most appealing geologic setting for CO_2 storage. Scenarios were run for injection of 25% and 50% of each sites' total emissions. The injection period was set at 20 years.

Table 4-1. Variable Density Simulation Input Parameters

Parameter	Value	Comment
Flow model	MODFLOW/SEWAT	MODFLOW 2000, transient simulation, total simulation time = 36,500 days (100 years)
Domain	700 x 700 km	Inactive cells specified in areas where Mount Simon is greater than 2,100 m deep or not present
Rows	163 - 262	Resolution increased near wells for injection scenarios
Columns	144 - 244	Resolution increased near wells for injection scenarios
Grid Spacing	10,000 × 10,000 m to 500 × 500 m	Variable grid spacing with grid increased grid resolution increased near injection wells
Layers	6	Variable thickness based on structure maps: Layer 1 = Knox Layer 2 = Eau Claire Layer 3 = Mount Simon (upper 1/3) Layer 4 = Mount Simon (middle 1/3) Layer 5 = Mount Simon (lower 1/3) Layer 6 = Precambrian
Permeability	Constant value for layers 1 and 6 Variable distribution for layers 2-5	Layer 1 (Knox) = 2.6 mD Layer 2 (Eau Claire) = based on geocellular model Layer 3-5 (Mount Simon) = based on geocellular model Layer 6 (Precambrian) = 0.0008 mD
Porosity	Constant value for layers 1 and 6 Variable distribution for layers 2-5	Layer 1 (Knox) = 0.044 Layer 2 (Eau Claire) = based on geocellular model Layer 3-5 (Mount Simon) = based on geocellular model Layer 6 (Precambrian) = 0.018
Bulk Compressibility	Constant value for layers 1-6	2E-6 1/m
Boundaries	Constant head, no flow	Constant head nodes specified at E, N, and W edges No flow boundary specified at southern boundary Constant head specified in central portion of Knox
Solution Parameters	WHS, head change criterion = 0.001	<0.01% volumetric budget error
Transport model	SEAWAT	Salinity proxy for CO_2
Reference Fluid Density	1,100 kg/m^3	Constant distribution
Reservoir Temperature	Not applicable	Not an input parameter in SEAWAT
Source Term	Constant Concentration Source	Low density salinity proxy for CO_2

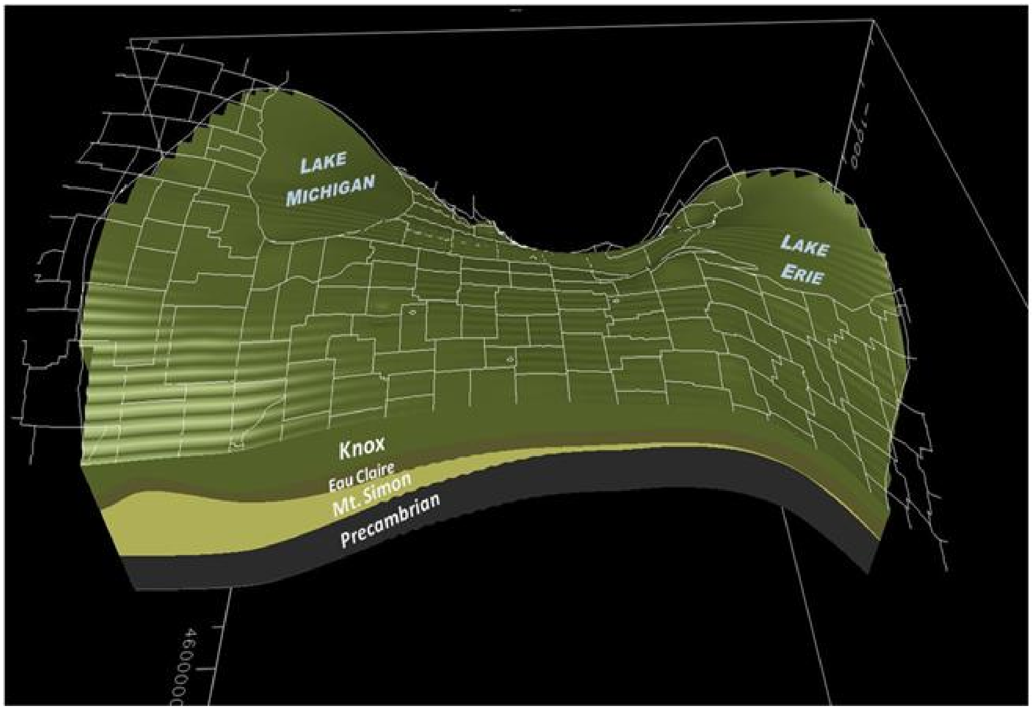


Figure 4-1. SEAWAT Layers

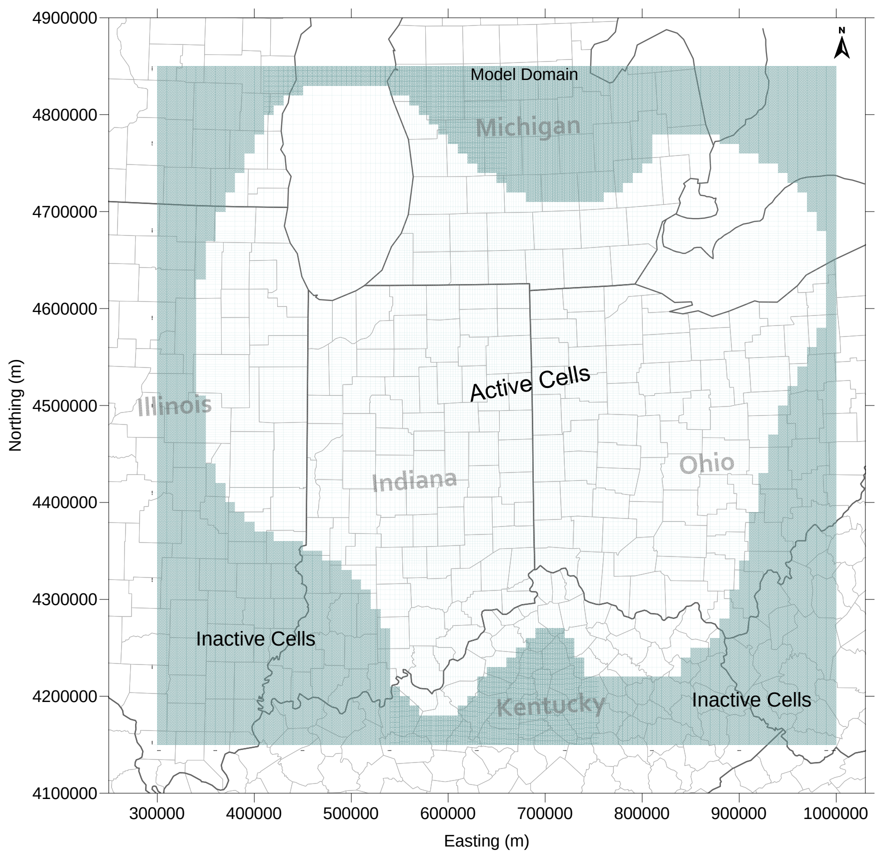


Figure 4-2. SEAWAT Model Domain and Grid

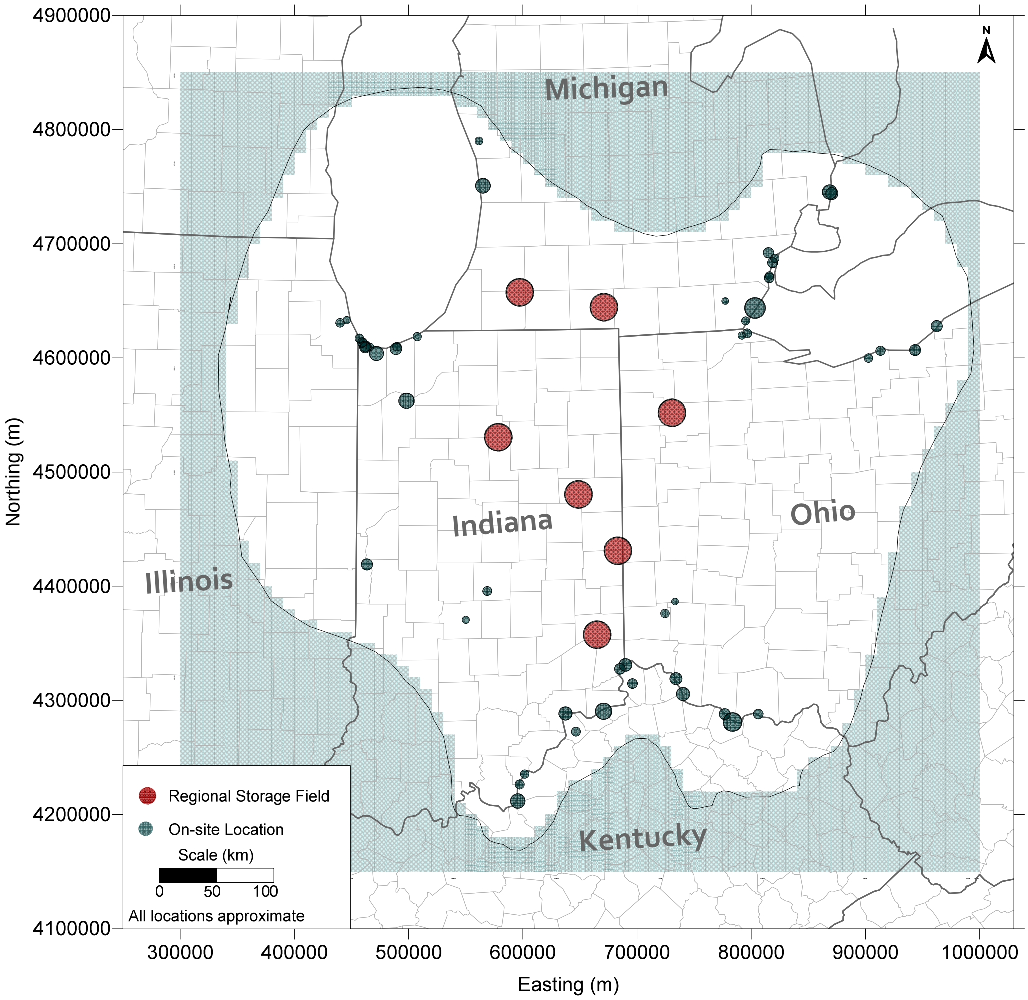


Figure 4-3. On-Site and Regional Injection Field Scenario Location Map

4.2 Results

Three main scenarios were evaluated with the SEAWAT model. The no-injection baseline model was employed for calibration, flow budget analysis, flow vector review, and sensitivity analysis. Regional injection and on-site injection scenarios were analyzed for pressure buildup and fluid migration.

Baseline Scenario- The objective of the baseline simulation was to replicate initial conditions in the Mount Simon and Eau Claire hydrologic system. The baseline scenario was specified with no injection. The model was calibrated to reservoir pressure in the Mount Simon as delineated in wells that penetrate the formation. Generally the baseline model showed a stable numerical convergence, with less than 0.01% volumetric budget error. Figure 4-4 shows simulated heads for the baseline model. As shown, the model matches the overall pressure distribution observed in the Mount Simon sandstone. The model slightly overestimates reservoir pressure in the south-central portion of the model domain.

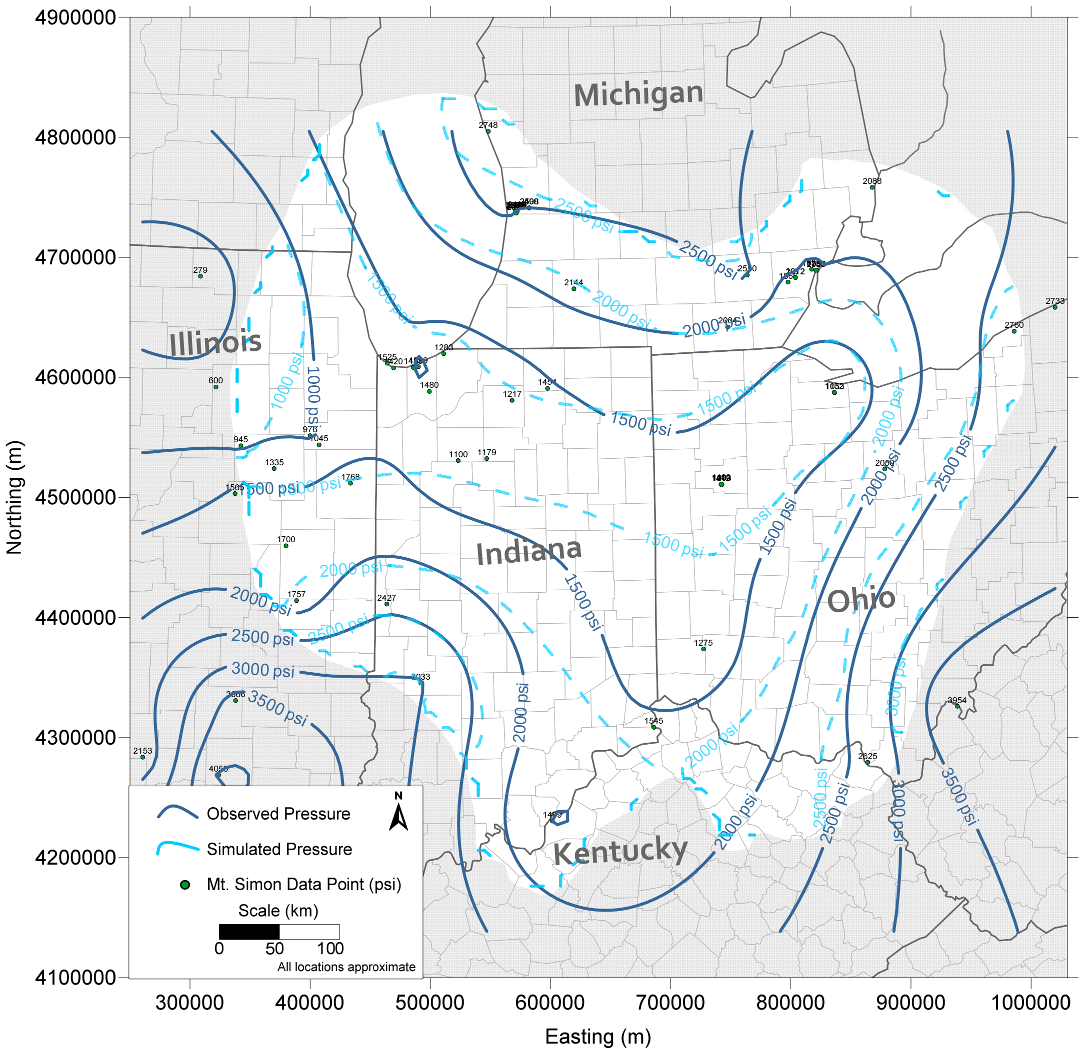


Figure 4-4. Calibration Map for SEAWAT Model Showing Observed vs. Simulated Pressure in the Mount Simon Formation

Model calibration statistics were calculated for the baseline run in comparison to observed pressures in 54 wells within the model domain. A plot of observed versus simulated pressure shows a satisfactory fit with a correlation coefficient of 0.93. The route mean squared error was approximately 354 psi and standard error was 44 psi. This may seem large, but given the pressure range in the simulated area, the normalized route mean square error is only 10.9%. A sensitivity analysis was also completed to examine model stability. The sensitivity analysis focused on the permeability of the Mount Simon because this input parameter has the greatest impact on simulation results. The permeability distribution in the Mount Simon was scaled by a factor of 0.2X, 0.5X, 2X, and 5X. Calibration statistics were produced for each simulation run. Figure 4-5 shows a plot of sensitivity factor versus calibration statistics for the sensitivity runs. As shown, error increases away from the baseline input. There is less sensitivity to the lower permeability scaling factor. Overall, the sensitivity analysis suggests the model has a stable solution and suitable permeability distribution.

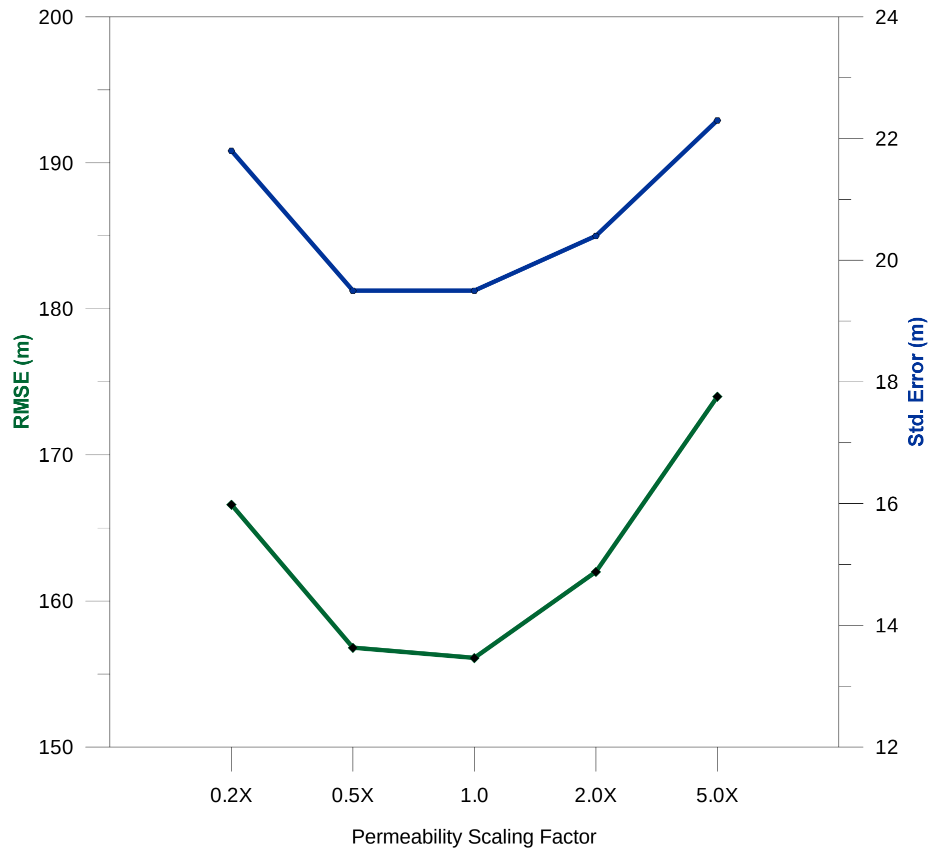


Figure 4-5. Sensitivity Plot for 0.2X to 5.0X Permeability Scaling Factors

Regional Storage Field Scenario- Regional storage scenarios were run with the SEAWAT model to assess pressure buildup and fluid migration due to large injection volumes. The SEAWAT simulations do not simulate super-critical CO_2 fluid. The models can only simulate low density water as a proxy for CO_2. In addition, the SEAWAT model has simplified grid spacing, layering, and injection well depiction. However, the simulations do provide guidance on basin-scale pressure buildup due to large-scale injection in the Mount Simon sandstone.

The regional storage field scenarios were run in transient mode in SEAWAT. Single injection wells were specified at the seven regional storage field locations. Injection rates of 1.0 MMT per year to 3.0 MMT per year were simulated. Wells were screened across the entire Mount Simon thickness. Injection rate was converted from CO_2 to water on a volumetric basis assuming CO_2 density of 0.7 kg/l. Based on this conversion, an injection rate of 1.0 MMT CO_2 per year equates to 700 gpm or 3,816 m^3/day. Injection was run for 20 years, followed by an 80-year post-injection period. In examining the model results, it was determined that increased grid spacing was necessary to obtain suitable numerical solutions. Grid spacing was increased to 500 m by 500 m near the injection wells.

Figures 4-6 and 4-7 show simulated pressure buildup for the region. The pressure buildup was calculated by subtracting the simulated pressure field under no-injection conditions from the simulated pressure field with injection. Pressure buildup is based on model layer 4 at the end of the 20-year injection period (middle Mount Simon). As shown, pressure buildup increases with increasing injection. There is some indication of well interference for the southern three injection wells. The radius of pressure

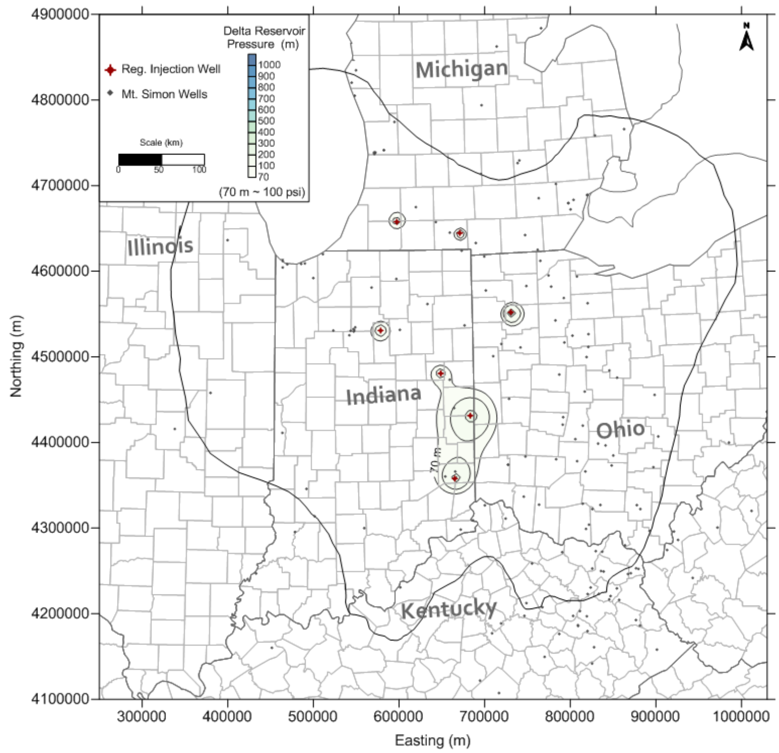


Figure 4-6. SEAWAT Simulated Delta Pressure 7 × 1.0 Million Metric Tons/y per well [7 Mt/yr total injection]

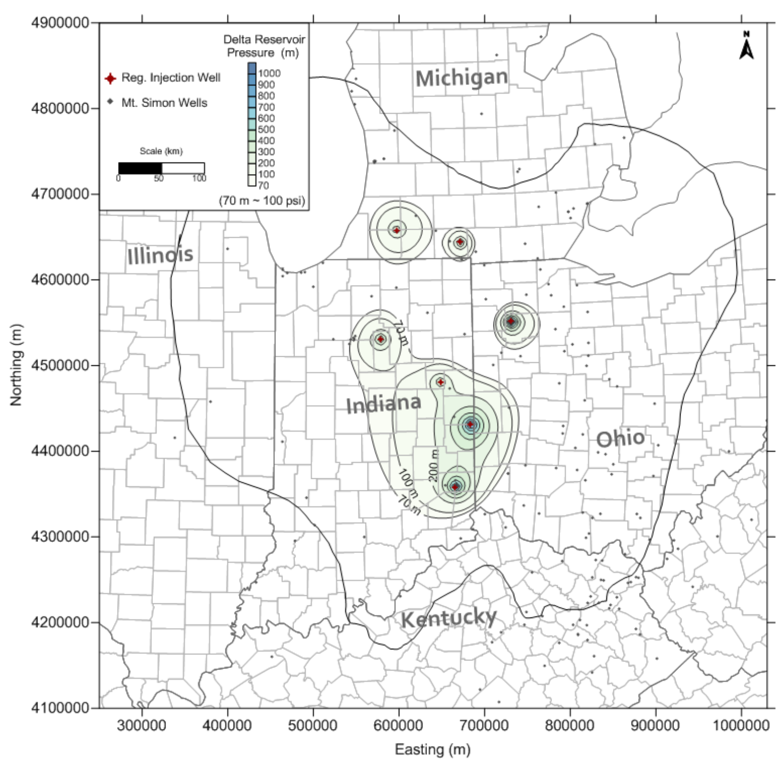


Figure 4-7. SEAWAT Simulated Delta Pressure 7 × 3 Million Metric Tons/y per well (21 Mt/yr total injection)

buildup is on the order of 10 to 50 km for lower injection scenarios and 50 to 200 km for the larger injection scenarios. In general, these results are very similar to other modeling studies on the Mount Simon in the Illinois basin (Zou et al., 2010), which suggest that operation of many large-scale injection fields would produce an area of pressure buildup covering several thousand square kilometers. The scenario for injection rates over 3.0 MMT CO_2 per year indicate pressure buildup in the injection wells would exceed 1000 psi, which would likely exceed rock fracture pressure limits imposed by UIC regulations. Furthermore, injection rates over 3.0 MMT per year in a single well would be difficult to implement due to flow limitations for injection tubing and well sizes. Therefore, it appears that multiple injection wells would be required to facilitate higher injection volumes.

On-Site Injection Scenario- On-site injection simulations were run with the SEAWAT model to assess pressure buildup and fluid migration due to injection at the source locations in the Arches Province. The SEAWAT simulations have the same limitations discussed in the regional storage field scenarios. Table 4-2 summarizes the on-site simulations. For the on-site scenarios, injection wells were specified at the location of 50 sources located in the active model area (note: two sources considered in an earlier source assessment were not located in the active model area). These sources have annual CO_2 emissions greater than 1 MMT CO_2 per year. Scenarios of 10%, 25%, 50%, and 100% of each source's total emissions were run with the SEAWAT model.

Table 4-2. SEAWAT On-Site Injection Scenarios

Injection Scenario	# Sources	Total Injection (MMT CO_2/yr)	Average Injection Rate per Well (MMT CO_2/yr)
10%	50	25.6	0.51
25%	50	64	1.28
50%	50	128	2.56
100%	50	256	5.13

Figures 4-8 and 4-9 show maps of simulated pressure buildup for SEAWAT simulations for 10% and 25% on-site injection. Since injection is distributed across 50 sources, the pressure buildup does not cover as large an area as in the regional storage scenarios. However, there is a zone of high pressure buildup in the southwest corner of the model where several large sources are located along the Ohio River. Model results are not reliable in this area because the pressure buildup extends to the model boundary, which can lead to model errors.

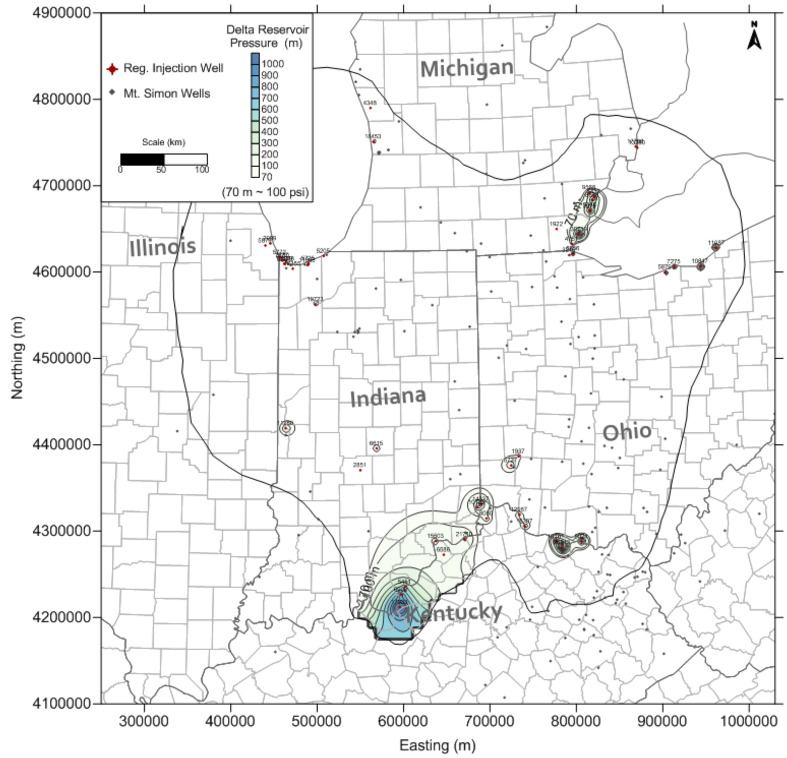


Figure 4-8. SEAWAT Simulated Delta Pressure- 10% On-Site Injection (25.6 Mt/yr total injection)

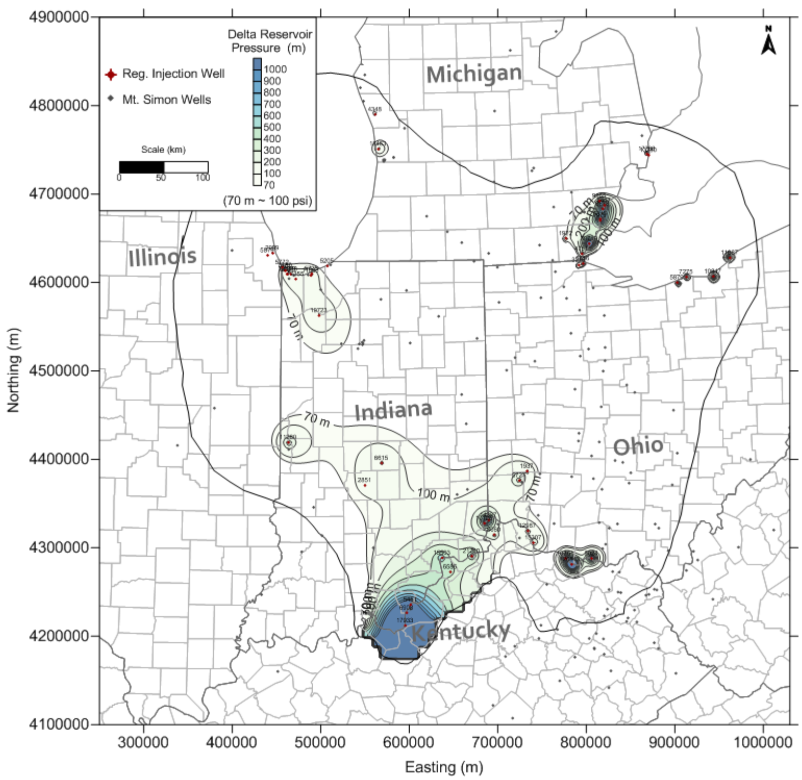


Figure 4-9. SEAWAT Simulated Delta Pressure- 25% On-Site Injection (64 Mt/yr total injection)

Section 5.0: MULTI-PHASE MODEL RUNS OF REGIONAL STORAGE INFRASTRUCTURE SCENARIOS

A series of multi-phase model runs was completed to evaluate regional infrastructure scenarios for the Arches Province study area. The baseline multi-phase, basin-scale model was developed in STOMP-CO2 numerical code based on the geocellular model. Several other tasks were completed to validate the model with the MRCSP East Bend CO_2 injection data, complete geomechanical simulations, run caprock models, and perform an evaluation of monitoring feasibility based on simulation output.

5.1 Baseline Simulation

Development of the baseline simulation was the initial step in performing the basin-scale, multiple-phase simulations. The baseline simulation is the basin-scale numerical model without any stresses applied from injection. Information from the geocellular model was ported to a numerical model using geologic visualization software. The STOMP-CO2 simulator (White and Oostrom, 2000; White and Oostrom, 2006; and White et al., 2012) developed at Pacific Northwest National Laboratory was used for the simulations.

The porosity and permeability distributions used in the basin-scale model were upscaled from the 3D geocellular model. The 3D, 49 million-cell porosity and permeability grids developed in EarthVision® were based on a vertical resolution of 2 m and a horizontal resolution of 5000 m. Initially, a four layer model was developed with three layers in the Mount Simon and one layer in the Eau Claire. This model was used to examine numerical settings in the computer code.

The final model contained 19 layers: 15 layers in the Mount Simon plus four layers in the Eau Claire. The 19-layer model contains 1,404,708 nodes. The simulation grid has variable grid spacing in the horizontal direction with finer resolution (500 m) in the regions containing the seven storage fields (Figure 5-1). This resulted in the lateral distribution of properties remaining nearly the same due to the coarser (5000 m) resolution of the geocellular model. In the vertical direction, however, the resolution of the basin-scale simulation grid was coarser (10 to 100s meters) than the geocellular model (2 m). This vertical coarsening was in part necessary to avoid simulation cell aspect ratios that are numerically unstable, as well as to limit the number of nodes in the simulation. Likewise, the horizontal fining was needed to track the movement of the CO_2 as it was injected. For the basin-scale model with CO_2 injection, the horizontal resolution of the simulation grid had more of an impact on the model results. Figure 5-2 shows a cutaway view of the 19-layer model in the region of storage field #4. The permeability of the Mount Simon is a variable distribution. Based on the results of initial model runs and caprock simulations discussed in Section 5.6, the Eau Claire layers were assigned a constant median permeability value of 7.6x10-5.

Simulations were conducted for variable salinity, constant salinity and freshwater conditions in the Mount Simon to evaluate the differences. Effects of salinity differences on the CO_2 plume extent and pressure buildup were not noticeable due to the size of the model domain. Therefore, results from the constant salinity case will be presented here. Figure 5-3 shows the initial pressure distribution in the top layer of the Mount Simon. The pressure field is a good match with the Mount Simon Reservoir pressure map based on data from wells in the region. The differences are in part due to the fact that the observed pressure map was generated by contouring observed pressure data from a variety of vertical locations within the Mount Simon, while the model pressures are calculated in 3D space.

Several boundary condition scenarios were considered; no-flow boundaries for the entire domain, fixed pressure boundaries for the entire domain, and a scenario with no-flow boundary conditions on the north and south edges of the domain and fixed pressure boundaries on the east and west. The third case was the most reasonable representation of the basin boundaries as presented here. The base model was used to simulated injection scenarios discussed in Section 6.0.

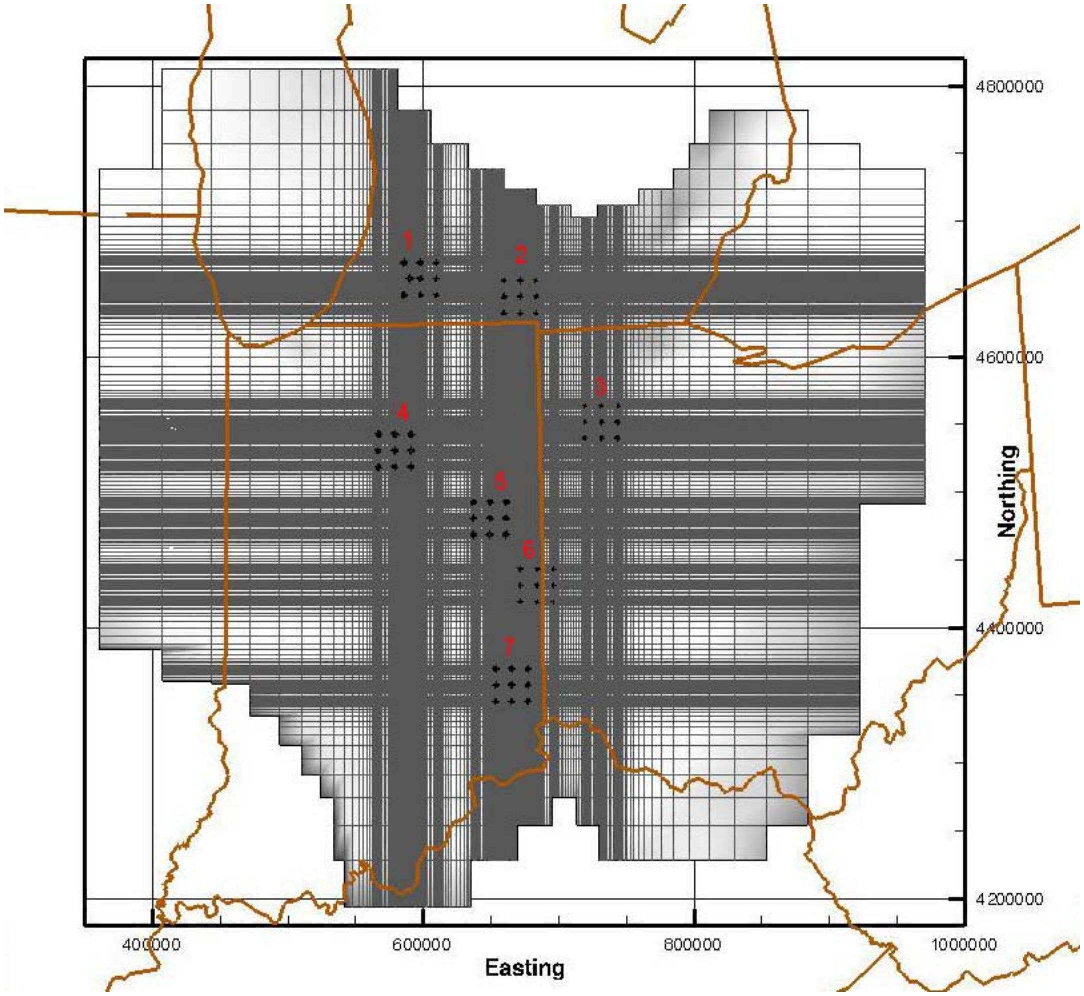


Figure 5-1. Map View of STOMP-CO_2 Simulation Grid Showing Locations of Seven CO_2 Storage Fields Containing a Total of 63 CO_2 Injection Wells

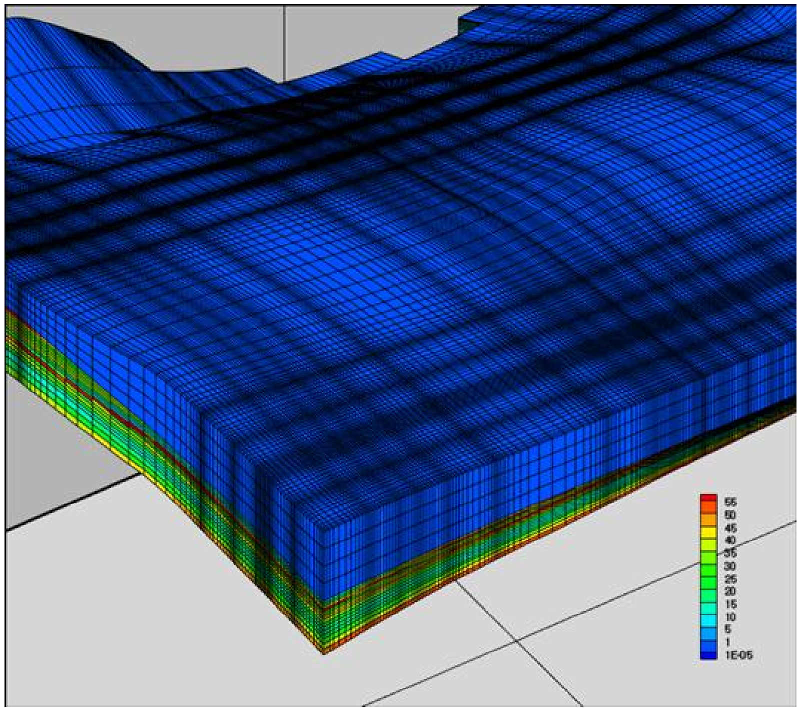


Figure 5-2. Cutaway View of Permeability Distributions for 19-Layer Model Near CO_2 Storage Field #4

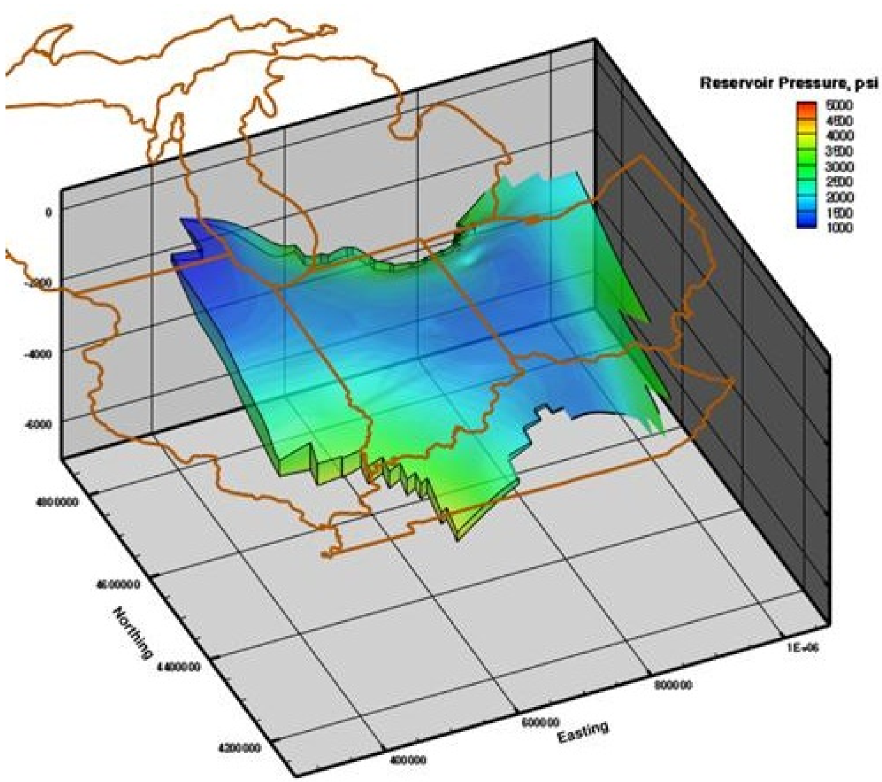


Figure 5-3. Initial Simulated Pressure in the Top Layer of the Mount Simon

5.2 Model Validation to Class I/MRCSP Data

A model validation exercise was completed to evaluate the ability of the model to accurately simulate CO_2 storage. The validation involved simulation of the CO_2 injection test completed by the MRCSP at the East Bend Generating Station in Rabbit Hash, Kentucky (Figure 5-4). At the East Bend test site, 1000 metric tons of CO_2 was injected into the Mount Simon Sandstone (Battelle, 2010). The test was completed in September 2009 and is the only CO_2 injection field test that has been completed in the Mount Simon sandstone in the Arches Province study area. Consequently, it is the best option for evaluating the accuracy of the model.

In the validation exercise, output from the Arches Simulations geocellular model was directly ported to a 2D radial STOMP model. A breakout 2D radial model was selected for the validation because the injection volume at the East Bend site was too small to evaluate in the basin-scale model. In general, validation of the basin-scale model would require a significant CO_2 injection, on the order of several MMT, because the model has coarse grid spacing designed to cover the entire study area. However, the geocellular model has finer resolution across the study area, so the validation study does provide feedback on the quality of the geologic input dataset. In addition, the basin-scale and 2D radial STOMP use the same numerical equations. The exact CO_2 injection schedule applied at the East Bend test was assigned to the STOMP model. The model was then run to simulate the CO_2 injection and post-injection period. Simulation results were compared with observed bottom hole pressure from the East Bend test site.

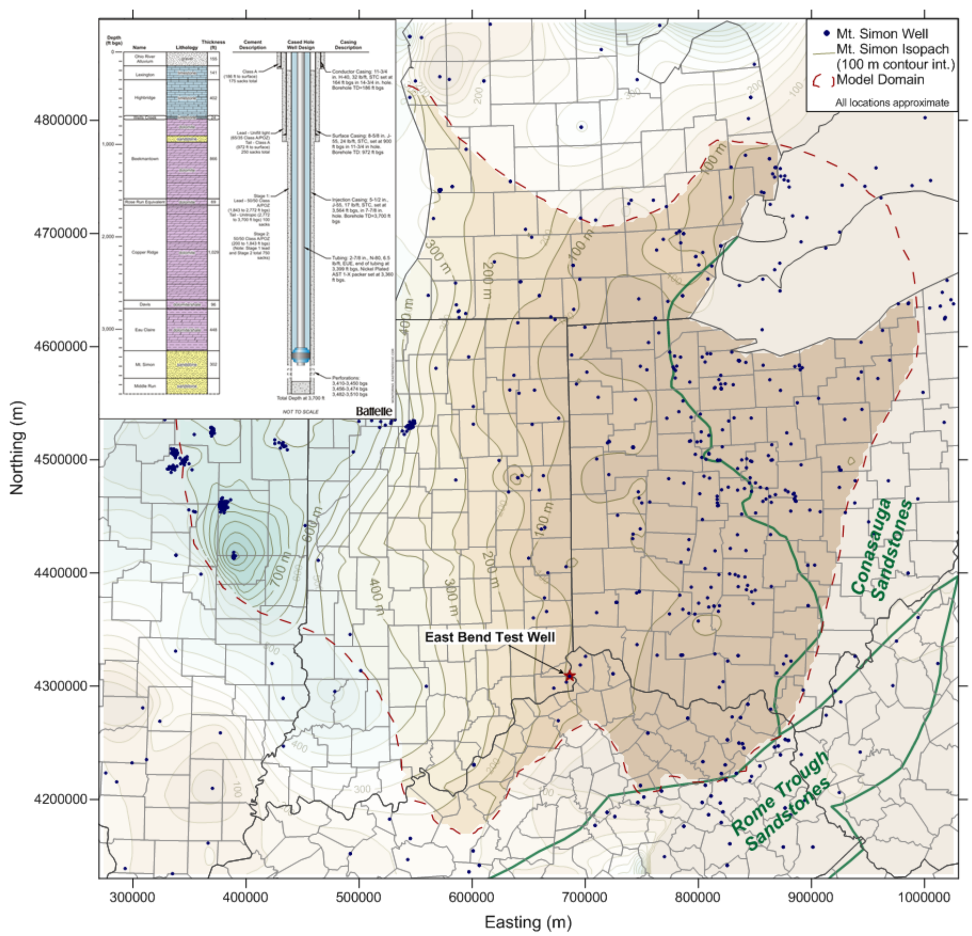


Figure 5-4. East Bend Test Well Location Map and Well Diagram

The validation model input was based directly from the geocellular model. Layer elevations, porosity, and permeability, were extracted from the geocellular model grids at the East Bend location. The geocellular model vertical resolution was 2 m, so the model was upscaled to represent one Precambrian layer, 15 Mount Simon layers, five Eau Claire layers, and one Knox layer to better match the basin-scale model layering. Figure 5-5 shows the data from the geocellular model and the numerical input.

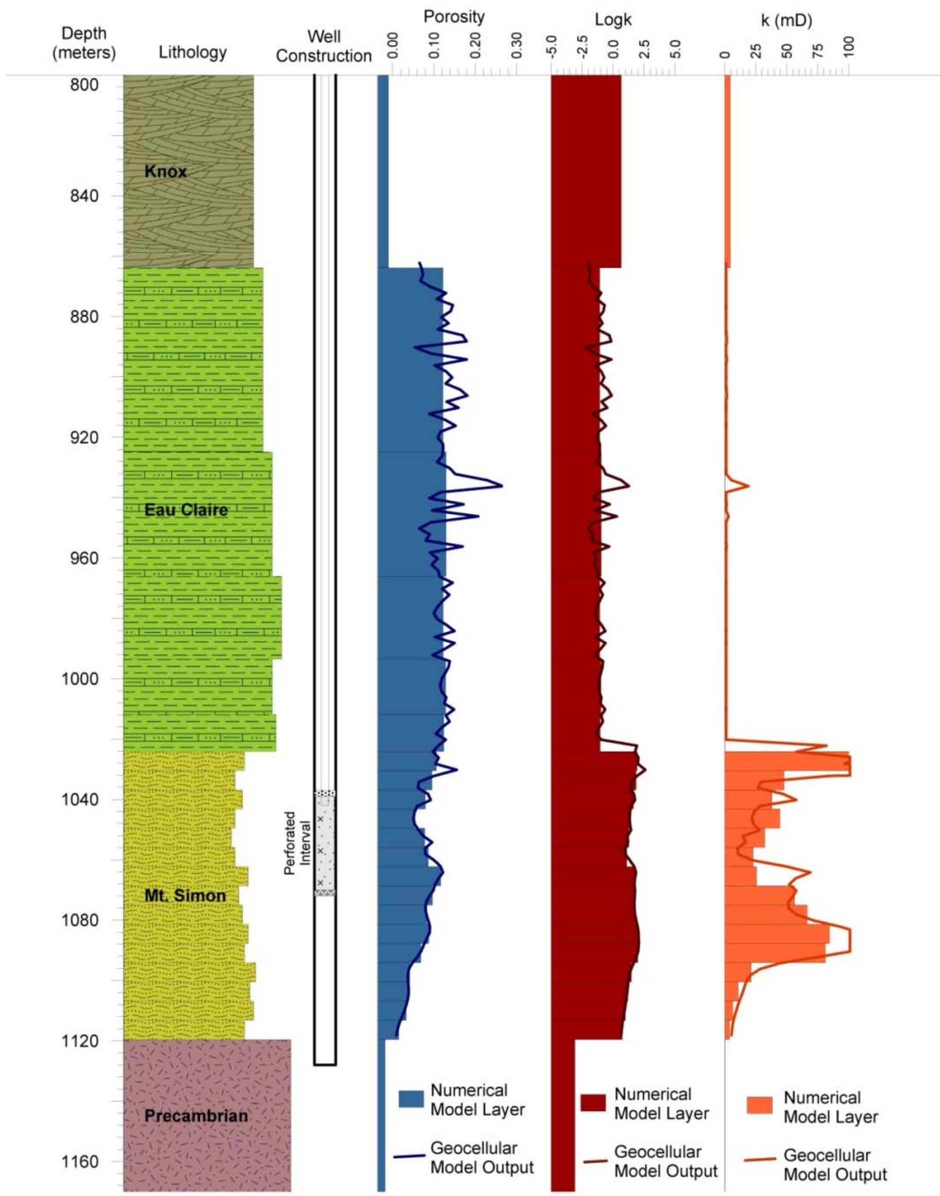


Figure 5-5. Summary of Geological Data Extracted from the Geocellular Model and Numerical Model Setup for the East Bend Model Calibration Exercise

The geocellular model was gridded to 5,000 by 5,000 by 2 meter X,Y,Z cells and averaged data to some extent. As such, there were some differences between the formation structure in the geocellular model versus observed geology at the site. For example, the Mount Simon was observed at a depth of 3230 ft below ground surface (bgs) in the East Bend test well, but the geocellular model indicated the Mount Simon at a depth of 3360 ft bgs. However, the geocellular model has Mount Simon thickness of 313 ft, which is fairly similar to the observed Mount Simon thickness of 302 ft.

Hydrologic parameters were also exported from the geocellular model to the numerical model. This input includes reservoir pressure, fluid salinity, and reservoir temperature (Table 5-1). These parameters generally match the observed conditions because the East Bend test well was included in the dataset used to develop the geocellular model. Other, fixed input for the STOMP model, such as CO_2 compositional parameters, was based on the same data input into the basin-scale model.

Table 5-1. Summary of Geocellular Model Data at East Bend Location

UWI (APINum)	EB1 Test Well	Geocellular Model
Surf X (UTM)	686073	686073
Surf Y (UTM)	4308582	4308582
Surface (ft msl)	526	612
EC Depth (ft)	2770	2834
Mount Simon Depth (ft)	3232	3360
PC Depth (ft)	3532	3673
Fluid Density	1.13	1.13
Salinity (mg/L)	203,000	195,000
Temperature (F)	80*	89.3
Pressure Gradient (psi/ft)	0.47	0.46
Pressure MS Bottom (psi)	1590*	1690

*pre-injection measurements

The CO_2 injection test at the East Bend site was completed over 3 days in September 2009. Initially, a step-rate injection test was run from 1 to 5 barrels per minute. The step-rate test was interrupted by a pump repair. After the step-rate test, there was a break to refill the CO_2 storage tanks. Then a constant rate injection test was run at 4.4 barrels per minute over about 11.3 hours. Total injection was approximately 332 metric tons CO_2.

In the validation exercise, output from the Arches Simulations geocellular model was directly ported to a 2D radial STOMP model. The numerical model was run with STOMP-WCS as a radial grid system. Figure 5-6 shows the model grid setup. The grid includes a total of 20 layers: four layers in the Eau Claire, 15 layers in the Mount Simon, and one layer for the Precambrian. The grid domain was assigned up to a distance of 3000 meters from the injection well. A total of 60 columns were specified with spacing from 0.10 m to 200 m. Dirichlet boundaries were assigned at the top and bottom model layers based on hydrologic output from the geocellular model. Hydraulic properties were assigned for each model layer based on the geocellular model. All layers were homogenous. Saturation properties were assigned as extended van Genuchten with the same values used in other scoping level simulations. Total simulation time was set at 1440 minutes. The injection was specified as a constant rate CO_2 volumetric source at 4.4 barrels per minute for 680 minutes across model layers 7 through 15, which corresponds to the perforated interval in the East Bend well.

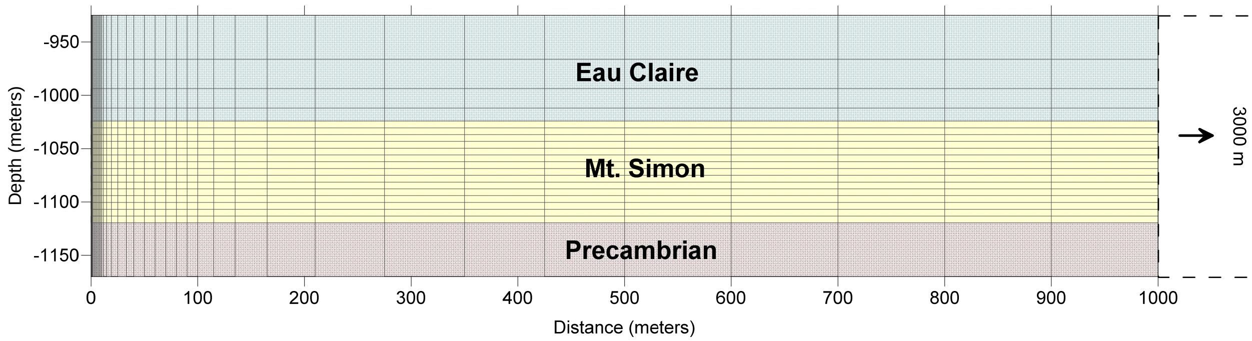


Figure 5-6. East Bend Model Validation Simulation Grid Setup

Simulated pressure was extracted at grid node 7,1,13 located approximately 1 meter from the injection nodes. Since a well model was not utilized for the source term, this node was selected to represent bottomhole pressures. The model was somewhat sensitive to which layer results were exported from because each layer was 6.7 meters thick. Thus, each layer would differ by approximately 10 psi due to depth in the reservoir. Figure 5-7 shows simulated bottomhole pressure along with observed pressure. Overall, the model matches the observed pressure response at the East Bend test well. Since a constant injection rate was specified in the model, simulated pressure exhibits a much smoother response. Simulated pressure shows a less steep pressure increase and steeper pressure falloff, which may suggest that the geocellular model slightly overestimates permeability. However, these differences are minor. Overall, the model validation exercise provides more confidence in the geocellular model and computational model used for the project.

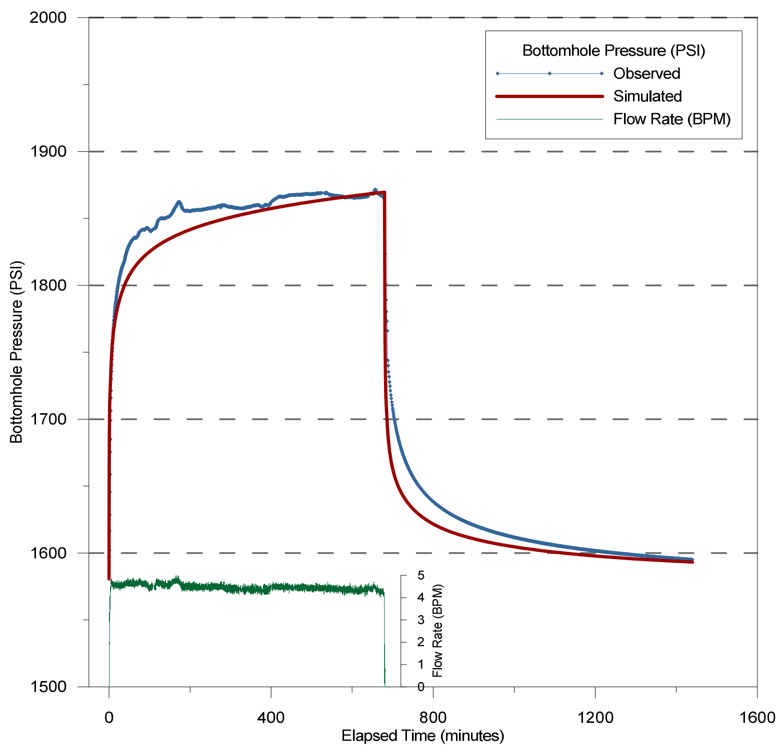


Figure 5-7. Simulated and Observed Bottomhole Pressure for the East Bend Model Validation

5.3 Regional Storage Scenarios

Regional storage scenarios were evaluated with a combination of parametric analysis of scoping level simulation results and output from the geocellular model. In association with the variable density simulations, estimations of injected CO_2 plume radii were calculated for various storage site scenarios (i.e., storage efficiency factors) and locations. These estimates were developed to provide another measure to validate simulation results against. The results also provide some general guidance for CO_2 storage infrastructure analysis. For all calculations it was assumed that injection of CO_2 takes place for 20 years at a given, constant rate. Site-specific characteristics were extracted from the geocellular model for use in the final calculation of plume size. These estimated attributes included reservoir thickness, average porosity, and fluid density of CO_2 (based on local estimated pressure and temperature conditions). The plume radius calculation was calculated based on a variation of the U.S. DOE Carbon Atlas capacity equation (U.S. DOE, 2008):

$$r = \sqrt{\frac{Total\ Mass\ Injected}{\pi h \Phi \mathrm{E_f}}}$$

where
r = plume radius estimate
h = reservoir thickness
Φ = average reservoir porosity
E_f = storage efficiency factor.

In the first scenario, it was assumed that seven regional storage sites, or fields, were implemented wherein CO_2 is transmitted via pipeline for injection into the Mount Simon. Two separate injection rates were used to determine two plume radii for each of the seven regional sites: 10 and 20 MMT/yr. Injection was assumed to take place for 20 years. The storage efficiency factors used were 0.01, or 1%, and 0.04, or 4%. Figure 5-8 shows the calculated plume radii for the seven regional sites.

In the second scenario, it was assumed that 50 source-located storage sites, or fields, were implemented wherein CO_2 was injected into the Mount Simon at, or near, the source itself. Injection rates used in the plume radii calculations were assumed to be 25% and 50% at each source, per year. Injection was assumed to take place over 20 years. The storage efficiency factors used were 1% and 4%. Figure 5-9 shows the calculated plume radii for the 50 site-source locations. It should be noted that Mount Simon thickness, particularly in Ohio, has a significant effect on the calculated plume sizes.

5.4 Data Analysis and Visualization

Data analysis and visualization were performed in conjunction with other technical tasks. Initial data compilation, cross sections, and mapping were performed in PETRA and ArcGIS. The geocellular model was developed in EarthVision® using 3D geological modeling algorithms. Simulation output was visualized in EarthVision® and TecPlot. Graphics are included in other technical sections. In addition, GIS and technical data were included in Technical Progress Reports.

5.5 Geomechanical Simulations

A break-out geomechanical model was developed for the Holland, Michigan, area in GEM code to examine issues related to geomechanical factors of the Mount Simon sandstone. The geomechanical model includes Poisson's Ration, Young's Modulus, and compressive strength parameters determined through rock core tests from the Arches Project.

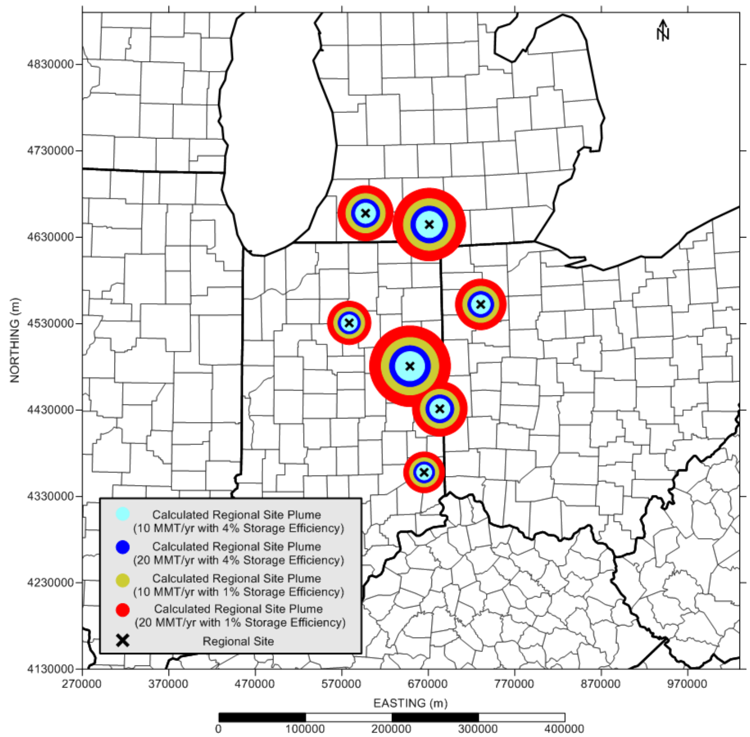


Figure 5-8. Calculated Plume Radii for Seven Regional Storage Sites in the Mount Simon for 20 Year Injection at 10 and 20 MMT/yr with 1% and 4% Storage Efficiency Factors

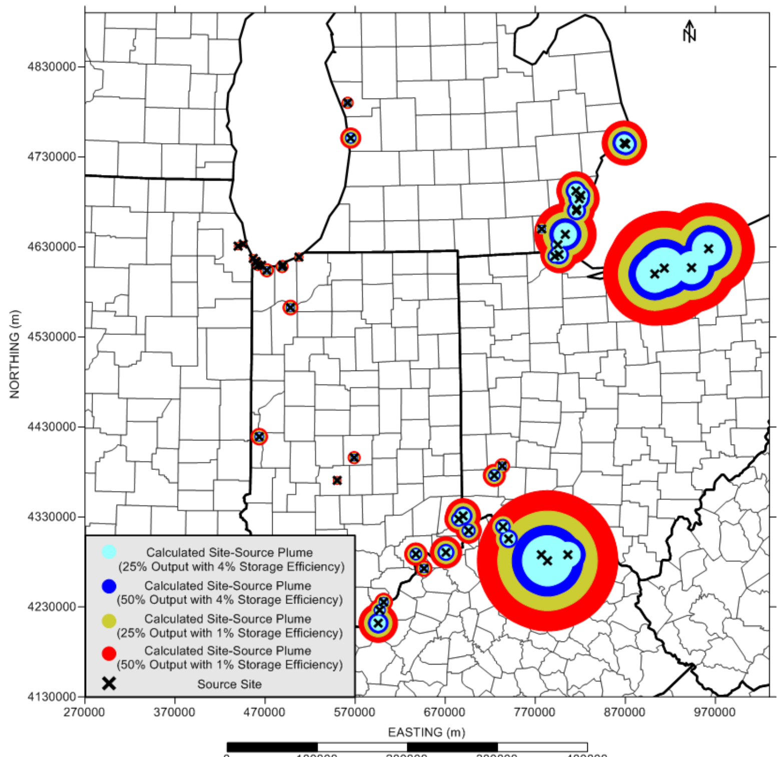


Figure 5-9. Calculated Plume Radii for 50 Source-Located Storage Sites in the Mount Simon for 20 Year Injection Using 25% and 50% CO_2 Source Output with 1% and 4% Efficiency Factors

The data were used in reservoir simulations to evaluate fracture pressures, rock deformation effects, and heterogeneity for the Mount Simon. For the geomechanical simulation a location near Holland, Ottawa County, Michigan, was chosen for a site-specific scenario. A static reservoir properties model in the southwestern area of Michigan of about 1.4 square miles was created using the Petrel geological modeling program. This model was used for geomechanical modeling of the Mount Simon. Seven well logs support this Petrel model and are shown in Figure 5-10.

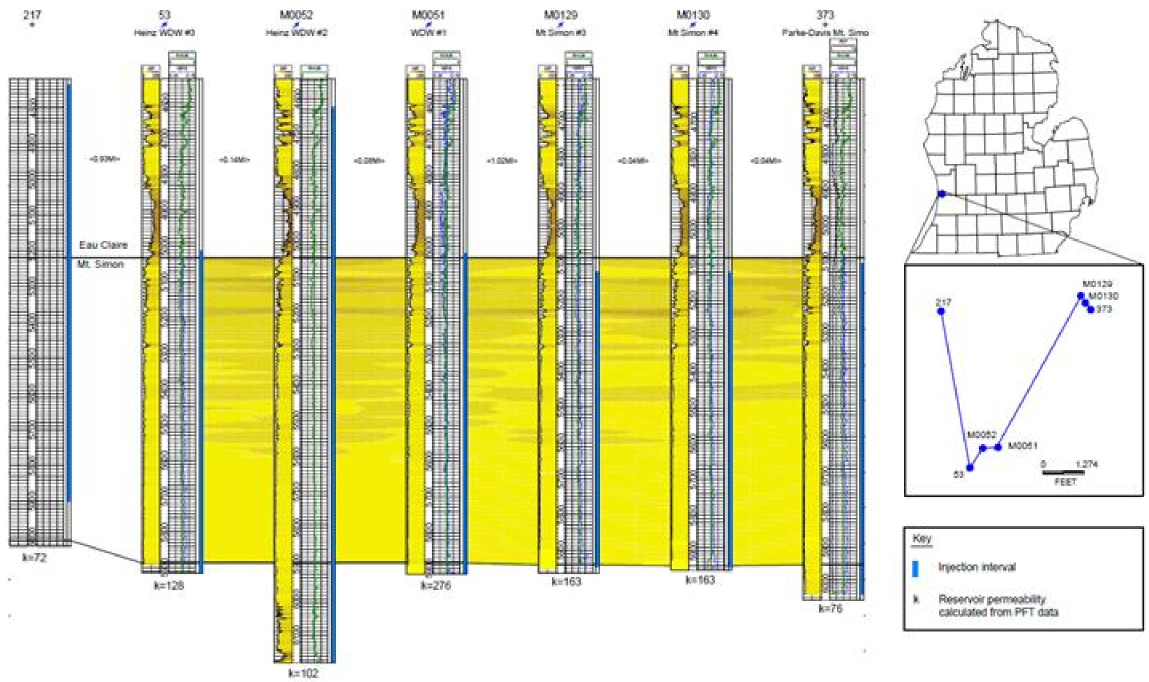


Figure 5-10. Wells and a Cross Section Through Geomechanical Model Area

Geomechanical parameters in the model were based on rock core tests from the Arches project. Static Young's Modulus and Poisson's Ratio values based on Mount Simon samples taken from Ottawa, Michigan were used in the geomechanical modeling. Sample numbers 1-8RMV and 1-9RMV are Eau Claire samples; the Static Young's Modulus and Poisson's Ratio values were used for geomechanical modeling. In order to test sensitivity of rock strength in the modeling, Static Young's Modulus and Poisson's Ratio values from Mount Simon samples 1-4RMV and 1-5RMV were used.

In the analysis, multiple model scenarios were created and studied. All models were assigned as dual permeability models. This allowed the models to have permeability values for the formation and the fractures rather than the formation alone. Each model was simulated over 15 years, with CO_2 injected during the first 10. Various supercritical CO_2 injection rates ranging from 10,000 ft^3/day to 2,000,000 ft^3/day were modeled. Injection well perforation depths and lengths were varied. Perforations were located just below the caprock layer, just below the upper Mount Simon and also at the bottom of the middle Mount Simon layer. Several rock strength parameters were tested for sensitivity as well. Variable caprock thicknesses were simulated. The default boundary conditions which were applied to all models constrained both the bottom and sides of the grid leaving only the top to move freely in space.

Principal stresses for Holland, Michigan were calculated based on methods described in *Reservoir Geomechanics* (Zoback, 2007). Two models were constructed. Model 1 assumes that regolith and rock density is constant with depth at an average value of 2.3 g/cm^3. This leads to a vertical stress gradient of 23 MPa/km or 1 psi/ft. At a depth of 5000 ft, approximately the top of the Mount Simon sandstone in Ottawa County, Michigan, the vertical stress S_v would be 5000 psi. Assuming pore water pressure increases 0.46 psi/ft depth, the total pore water pressure at a depth of 5000 ft would be 2300 psi. In a geologic environment best characterized as a basin with a hydrostatic pressure distribution and where the stress regime would be normal faulting rather than strike-slip or reverse, S_{hmin}, the least horizontal principal stress must be greater than the pore pressure (Zoback, 2007, p. 14). In Model 1, S_{hmin} is to be 2500 psi. Assuming that S_{hmax}, the maximum principal horizontal stress, is halfway between S_{hmin} and S_v as shown in Zoback (2007), S_{hmax} equals the average of the two, or 3750 psi.

The second stress state model is similar to the first, but assumes that regolith and rock density increases linearly with depth. Model 2 assumes a density of 1.8 g/cm^3 at the surface, 2.5 g/cm^3 at a depth of 7000 ft, with a linear variation between those depths. The density equation becomes

$$\rho(z) = 1.8\ g/cm^3 + (0.0001\ g/cm^3/ft)\ z$$
$$S_v = \int \rho(z) G\, dz = G\,[1.8\, z + 0.00005\, z^2]$$
where G = the gravitational acceleration constant.

At z = 5000 ft, S_v = 4457 psi, and the vertical gradient of S_v = 1 psi/ft. The pore pressure is still 2300 psi at that depth, and again S_{hmin} is to be 2500 psi at z = 5000 ft. Again assuming that S_{hmax} is halfway between S_{hmin} and S_v, S_{hmax} equals the average of the two, or 3480 psi. 3500 psi was used here.

Table 5-2 summarizes the four different model types used to study the geomechanical stability of the study site in Ottawa County, Michigan. The primary differences were in dimensionality and the geologic distribution of permeability.

Table 5-2. Geomechanical Model Description

Model #	Space	K distribution
1	3D	Heterogeneous
2	2D	Heterogeneous
3	3D	Layer Cake
4	2D	Layer Cake

The first model was a 3D model created using Petrel using permeability and porosity values obtained from the wells in Ottawa County. A key assumption made was when the permeabilities from the well logs were upscaled in Petrel, the maximum permeability in an interval was used rather than the geometric or harmonic mean permeability. A second model was created in 2D also using permeability and porosity values obtained from the wells in Ottawa County. The third and fourth models were homogenous (or "layer cake") models with single permeability and porosity values for each of three layers: Eau Claire, Upper Mount Simon and Lower Mount Simon. These models were 2D and 3D. These model studies included sensitivity analysis of permeability values in the Eau Claire.

All the models used the Barton-Bandis model for the Eau Claire caprock layer. The Barton-Bandis model allows for fracture permeability to be computed from effective stress in GEM. When a fracture occurs, a fracture permeability value is assigned. Initially, the fracture permeability is relatively large. As pressure is relieved due to CO_2 migration, the fracture permeability decreases. However, the crack can never fully heal and close completely, so eventually the minimum fracture permeability is used at the fracture location.

When upscaling the original Petrel Mount Simon model, maximum permeability was used for the upscaled grid blocks. Although this likely represents reality, it was not ideal when attempting to break the caprock. Breaking the caprock was not seen in these models. However, upward movement was shown in the scenarios, which may have reduced pressure buildup at the caprock interface. Figure 5-11 depicts CO_2 accumulated in the Eau Claire formation after 10 years of injection. The white line is the location of the bottom of the Eau Claire layer.

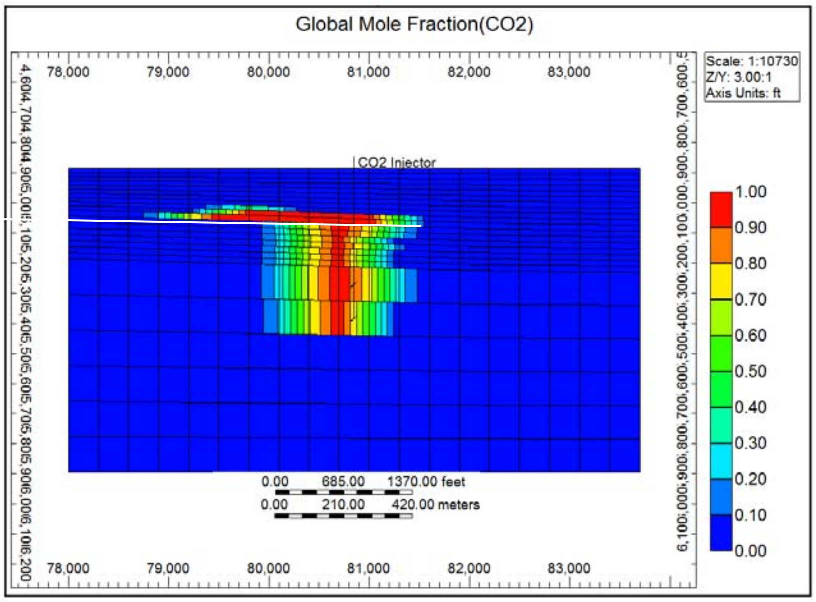


Figure 5-11. 2D Geomechanical Model Simulated CO_2 Mole Fraction

5.6 Caprock Simulations

Caprock simulations were performed to better understand the potential for CO_2 to migrate into the Eau Claire caprock. Due to the large model domain and numerical constraints in the basin-scale model, the Eau Claire was represented with only three grid layers. Consequently, the hydraulic properties were averaged across the unit. In areas where sandstone 'stringers' are interlayered with shale and dolomite in the Eau Claire, the grid layers were represented as fairly high permeability units due to the sandstone layers. Simulation results indicated some CO_2 movement into the Eau Claire. However, it was uncertain whether this process was related to grid upscaling issues or the actual geology.

Separate simulations were completed with more detailed representation of the Eau Claire interval. Two well sites (Allen County Indiana and Warren County Ohio) with distinct Eau Claire character were selected for simulation. 2D radial models were developed for each site. Higher layer resolution was included across the Eau Claire based on facies analysis of the unit. CO_2 injection was simulated into the Mount Simon at 500,000 metric tons per year for 10 years. Then the upward migration of CO_2 was simulated for 1,000 years. The simulations provide a more accurate depiction of upward migration into the Eau Claire.

Intervals were classified with the GAMLS according to dominant facies based on the following units: shale, silty-shale, silt, dolomitic shale, dolomite, and sand. Based on review of the GAMLS output, two well locations were selected for numerical simulation (Figure 5-12). The wells were chosen to represent dominant Eau Claire facies distributions. Well IN-143816 is more variable with distinct shale and silt layers in the lower Eau Claire. Well 3416562627 is mostly silty shale.

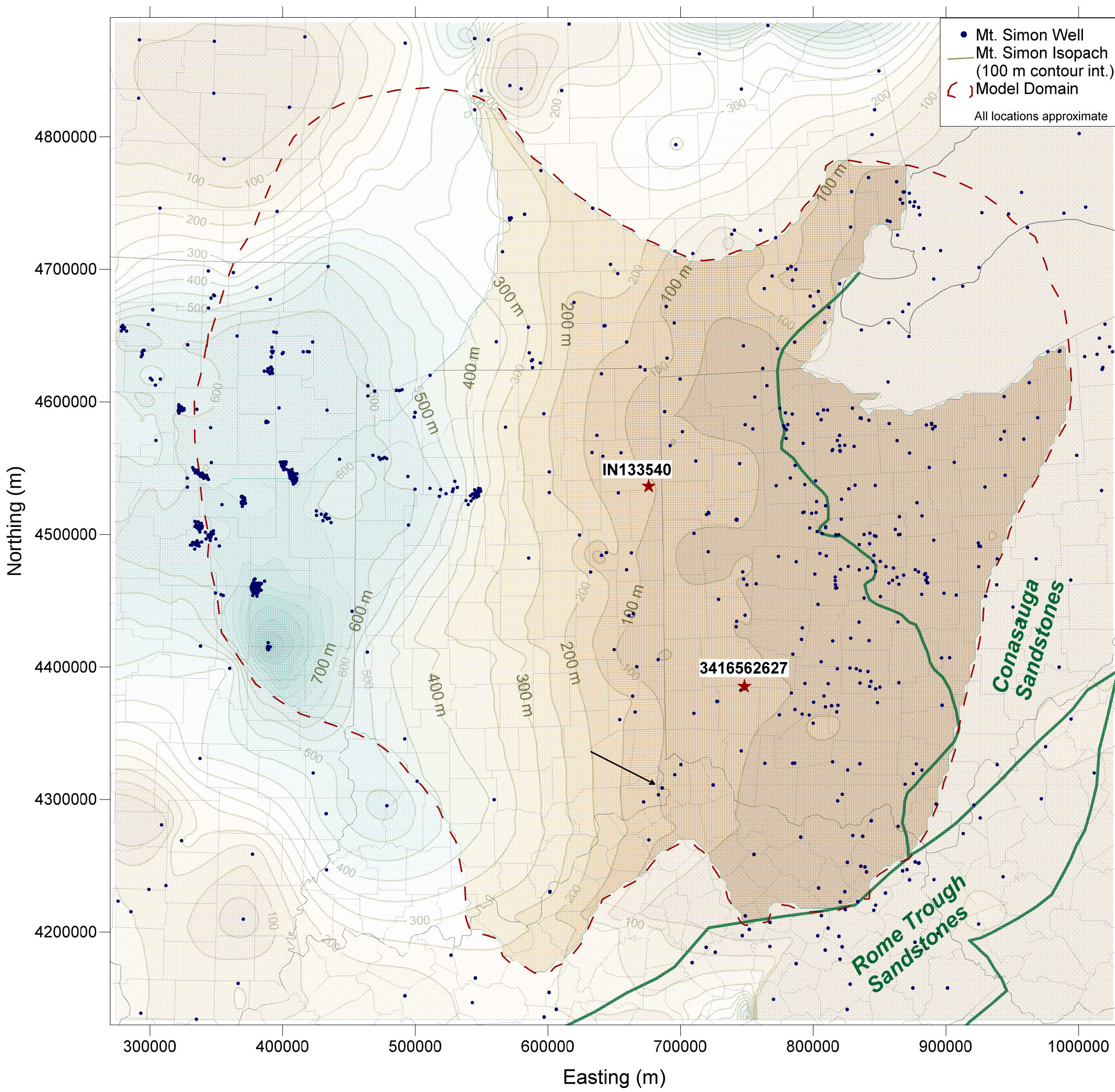


Figure 5-12. Location of Three Wells Used as Basis for Eau Claire Simulations

To transfer the GAMLS analysis into the numerical model, a process similar to the method used for the basin-scale model was used. First, the GAMLS designation was compiled for each well on a 1 foot basis. The best available porosity data from geophysical well logs in the Eau Claire interval were also compiled for the three wells. Intervals were then grouped according to predominant GAMLS facies. These intervals were used for model layers. In the lower 40 to 50 ft of the Eau Claire, a 2-foot interval was assigned to retain vertical detail in this zone. Thus, the model accounts for variability in the Eau Claire where upward migration is most likely to occur. The model layers increase in thickness in the upper Eau Claire.

A separate porosity vs. permeability curve was used for each GAMLS unit to estimate permeability in the Eau Claire. The porosity vs. permeability curves were also based on analysis presented in Nuefelder (2011), which presented relationships based on a core test for silt and shale facies. This research did not present curves for dolomitic shale and silty. Consequently, the authors recommended using the following relationship to depict porosity vs. permeability:

Silty Shale = (0.33 • silt K) + (0.67 • shale K)

Dolomitic Shale = (0.10 • dolomite K) + (0.90 • shale K)

Figure 5-13 shows the porosity vs. permeability curves used to set up the model. Shale facies are assigned the lowest permeability, followed by dolomitic shale, silty shale, silt, and dolomite. In the models, the Mount Simon was input as three layers with permeability based on the geocellular model.

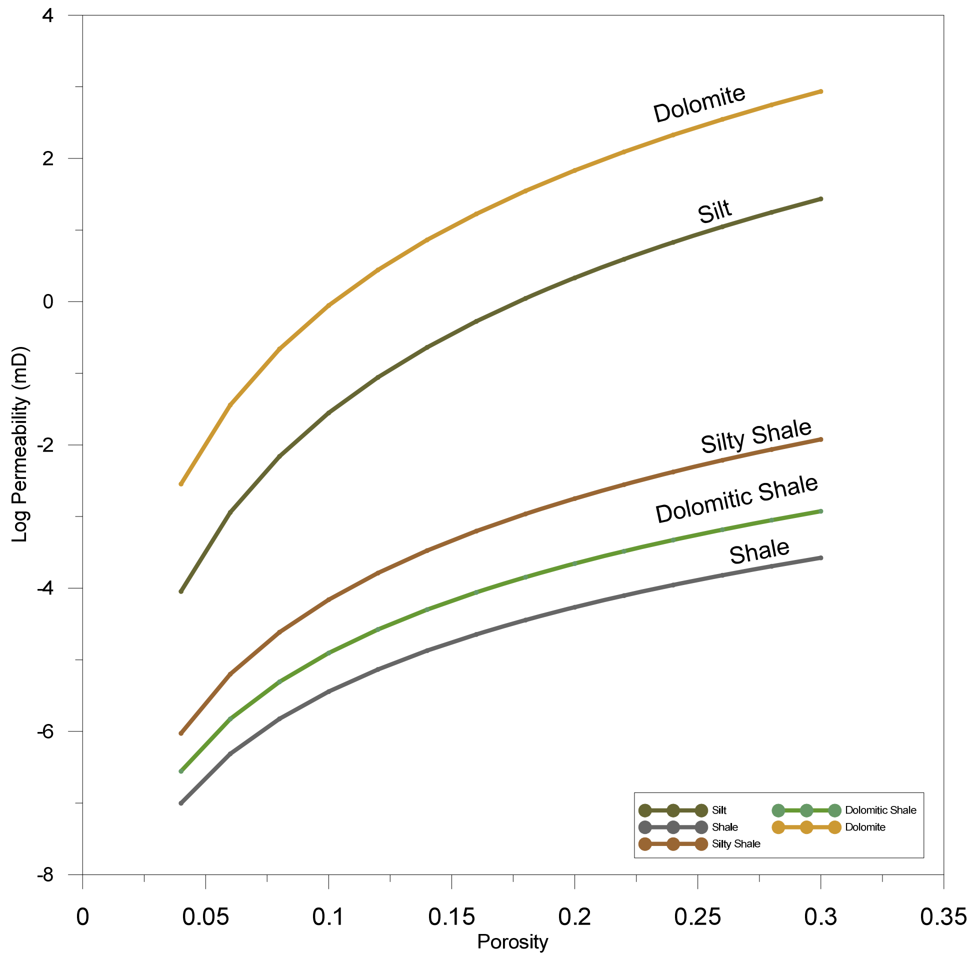


Figure 5-13. Porosity vs. Permeability Curves Used to Develop the Eau Claire Models

The two well sites were input into 2D STOMP simulations of CO_2 injection and long-term migration of CO_2. Figure 5-14 shows the model for well IN-133540 in Allen County, Indiana, and well 341656227 in Warren County, Ohio.

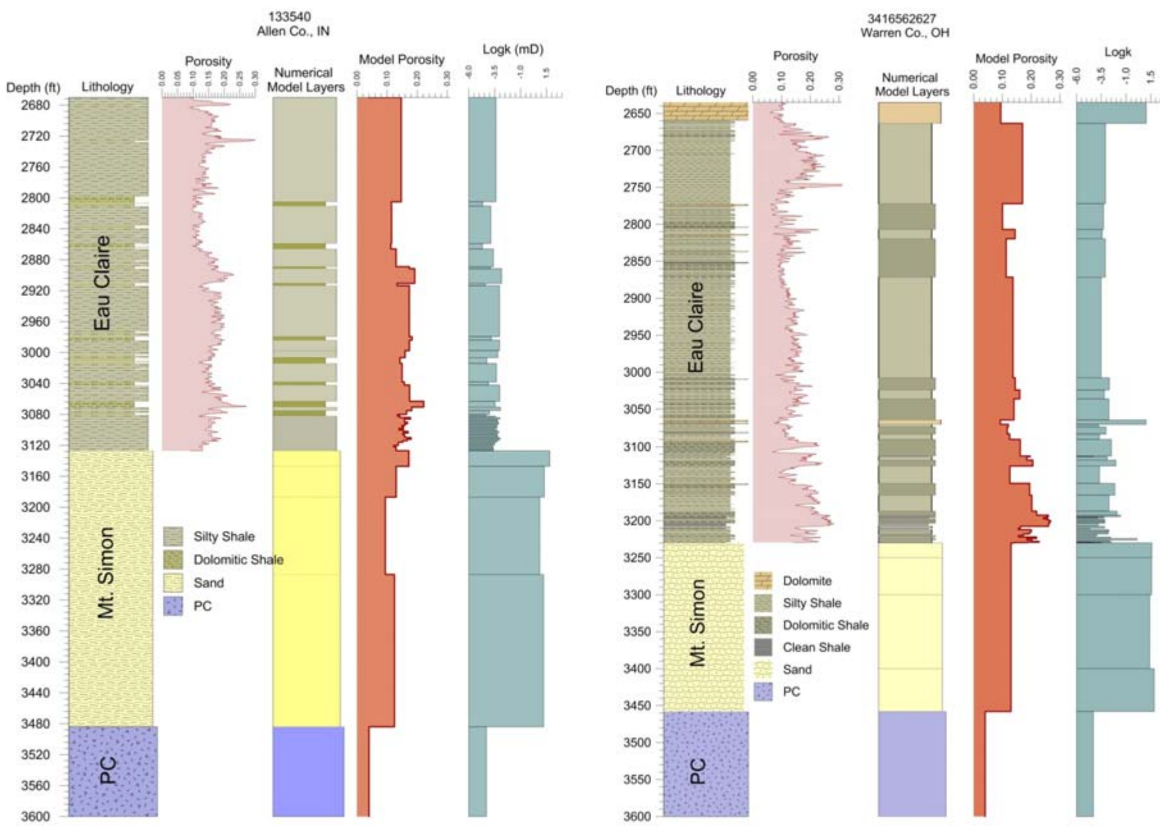


Figure 5-14. Summary of Eau Claire Model for Well IN-133540 and Well 3416562627

Overall, the caprock simulations showed minimal CO_2 movement into the Eau Claire formation. Figure 5-15 shows simulations from the Allen County, Indiana site and Figure 5-16 shows simulation results for the Warren County, Ohio site. As shown, there is no significant migration of CO_2 into the Eau Claire at the end of injection (10 years) or end of the simulation (1000 years). Results confirm that previous simulations with coarse model layers in the Eau Claire did not accurately portray CO_2 behavior in the caprock. In general, it is important to include details of the lower caprock for numerical simulations of CO_2 storage.

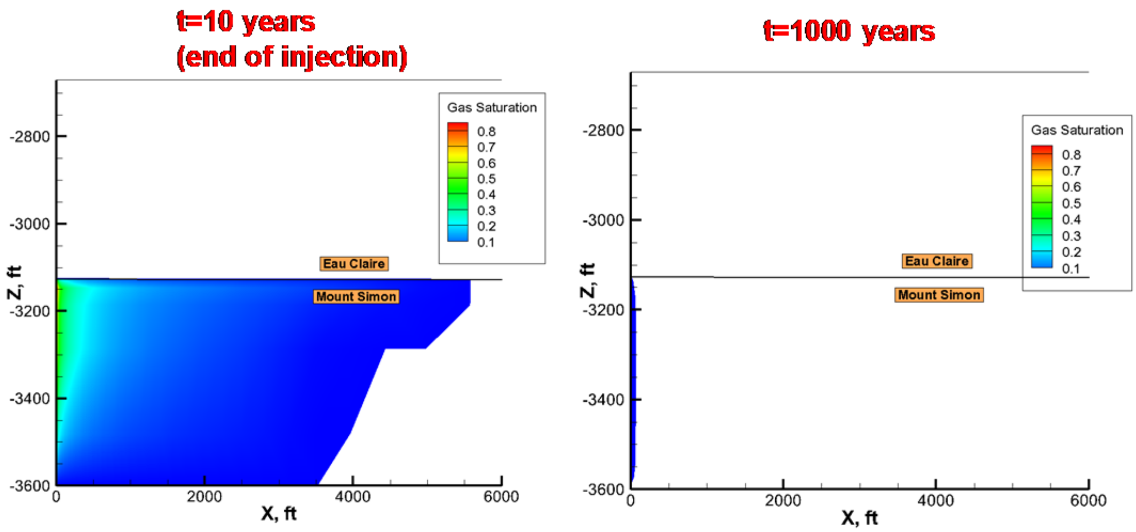


Figure 5-15. Caprock Simulation Results Showing CO_2 Saturation for the Allen County, IN Site (Well IN-133540)

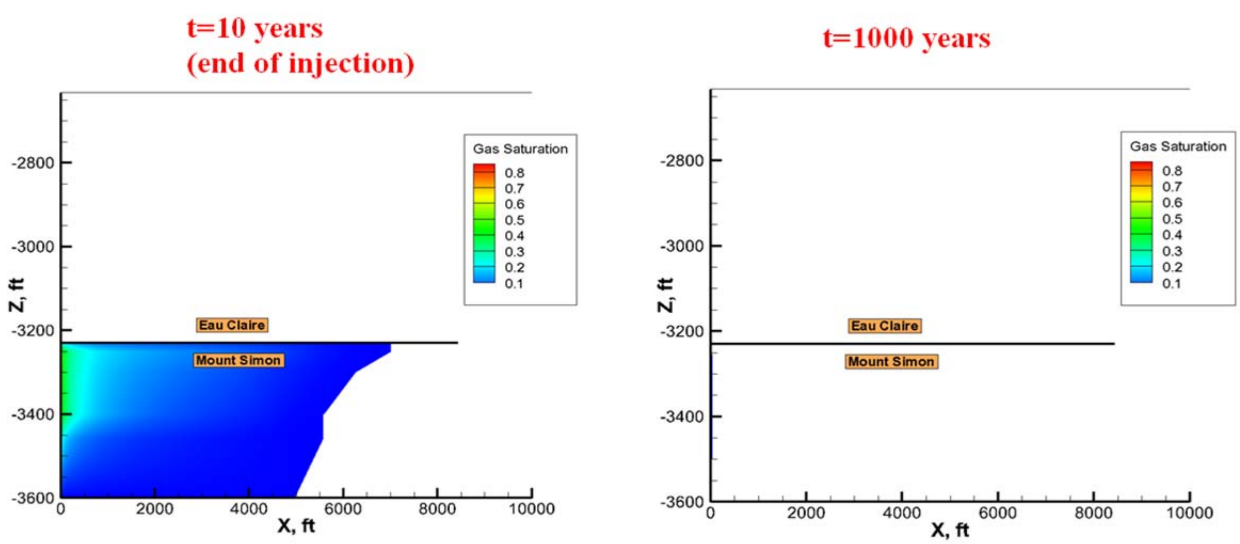


Figure 5-16. Caprock Simulation Results Showing CO_2 Saturation for the Warren County, OH Site (Well IN-3416562627)

Caprock simulation results also indicated that long-term behavior of CO_2 is sensitive to parameters controlling CO_2 dissolution rate into formation fluids. The caprock simulations showed little free phase CO_2 remaining after 1000 years in the reservoir due to dissolution into formation fluid. This process may not be significant in simulations over smaller time periods, but the process may need further examination for long-term simulations.

Additional analysis was also completed by the Kentucky Geological Survey to better characterize the Eau Claire confining interval above the Mount Simon Sandstone in the southeastern part of the Arches Province. Downhole geophysical logs from more than 50 wells north of the Rome Trough were examined in the interval between the Mount Simon Sandstone and base of the Knox Group. To the west

(Illinois Basin), this stratigraphic interval is called the Eau Claire Formation and is dominated by shales. To the east (Appalachian Basin), the interval is called the Conasauga Group and consists of shales, carbonates, and clastics. The Conasauga Group thickens southward into the Rome Trough, but because the Mount Simon is restricted to the area north of the Rome Trough, the area north of the trough was the major focus for this study. A series of cross sections was constructed to examine lateral and vertical variability within the potential confining interval. Where possible, these data were augmented with available core and cuttings data.

The Eau Claire Formation of the Illinois Basin is laterally equivalent with the Conasauga Group of the Appalachian Basin. The Conasauga Group north of the Rome Trough consists of (from top to bottom) the Maynardsville Limestone, Nolichucky Formation, and Maryville Limestone. Picking the boundaries of the three formations in the Conasauga Group is generally inconsistent because of lateral changes in lithology, which does not aid in description or interpretation of the confining characteristics of the interval. The entire interval was divided into as many as seven units based on geophysical log correlations. Sharp changes in gamma and porosity (density, neutron, resistivity) log signatures reflecting changes in lithology and, in some cases, sequence boundaries. Each unit was correlated as extensively as possible across the study area, using available geophysical logs. All of the wells used had gamma ray logs. Neutron, bulk density, and resistivity signatures were variably available.

Results of the analysis show that the Nolichucky Formation contains a low-density, high-gamma shale interval that can be correlated readily across the area and westward into the upper Eau Claire Formation. The base of the formation is variably picked because of a gradational lower boundary. The Maryville Limestone is thick carbonate in the eastern part of the study area, but is mostly a dolomite rather than limestone. The formation splits westward into a series of interbedded carbonates and shales, which interfinger laterally with the Eau Claire Formation. The lateral transition from Maryville carbonates into Eau Claire siltstones occurs near the trend of the Grenville Front, a Precambrian thrust which marks the boundary between the Middle Run sandstone to the west and Grenville province metamorphic rocks to the east. The "Mount Simon" Sandstone in the eastern part of the study area is similar to the Maryville transition sandstones. Cuttings indicate the eastern sandstone is often pinker, shalier, and possibly more arkosic than the typical quartzose Mount Simon Sandstone of the Illinois Basin. The change occurs near the Grenville Front, which is sometimes used as an arbitrary boundary between the Mount Simon and Basal sandstones. West of the front, geophysical log signatures for the upper Mount Simon Sandstone tend to have a clean "blocky" gamma signature. This signature thins and may pinch out east of the Grenville Front. Basal or Maryville sands may onlap the Mount Simon Sandstone where it thins. Available permeability data are not evenly distributed and the majority of the section does not have permeability data. Where permeability data are lacking, however, porosities are generally very low. Few data are available for the shaliest parts of the interval, which likely are good confining zones. Likewise, no data are available for the Maryville dolomites in this area, although core resembles typical tight dolostone in the USS Chemical/US Steel well in Scioto County, Ohio.

5.7 MVA Comparison

Analysis of monitoring technologies was completed to provide guidance on the application of CO_2 storage monitoring methods in the Arches Province. This analysis integrated geotechnical analysis, numerical simulations, and monitoring techniques. Geotechnical analysis provided a range of parameters related to the Mount Simon formation. The numerical simulations produced information related to CO_2 saturation and reservoir conditions that may be expected at storage sites. Finally, the monitoring technologies have response attributes related to the amount of CO_2 present and rock parameters. Together, this information was used to complete substitution analysis for monitoring methods. Monitoring analysis was completed for sonic analysis and saturation logs because they are prevalent methods for monitoring CO_2 in the reservoir.

Saturation log analysis was also completed for monitoring applications in the Mount Simon formation. PNC wireline logging is a technique used to examine the CO_2 saturation in the near wellbore environment. PNC logging generates Sigma (Σ) values as a function of depth. Σ values in turn can be used to infer the type of fluid or saturation in the pore space at a particular depth.

Σ is a measurement of an element's ability to capture thermal neutrons. The higher the Σ value, the greater the ability of an element to absorb the neutrons. Chlorine, one of the dominant ions in native formation brines, has a very high Σ. In comparison, CO_2 has a very low Σ. Therefore, if CO_2 displaces brine in the rock surrounding the wellbore, the observed Σ values should decrease. Repeat PNC logging can be used to infer the presence of CO_2 adjacent to the well if a change is detected after CO_2 has been injected. Thus, repeat PNC logging has been used in monitoring wells to track the vertical distribution of CO_2 in the reservoir.

Although there are many variables that play into equating a PNC Sigma value, the Sigma value will decrease with an increase in CO_2 concentration. If a PNC baseline log is run prior to CO_2 injection, the baseline may be compared with post-injection logs where the CO_2 has migrated due to a change in Sigma values. Mimoun et al. (2011) provides an equation to estimate Sigma values based on methods discussed in Smolen (1996):

$$\sum bulk = (1-\Phi)(\sum matrix) + (\Phi)(\sum brine)Sw + \Phi(1- Sw)\sum CO2$$

Φ = porosity

-porosity of formation determined from the log.

$\sum$matrix = sigma for the rock component

-values range from 6 to 12 capture units (c.u.) for clean-dirty sandstones. For this specific case a value of 6 c.u. was assumed due to the Mount Simon being relatively clean sandstone.

$\sum$brine = sigma for the brine component

-values calculated from the estimated salinity for the fluid in the formation

Sw = estimated water saturation

-the given CO_2 saturation, ranging from 0-50% saturated based on simulation results

$\sum CO_2$ = sigma for the CO_2 component

-value defined as 0.03 in the equation

To evaluate the feasibility of using saturation logs for monitoring CO_2 in the Mount Simon Formation in the Arches Province, the Σ response was estimated for the 105 core plugs tested as part of the project. This provides a subset of values across the study area. Porosity was based on core test results. Salinity was estimated as a function of depth. Rock matrix was assumed to be a clean sandstone. The Σ response was calculated for saturations from 0% to 50%, which numerical simulations suggest may be expected at distances over 2,000 ft from an injection well. Figure 5-17 shows calculated Σ response for saturation of 0 to 50%. There is a 'double hump' distribution related to the porosity of the cores (Figure 5-18). At higher CO_2 saturations, PNC response may decrease by a factor of 2X. At lower CO_2 saturations, a less significant PNC change may be expected.

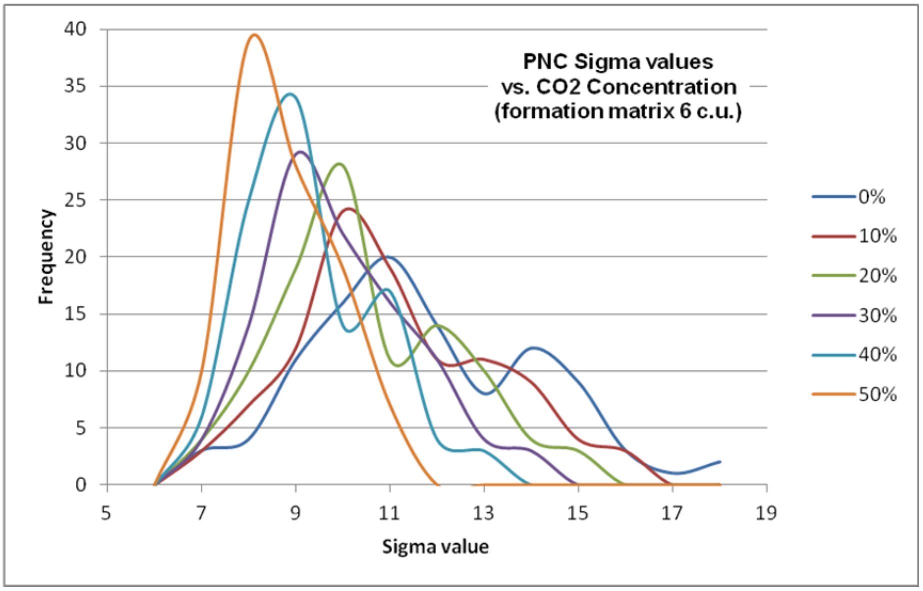


Figure 5-17. Calculated Σ Response for 105 Mount Simon Rock Cores Tested as Part of the Arches Project

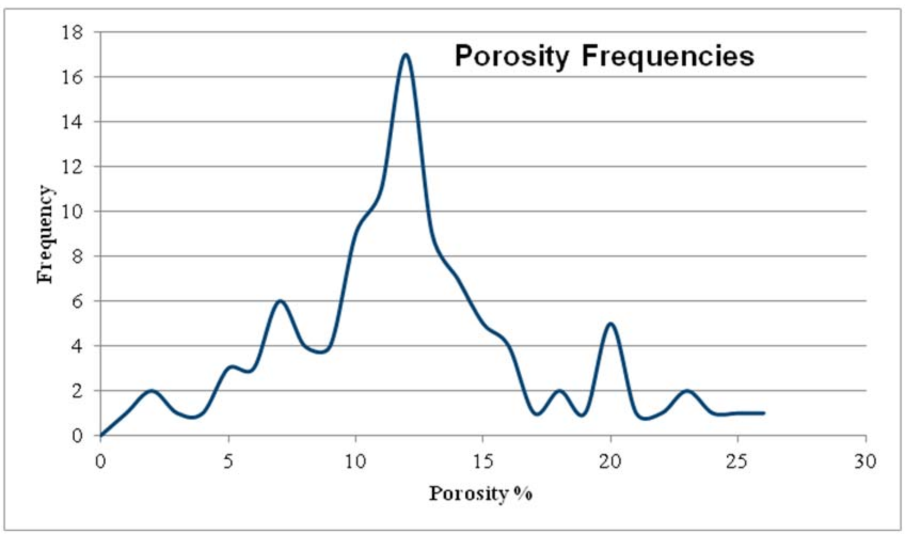


Figure 5-18. Porosity Distribution for 105 Mount Simon Rock Cores Tested as Part of the Arches Project

Substitution analysis for sonic wave response was based on geomechanical properties of the Mount Simon and CO_2 saturation. The objective of the analysis was to determine changes in sonic velocities at realistic CO_2 saturation values. This information will aid in determining the feasibility of several monitoring technologies such as four-dimensional (4D) seismic, crosswell seismic, and vertical seismic profiling.

The geophysical characteristics of the reservoir will change as CO_2 is introduced due to fluid density changes. Several fluid substitution studies (Han and Batzle, 2004; Simm, 2007; Khatiwada et al., 2012) have been conducted to refine calculated results based on field observations. Researchers commonly use a variant of Gassmann's (1951) fluid substitution equations to estimate P- (V_p) and S-wave velocity (V_s) changes with increasing CO_2 saturation. V_p and V_s logs are needed to use Gassmann's fluid substitution.

Substitution analysis was completed for sonic wave response based on geomechanical properties of the Mount Simon and CO_2 saturation. The objective of the analysis was to determine changes in sonic velocities at realistic CO_2 saturation values. This information will aid in determining the feasibility of several monitoring technologies such as 4D seismic, crosswell seismic, and vertical seismic profiling. As CO_2 is introduced into a reservoir, the geophysical characteristics of the reservoir will change. Given,

$$V_p = \sqrt{\frac{K + {}^4\!/_3\,\mu}{\rho}}$$

and

$$V_s = \sqrt{\frac{\mu}{\rho}}$$

K=saturated bulk modulus
μ=shear modulus (remains constant)
ρ=initial bulk density

Initial saturated bulk modulus (K_{sat}) can be calculated by combining the equations and solving for K:

$$K_{sat} = \rho\left(V_p^2 - {}^4\!/_3\,V_s^2\right)$$

Bulk density changes can be computed using

$$\rho_{b2} = \rho_{b1} - \left(\phi\rho_{f1} - \phi\rho_{f2}\right)$$

ρ_{b2}=bulk density after fluid substitution
ρ_{b1}=initial bulk density
ρ_{f1}=initial fluid density
ρ_{f2}=substituting fluid density
Φ=porosity.

Saturated bulk modulus (K_{sat}) can also be expressed by the Gassmann equation (Gassmann, 1951) as:

$$K_{sat} = K_{frame} + \frac{\left(1 - \frac{K_{frame}}{K_{matrix}}\right)^2}{\left(\frac{\phi}{K_{fluid}} + \frac{(1-\phi)}{K_{matrix}} - \frac{K_{frame}}{K_{matrix}^2}\right)}$$

K_{sat}= saturated bulk modulus
K_{frame}=dry rock bulk modulus
K_{matrix}=mineral bulk modulus
K_{fluid}=pore fluid bulk modulus
Φ=porosity

The lower bound pore fluid bulk modulus can be calculated using the Reus average:

$$\frac{1}{K} = \sum_{i=1}^{N} \frac{f_i}{K_i}$$

f_i=the volume fraction of the ith constituent
K_i=the bulk modulus of the ith constituent

The upper bound pore fluid bulk modulus can be calculated using the Voigt average:

$$K = \sum_{i=1}^{N} f_i K_i.$$

Use of the Gassmann fluid substitution equation is contingent upon having V_p and V_s logs. Using the measured compressibility for the Mount Simon, and bulk moduli of 6671.7 psi for supercritical CO_2 and 333586.8 psi for brine (Xue and Ohsumi, 2004), the elastic changes in the reservoir were estimated. The Voigt upper bound was estimated as:

$$K_{sat} = \phi\left(f_{brine}K_{brine} + (1 - f_{brine})K_{CO_2}\right) + (1 - \phi)K_{rock}$$

K_{sat}=saturated bulk modulus
K_{brine}=brine bulk modulus
K_{CO2}=CO_2 bulk modulus
K_{rock}=rock bulk modulus
f_{brine}= the volume fraction of CO_2
The Reus lower bound was estimated as

$$\frac{1}{K_{sat}} = \phi\left(\frac{f_{brine}}{K_{brine}} + \frac{1-f_{brine}}{K_{CO_2}}\right) + \frac{1-\phi}{K_{rock}}.$$

These equations were used in combination with a STOMP 2D radial simulation completed as part of scoping simulation task and geomechanical rock core test results. STOMP predicts the CO_2 gas saturation field as a result of injection. The geomechanical tests provide a range of bulk moduli for the Mount Simon (Table 5-3). Together, this information may be applied to the simulated model area. Figure 5-19 shows a 2D radial simulated saturation and Vp/Vs change based on fluid substitution calculations. Results showed less than 1% change in Vp/Vs using a bulk modulus value of 26 Gpa, the average from the Arches Simulation core tests. In fact, the results suggest it may be difficult to ascertain CO_2 saturation with seismic methods except near the injection well. At lower bulk moduli, the change in Vp/Vs extended to a larger area, but still at less than 1% change. Overall, these results suggest that seismic monitoring in the Mount Simon formation in the Arches Province may be difficult due to lower CO_2 saturation levels in the reservoir and geomechanical properties of the rock matrix. Methods may be an indicator of saturation rather than measure of saturation levels.

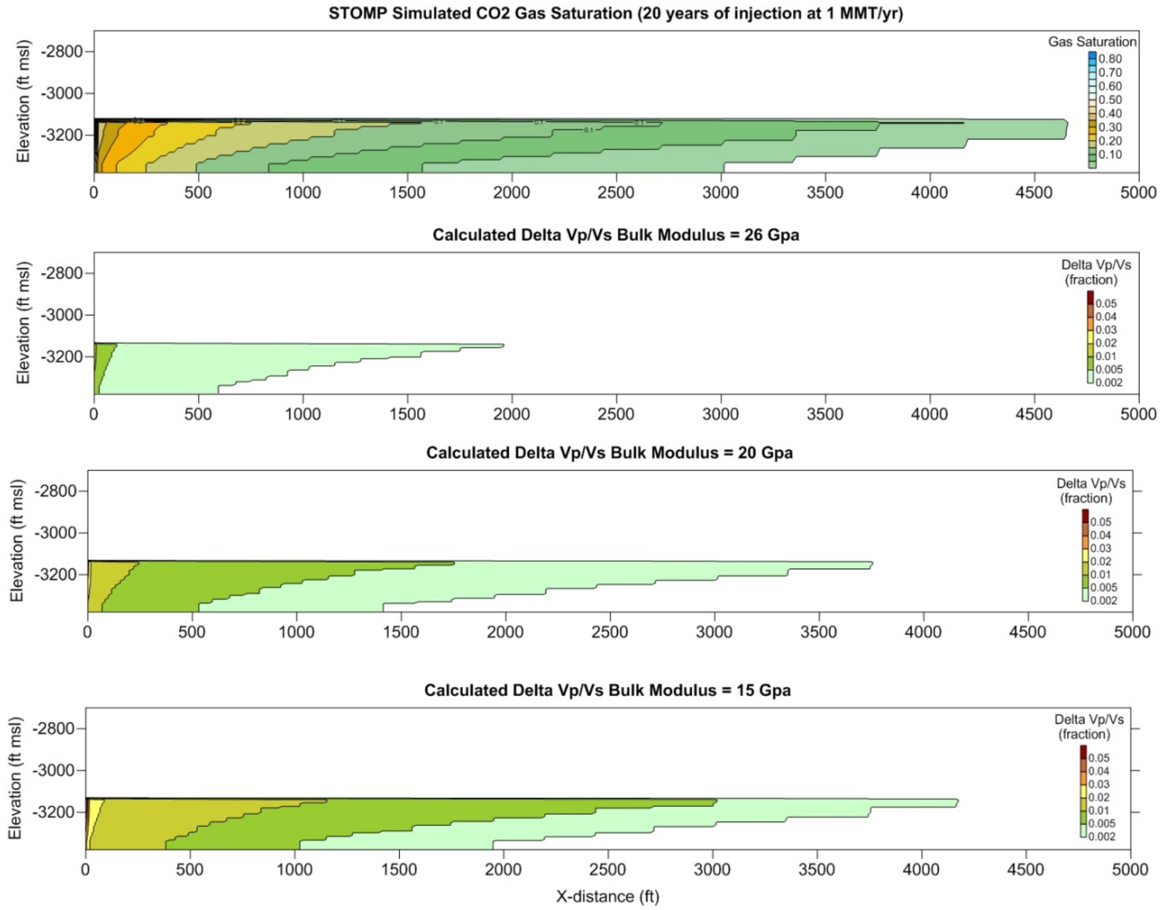


Figure 5-19. Simulated CO_2 Saturation Profile Simulated in a STOMP 2D Radial Model and Calculated Delta Vp/Vs for Different Bulk Moduli

Table 5-3. Summary of Geomechanical Test Results for Mount Simon Samples

Sample No.	Depth (ft)	Porosity	Confining Pressure (psi)	Compressive Strength (psi)	Static Young's Modulus ($x10^6$ psi)	Static Poisson's Ratio	Density	Bulk Compressibility (1/psi)	Dry Bulk Modulus 1/psi	Dry Bulk Modulus Gpa
1-1RMV	2967.55	0.19	1000	15202	3.03	0.36	2.05	2.74E-07	3.66E+06	25.2
1-2RMV	3066.40	0.16	1000	15729	3.34	0.32	2.36	3.24E-07	3.09E+06	21.3
1-3RMV	5022.40	0.12	1650	17259	2.33	0.31	2.29	4.94E-07	2.03E+06	14.0
1-4RMV	4970.65	0.02	1650	36729	6.45	0.29	2.55	1.97E-07	5.07E+06	35.0
1-5RMV	4978.90	0.11	1650	31557	5.55	0.21	2.38	3.16E-07	3.17E+06	21.8
1-6RMV	5528.55	0.11	1850	32376	4.96	0.35	2.36	1.85E-07	5.40E+06	37.2
1-7RMV	5334.10	0.11	1850	28477	4.54	0.17	2.40	4.32E-07	2.31E+06	16.0
1-8RMV	5730.25	0.13	1850	41184	7.86	0.25	2.75	1.89E-07	5.30E+06	36.6
1-9RMV	5731.50	0.12	1850	30082	4.65	0.30	2.44	2.58E-07	3.87E+06	26.7
Avg	4814.48	0.12	1594.44	27621.67	4.74	0.28	2.40	2.96E-07	3.77E+06	26.0

Section 6.0: IMPLICATIONS FOR REGIONAL STORAGE FEASIBILITY

Task 6 included a sequence of items to better define large-scale storage applications in the Arches Province. Infrastructure analysis was completed through a pipeline routing study, scoping level simulations, and basin-scale simulations. Regional upscaling analysis was completed with parametric analysis of CO_2 storage impacts.

6.1 Infrastructure Analysis

Infrastructure analysis was focused on determining potential routes for CO_2 pipelines from sources to injection fields. In addition, scoping level simulations were completed to determine feasible injection rates, number of injection wells for well fields, separation distance for well fields, well spacing for injection wells, and simulated pressure/saturation front buildup due to CO_2 injection. This information was used as input for basin-scale multi-phase simulation of a regional storage scenario with seven injection fields.

6.1.1 Pipeline Routing Analysis. A least cost path study was conducted using the CO_2 pipeline transport cost estimation model developed by MIT's Carbon Capture and Sequestration Technologies Program (2009). This program was used in conjunction with CO_2 source and carbon sink location data selected for the study. The objective of the analysis was to investigate least cost path trends for CO_2 transportation pipelines routed from significant point sources of CO_2 to pre-selected carbon sequestration sites in the Arches Province region. The MIT model was developed as a tool to be used within the ArcGIS software package to calculate a least cost path between two selected points and produce construction cost outputs associated with that path. The program package consists of three layers: A U.S. map layer, a states layer and the least cost path layer, or obstacles layer. The analytical power of the model is in the obstacle layer, which ArcGIS utilizes to perform the least cost path analysis. The obstacle layer is pre-built and cannot be modified by the user.

For the purposes of this study, 20 CO_2 sources and three CO_2 sinks were selected to run the CO_2 pipeline transport cost estimation simulation in the Arches Province. The top 20 significant CO_2 point sources in the Arches Province were screened base on their annual CO_2 output. Three carbon point sink locations were selected based on their proximity to the selected CO_2 point sources and geologic conditions of the Mount Simon sandstone favorable to carbon sequestration and storage within the MRCSP region. Location coordinates of the 20 CO_2 point sources and three carbon sink sources were uploaded to the ArcGIS module. The uploaded CO_2 point source and carbon sink locations were then selected from the least cost path interface for each least cost path simulation.

A map displaying the least cost path for the calculated CO_2 transportation pipeline routes is shown in Figure 6-1. These pipeline routes suggest there are some central areas where pipeline routes intersect or blend together. These locations may be practical potential regional storage fields. Seven locations were selected as potential regional storage field locations. These locations are fairly arbitrary. Several other locations may be feasible for regional storage fields. However, the seven locations do represent coverage across the Arches Province. The locations are separated by at least 50 km, which should minimize interference between storage fields. Total injection of 10 to 20 MMT CO_2 at each location would represent total injection rates of 70 to 140 MMT CO_2 per year (represents approximately 25 to 50% reduction of CO_2 emissions from large point sources across the Arches Province).

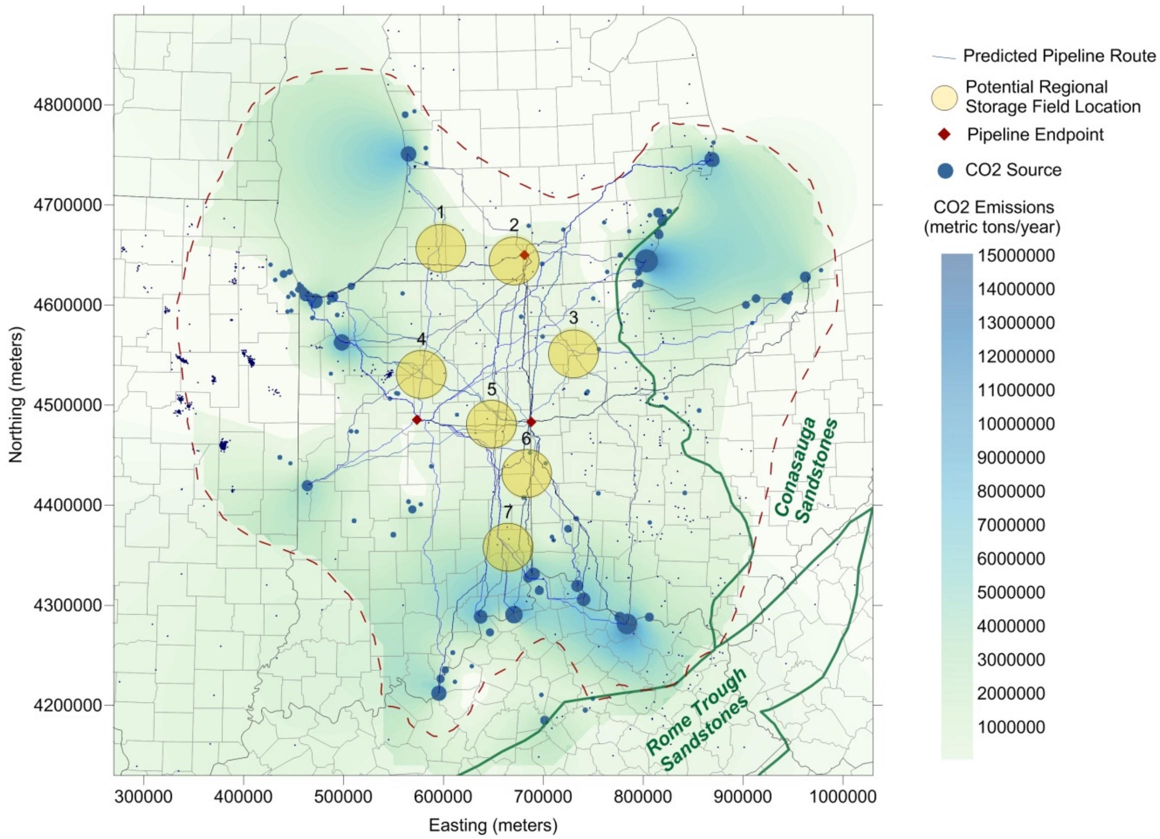


Figure 6-1. Pipeline Routing Analysis Results

6.1.2 Scoping Level Simulations. Scoping level simulations were run with the multi-phase code STOMP in 2D mode. The first set of simulations was completed based on general conditions in the model domain for 5 by 5, 6 by 6, and 7 by 7 well clusters at several injection rates. Simulation results were analyzed for injection potential and pressure buildup. The second set of simulations was based on site-specific conditions at seven potential regional storage sites identified in the pipeline routing study. These simulations were used to evaluate the range of conditions expected within the Arches Province. The first set of simulations was based on generic conditions in the model domain. Simulations were designed to represent a cluster of injection wells at a regional storage site. In this arrangement, a well in the middle of each regional storage site would essentially inject into a cylinder of finite lateral extent due to well interference, and could be taken as the conservative case. Using this description of a well in a closed volume as a representative case, simple 2D r-z simulations were carried out to examine the interplay between well spacing and pressure buildup. The model domain consists of the Eau Claire sealing unit and the Mount Simon sandstone where CO_2 is injected.

The second set of simulations was based on site-specific conditions in the model domain. Seven potential regional storage field locations were identified using a GIS study that takes into consideration the location of stationary CO_2 sources and least cost CO_2 pipeline distribution networks. Each regional site has a storage area of approximately 50 miles, and each site is expected to inject 10 to 20 MMT CO_2 per year. Two representative well configurations were selected to mimic flow geometries in the middle and the edge of the injection well cluster. As before, 2D r-z simulations were designed to evaluate the range of conditions to be expected with respect to pressure buildup and plume movement. In these simulations,

the model domain also consists of the Eau Claire sealing unit and the Mount Simon sandstone where CO_2 is injected.
The simulations were carried out using STOMP. The STOMP simulator was developed by the Pacific Northwest National Laboratory for modeling subsurface flow and transport systems and remediation technologies. The simulator's fundamental purpose is to produce numerical predictions of thermal and hydrogeologic flow and transport phenomena in variably saturated subsurface environments, which are contaminated with volatile or nonvolatile organic compounds. The governing coupled flow equations are partial differential equations for the conservation of water mass, air mass, (dissolved) organic compound mass and thermal energy. Quantitative predictions from the STOMP simulator are generated from the numerical solution of these partial differential equations that describe subsurface environment transport phenomena. Solution of the governing partial differential equations occurs by the integral volume finite difference method. The governing equations that describe thermal and hydrogeological flow processes are solved simultaneously using Newton-Raphson iteration to resolve the nonlinearities in the governing equations. Governing transport equations are partial differential equations for the conservation of solute mass. Solute mass conservation governing equations are solved sequentially, following the solution of the coupled flow equations, by a direct application of the integral volume finite difference method. The STOMP simulator is written in the FORTRAN 77 language, following American National Standards Institute standards (White and Oostrom, 2000).

6.2 Model Setup – Generic Case

Figure 6-2 shows the model geometry used for the generic case simulations. The model consists of 20 vertical rows that extend from the top of the Eau Claire to the base of the Mount Simon, and 100 radial columns that extend from the center of the injection well to the closed (symmetry) outer boundary. Vertically, the model is 357 m thick (from a depth of 1000 m to 1357 m), and radially, the model has variable radial extent depending on the assumed site radius and the number of wells in the injection cluster (as described in the next section). At the bottom of the model, the reference pressure and temperature are assumed to be 2000 psi and 100 ^{o}F, respectively. These parameters represent fairly typical conditions in the Arches Province.

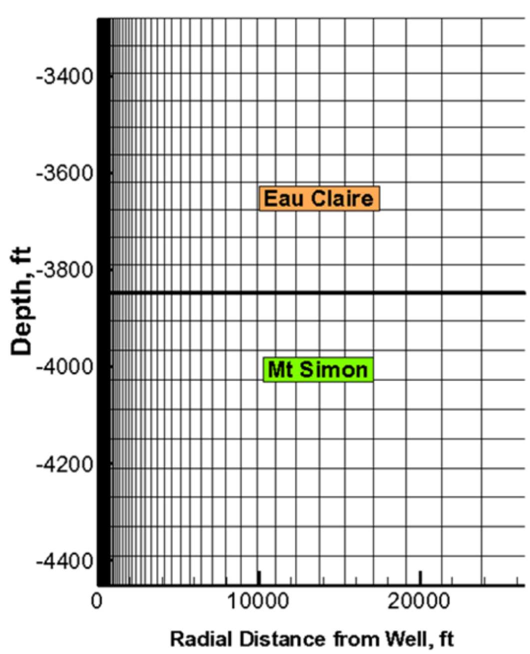


Figure 6-2. Model Geometry, Generic Case

Porosity and permeability for the Eau Claire and the Mount Simon are based on average conditions within the model domain. Capillary pressure and relative permeability data are based on assumed values. These are shown in Table 6-1.

Table 6-1. Model Parameters, Generic Case

Unit	Thickness (m)	Porosity (%)	Permeability (mD)	Capillary Pressure and Relative Permeability Parameters
EC	172	7	0.02	Brooks-Corey saturation function card with the Mualem porosity distribution model (capillary entry head = 34.9 cm, lambda parameter = 1.36, minimum water saturation = 0.0767)
MS	185	11	53	

6.3 Scenarios – Generic Case

The generic case considers three site radii (25 miles, 32 miles, 40 miles) and three well arrays (7×7, 6×6, 5×5). Constant rate CO_2 injection is assumed at a rate of ~100 MMT/yr (for all three sites) for 30 years into the Mount Simon. This leads to the following combinations with respect to model dimensions and per-well injection rate, as shown in Table 6-2.

Table 6-2. Model Dimensions and Injection Rate, Generic Case

Site radius →		25 miles	32 miles	40 miles	Injection Rate (MMT/yr)
Well array	**# of wells**	**Storage radius (m)**			
7×7	49	5782	7401	9251	0.68
6×6	36	6746	8635	10793	0.93
5×5	25	8095	10362	12952	1.33

Performance metrics for these simulations are taken to be: (a) 2D pressure and saturation contours at 30 yrs, and (b) pressure buildup at the mid-point of the Mount Simon.

6.4 Results – Generic Case

Figure 6-3 shows pressure and saturation contours at t = 30 years for the 25 mile site radius, 5×5 well array scenario. This set of conditions corresponds to the smallest sized system at the highest injection rate. As expected, the pressure contours suggest an upward gradient between the Mount Simon and the Eau Claire (left panel). The saturation contours also show the development of significant buoyant effects – especially at the Eau Claire-Mount Simon interface.

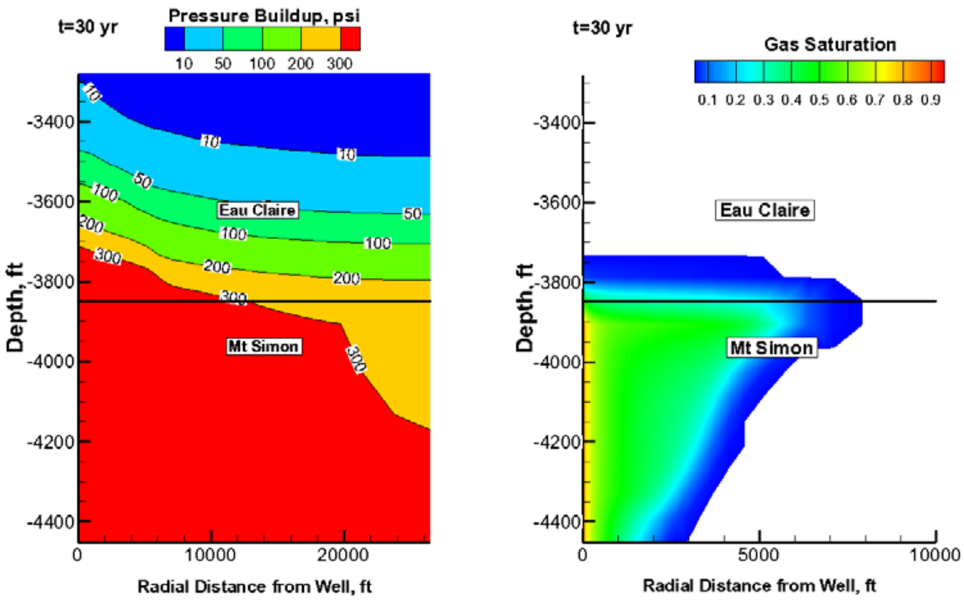


Figure 6-3. Pressure and Saturation Contours (25 mile site radius, 5×5 well array)

Figure 6-4 illustrates the pressure buildup at the mid-point of the Mount Simon. After an initial transient period, the effect of the closed outer boundary can be clearly seen in the pseudo-steady state type pressure buildup after ~2200 days, where pressure tends to increase linearly with time. Also shown for comparison is the fracture pressure, which is not exceeded during the injection period.

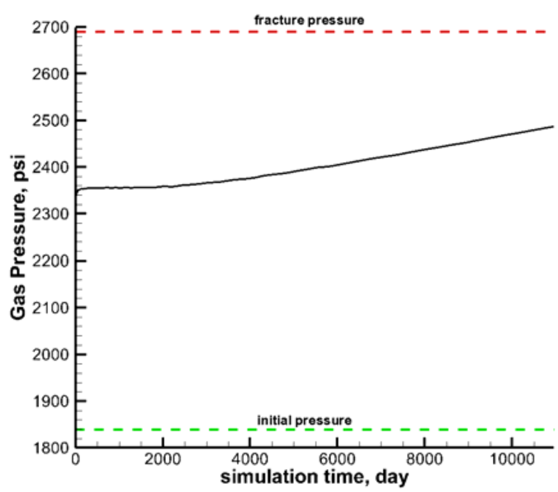


Figure 6-4. Pressure Buildup at Mid-point of Mount Simon (25 mile site radius, 5×5 well array)

Figure 6-5 shows pressure and saturation contours at t = 30 years for the 32 mile site radius, 6×6 well array scenario. This set of conditions corresponds to the mid-sized system at the medium injection rate. The pressure contours suggest less upward gradient between the Mount Simon and the Eau Claire (left panel) than that seen earlier in Figure 3-2. Similarly, the saturation contours (right panel) show the development of less significant buoyant effects at the Eau Claire-Mount Simon interface than seen in Figure 6-3.

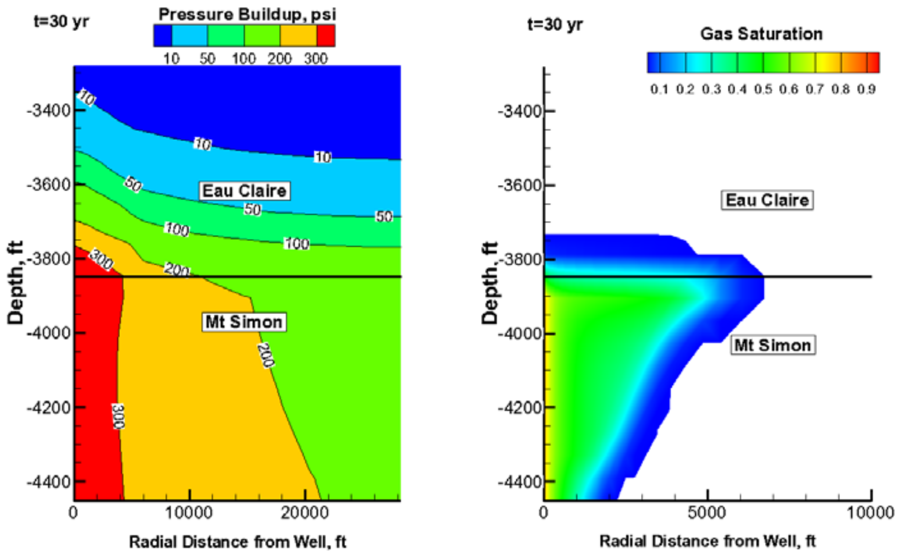


Figure 6-5. Pressure and Saturation Contours (32 mile site radius, 6×6 well array)

Figure 6-6 shows the simulated pressure buildup for this scenario at the mid-point of the Mount Simon. After an initial transient period, the effect of the closed outer boundary can be clearly seen in the pseudo-steady state type pressure buildup after ~3000 days, where pressure tends to increase linearly with time. Also shown for comparison is the fracture pressure, which is not exceeded during the injection period.

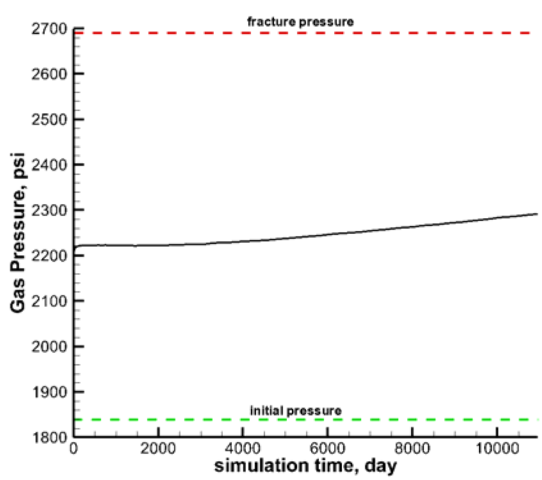


Figure 6-6. Pressure Buildup at Mid-point of the Mount Simon (32 mile site radius, 6×6 well array)

Figure 6-7 shows pressure and saturation contours at t = 30 years for the 40-mile site radius, 7×7 well array scenario. This set of conditions corresponds to the largest system at the smallest injection rate. The pressure contours suggest primarily horizontal flow in the near-wellbore region, with some cross-flow between the Mount Simon and the Eau Claire (left panel) at the right-edge of the model. Similarly, the saturation contours (right panel) show the development of moderate buoyant effects at the Eau Claire-Mount Simon interface.

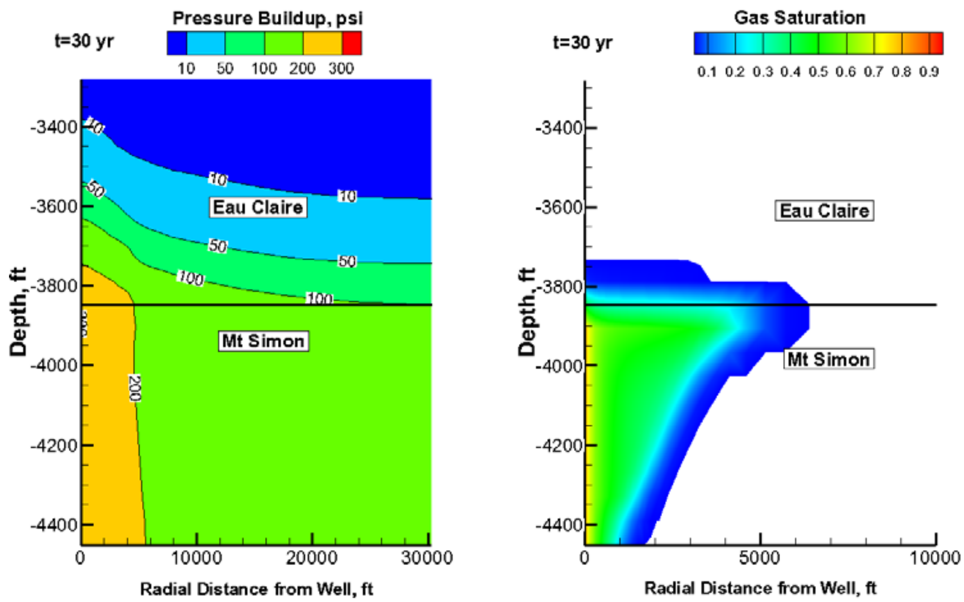


Figure 6-7. Pressure and Saturation Contours (40 mile site radius, 7×7 well array)

Figure 6-8 shows the pressure buildup for the 7×7 well array scenario at the mid-point of the Mount Simon. After an initial transient period, the effect of the closed outer boundary can be clearly seen in the pseudo-steady state type pressure buildup after ~4000 days, where pressure tends to increase linearly with time. Also shown for comparison is the fracture pressure, which is not exceeded during the injection period.

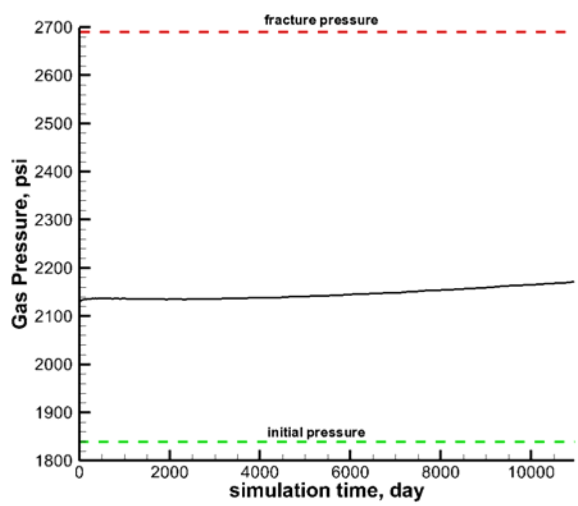


Figure 6-8. Pressure Buildup at Mid-point of the Mount Simon (40 mile site radius, 7×7 well array)

Figure 6-9 shows the pressure buildup at 30 years as a function of site radius and well array from all of the scenarios detailed in Table 6-2. This figure provides information on the interplay between well spacing and pressure buildup that can be useful for system design when used in conjunction with site-specific information.

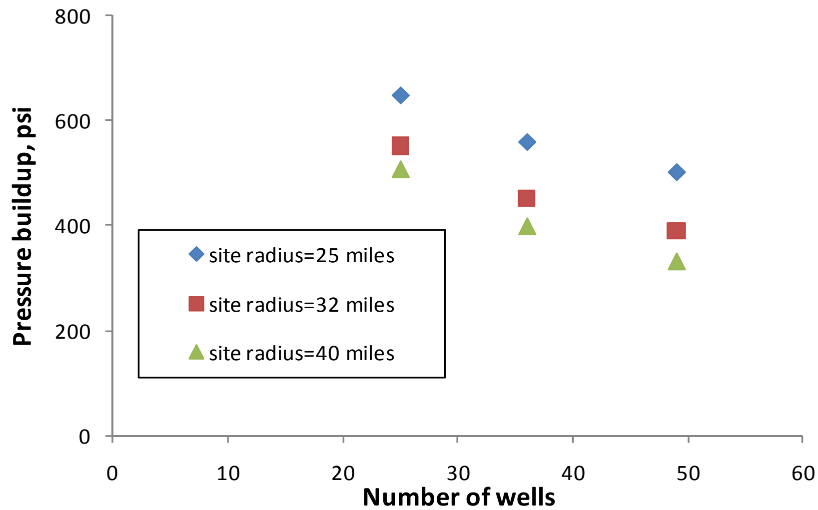


Figure 6-9. Pressure Buildup as a Function of Site Radius and Well Array

6.5 Summary – Generic Case

Thus far, simple scoping simulations have been presented to examine the relationship between well spacing versus pressure buildup. These preliminary calculations have been carried out with "average" porosity/permeability values and generic assumptions regarding storage site location and dimension. The next set of simulations address site-specific cases, including stratigraphic column variability, vertical heterogeneity in porosity and permeability, and relative permeability model choice.

6.6 Model Setup – Site-specific Case

The site-specific simulations follow the strategy adopted in the generic case simulations, i.e., the aim is not to conduct a full basin-scale simulation, but to simplify the problem by studying the effect of equivalent single well systems. As before, simple 2D r-z simulations were carried out to examine plume migration, pressure propagation, and CO_2 flux across the Mount Simon-Eau Claire interface.

The starting point of these simulations is the map of seven potential regional storage site locations shown in Figure 6-10. These locations were selected on the basis of GIS analyses that balanced the location of stationary CO_2 sources with existing pipeline networks.

A vertical stratigraphic column was extracted at the mid-point of each of the seven sites shown in Figure 6-11. These represent a broad range of conditions with respect to the depth of the Mount Simon, relative thickness of the Eau Claire and the Mount Simon, and the amount of buffer available above the Eau Claire. For example, Site 3 has the lowest Mount Simon thickness, combined with a much thicker Eau Claire, and the smallest column of overlying formations. Site 1 has the thickest column of the Mount Simon beneath a much thinner Eau Claire, but the thickest column of overlying formations. Site 7 represents more or less average conditions across the seven sites.

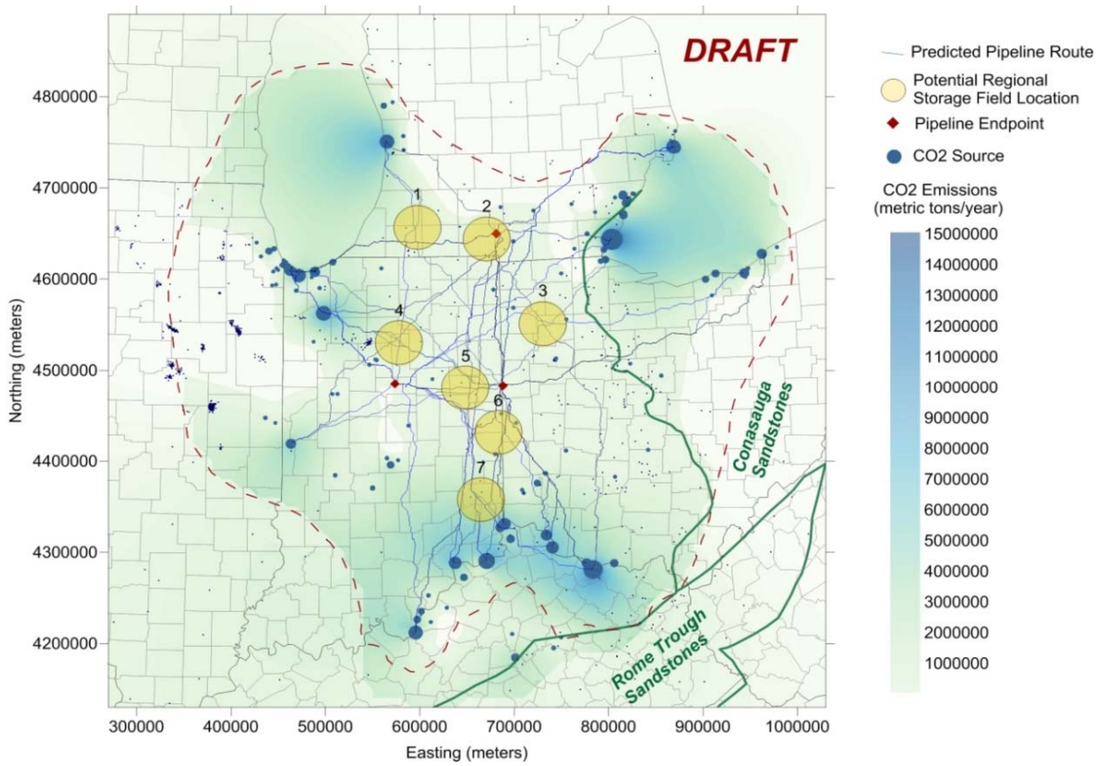


Figure 6-10. Potential Regional Storage Field Locations

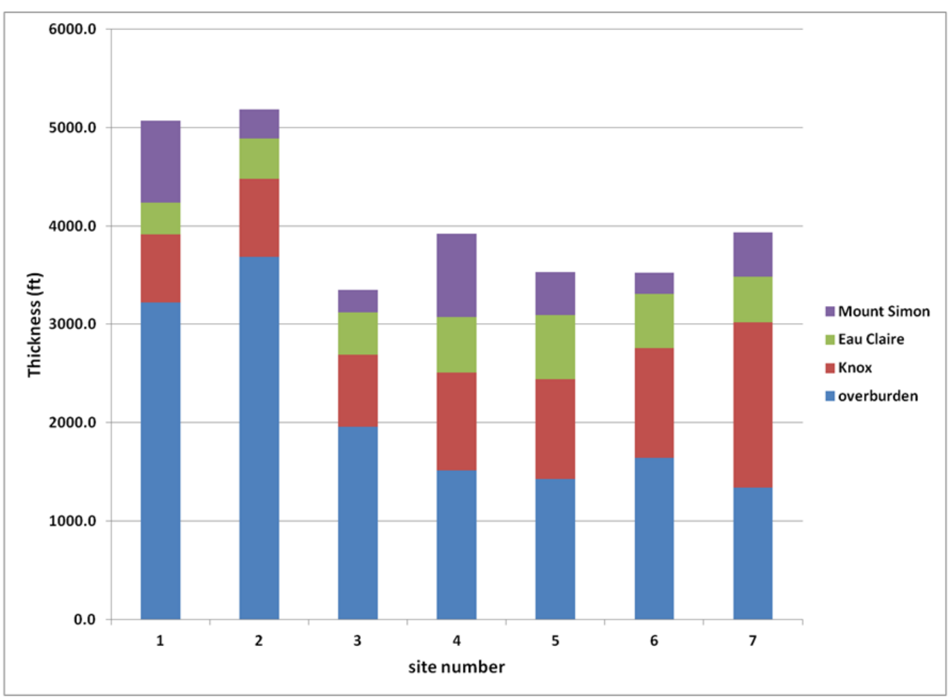


Figure 6-11. Stratigraphic Columns at Each Regional Site

Each site is assumed to have a 4×4 array of injection wells – such that the nominal injection rate is ~1 MMT/yr/well. Within this array, two end member scenarios were identified. The first one corresponds to a well in the middle of the model domain, where symmetry conditions create a no-flow boundary on all sides. This is designated as Model A in Figure 6-12. The second corresponds to a well at the edge of the well network, which can be represented as an equivalent semi-infinite system. This is designated as Model B in Figure 6-12. Model A can be seen as the conservative case, as it will result in the maximum amount of pressure buildup. Model B is the other end-member case, as it will result in the minimum amount of pressure buildup.

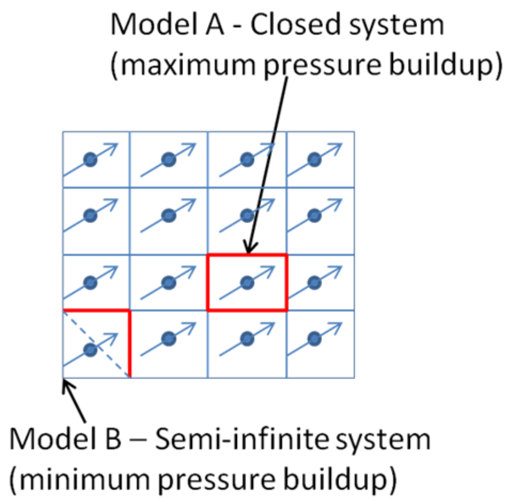


Figure 6-12. Model Domain Simplification

The first set of simulations described here corresponds to Site 7, Model A. Figure 6-13 shows the model geometry used for this case. The model consists of 28 vertical layers that extend from the top of the Eau Claire to the base of the Mount Simon, and 200 radial columns that extend from the center of the injection well to the closed (symmetry) outer boundary. Vertically, the model is 280 m thick (from a depth of 644 m to 924 m), and radially, the model has variable radial extent depending on the assumed site radius and the number of wells in the injection cluster (as described in the next section). At the bottom of the model, the reference pressure and temperature are assumed to be 1870 psi and 92 ^{o}F, respectively.

The averaged porosity profile is shown in Figure 6-14 (left panel). Here, the Eau Claire has been sub-divided into three primary flow units, and the Mount Simon has been divided into six primary flow units. The primary flow units have also been subdivided into additional computational model layers. Note that EC2 and MS2 are low porosity layers sandwiched between two higher-porosity layers. Note also that MS4, MS5 and MS6, in combination, have characteristics similar to that of MS2. The averaged permeability profile, also shown in Figure 6-14 (right panel), mirrors the porosity layering since it is estimated from porosity using a simple exponential transform:

$$k = 0.000226 \exp\left(\frac{37.27\varphi}{100}\right)$$

where
k = permeability (mD),
Φ = porosity (%).

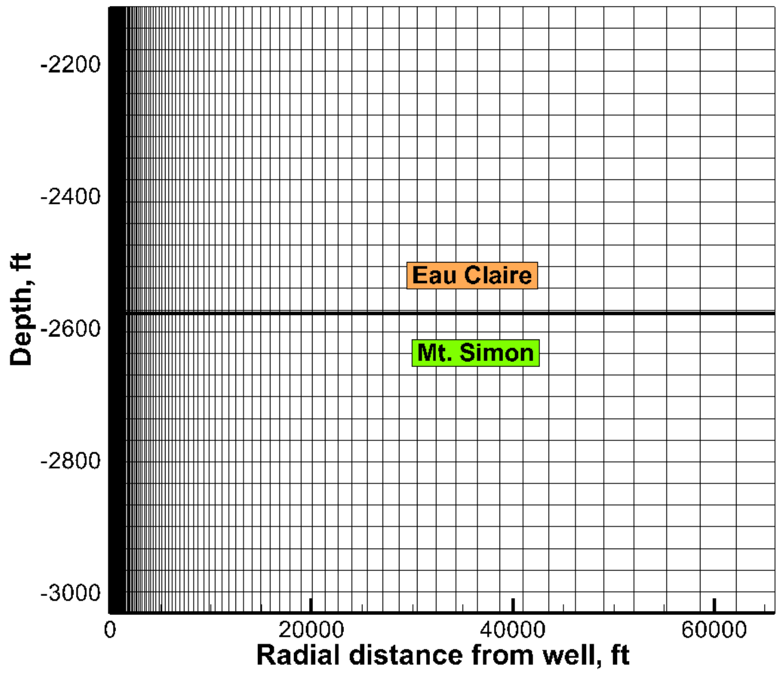


Figure 6-13. Model Geometry (Site 7, Model A)

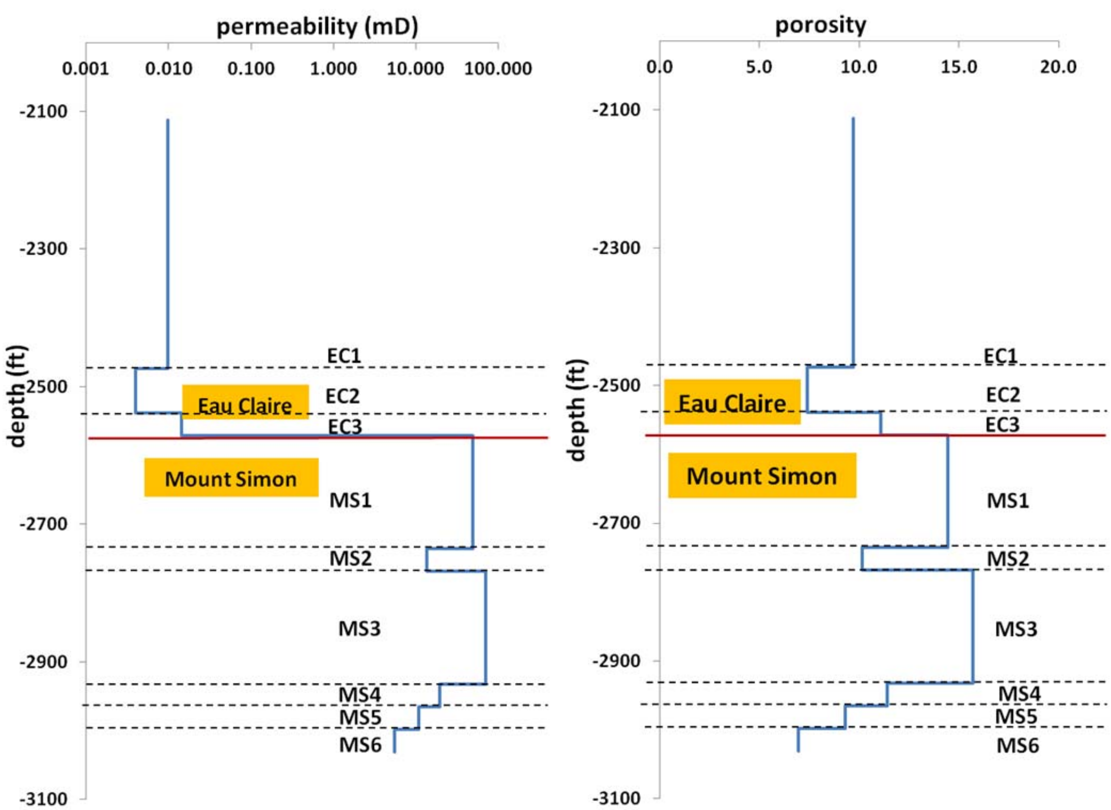


Figure 6-14. Averaged Permeability Profile (left panel) and Porosity Profile (right panel) at Site 7

Two variants were created to characterize the relative permeability – capillary pressure relationship.

Case 1 (VG_Mualem) – For the Mount Simon, the capillary entry pressure value, corresponding to the porosity and permeability of the reference layer, is taken from a preliminary FutureGen modeling study (White and Zang, 2011). Leverett-J function scaling was used to evaluate the value of the capillary entry pressure for each of the layers of the Mount Simon in this current model, depending on the layer's porosity and permeability. The procedure is similar for the Eau Claire, with the only difference being that the capillary entry pressure value, and the corresponding porosity and permeability of the reference layer, are taken from Zhou et al. (2010). The Leverett J-scaling is expressed as (Leverett, 1941):

$$\frac{P_c\sqrt{k/\phi}}{\sigma\cos\theta} = J\left(S_w,\Gamma\right)$$

where

P_c = capillary pressure
J = Leverett J-function
k = absolute permeability
Φ = porosity
σ = interfacial tension
θ = contact angle
S_w = water saturation
τ = tortuosity.

Case 2 (VG_Mualem_fit) – Mercury injection capillary pressure (MICP) tests were performed on 14 samples from the Mount Simon, and two samples from the Eau Claire. The sample Leverett *J* function data for each of the two units was plotted as a function of S_w, and a curve is fit through the 14 samples, and two samples, respectively, to obtain $J_{MS}(S_w,\tau)$ and $J_{EC}(S_w, \tau)$. Using the Leverett *J*-function scaling, it is possible to calculate P_c=f(S_w), for a given layer, of porosity Φ, permeability k, interfacial tension σ and contact angle θ.

A non-linear least squares optimization procedure is then employed to fit this capillary pressure data to the van-Genuchten saturation function (van Genuchten, 1980). From this procedure, the van-Genuchten model parameters are obtained, which are used as input in the STOMP saturation function card.

$$\log h = \frac{\left(\left(\frac{S_w - S_{wr}}{1 - S_{wr}}\right)^{\frac{-1}{m}} - 1\right)^{\frac{1}{n}}}{\alpha}$$

where

h = capillary pressure head
S_w = water saturation
S_{wr} = irreducible water saturation
and m, n, α = van-Genuchten model parameters.

The corresponding relative permeability curves are shown in Figure 6-15. Capillary pressure related parameters are given in Table 6-3. The van-Genuchten saturation function and the Mualem porosity distribution models are used in the saturation function and relative permeability cards, respectively.

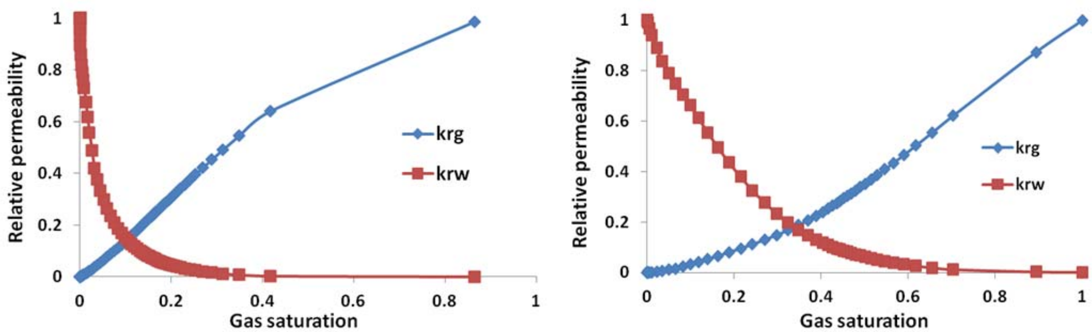


Figure 6-15. Relative Permeability Curves (Case 1 [VG_Mualem] – left panel, and Case 2 [VG_Mualem_fit] – right panel)

Table 6-3. Capillary Pressure Curve Parameters, Case 1 and Case 2

Rock Type	van-Genuchten α Parameter (1/ft)	van-Genuchten n Parameter	Irreducible Water Saturation ($S_{w,irr}$)	van-Genuchten m Parameter
Case 1				
EC	0.000643	1.695	0.4	0.41
MS	0.0461	1.695	0.3	0.41
Case 2				
EC1, EC3	0.3902	5.61	0.0021	0.822
EC2	0.365	5.904	0.0028	0.8306
MS1, MS3	0.829	3.623	9.87E-05	0.724
MS2, MS4, MS5	0.7006	3.96	0.00014	0.747
MS6	0.643	4.15	0.00017	0.759

As described earlier, seven stratigraphic columns were extracted to form representative models covering the entire Arches study area. For each of these sites, two model configurations were identified. Model A represents the conservative closed outer boundary case, and Model B represents the semi-infinite outer boundary case (Figure 6-16). Finally, there are two sets of relative permeability curves, viz: Case 1 (VG_Mualem), and Case 2 (VG_Mualem_fit). This leads to a total of 28 scenarios. In each of these cases, CO_2 injection is simulated for 30 years at the rate of 0.93 MMT/yr. In the next section, the results for two of these 28 scenarios (Site 7, Model A, and Cases 1 and 2) are described.

Figure 6-17 shows pressure and saturation contours at t = 30 years for Site 7, Model A, Case 1. The pressure contours (left panel) suggest primarily horizontal flow in the near-wellbore region, although the saturation contours (right panel) show the development of buoyancy driven effects as indicated by the angled CO_2-brine interface. Pressure contours for Case 2 (Figure 6-16, left panel) show similar behavior, i.e., vertical contours within the Mount Simon indicating near-horizontal flow. However, saturation contours for Case 2 (right panel) show an attenuated front, possibly because of the lower relative permeability to CO_2 in Case 2 compared to Case 1.

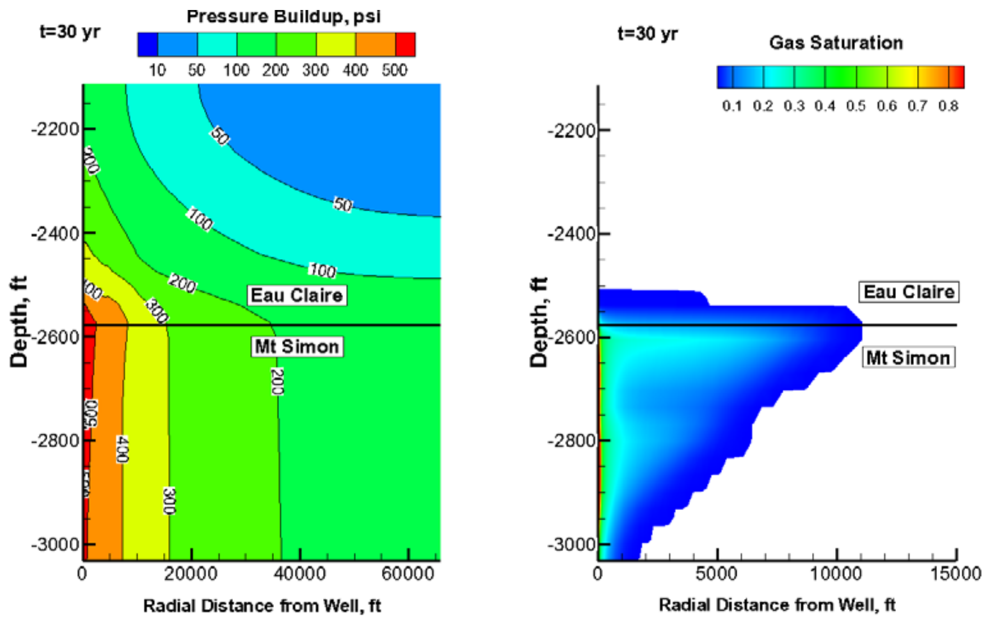


Figure 6-16. Pressure and Saturation Contours (Site 7, Model A, Case 1)

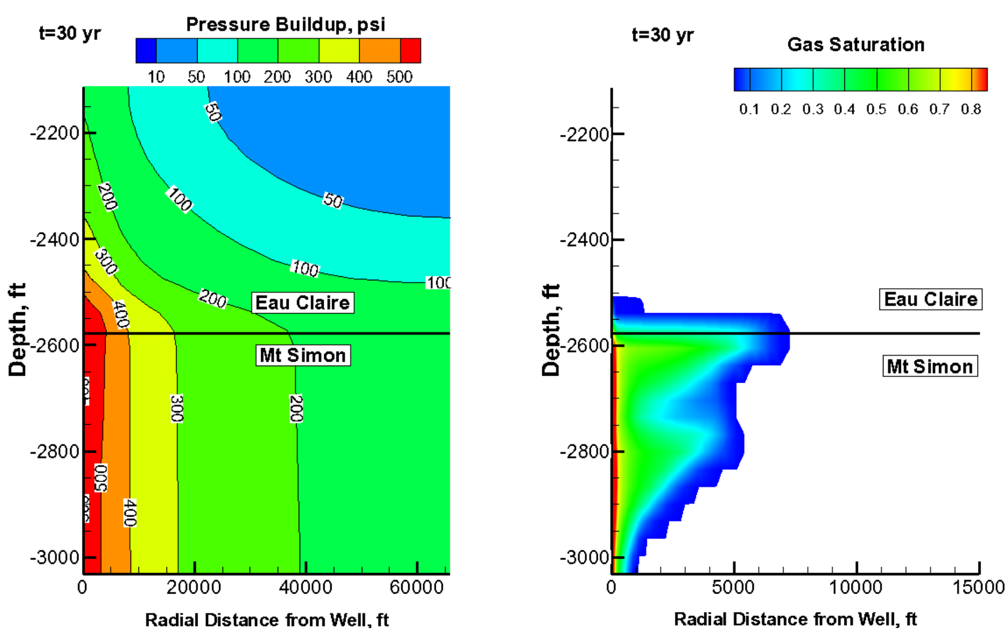


Figure 6-17. Pressure and Saturation Contours (Site 7, Model A, Case 2)

Figure 6-18 shows the pressure buildup history at the mid-points of the Eau Claire for the two relative permeability variants (Case 1 and Case 2). At late times, both sets of pressure curves tend to converge, suggesting that the pressure front is essentially responding to the properties of the brine-filled region beyond the CO_2 front, and is therefore relatively insensitive to relative permeability differences.

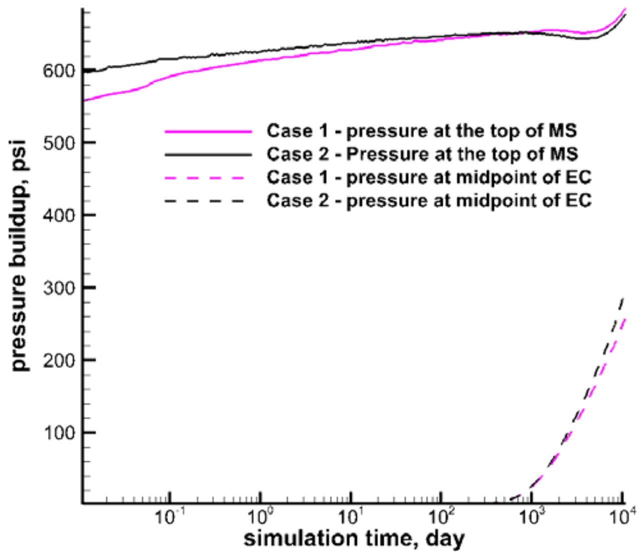


Figure 6-18. Injection Well Pressure Buildup (Site 7, Model A Case 1, Case 2)

The cumulative mass flux across the Mount Simon-Eau Claire interface is shown in Figure 6-19. Here, the impact of relative permeability effects is shown. Case 1 has a much higher relative permeability to CO_2 than Case 2, which leads to a higher mobility for CO_2 and, hence, greater movement of CO_2 mass across the Eau Claire-Mount Simon interface.

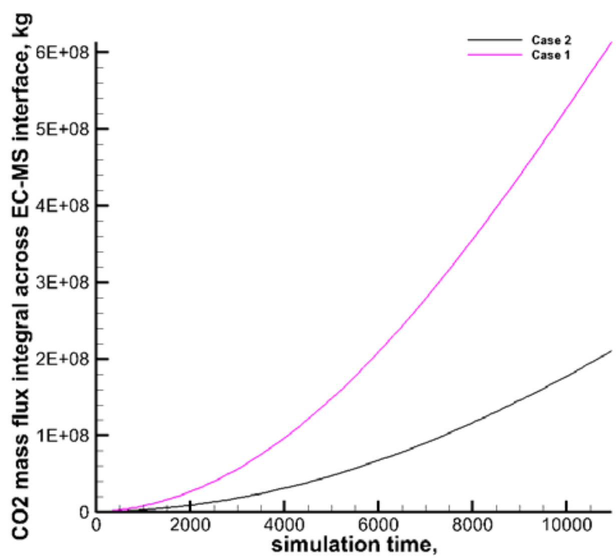


Figure 6-19. CO_2 Mass Flux Integral across EC-MS Interface (Site 7, Model A, Case 1, Case 2)

Scoping level simulations were completed for one of the sites (Site 7), which represents average conditions for layer thicknesses in the Arches study area. Also, the simulations use the configuration for Model A, which has a closed outer boundary and thus produces the highest pressure buildup. Both relative permeability variants (Case 1 and Case 2) have been utilized, and show different system response for saturation contours and CO_2 mass flux integral across the Mount Simon-Eau Claire interface. Pressure response is relatively unaffected by relative permeability effects.

6.6.1 Basin-Scale Multi-Phase Simulations. As part of the regional storage analysis, the basin-scale model was used to simulated large-scale injection. CO_2 was injected into 63 wells in the seven potential regional injection fields determined in the pipeline routing study. A maximum injection pressure for each well was determined using 0.675 (90% of the 0.75 psi/ft fracture gradient) times the depth. In certain areas within the designated storage sites, the Mt Simon is quite shallow and the permeabilities are rather low (less than 50 mD). This results in limitations on the screened interval, the maximum injection pressure, and the injection rate. For the basin scale model it was assumed that all injection wells were screened over the entire Mt Simon and that the maximum injection pressure would determine if the specified injection rate could be sustained. The simulation results show that only about 8.65% of the total mass can be injected at the selected well locations for the given scenario (Figure 6-20). This is due to the shallowness of the Mt Simon in the areas near large point sources, resulting in a low injection pressure limit which thereby limits the injection rate to less than one quarter the specified rate at storage fields 1 and 2 and much less than that at the other sites. Because of the low injection rates, the pressure buildup at the top of the Mt Simon after 20 years of injection is very localized (Figure 6-21).

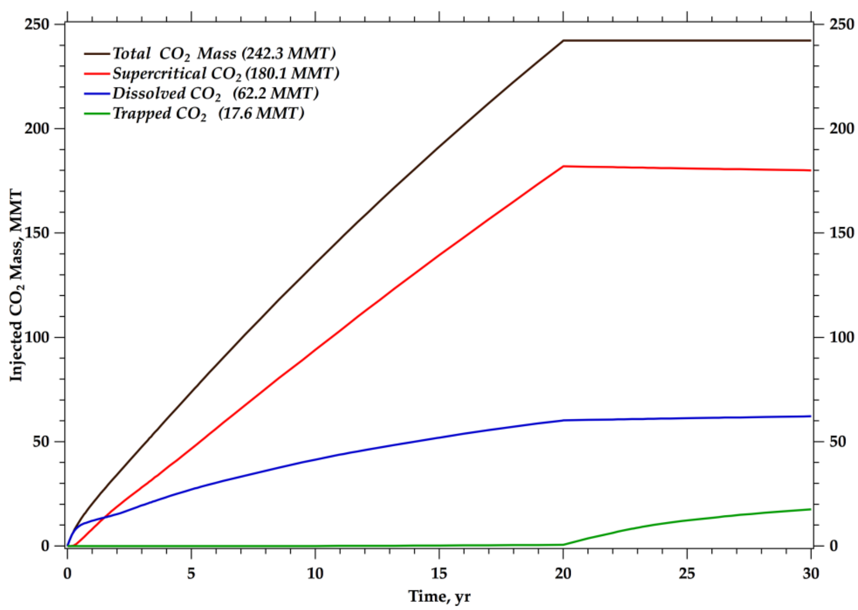


Figure 6-20. Mass of Injected CO_2 Mass vs. Time

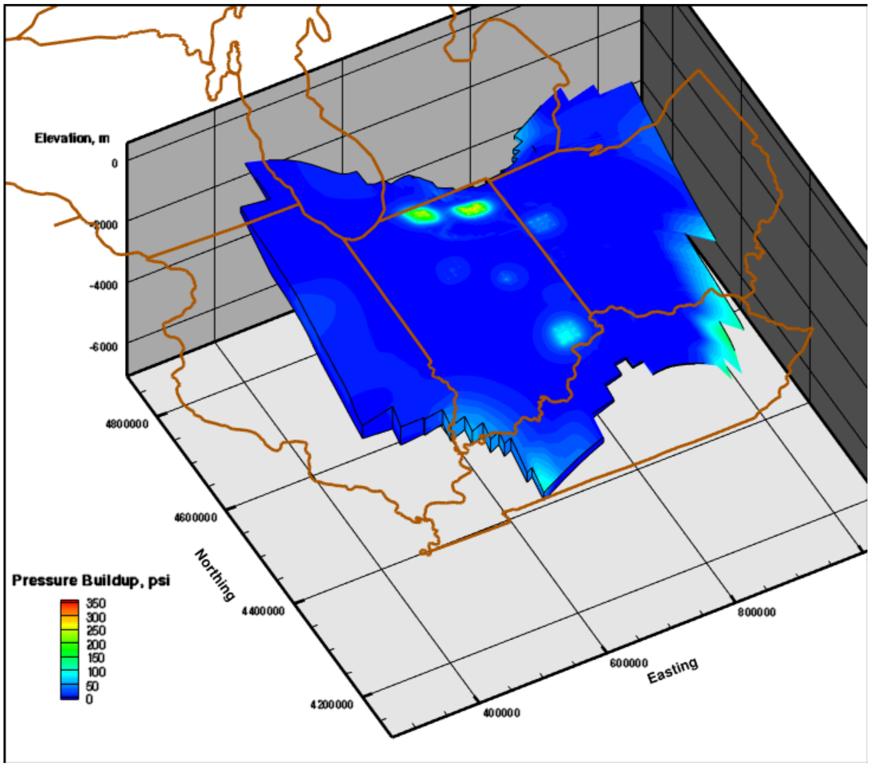


Figure 6-21. Basin-Scale Simulation Pressure Buildup in the Top Layer of the Mount Simon after 20 Years of CO_2 Injection

An alternative scenario was developed that maintained the 7x9 well array configuration, but relocated the storage fields to areas with higher transmissivity in the Mt Simon, representing areas more likely to be designated as suitable injection sites (Figure 6-22). This resulted in higher maximum injection pressures and higher permeability layers which thereby resulted in higher CO_2 injection rates. Figure 6-23 shows the injected mass over time for this scenario, demonstrating that about 75% of the total mass can be injected into 63 wells using this scenario.

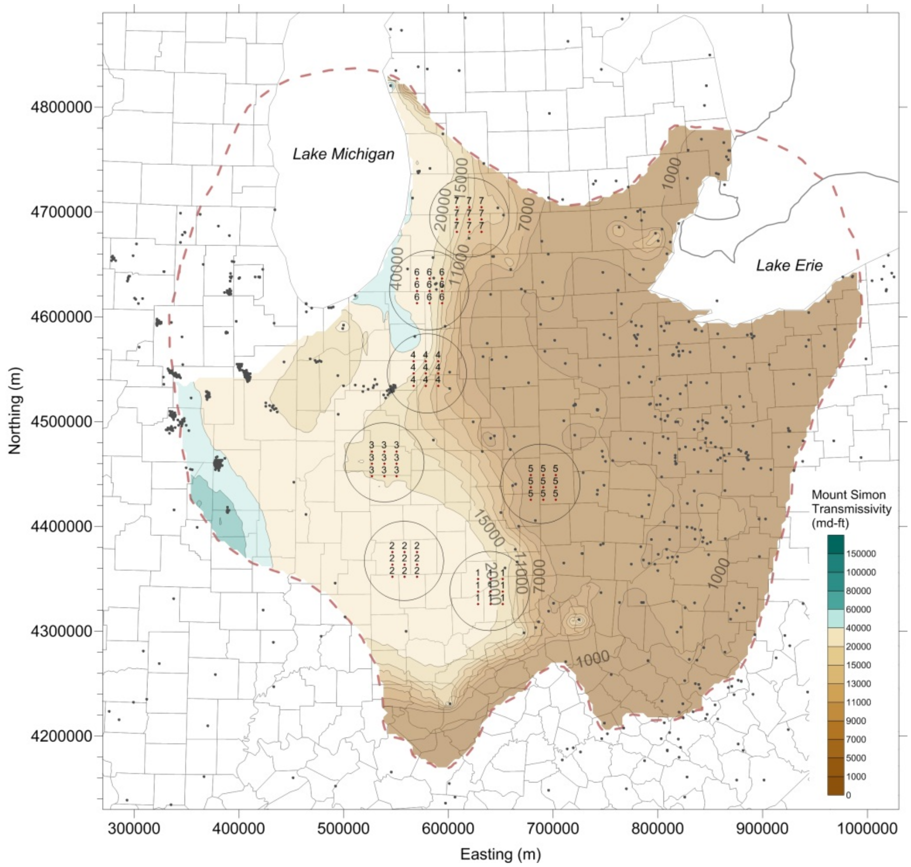


Figure 6-22. Alternate Scenario with Storage Fields Relocated to Areas of Higher Transmissivity

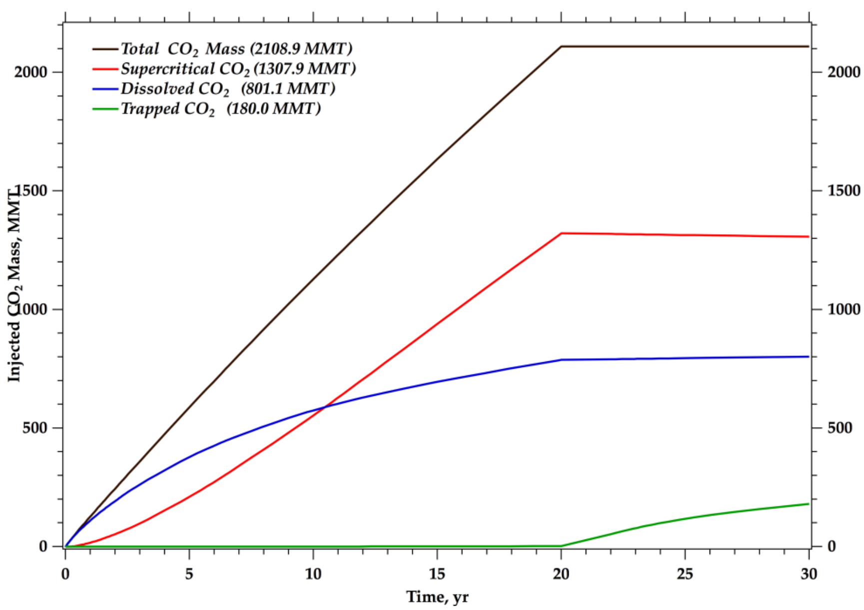


Figure 6-23. Mass of Injected CO_2 Mass vs. Time for Relocated Storage Field Scenario

Figure 6-24 shows the pressure buildup after 20 years of injection for the relocated storage field scenario. Even with the higher injection rates in this scenario, the pressure buildup is fairly localized. Because the injection rates and total CO_2 mass being injected are higher, the pressure buildup covers a larger area. However, pressure interference between injection fields is minor. Figure 6-25 shows a cutaway view of the CO_2 gas saturation in the Mt Simon in the area near storage field #5 after 20 years of injection. The Eau Claire is not shown in this figure so that the lateral plume migration along the bottom of the caprock can be seen. The well spacing is sufficient to avoid significant interference between wells in the 9-spot pattern. The CO_2 saturation fronts are isolated and each extends on the order of about 3000 to 5000 m.

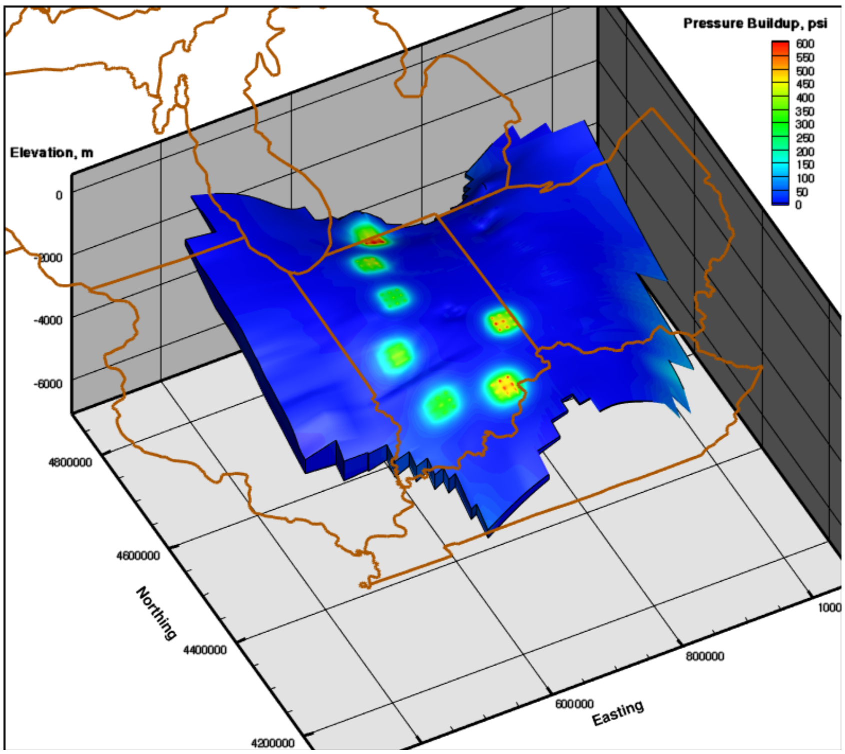


Figure 6-24. Pressure Buildup after 20 Years of Injection for Relocated Storage Field Scenario

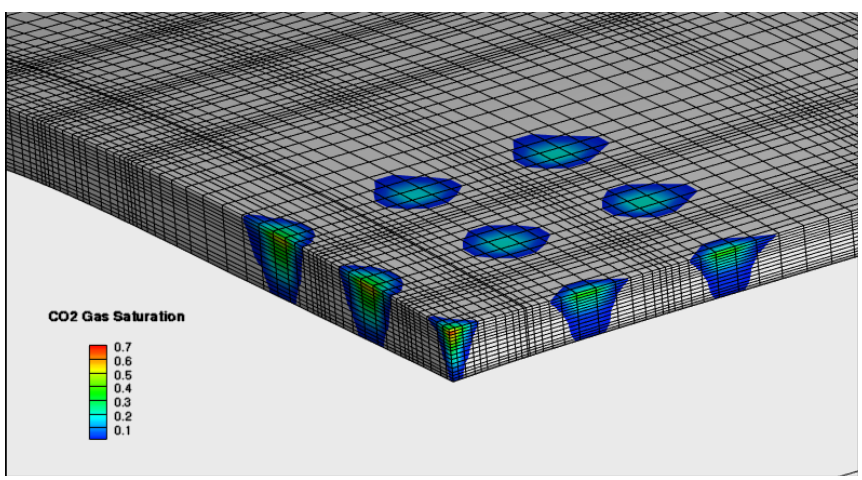


Figure 6-25. CO_2 Gas Saturation in Mt Simon near Storage Field 5

6.7 Regional Upscaling Analysis

Regional upscaling analysis was completed to delineate favorable and unfavorable locations for CO_2 storage in the Arches Province. Based on the conceptual model and simulation results, parametric analysis was completed for aspects related to CO_2 storage applications such as well spacing and sustainable term injection rates. This method allowed for coverage across the entire study area rather than individual scenarios of CO_2 injection, since it is difficult to predict future locations of CO_2 storage sites. These correlations may serve as a 'proxy simulator' to quickly evaluate various design options, instead of having to run time-consuming numerical simulations. These results will be useful for developing injection strategies for regional storage scenarios in the Arches Province.

Parametric analysis was based on scoping level simulations. The scoping level simulations were run in STOMP with a 2D r-z model consisting of 20 vertical rows that extend from the top of the Eau Claire to the base of the Mount Simon, and 100 radial columns that extend from the center of the injection well to the closed (symmetry) outer boundary. The site radius was set at 25 miles, and the model has variable radial extent (and hence the well spacing), depending on the number of wells in the injection cluster. The injection was pressure-constrained with the injection pressure being 90% of the fracture pressure limit at the site location. The model was simulated for 30 years of CO_2 injection.

A matrix of three synthetic sites were developed for analysis based on the regional storage sites 1, 3 and 7 determined in the pipeline routing study. These synthetic cases assumed a homogeneous porosity and permeability distribution for Mount Simon and Eau Claire, and do not employ the detailed geocellular model developed for Sites 1, 3 and 7.

A series of simulations was run for each of these synthetic sites, with design variables such as permeability of Mount Simon and Eau Claire units, capillary entry pressure and well spacing spanning the expected range of conditions for CO_2 storage applications. For each synthetic site case, simulations with four different well patterns (3 × 3, 4 × 4, 5 × 5 and 6 × 6 well arrays), and three different permeability group variations (High k, Medium k and Low k) were run. Each permeability group consisted of a set of correlated variables – permeability of Mount Simon, permeability of Eau Claire and the capillary entry pressure.

A suite of 36 simulations with parameter values covering a broad range of conditions was run. The performance metrics were identified as the cumulative CO_2 mass injected in the system, the radial extent of the CO_2 plume and the percent mass flux of CO_2 entering into the Eau Claire sealing unit. Figure 6-26 shows the performance metrics for the high permeability group, 4x4 well array, deep aquifer case (Synthetic site 1). At the end of 30 years of injection, 49 MMT of CO_2 have been injected into the aquifer. Figure 6-26 shows a plot of the CO_2 plume extent vs. well spacing, which follows the same trends as the CO_2 mass rate. It can be seen that the CO_2 plume extent increases as the permeability and well spacing increase. Similar trends are noticed for Synthetic Sites 1 and 3 as well.

Results of the scoping level simulations were used to develop correlations relating the performance metrics such as the total CO_2 mass injected and the CO_2 plume extent to the design variables such as the depth of the injection formation, the permeability-thickness product of Mount Simon, the well spacing and the thickness of the Eau Claire unit. The correlations were developed based on regression analysis of data from the 36 simulations:

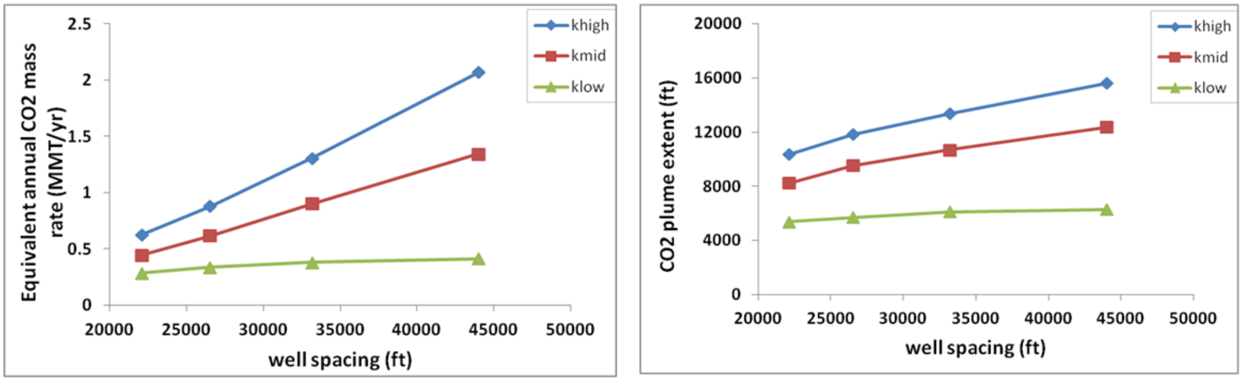


Figure 6-26. Summary of the Results for the Medium-Depth Aquifer Case (Synthetic Site 7) for High, Medium and Low Permeability Groups. (a) Plot of equivalent annual CO_2 mass rate vs. well spacing (b) Plot of CO_2 plume extent vs. well spacing

$$Cum\_CO_2 = a_0 + a_1 D + a_2 \times kh_{MS} \times L + a_3 \times kh_{MS} \times D$$
$$\log(CO_2\_R) = b_0 + b_1 \log(kh_{MS}) + b_2 \log(L)$$

where
Cum_CO_2 = cumulative CO_2 injected in the aquifer, MMT
CO_2_R = radial extent of the CO_2 plume, ft
D = depth of top of Mount Simon formation, ft
L = well spacing, m
kh = permeability-thickness product of Mount Simon, mD-ft
$a0$ = -30.51; $a1$ = 1.043×10^{-2}; $a2$ = 3.65×10^{-7}; $a3$ = -5.09×10^{-7}
$b0$ = 2.21331; $b1$ = 0.26878; $b2$ = 0.49997

Figure 6-27 is a scatter plot matrix which is a common visualization technique in statistical data mining. It shows the correlation between the performance metrics and the design variables. Each of the many plots in the matrix represents the correlation between a design variable pair or a performance metric pair or a design variable-performance metric pair. It can be observed that the cumulative CO_2 injected and the CO_2 plume extent show a good correlation with *kh* and *L* (well spacing).

Figure 6-28 shows multiple linear regression fits for the cumulative CO_2 mass injected and the radial extent of the CO_2 plume. The regression results show an excellent match with the simulator results, exhibiting a very high correlation coefficient for the fit. Hence, these equations in effect act as a proxy simulator for predicting the performance metrics at a particular site without having to run time consuming numerical simulations.

These regression equations were tested on three new cases – Synthetic Sites 4, 5 and 6 (which are similar to Sites 4, 5 and 6 in terms of the formation depths and thicknesses). The results of the regression fits compared with those from the simulator are shown by the colored triangles of Figure 6-28. The results indicate a very good model performance, with the predicted performance metrics lying well within the range of scatter of the original suite of simulations.

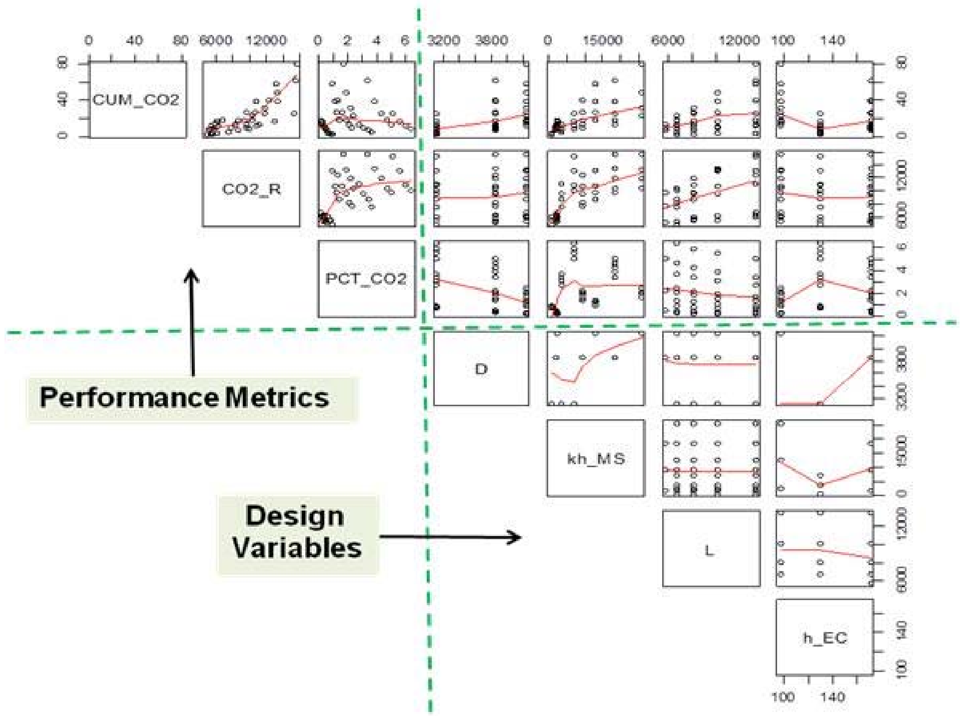


Figure 6-27. Scatter Plot Matrix Showing Correlations Between Various Design Variables and Performance Metrics

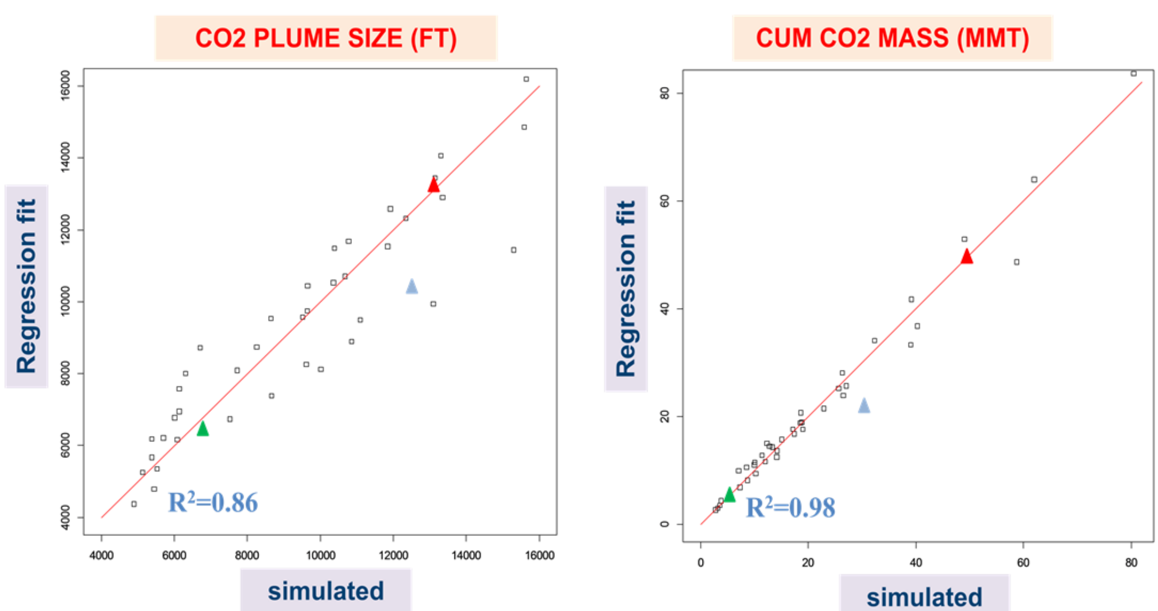


Figure 6-28. Multiple Linear Regression Results – Proxy Simulator

Proxy simulator results were expressed on maps of estimated cumulative CO_2 injection mass and CO_2 saturation radius. Maps were based on equations from the parametric analysis along with geocellular model grid data of Mount Simon thickness and permeability. Thus, estimated simulation results can be posted across the model domain, eliminating the need to run multiple model scenarios of injection fields, pumping rates, etc. Figure 6-29 shows estimated cumulative CO_2 injection assuming 5 km well spacing. As might be expected, the highest values are present in the western portion of the study area where the Mount Simon is thickest. Values decrease towards the east into the Appalachian Basin. Areas in southwestern Indiana are uncertain because there are few wells in the region. Other maps of cumulative injection potential indicate that more injection is possible by increasing well spacing.

Maps of CO_2 saturation front radius were more difficult to interpret. These maps show larger saturation radius in the west. However, this behavior is more related to cumulative injection volume. In areas where large volumes of CO_2 may be injected, the CO_2 may tend to spread out into larger areas. Thus, these maps reflected multiple variables and were more difficult to interpret.

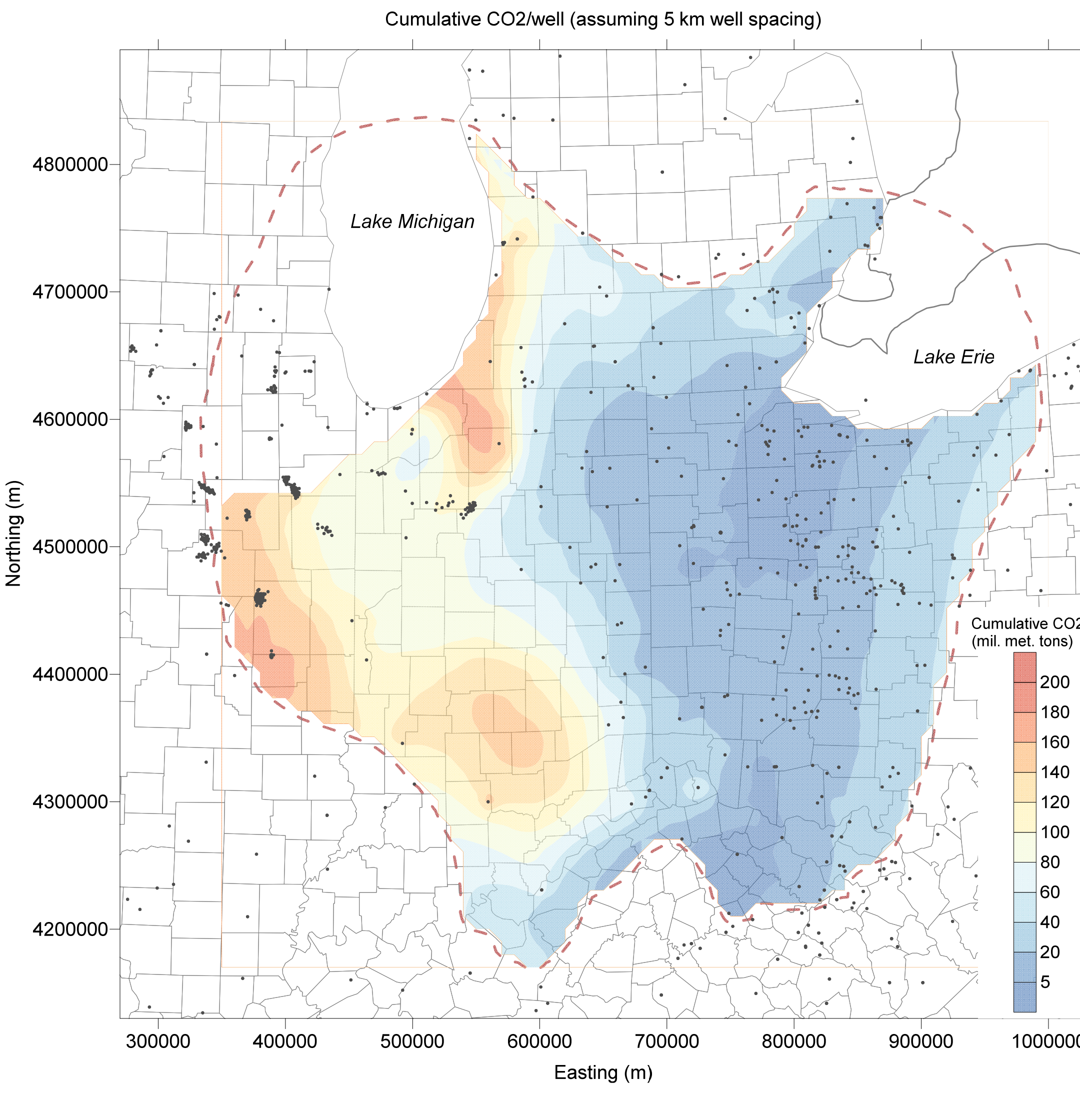


Figure 6-29. Estimated Cumulative Injection Potential Per Well Based on Parametric Analysis and 5 km Well Spacing

Section 7.0: CONCLUSIONS

A geologic model and numerical simulations were completed to analyze infrastructure requirements for large-scale CO_2 storage applications in the Arches Province in the Midwestern U.S. The work focused on the Mount Simon formation, which has the most suitable pressure-temperature conditions for geologic CO_2 storage. Initial work included compilation of geotechnical information on the rock formations and historical records on wastewater injection into the Mount Simon. This information was integrated into a geocellular model representing the distribution of key reservoir parameters and conditions in the study area. This model was normalized to results of reservoir tests in injection wells. Based on the geocellular model, a series of numerical models was developed to simulate injection. The simulation effort included a variable density model, scoping level simulations, pipeline routing analysis, and basin-scale multiple-phase model. In addition, several other subtasks were completed to validate model results to CO_2 injection testing in the study area, evaluate potential for CO_2 migration into the Eau Claire caprock, and assess the feasibility of CO_2 storage monitoring technologies for the Mount Simon in the Arches Province.

Overall, the technical work on the project concluded that large-scale injection may be achieved with proper field design, operation, siting, and monitoring. The multi-state team effort was useful in researching the geology of the Mount Simon. There is geographic variability in the Mount Simon reservoir properties which affects injection potential and layout of a storage system. The simulations better defined potential well fields, well field arrangement, CO_2 pipeline distribution system, and operational parameters for large-scale injection in the Arches Province. The project was organized into the five following major technical tasks:

- Compilation of geologic, hydraulic and injection data on Mount Simon
- Development of model framework and parameters
- Preliminary variable density flow simulations
- Multi-phase model runs of regional storage scenarios
- Implications for regional storage feasibility.

The model had several inherent assumptions and limitations related to depicting the nature of deep rock formations. This was a basin-scale simulation study, and many trends in geology and input parameters were generalized. The simulation results are intended to provide general guidance for a large region of the Midwestern U.S. A CO_2 storage project would require field work such as seismic surveys, drilling, geophysical logging, reservoir tests, detailed reservoir modeling, and system design. The results of this report shall not be viewed or interpreted as a definitive assessment of suitability of candidate geologic CO_2 storage formations, the presence of suitable caprocks, or sufficient injectivity to allow CO_2 sequestration to be carried out in an economical manner. Conclusions on each task are summarized as follows.

Compilation of geologic, hydraulic and injection data on Mount Simon

Geotechnical data included wireline logs, rock core tests, structure maps, thin sections, geologic reports, and other test data related the Mount Simon formation in the study area. The data were evaluated and used to develop and refine maps of key formations, and geotechnical parameters. Injection records for Class I UIC wells were compiled for the study area. This information included reservoir testing, which was used to update pressure field maps for the Mount Simon. A summary of the data compiled is provided as follows:

- Information from over 500 wells that penetrate the Knox or deeper rock zones general region
- Geophysical well logs from 496 wells
- Approximately 4,000 rock core test results in Eau Claire or Mount Simon intervals
- 105 additional standard permeability and porosity tests on Mount Simon/Eau Claire rock samples
- Completion of geomechanical tests on 11 rock samples
- 16 mercury injection capillary pressure tests on rock samples
- 10 other advanced saturation tests on rock core samples
- Deep well injection operational data from 48 wells in the study area
- Pressure fall-off reservoir test data from 31 wells
- Compilation and analysis of a total of 960,000 porosity data from geophysical logs
- Many other geological maps, research, and publications.

Based on analysis of this information, several major conclusions were made on the nature of the Mount Simon in the Arches Province:

- The southern boundary of the Mount Simon sandstone in Kentucky and southern Indiana was re-interpreted. Structures associated with Cambrian rifting in the Rough Creek Graben (western Kentucky, Illinois basin) and Rome Trough (eastern Kentucky, Appalachian basin) influence the southern limit of the sandstone, causing thinning or absence on structural highs. The sandstone deepens to more than 8,000 ft west of the Owensboro Graben in Hancock County, Kentucky, where reservoir quality appears to decrease based on depth-porosity relationships in the basin.

- Geologic structure maps were revised for the Mount Simon in the Arches Province to better define formation continuity across state lines.

- The Eau Claire formation was better classified with the GAMLS according to dominant facies based on the following units: shale, silty-shale, silt, dolomitic shale, dolomite, and sand.

- Injection records from Class I Mount Simon injection wells were compiled. Records indicate over 20 billion gallons of fluid have been injected into the Mount Simon formation in the Arches Province over the past 40 years. This volume is equivalent to approximately 60 MMT CO_2. Injection rates were generally 30 to 300 gpm. Maximum wellhead injection pressures were 400 to 1600 psi.

- Reservoir tests (pressure fall-off tests) were compiled for 31 injection wells. Review of the tests indicated 21 tests were acceptable. Average reservoir permeability from these tests was 62 mD.

- Pressure fall-off data was combined with historical tests on reservoir pressure to better define reservoir pressure distribution in the Mount Simon formation.

Development of model framework and parameters

A conceptual model was developed that represents the geologic setting, stratigraphy, geologic structures, hydrologic features, and distribution of key hydraulic parameters in the Arches Province. The data were integrated into a 3D grid of porosity and permeability, which are key parameters regarding fluid flow and pressure buildup due to CO_2 injection. Permeability data were corrected in locations where reservoir tests have been performed in Mount Simon injection wells. The final geocellular model covers an area of 600 km by 600 km with 49,000,000 cells representing estimated porosity and permeability distribution. Development of the conceptual model revealed several key conclusions regarding the geologic framework for CO_2 storage in the Arches Province:

- The Arches Province covers a large area where the character of rock formations changes substantially. The Mount Simon sandstone and equivalent basal sandstone interval are present from Iowa to West Virginia. The Arches Province is located along the east-central region of the overall basal sandstone unit. Thus, the formation exhibits several facies changes across the study area and related to its original depositional setting and subsequent diagenetic alteration. Many of these trends were exhibited in maps of hydraulic and geotechnical parameters.
- Interpretation of the Mount Simon was refined in the Arches Province to define the distribution of the formation in more detail. The mapping was based on detailed geologic cross sections which built upon previous work performed by the MRCSP and other research. In the Arches Province, the interval generally thickens from 100 ft on the edge of the Appalachian basin to over 2,000 ft in the northern portion of the Illinois basin.
- Hydrostratigraphic units were identified to aid in delineation of formation structure, which defines the overall framework of the model. However, a sharp contact between reservoir and confining unit was not explicitly defined in the conceptual model. In developing the conceptual model, it was determined that there is often no clear break between hydrostratigraphic units. Thus, the Cambrian basal sandstone and Eau Claire formation were represented with a variable distribution of input parameters.
- A major result of this portion of this research was revision to the southern margin of the Mount Simon sandstone into Kentucky. This area is important for the Arches Province because many large CO_2 sources are located along the Ohio River. New seismic interpretations and well data collected from recent CO_2 injection tests were used to re-interpret the southern boundary of the Mount Simon sandstone and examine the manner in which the sandstone thins south- and eastward. Structures associated with Cambrian rifting in the Rough Creek Graben (western Kentucky, Illinois basin) and Rome Trough (eastern Kentucky, Appalachian basin) influence the southern limit of the sandstone, causing thinning or absence on structural highs.
- Geostatistical analysis of geophysical porosity data was completed for the Mount Simon and Eau Claire intervals. Geostatistical analysis for the Mount Simon suggests a fairly erratic dataset. Subsampling methods were necessary to interpret the data and indicated a lateral correlation range of 50 to 60 km. Indicator analysis for the Eau Claire showed an area of low dolomite content extending for much of the north-south extent in the middle of the region, which might suggest a very long range of covariance along this orientation; outside of this area the range along this direction or any direction is obviously limited to a shorter distance. Empirical variograms in the Eau Claire layer indicated some anisotropy, with a longer range in the north-south orientation (roughly 10 km) and about half that in the east-west orientation.
- There are 131 large CO_2 point sources in the Arches Province with combined emissions of approximately 286 MMT CO_2 per year. However, the 53 sources greater than 1 MMT CO_2 per year account for over 90% of total emissions. Based on review of these sources, on-site injection and regional storage field scenarios were identified for simulation. A pipeline routing study was used to identify seven potential locations for regional storage fields.
- A 49 million node geocellular model was developed outlining the structural layout of the Mount Simon-Eau Claire in the study area. The geocellular model was based mainly on structural maps and 960,000 wireline porosity points. A porosity-permeability transform was used to estimate permeability distribution. Correction factors were used to normalize the permeability grid to pressure fall-off data from injection wells. Initial average permeability from the wireline log porosity data was 49.1 mD, and the corrected average permeability was 69 mD.

- Areas in the southern Indiana, northwestern Kentucky, and several other areas have sparse well control with well spacing of 50 to 100+ km. The geocellular model tended to predict average data in these areas since there were few control points nearby.

The geocellular model has limitations related to depicting the nature of deep rock formations. This is a basin-scale simulation study, and many trends in geology and input parameters were generalized. Research was focused on the Arches Province, and areas outside this region were not reviewed in detail. Data coverage is limited in some areas and should be considered when examining maps and figures. Geological information on the Mount Simon has been collected over a period of many decades and the quality of the information varies.

Preliminary variable density flow simulations

Initial single-phase flow simulations were developed for the Arches Province based on the geocellular model dataset. The single-phase flow simulations were completed with the computer codes MODFLOW (McDonald and Harbaugh, 1988) and SEAWAT (Langevin et al., 2007). These single-phase simulations helped provide guidance on input parameters for the more complex multiple-phase simulations. The model results indicated suitable calibration to observed reservoir pressure, flow budget, and flow vectors in the Mount Simon.

- The variable density simulations indicated fluid flow rates in the Mount Simon of 67 cm/year.
- Simulation of regional versus on-site injection suggested that there are some advantages to distribution injection across many on-site sources. However, areas where large sources are clustered along the Ohio River and Great Lakes coast would have large volumes of CO_2, which would create high pressure impact.
- Sensitivity analysis on model input parameters indicates that the model error more sensitive to increases in overall permeability. Flow budgets for the deep rock units were similar to other research on flow in bedrock units for the region.

Multi-phase model runs of regional storage scenarios

To evaluate regional infrastructure scenarios for the Arches Province study area, a series of multi-phase model runs was completed. A base multi-phase, basin-scale model was developed in STOMP model code based on the geocellular model. Several other tasks were completed to validate model with the MRCSP East Bend CO_2 injection data, complete geomechanical simulations, run caprock models, and perform an evaluation of monitoring feasibility based on simulation output. Conclusions on the multi-phase model runs are summarized as follows:

- A basin-scale multiple-phase model was developed in STOMP. The geocellular model was upscaled from the 49 million node geocellular model into a 1,404,708 node numerical simulation. The model includes variable permeability and porosity distributions. This model setup was able to simulate base reservoir pressure conditions observed in the Mount Simon formation.
- A model validation exercise demonstrated that the geocellular and numerical model could recreate bottomhole pressures observed in a CO_2 injection test at the MRCSP East Bend test site. The geocellular model was exported to a 2D radial STOMP simulation and a 680 minute injection test was run. Simulated results matched observed pressures in the injection well, which provides confidence in the simulation methodology and geocellular model.

- A combination of parametric analysis of scoping level simulations results and output from the geocellular model were used to evaluate regional storage scenarios. Estimates of injected CO_2 plume radii were calculated for various storage site scenarios (i.e., storage efficiency factors) and locations. In general, results indicate areas in southwestern Michigan and northern Indiana may have the greatest storage capacity.
- Site-specific caprock simulations based on GAMLS analysis of the Eau Claire formation better defined potential for CO_2 migration into the caprock. STOMP simulations were developed that included more layers in the Eau Claire based on GAMLS classification process. The caprock simulations showed minimal CO_2 movement into the Eau Claire formation, highlighting the importance of including detail for caprock units in CO_2 storage simulations.
- Substitution analysis of PNC and seismic monitoring technologies was completed based on simulated CO_2 saturation levels and geotechnical properties of the Mount Simon formation. Results suggest that PNC logs would be effective for detecting CO_2 saturation in a well. Analysis results suggest that seismic monitoring in the Mount Simon formation in the Arches Province may be difficult due to lower CO_2 saturation levels in the reservoir and geomechanical properties of the rock matrix. Methods may be a qualitative indicator of saturation rather than a quantitative measure of saturation levels.

Implications for regional storage feasibility

To better define the infrastructure necessary to support large-scale storage applications in the Arches Province, a pipeline routing study, scoping level simulations, and basin-scale simulations were completed. In addition, regional upscaling analysis was completed with parametric analysis of CO_2 storage impacts.

- A source-sink least-cost pipeline routing analysis suggests there are some central areas where CO_2 pipeline routes intersect or blend together, which may be practical potential regional storage fields. Seven locations were selected as potential regional storage field locations. Total injection of 10 to 20 MMT CO_2 at each location would represent a total injection rate of 70 to 140 MMT CO_2 per year (represents approximately 25 to 50% reductions of CO_2 emissions from large point sources across the Arches Province).
- Multi-phase scoping level simulations were completed in 2D radial version of STOMP based on the geocellular model. The one well simulation results were set up to represent storage field conditions. The scoping simulations suggest that injection fields with arrays of 25 to 50+ wells may be used to accommodate large injection volumes. Individual wells may need to be separated by 3 to 10 km. Injection fields may require spacing of 25 to 40 km to limit pressure and saturation front interference.
- A full basin-scale multiple-phase simulation was developed in STOMP for the Arches Province. In the model, CO_2 was injected in seven storage fields across 63 wells with a pressure limit of 0.675 psi/ft.
- Results from the basin-scale simulations reflect variability in the Mount Simon. Better injection potential was present in fields located in areas where the Mount Simon is thickest. Areas where the Mount Simon is shallow and thin had less injection potential.
- A simulation scenario where injection fields were located in areas with thicker reservoir indicated total injection rates over 100 MMT/yr may be sustained.
- Simulation results showed that distributing injection across multiple wells in injection fields may limit the overall pressure fields created by deep well injection.

The model has several inherent assumptions and limitations related to depicting the nature of deep rock formations. This is a basin-scale simulation study, and many trends in geology and input parameters were generalized. Research was focused on the Arches Province, and areas outside this region were not reviewed in detail. The project plan was intended to provide general guidance for a large region of the Midwestern U.S. A CO_2 storage project would require field work such as seismic surveys, drilling, geophysical logging, reservoir tests, detailed reservoir modeling, and system design. The results of this report shall not be viewed or interpreted as a definitive assessment of suitability of candidate geologic CO_2 storage formations, the presence of suitable caprocks, or sufficient injectivity to allow CO_2 sequestration to be carried out in an economic manner.

Section 8.0: REFERENCES

Asquith, G.B. and C.R. Gibson. 1982. *Basic Well Log Analysis for Geologists*. Methods in Exploration Series. American Association of Petroleum Geologists, Tulsa, OK.

Barnes, D., D. Bacon, and S. Kelley. 2009. "Geological Sequestration of Carbon Dioxide in the Cambrian Mount Simon Sandstone: Regional Storage Capacity, Site Characterization, and Large-scale Injection Feasibility, Michigan Basin," *Environmental Geosciences*, v. 16, no. 3, pp. 163-183.

Battelle. 2010. Appalachian Basin- CO_2 Injection Test in the Cambrian-Age Mount Simon Formation Duke Energy East Bend Generating Station, Boone County, Kentucky, Midwest Regional Carbon Sequestration Partnership. Prepared for U.S. DOE NETL. 158 p.

Becker, L.E., A.J. Hreha, and T.A. Dawson. 1978. Pre-Knox (Cambrian) Stratigraphy in Indiana. Department of Natural Resources: Geological Survey Bulletin 57, 72 p.

Birkhozer, J.T., Q. Zhou, and C.-F. Tsang. 2008. "Large-scale Impact of CO_2 Storage in Deep Saline Aquifers: A Sensitivity Study on the Pressure Response in Stratified Systems," *International Journal of Greenhouse Gas Control*, doi:10.1016/j.ijggc.2008.08.002.

Bond, D.C. 1972. *Hydrodynamics in Deep Aquifers in the Illinois Basin*: Illinois State Geological Survey Circular 470.

Bowen, B.B., R.I. Ochoa, N.D. Wilkens, J. Brophy, T.R. Lovell, N. Fischietto, C.R. Medina, and J.A. Rupp. 2011. "Depositional and Diagenetic Variability within the Cambrian Mount Simon Sandstone: Implications for Carbon Dioxide Sequestration," *Environmental Geosciences*, June 1, 2011; 18(2): 69 - 89.

Brower, R.D., A.P. Visocky, E.G. Krapac, B.R. Hensel, G.R. Peyton, J.S. Nealon, and M. Guthrie. 1989. *Evaluation of Underground Injection of Industrial Waste in Illinois Final Report,* ENR Contracts AD-94 and UI-8501, Illinois State Geological Survey.

Clifford, M.J. 1973. "Hydrodynamics of Mount Simon Sandstone, Ohio and Adjoining Areas," *Underground Waste Management and Artificial Recharge*, Vol. 1, pp. 349-356.

Eberts, S.M. and L.L. George. 2000. "Regional Ground-Water Flow and Geochemistry in the Midwestern Basins and Arches Aquifer System in Parts of Indiana, Ohio, Michigan, and Illinois," U.S. Geological Survey Professional Paper 1423-C. 103 p.

Gassmann, F. 1951, Über die Elastizät Poröser Medien: Vieteljahrsschrift der Naturforschenden in Zürich 96, p. 1-23.

Ghaderi, S.M., D.W. Keith, and Y. Leonenko. "Feasibility of Injecting Large Volumes of CO_2 into Aquifers," *Energy Procedia* 2009, 1 (1) 3113– 3120.

Greb, S., D.C. Harris, M.P. Solis, W.H. Anderson, J.A. Drahovzal, B.C. Nuttall, R.A. Riley, W. Solano-Acosta, J.A. Rupp, and N. Gupta. 2009. "Cambrian-Ordovician Knox Carbonate Section as Integrated Reservoirs and Seals for Carbon Sequestration in the Eastern Mid-continent United States," in M. Grobe, J. Pashin, and R.L. Dodge, eds., *Carbon Dioxide Sequestration in Geologic*

Media - State of the Science, Tulsa, Okla., American Association of Petroleum Geologists, p. 241-259.

Gupta, N. 1993. "Geologic and Fluid-Density Controls on the Hydrodynamics of the Mount Simon Sandstone and Overlying Geologic Units in Ohio and Surrounding States," PhD dissertation, The Ohio State University, Columbus, Ohio.

Gupta, N, and E.S. Bair. 1997. "Variable-Density Flow in the Mid-Continent Basins and Arches Region of the United States," *Water Resources Research*, Vol. 33, No. 8, pp. 1785-1802.

Gupta, N., B. Sass, and J. Sminchak. 2002. "Feasibility of CO_2 Sequestration in Deep Saline Reservoirs in the Midwestern USA," *Proceedings of the 2002 Geological Society of America Annual Conference*, Lexington, KY.

Gupta, N., B. Sass, S. Chattopadhyay, J. Sminchak, P. Wang, and T. Espie. 2004. "Geologic Storage of CO_2 from Refining and Chemical Facilities in the Midwestern US," *Energy*, Vol. 29, pp. 1599-1609.

Han, D. and M. Batzle. 2004. "Gassmann's Equation and Fluid-saturation Effects on Seismic Velocities," G*eophysics*, Vol. 69, No. 2, pp. 398-405.

Khatiwada, M., L. Adam, M. Morrison, and K. van Wijk. 2012. "A Feasibility Study of Time-lapse Seismic Monitoring of CO_2 Sequestration in a Layered Basalt Reservoir," *Journal of Applied Geophysics*, Vol. 82, pp. 145-152.

Lahann, R.W., C. Medina, J.A. Rupp, T.R. Lovell, B.B. Bowen, D.A. Barnes, J. Hickman, R. Bandy, and J. Sminchak. 2012. A Regional Lithostratigraphic Model of the Eau Claire Formation (Cambrian): How Much Shale is in this Confining Unit? 41st Annual Meeting of the Eastern Section of the American Association of Petroleum Geologists Cleveland, Ohio, September 22-26, 2012.

Langevin, C.D., D.T. Thorne, Jr., A.M. Dausman, M.C. Sukop, and Weixing Guo. 2007. SEAWAT Version 4: A Computer Program for Simulation of Multi-Species Solute and Heat Transport: U.S. Geological Survey Techniques and Methods Book 6, Chapter A22, 39 p.

Leverett. M.C. 1941. "Capillary Behaviour in Porous Solids," *Transactions of the AIME* (142): 159–172.

McDonald, G. and A.W. Harbaugh. 1988. "A Modular Three-Dimensional Finite-Difference Ground Water Flow Model." *Techniques of Water Resources Investigations of the U. S. Geological Survey*, Book 6, Chapter A1.

Medina, C., D. Barnes, and J. Rupp. 2008. Depth Relationships in Porosity and Permeability in the Mount Simon Sandstone of the Midwest Region: Applications for Carbon Sequestration. Eastern Section Meeting of the AAPG, Pittsburgh, PA, October 14, 2008.

Medina, C. R., and J.A. Rupp. 2010. Reservoir Characterization and Lithostratigraphic Division of the Mount Simon Sandstone: Implications for Estimations of Geologic Sequestration Storage Capacity. AAPG Eastern Section, Annual Meeting, 9/26/10-9/28/10, Kalamazoo, Michigan.

Medina, C. R., J.A. Rupp, and D.A. Barnes. 2011. "Effects of Reduction in Porosity and Permeability with Depth on Storage Capacity and Injectivity in Deep Saline Aquifers - A Case Study from the

Mount Simon Sandstone Aquifer," *International Journal of Greenhouse Gas Control*, Vol. 5, pp. 146-156.

Midwest Geological Sequestration Consortium (MGSC). 2005. "An Assessment of Geological Carbon Sequestration Options in the Illinois Basin," U.S. DOE Contract: DE-FC26-03NT41994, The Board of Trustees of the Univ. of Illinois, Illinois State Geological Survey, Final Report December 31.

Midwestern Regional Carbon Sequestration Partnership (MRCSP). 2005. The Midwest Regional Carbon Sequestration Partnership (MRCSP): Phase I Final Report. Submitted by Battelle. DOE Cooperative Agreement #DE-FC26-03NT41981.

MIT Carbon Capture and Sequestration Technologies Program. 2009. Carbon Management GIS: CO2 Pipeline Transport Cost Estimation. Report for NETL, DOE Contract: Contract DE-FC26-02NT41622.

Mimoun, J.G., Torres-Verdin, C.T., and Preeg, W.E. 2011. Quantitative Interpretation of Pulsed Neutrong Capture Logs: Part 1- Fast Numerical Simulation. Geophysics, Vol. 76, No. 3, p. E81-E93.

Mossier, J.H. 1992. Sedimentary Rocks of the Dresbachian Age (Late Cambrian), Hollendale Embayment, Southeastern Minnesota. University of Minnesota Report of Investigations 40.

Nicot, J.P., S. Hovorka, and J. Choi, 2009. "Investigation of Water Displacement Following Large CO_2 Sequestration Operations". *Energy Procedia* 1, 2009, p. 4411-4418.

Nuefelder, R.J. 2011. Petrographic, Mineralogical, and Geochemical Evidence of Diagenesis in the Eau Claire Formation, Illinois Basin: Implications for Sealing Capability in a Carbon Dioxide Sequestration System. Master of Science Thesis, Purdue University, West Lafayette, Indiana. 153 p.

Patterson, K.J. 2011. Geologic Controls on Reservoir Quality and Geologic Carbon Sequestration Potential in the Upper Cambrian Mount Simon Sandstone. Western Michigan University, Geosciences Department.

Person, M., A. Banerjee, J. Rupp, C. Medina, P. Lichtner, C. Gable, R. Pawar, M. Celia, J. McIntosh, and V. Bense. 2010. "Assessment of Basin-scale Hydrologic Impacts of CO_2 Sequestration, Illinois Basin," *International Journal of Greenhouse Gas Control*, Vol. 4, pp. 840-854.

Pruess, K., J. García, T. Kovscek, C. Oldenburg, J. Rutqvist, C. Steefel and T. Xu. 2002. Intercomparison of Numerical Simulation Codes for Geologic Disposal of CO_2. LBNL-51813 Lawrence Berkeley National Laboratory, Berkeley, California.

Schlumberger. 1972. Log Interpretation, Volume I - Principles.

Shafeen, A., P. Douglas, E. Croiset, and I. Chatzis. 2004. "CO_2 Sequestration in Ontario, Canada, Part 1: Storage Evaluation and Potential Reservoirs," *Energy Conversion and Management*, Vol. 45, pp. 2645-2659.

Simm, R. 2007. Practical Gassmann Fluid Substitution in Sand/Shale Sequences: first break, v. 25, p. 61-68.

Smolen, J. 1996. *Cased Hole and Production Log Evaluation*. Pennwell Books, Tulsa, OK. 365 p.

Tóth, J. 1963. "A Theoretical Analysis of Groundwater Flow in Small Drainage Basins," *Journal of Geophysical Research*, Vol. 68, No. 16, pp. 4795-4812.

van Genuchten, M. Th. 1980. A closed-form equation for pre- dicting the hydraulic conductivity of unsaturated soils. Soil. Sci. Soc. Am. J. 44:892-898.

U.S. Department of Energy (DOE). 2008. Carbon Sequestration Atlas of the United States and Canada. National Energy Technology Laboratory, Pittsburgh, PA, USA.

Warner, D.L. 1988. *Hydrogeologic and Hydrochemical Assessment of the Basal Sandstone and Overlying Paleozoic Age Units for Wastewater Injection and Confinement in the North Central Region (Draft Final Report),* Underground Injection Practices Council, Oklahoma City, OK.

White, M.D. and M. Oostrom. 2000. *STOMP Subsurface Transport Over Multiple Phases, Version 2.0, Theory Guide*. PNNL-12030, UC-2010, Pacific Northwest National Laboratory, Richland, Washington.

White, M.D. and M. Oostrom. 2006. *STOMP Subsurface Transport Over Multiple Phases, Version 4.0, User's Guide*. PNNL-15782, Pacific Northwest National Laboratory, Richland, Washington.

White, M.D., D.H. Bacon, B.P. McGrail, D.J. Watson, S.K. White, and Z.F. Zhang. 2012. STOMP Subsurface Transport Over Multiple Phases: STOMP-CO2 and STOMP-CO2e Guide: Version 1.0 . PNNL-21268, Pacific Northwest National Laboratory, Richland, WA.

White, S.K., and Z.F. Zang. 2011. *Draft Report: Impacts of Well Spacing and Reservoir Heterogeneity on the Extent of the Injected CO_2 Plume, FutureGen Industrial Alliance*. Report No. PNWD-4289.

Wickstrom, L.H., E.R. Venteris, J.A. Harper, J. McDonald, E.R. Slucher, K.M. Carter, S.F. Greb, J.G.Wells, W.B. Harrison III, B.C. Nuttall, R.A. Riley, J.A. Drahovzal, J.A. Rupp, K.L. Avary, S. Lanham, D.A. Barnes, N. Gupta, M.A. Baranoski, P. Radhakrishnan, M.P. Solis, G.R. Baum, D. Powers, M.E. Hohn, M.P. Parris, K. McCoy, G.M. Grammer, S. Pool, C.M. Luckhardt, P. Kish. 2005. Characterization of Geologic Sequestration Opportunities in the MRCSP Region: Phase I Task Report Period of Performance, October 2003–September 2005, p. 152.

Wickstrom, L.H., E.R. Venteris, E.R. Slucher, K.M. Carter, J. McDonald, J.A. Rupp, S.F. Greb, G.R. Baum, W.B. Harrison, and M.B. Hohn, 2006, "Geologic Storage Options and Capacities for Carbon Dioxide Sequestration in the Midwest Regional Carbon Sequestration Partnership (MRCSP)," *Proceedings of the 5th Annual Conference on Carbon Capture and Sequestration*, May 8-11, Alexandria, Virginia, 23 p.

Wiese, B. 2010. Mass Flow and Sensitivities for Injection of CO_2 into Saline Aquifers. Proceedings of the 10th International Conference on Greenhouse Gas Technologies (GHGT10). Amsterdam, The Netherlands, September 19-23, 2010.

Xue, Z. and Ohsumi, T., 2004, Seismic wave monitoring of CO2 migration in water-saturated porous sandstone: Exploration Geophysics, v. 35, p. 25-32.

Zhou, Q., J.T. Birkholzer, H. Leetaru, E. Mehnart, Y.-F. Lin, C.-F. Tsang, P. Jordan, S. Fraily, and R. Finley. 2009. Basin-Scale Environmental Impact of Geological Carbon Sequestration in the

Illinois Basin, Abstract submitted to Geological Society of America, North-Central Section, 43rd Annual Meeting, April 2009.

Zhou, Q., J.T. Birkholzer, E. Mehnert, Y.-F. Lin, and K. Zhang. 2010. “Modeling Basin- and Plume-Scale Processes of CO_2 Storage for Full-Scale Deployment,” *Ground Water*, Vol. 48, pp. 494-514.

Zoback, M. 2007. *Reservoir Geomechanics*. New York: Cambridge University Press, 449 p.

Section 9.0: LIST OF ACRONYMS

2D	two-dimensional
3D	three-dimensional
4D	four-dimensional
bgs	below ground surface
CO_2	carbon dioxide
c.u.	capture units
DOE	United States Department of Energy
EPA	Environmental Protection Agency
GAMLS	Geologic Analysis via Maximum Likelihood System
GIS	Geographic Information System
gpd	gallons per day
gpm	gallons per minute
mD	milliDarcy
MGSC	Midwest Geological Sequestration Consortium
MICP	mercury injection capillary pressure
MMT	million metric ton
MRCSP	Midwestern Regional Carbon Sequestration Partnership
MVA	monitoring, verification, and accounting
NETL	National Energy Technology Laboratory
PDMS	Petroleum Database Management System
psi	pounds per square inch
PNC	pulsed neutron capture
QA/QC	quality assurance/quality control
STOMP	Subsurface Transport Over Multiple Phases
UIC	Underground Injection Control
USGS	United States Geological Survey