Class VI UIC Project Information Tracking

This submission is for:

Project ID: R05-IL-0006

Project Name: Marquis Carbon

Current Project Phase: Pre-Injection Prior to Construction

General Information

Number of proposed Class VI wells: 1

Brief description of the project: Marquis Carbon Injection will capture and compress 1.5 MMtonnes of CO2 from ethanol fermentation and store it under Marquis owned property in the Mt. Simon sandstone.

Optional Additional Project Information

Facility and Owner/ Operator Information

Facility name: Marquis Biocarbon Project

Facility mailing address: 10000 Marquis Dr. Hennepin, IL 61327

Facility location: Latitude: 41.270265 Longitude: -89.309393

Up to four Standard Industrial Classification (SIC) codes for the products/services provided by the facility: 2813

Facility located on Indian lands: No

Facility contact information

Contact person: Elizabeth Steinhour

Contact's business phone number: 815 - 925 - 7300

Contact's business email: BETHSTEINHOUR@MARQUISENERGY.COM

Operator's name: Marquis Carbon Injection, LLC

Operator's business address: 10000 Marquis Dr. Hennepin, IL 61327

Operator's business phone number: 815 - 925 - 7300

Operator's status: Private

Ownership status: Owner

Initial Permit Application

Permit Application Narrative: https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R05-IL-0006/Phase1-PreConstruction/ProjInfo-06-27-2022-1024/1.--Project--Narrative.pdf

https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R05-IL-0006/Phase1-PreConstruction/ProjInfo-06-27-2022-1024/1.--Project--Narrative.pdf

Proposed project plans, submitted with the Project Plan Submission module:

An Area of Review (AoR) and Corrective Action Plan

A Testing and Monitoring Plan

A Well Plugging Plan

A Post-Injection Site Care (PISC) and Site Closure Plan

An Emergency and Remedial Response Plan

Computational modeling information, submitted with the Area of Review Computational Modeling module

A financial responsibility demonstration, submitted with the Financial Responsibility Demonstration module

A proposed pre-operational logging and testing program, submitted with the Pre-Operational Testing module

An optional alternative PISC timeframe demonstration, submitted with the Alternative PISC Timeframe Demonstration module

Updated Information

Other Required Information: https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R05-IL-0006/Phase1-PreConstruction/ProjInfo-06-27-2022-1024/4.--Injection--Well--Construction--Plan--REV--1.pdf

Complete Submission

Authorized submission made by: Jared Lee Walker

Comments regarding this submission: Please find attached the well construction plan that includes much of the data requested around 40 CFR 146.86

For confirmation a read-only copy of your submission will be emailed to: bethsteinhour@marquisenergy.com

1.0 PROJECT NARRATIVE
40 CFR 146.81

MARQUIS BIOCARBON PROJECT

Facility Information

Facility name:	MARQUIS BIOCARBON PROJECT
Facility contact:	ELIZABETH STEINHOUR DIRECTOR OF ENVIRONMENTAL AFFAIRS 10000 MARQUIS DRIVE, HENNEPIN, IL 61327 815.925.7300 / BETHSTEINHOUR@MARQUISENERGY.COM
Well name:	MCI CCS 3
Well location:	PUTNAM COUNTY, ILLINOIS S2 T32N R2W Latitude: 41.27026520 N, Longitude: 89.30939322 W

Table of Contents

1.0 Project Narrative 9
1.1 Project Background and Contact Information 9
1.1.1 Project Goals 9
1.1.2 Partners/Collaborators 10
1.1.3 Overview of the Project Timeframe 10
1.1.4 Proposed Injection Mass/Volume and CO_2 Source 11
1.1.5 Injection Depth Waiver or Aquifer Exemption Requested 12
1.1.6 Other Administrative Information 12
1.2 Site Characterization 12
1.2.1 Regional Geology, Hydrogeology, and Local Structural Geology [40 CFR 146.82(a)(3)(vi)] 12
1.2.2 Maps and Cross Sections of the AoR [40 CFR 146.82(a)(2), 146.82(a)(3)(i)] 17
1.2.3 Faults and Fractures [40 CFR 146.82(a)(3)(ii)] 20
1.2.4 Injection and Confining Zone Details [40 CFR 146.82(a)(3)(iii)] 20
1.2.5 Geomechanical and Petrophysical Information [40 CFR 146.82(a)(3)(iv)] 32
1.2.6 Seismic History [40 CFR 146.82(a)(3)(v)] 32
1.2.7 Hydrologic and Hydrogeologic Information [40 CFR 146.82(a)(3)(vi), 146.82(a)(5)] 35
1.2.8 Geochemistry [40 CFR 146.82(a)(6)] 35
1.2.9 Other Information (Including Surface Air and/or Soil Gas Data, if Applicable) ... 37
1.2.10 Site Suitability [40 CFR 146.83] 37
1.3 Permit Section 2.0: AoR and Corrective Action 37
1.4 Permit Section 3.0: Financial Responsibility 38
1.5 Permit Section 4.0: Injection Well Construction 38
1.5.1 Proposed Stimulation Program [40 CFR 146.82(a)(9)] 38
1.5.2 Construction Procedures [40 CFR 146.2(a)(12)] 38
1.5.3 Casing and Cementing 38
1.6 Permit Section 5.0: Pre-Operational Logging and Testing 40
1.7 Permit Section 6.0: Well Operations 40
1.7.1 Operational Procedures [40 CFR 146.82(a)(10)] 40
1.7.2 Proposed Carbon Dioxide Stream [40 CFR 146.82(a)(7)(iii) and (iv)] 43
1.8 Permit Section 7.0: Testing and Monitoring 43

1.9 Permit Section 8.0: Injection Well Plugging 47
1.10 Permit Section 9.0: Post-Injection Site Care (PISC) and Site Closure 48
1.11 Permit Section 10.0: Emergency and Remedial Response 48
1.12 Injection Depth Waiver and Aquifer Exemption Expansion 49
1.13 Other Information 49
References 50

List of Tables

Table 1-1: Key project partners and collaborators. 10
Table 1-2: Project Gantt Chart 11
Table 1-3: Anticipated composition of the CO_2 stream injected at by the Marquis Biocarbon Project. 11
Table 1-4: General Class VI waste injection well permit application information. 12
Table 1-5: Summary of alternative subsurface scenarios for the Marquis Biocarbon Project. 30
Table 1-6: Casing details. 39
Table 1-7: Cement program for the CO_2 injection well. 40
Table 1-8: Proposed operational procedures. 41
Table 1-9: Wellhead injection stream specifications. 42
Table 1-10: Sampling devices, locations, and frequencies for continuous monitoring. 43
Table 1-11: General schedule and spatial extent for the testing and monitoring activities for the Marquis Biocarbon Project. 46
Table 1-12: Intervals to be plugged and materials/methods used (40 CFR 146.92 (b)(2 – 4)). 47

List of Figures

Figure 1-1: The Marquis Biocarbon Project site sits on the northern edge of the Illinois Basin. The Mt. Simon Sandstone in Hennepin, Illinois has been identified as the target injection zone for CO_2 storage. Also shown are the FutureGen2 and the Illinois Basin – Decatur Project sites, which have demonstrated the capability for CO_2 storage in the Mt. Simon Sandstone. 14
Figure 1-2: Stratigraphic column with lithology and hydrostratigraphy for the Marquis Biocarbon Project site based on data from the characterization well, MCI MW 1. ft = feet; MDKB = measured depth below kelly bushing; ppm = parts per million; USDW = underground source of drinking water. 15
Figure 1-3: Principle geologic structures of Illinois (modified from Willman et al., 1975). Red lines A-A' and B-B' are cross section of the region, see Figure 1-5. 17
Figure 1-4: Map showing the modeled CO_2 plume footprint, AoR, and existing and proposed project wells within the AoR. 19
Figure 1-5: Geologic cross sections near Putnam County featuring the structural configuration of Cambrian strata that contains the target injection zone and caprock. Modified from Willman et al., 1975. 19
Figure 1-6: Example of 2D seismic line acquired in 2020. 20
Figure 1-7: Mt. Simon Sandstone thickness map over the west-central portion of the Illinois Basin (modified from FutureGen Alliance, 2013). 22
Figure 1-8: Mt. Simon Sandstone elevation depth map over the west-central portion of the Illinois Basin (modified from FutureGen Alliance, 2013). 22
Figure 1-9: Model Zones and corresponding gamma ray, resistivity, and porosity logs. Lower part of the Elmhurst and all the Mt. Simon are considered reservoir, while the upper Elmhurst and Eau Claire shale act as the seal. 23
Figure 1-10: Interpreted Mt. Simon depositional environments and corresponding intraformational zones. 25

Figure 1-11: Example conceptual schematic drawing of the Mt. Simon Zone 5 representing the eolian depositional environment and interpreted orientations at the Marquis site (not to scale), as well as representative bedding features in whole acquired from Mt. Simon Zone 5. Modified from Freiburg et al. (2020)..... 25
Figure 1-12: Histograms of porosity ranges by facies type showing correlative distributions for the clean sand, dirty sand, and shale facies. Distinctly different distributions for clean sand and dirty sand in Mt. Simons 2 and 3, where normal distribution means are lower. 26
Figure 1-13: Porosity-Permeability cross-plot colored by flow facies showing the utilization of two different transforms, applied by flow-based rock classifications. 27
Figure 1-14: Plot of Cumulative CO_2 injection (blue) and Bottom Hole Pressure (grey). 28
Figure 1-15: Development of CO_2 plume after 5 years of injection. 28
Figure 1-16: CO_2 plume in plan view for selected layers. 29
Figure 1-17: Porosity and permeability relationships for High Side Case (orange line) and Low Side Case (blue line). The numbers on the orange are permeability values, number on the blue line are porosity values. 30
Figure 1-18: CO_2 plume at wellbore cross section after 3 years of injection. The left plume diagram represents the base case, middle represents the High Side Case, and the right plume diagram represents the Low Side Case. 31
Figure 1-20: CO_2 plume at layer 153 (used to delineate AoR) at the end of injection, 1, 5 and 10 years after injection stopped for the High Side Case (top row) and Low Side Case (bottom row). 32
Figure 1-21: Regional Historic Earthquakes. Modified after FutureGen Alliance, 2013. Close-up map shown in subsequent figure. 33
Figure 1-22: Local earthquakes since 1900 (modified from USGS, 2021). 34
Figure 1-23: 2014 Regional seismic hazard Map for Illinois (USGS, 2014). 34
Figure 1-24: Chloride and TDS concentrations in the water/brine samples collected from the MCI MW 1 characterization well. 36

List of Abbreviations

Abbreviation	Description
°	Degree
µm	Micrometer
2D	Two-dimensional
3D	Three-dimensional
4D	Four-dimensional
ACZ	Above confining zone
AoR	Area of Review
APT	Annular pressure test
ASTM	American Society for Testing and Materials
AVA	Amplitude versus angle
AVO	Amplitude versus offset
Bbl	Barrel
BHA	Bottom-hole assembly
BOP	Blowout preventor
BOPE	Blow out prevention equipment
C	Celsius
CBL-VDL	Cement bond log – variable density log
CCS	Carbon capture and storage
CO_2	Carbon dioxide
cP	Centipoise
DOT	Department of Transportation
DST	Drill stem test
DT	Delta time
DV	Differential valve
EOD	Environment of deposition
ERRP	Emergency and Remedial Response Plan
F	Fahrenheit
FBP	Formation breakdown pressure
ft	Feet
FPP	Fracture propagation pressure
FZI	Flow zone indicator
gal	Gallon
GC	Gas chromatograph
GS	Geologic sequestration
ID	Identification
ISIP	Instantaneous shut-in pressure
ISGS	Illinois State Geological Survey
ISWS	Illinois State Water Survey
KB	Kelly bushing
KCl	Potassium chloride
L	Liter

LAS	Log ascii standard
lb	Pound
m	Meter
MD	Measured depth
mD	Millidarcy
mg	Milligram
MI	Move-in
mi	Mile
MIT	Mechanical integrity test
mL	Milliliter
MMSCF	Million standard cubic feet
ms	Millisecond
MSL	Mean sea level
MM	Million tonnes
MVA	Monitoring, Verification, and Accounting
NACE	National Association of Corrosion Engineers
NaCl	Sodium chloride
NELAP	National Environmental Laboratory Accreditation Program
NMR	Nuclear magnetic resonance
NPT	National pipe thread
P&A	Plug and abandonment
PFO	Pressure fall-off
PGA	Peak ground acceleration
PISC	Post-injection site closure
PNC	Pulsed neutron capture
POZ	Pozzolan
ppg	Pounds per gallon
ppm	Parts per million
psi	Pounds per square inch
psig	Pounds per square inch gauge
QA	Quality assurance
QC	Quality control
QASP	Quality Assurance and Surveillance Plan
RPD	Relative percent difference
RU	Rig up
SCADA	Supervisory Control and Data Acquisition
SCSSV	Subsurface safety valve
SEM	Static Earth Model
SF	Safety factor
SIC	Standard Industrial Classification
SOP	Standard operating procedures
SP	Spontaneous potential
SPF	Shots per foot
SSTVD	SubSea true vertical depth
TD	Total depth
TDS	Total dissolved solids

TEG	Triethylene glycol
UIC	Underground Injection Control
USDW	Underground source of drinking water
USGS	United States Geological Survey
v	Volume
vClay	Clay fraction
VSP	Vertical Seismic Profile
XRD	X-ray diffraction
XRF	X-ray fluorescence

1.0 Project Narrative

1.1 Project Background and Contact Information

Marquis Carbon Injection, LLC's primary goal of this project is to capture and sequester carbon dioxide (CO_2) near Hennepin, Putnam County, Illinois. As this application will show, the Marquis Biocarbon Project site possesses outstanding features which once developed will enhance the standing of Illinois as the country's leader in the geological sequestration of CO_2.

The Marquis Biocarbon Project will result in the sequestering over a million tons per year of pure biogenic CO_2 upon project completion without the development of any advanced stack gas cleanup technologies. Additionally, carbon capture and storage can play a key role in reducing the carbon intensity for hydrogen hubs being developed within Illinois and the ongoing efforts to reach climate neutrality.

The potential of the project has been confirmed by an extensive campaign of data collection from regional sources and included drilling, logging, reservoir testing and core sampling a deep characterization well (MCI MW 1) and acquiring a comprehensive two-dimensional (2D) seismic program which was completed in 2021, and a high-density three-dimensional (3D) seismic program which was completed in 2022. The 3D high density seismic data will be tied to the site characterization well data and the CO_2 velocity modeling in order to provide the most accurate prediction of CO_2 plume development over time. The 3D seismic data will also serve as a baseline survey for future time-lapse 3D surface seismic surveys. The information collected did not show the potential for faulting or significant fracture pathways that would affect the containment of CO_2 at the Marquis Biocarbon Project site. This data collection program was specifically acquired to support this application and was designed to address the specific requirements of the EPA Class VI rule.

A robust earth model has been built and calibrated using this new data and modeling results clearly indicate that the Marquis Biocarbon Project site has world class subsurface characteristics making it an ideal location for the safe and efficient sequestration of CO_2. The Mt. Simon sandstone formation has very favorable characteristics at the site and the overlaying Eau Claire shale provides a significant cap rock to prevent upward migration of CO_2.

1.1.1 Project Goals

In this project, Marquis Carbon Injection, LLC plans to:

- Construct a capture and compression system at the ethanol facility
- Build the infrastructure needed to transport CO_2 to the injection site
- Drill injection (MCI CCS 3) and monitoring (MCI MW 2 and MCI ACZ 1) wells to inject and monitor CO_2, respectively

- Monitor the subsurface for any potential impacts to the deepest underground source of drinking water (USDW)
- Upon completion of the injection phase of the project, verify stability of the CO2 plume and decline of storage formation pressure to pre-injection levels, verify plume predictions made by the computational modelling, demonstrate non-endangerment of USDWs, and safely plug the MCI CCS 3 well and decommission associated infrastructure.

1.1.2 Partners/Collaborators

Key partners and collaborators on this project are listed in Table 1-1.

Name	Role
Marquis Carbon Injection, LLC	Owner
Marquis Carbon Injection, LLC	Storage Operator
Marquis Carbon Capture, LLC	CO_2 Capture Operator

Table 1-1: Key project partners and collaborators.

1.1.3 Overview of the Project Timeframe

The overall timeframe of the project, including well drilling, CO_2 injection, monitoring, and closure, is anticipated to be approximately 12 years. This includes:

- 1 year for permit approval
- Construction during the second year
- 5 years of CO_2 injection and monitoring
- 5 years of post-injection site care (PISC) and monitoring

	Elapsed years											
	1	2	3	4	5	6	7	8	9	10	11	12
Class VI approval												
Construction												
Injection												
Closure												
Post-closure monitoring												

Table 1-2: Project Gantt Chart

1.1.4 Proposed Injection Mass/Volume and CO_2 Source

Total injection mass to be injected over the course of the project is 7,500,000 million tonnes (MT). This equals an annual average injection rate of 1,500,000 tonnes/ year over the 5-year injection period. The CO_2 will be sourced from an ethanol plant with an anticipated purity of 99.86%. This stream will be dehydrated and compressed to obtain the stream composition outlined in Table 1-3.

Component	Quantity
CO_2	99.86%
Oxygen	0.03%
Nitrogen	0.1%
TEG	<0.3 Gal/MMSCF
Water Vapor	50 ppm
Hydrogen sulfide (H_2S)	NA

Table 1-3: Anticipated composition of the CO_2 stream injected at by the Marquis Biocarbon Project.

1.1.5 Injection Depth Waiver or Aquifer Exemption Requested

There is no injection depth waiver or aquifer expansion being sought as a part of this permit application.

1.1.6 Other Administrative Information

Table 1-4 provides the administrative information for the Class VI injection well permit application as required by 40 CFR 144.31(e)(1 through 6).

Injection Well Information	
Well Name and Number	MCI CCS 3
County	Putnam County, Illinois
Section−Township−Range	S2 T32N R2W
Latitude and Longitude	41.27026520 N, 89.30939322 W
Applicant Information	
Name	Marquis Carbon Injection LLC
Address and Phone Number	10000 Marquis Drive Hennepin, IL 61327 Phone: (815) 925-7300
Project point of contact	Elizabeth Steinhour Director of Environmental Affairs
Ownership Status	Private
Status as federal, state, private, public, or other entity	Private entity
The injection well and the sequestration site are not located on Indian land.	

Table 1-4: General Class VI CO_2 injection well permit application information.

In addition to the Underground Injection Control (UIC) permit for the MCI CCS 3 well, Marquis Carbon Injection, LLC will be required to obtain authorizations, permits, and certifications from other federal, state, regional, and local agencies for the construction and operation of the CO_2 pipeline, the proposed CO_2 storage site, and associated monitoring systems.

1.2 Site Characterization

1.2.1 Regional Geology, Hydrogeology, and Local Structural Geology [40 CFR 146.82(a)(3)(vi)]

The Marquis Biocarbon Project site is located on the northern edge of the Illinois Basin near Hennepin, Putnam County, Illinois (Figure 1-1). This basin contains dominantly marine sedimentary sequences which range in thickness from 1,500 feet (ft) to 15,000 ft from north to

south. Figure 1-2 shows the generalized stratigraphic succession at the Marquis Biocarbon Project site based on the characterization well, MCI MW 1, along with the proposed injection and confining zones and hydrostratigraphy. Marquis will utilize the MCI MW 1 well as a future monitoring well under the Class VI permit. The target injection zone is the regionally extensive Cambrian-age Mt. Simon Sandstone, which is locally over 1,700 ft thick. Overlying the Mt. Simon Sandstone are regionally extensive shale units of the primary confining zone, the Cambrian-age Eau Claire Shale.

The Mt. Simon Sandstone consists of fine- to coarse-grained sandstones containing intermittent sections of pebbly conglomerates near the base and increased clay content near the top. This sandstone formation sits at a depth of almost 2,600 ft sub surface true vertical depth (SSTVD) at the Marquis Biocarbon Project site based on data from the MCI MW 1 well. The Mt. Simon Formation rests on crystalline basement rock, which represents the underlying confining unit. Overlying the Mt. Simon Formation is the primary caprock, the Eau Claire Shale.

The Eau Claire Formation consists of shale, siltstone, sandstone, and minor dolomite, as well as a basal sandstone member, the Elmhurst Sandstone. The upper portion of the Eau Claire Formation acts as a thick, confining layer for the underlying sandstones. The Eau Claire is 2,706 ft measured depth (MD) and 404 ft thick at the MCI MW 1 well. More detailed regional information for these units can be found in section 1.2.4 of this document and section 2.1.2 Site Geology and Hydrology of permit section 2, AoR and Corrective Action Plan.

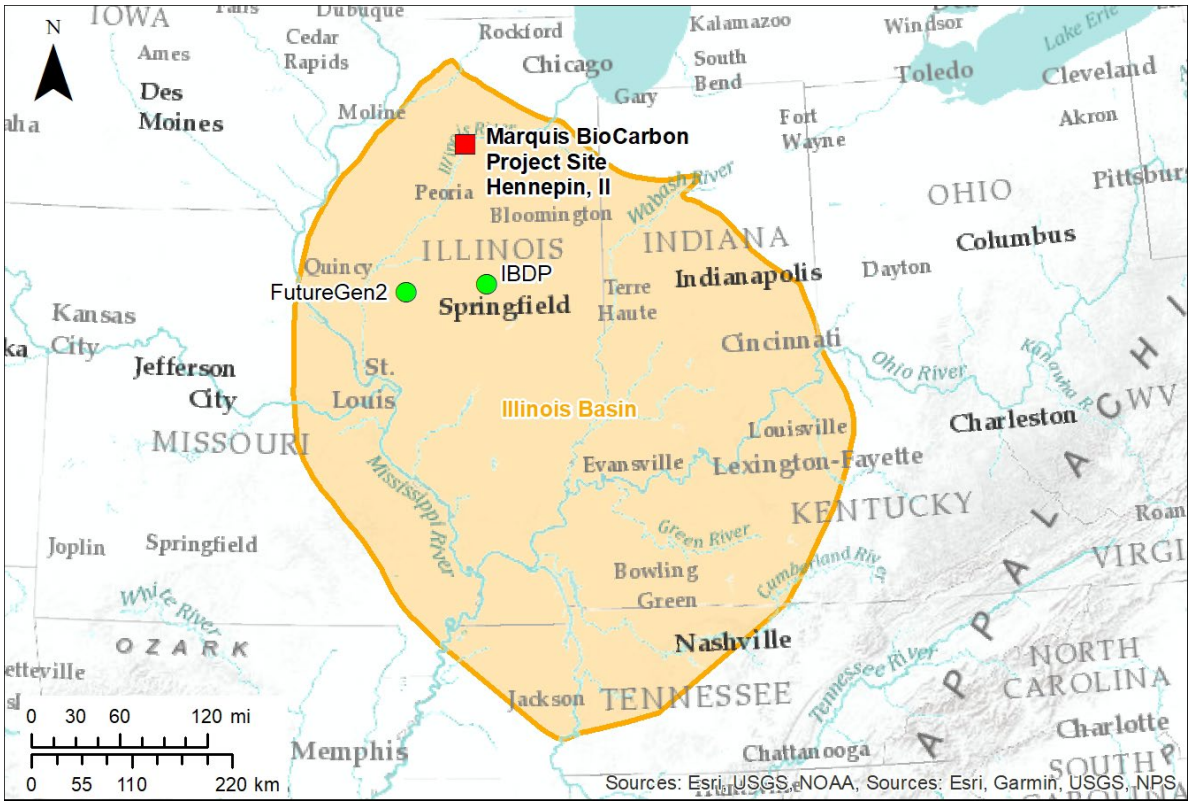


Figure 1-1: The Marquis Biocarbon Project site sits on the northern edge of the Illinois Basin. The Mt. Simon Sandstone in Hennepin, Illinois has been identified as the target injection zone for CO_2 storage. Also shown are the FutureGen2 and the Illinois Basin – Decatur Project sites, which have demonstrated the capability for CO_2 storage in the Mt. Simon Sandstone

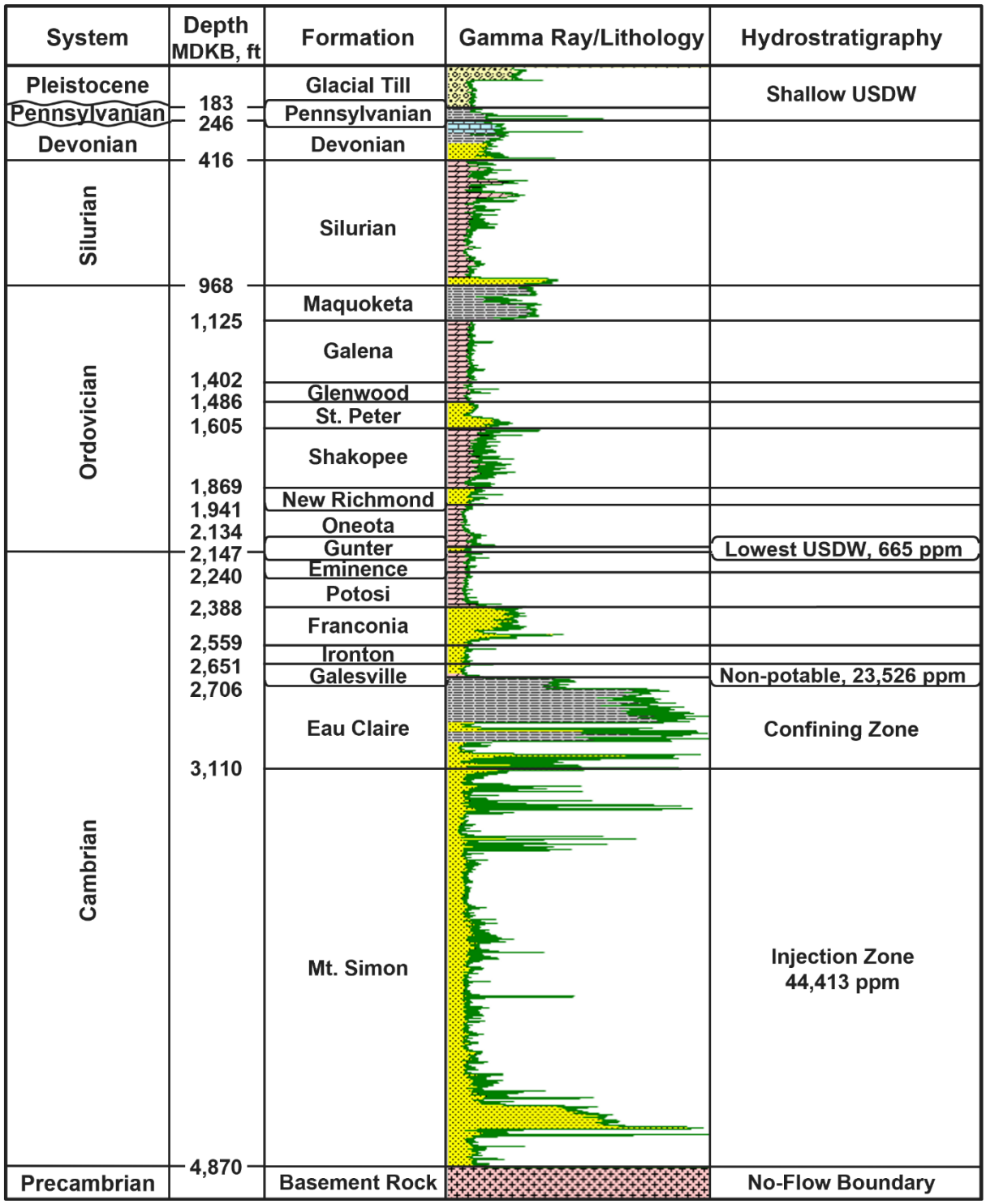


Figure 1-2: Stratigraphic column with lithology and hydrostratigraphy for the Marquis Biocarbon Project site based on data from the characterization well, MCI MW 1. ft = feet; MDKB = measured depth below kelly bushing; ppm = parts per million; USDW = underground source of drinking water.

The Precambrian basement forms a non-conformable base upon which all the sedimentary strata were deposited and is the oldest rock in the stratigraphic sequence. Locally, the basement is composed of granite and acted as a structural control during the deposition of the basal sedimentary units. The depositional thickness of the Mt. Simon is not concentric with its structural top—a shift in basin subsidence gradually caused the center of the basin to migrate southeast. While the Mt. Simon deepens to the southeast, it thickens to the northeast. During the Cambrian Period, sediments were transported from topographically higher regions, such as mountains to the north, to a shallower region in Illinois. Depositional environments of the Mt. Simon were primarily fluvial and eolian. As the paleoshoreline migrated in the Cambrian, continental shelf and shallow marine systems deposited the upper Mt. Simon Sandstone and Eau Claire Shale.

There are several geologic structures northeast of Putnam County (Figure 1-3). At the Marquis Biocarbon Project site, these structures do not appear to have a significant impact on the confining zone and saline storage reservoir. The La Salle Anticlinorium is the dominant regional structure within the basin and extends from La Salle County in north central Illinois to the southeast towards Lawrence County near Vincennes, Indiana. This feature is believed to be a drape fold or fault-propagation fold similar in structural style to monoclines that developed during the Laramide Orogeny in the western United States (Nelson, 1995). More than half of the La Salle Anticlinorium's uplift is believed to occur during Late Mississippian time, with the remaining uplift and nearby structural features occurring during the Pennsylvanian. There are small faults, anticlines, and domes near the La Salle Anticlinorium and along its trend. The Marquis Biocarbon Project site resides in an area fully off and away from the anticline. Other structural features to the northeast of Putman County include the Kankakee and Wisconsin Arches and several minor synclines, anticlines, and domes. To the northeast of the La Salle Anticline is the Ashton Arch and the Sandwich Fault.

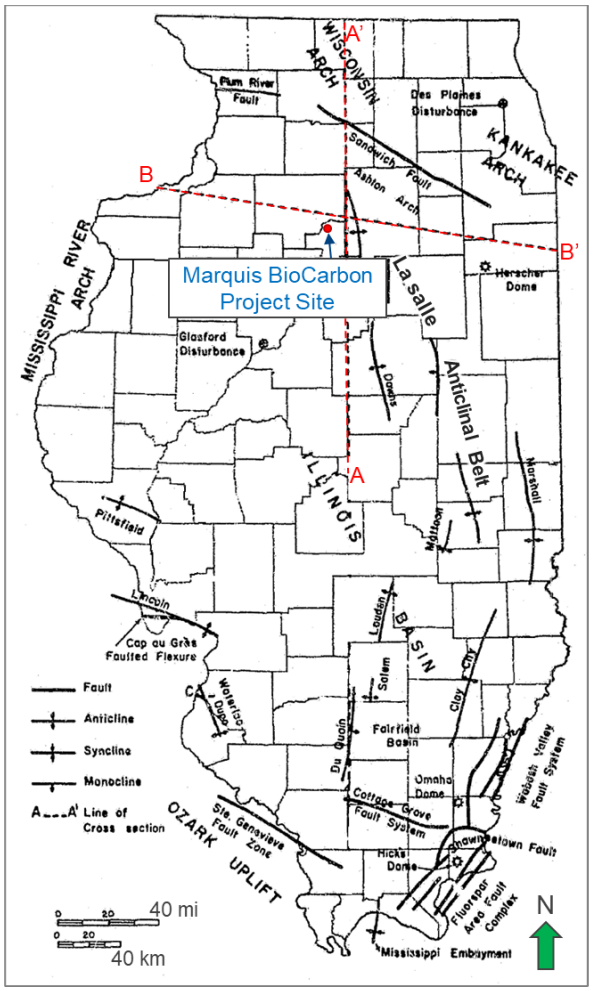


Figure 1-3: Principle geologic structures of Illinois (modified from Willman et al., 1975). Red lines A-A' and B-B' are cross section of the region, see Figure 1-5.

1.2.2 Maps and Cross Sections of the AoR [40 CFR 146.82(a)(2), 146.82(a)(3)(i)]

At the Marquis Biocarbon Project site, the Mt. Simon Sandstone is not considered an underground source of drinking water (USDW) based on salinity samples acquired from MCI MW 1 with total dissolved solids (TDS) concentrations greater than 10,000 milligrams per liter (mg/L) or 10,000 parts per million (ppm). The lowermost USDW is defined locally as the Gunter Sandstone of the Prairie du Chien Group (Knox Supergroup). At the MCI MW 1 well, the base of the Gunter Sandstone is 963 ft above the top of the Mt. Simon (Figure 1-2). USDWs in the project site range in depth from the Gunter Sandstone to shallow, near-surface glacial till aquifers. A map of the CO_2 plume, AoR, existing wells within the AoR and corresponding total depths, and proposed project wells are shown in Figure 1-4. Available well information indicates that wells inside the AoR are all shallow groundwater wells less than 220 ft MD. A total of seven shallow groundwater wells are present within the AoR. However, Marquis will be utilizing one of the existing groundwater wells and installing three additional shallow groundwater wells for

purposes of monitoring the area within the AoR. See Table 2-6 of Section 2 for details concerning the wells.

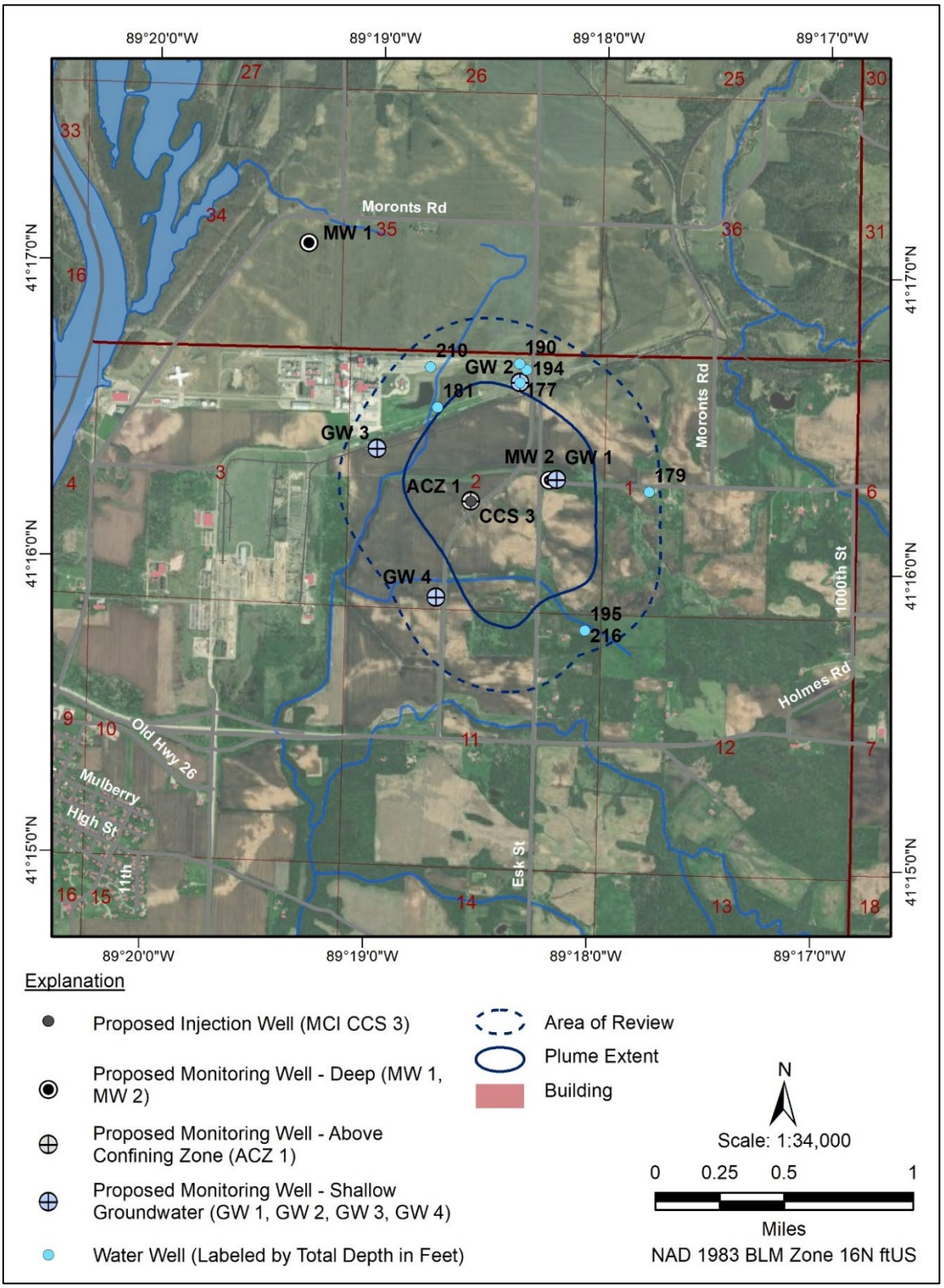


Figure 1-4: Map showing the modeled CO_2 plume footprint, AoR, and existing and proposed project wells within the AoR.

Both the injection and confining zones are laterally extensive across the Illinois Basin. This was determined around the proposed site by correlating well data from MCI MW 1 and surrounding regional wells, as well as 2D seismic data, and regional cross sections. Regional structure and thickness maps for these units can be found in Section 1.2.4 Injection and Confining zone details.

Major geologic units and their stratigraphic relationships are depicted in regional cross sections shown in Figure 1-5. The location of these cross sections is shown in Figure 1-3. The Cambrian sedimentary rock shallows to the north, but local stratigraphic dips for the confining and injection zones are low. While the Cambrian formation is regionally affected by the La Salle Anticline northeast of Putnam County, the proposed Marquis Biocarbon Project injection well is outside of the area affected by the anticline.

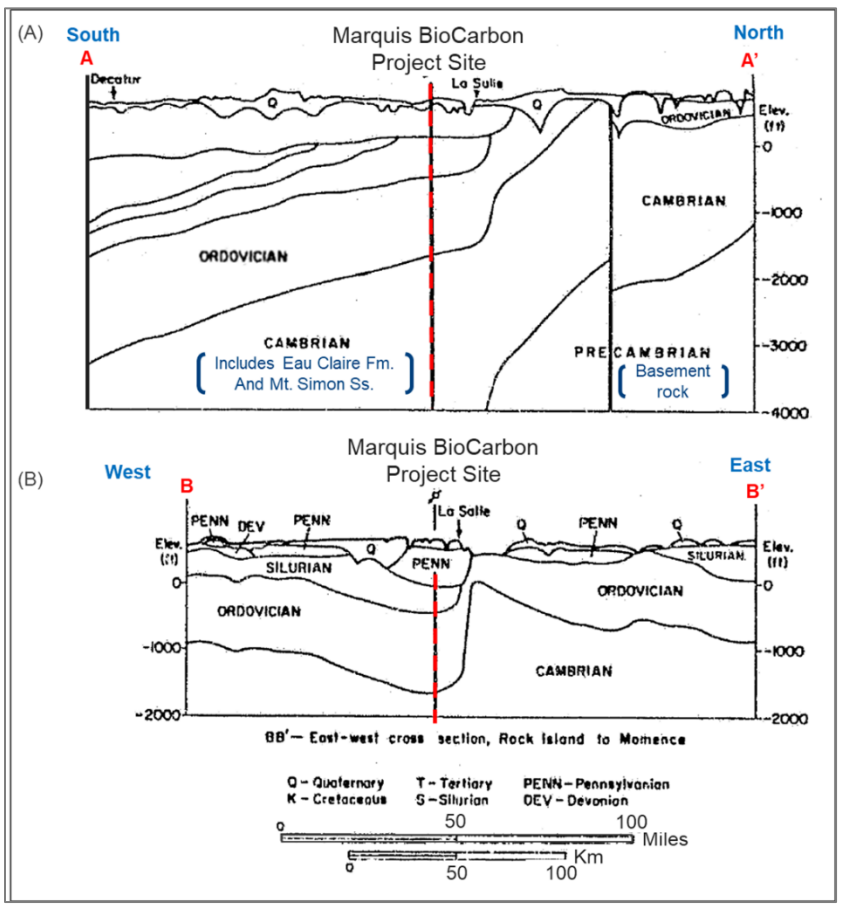


Figure 1-5: Geologic cross sections near Putnam County featuring the structural configuration of Cambrian strata that contains the target injection zone and caprock. Modified from Willman et al., 1975.

1.2.3 Faults and Fractures [40 CFR 146.82(a)(3)(ii)]

While numerous structural features have been identified regionally around the Illinois Basin, no structural faulting is expected to impact the injection or confining zones within the Area of Review for the Marquis Biocarbon Project Site. The La Salle Anticlinorium is the dominant regional structure within the basin and has associated faults which cause varied relief of the strata along its trend. The Marquis Biocarbon Project site resides in an area fully off and away from the anticline. A 2D seismic program was completed in 2021 to assess any large-scale faulting in the area. The program confirmed the absence of large-scale faulting in the vicinity of the Marquis Biocarbon Project site. An example of one of the 2D lines is shown in Figure 1-6.

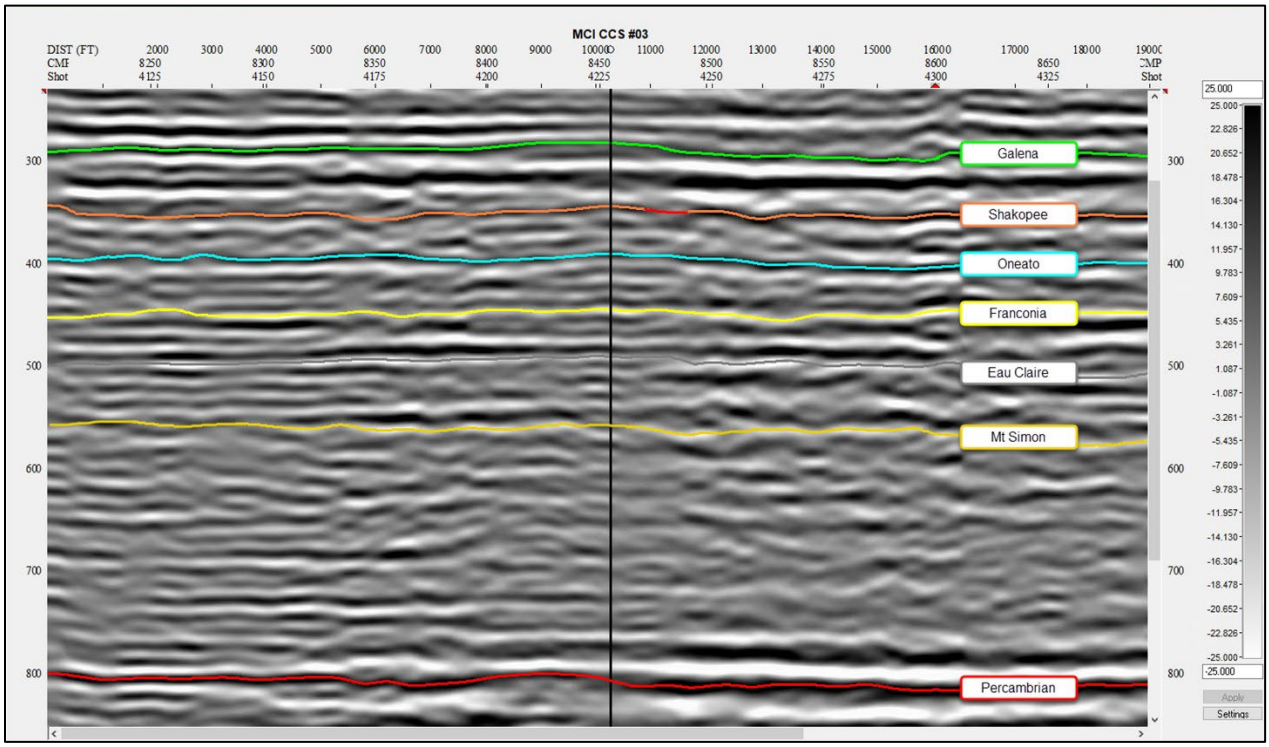


Figure 1-6: Example of 2D seismic line acquired in 2020.

1.2.4 Injection and Confining Zone Details [40 CFR 146.82(a)(3)(iii)]

Confining Unit: Eau Claire Formation

The confining zone for the Marquis Biocarbon Project is the Eau Claire Formation, which consists of interbedded shales, siltstones, sandstones, and minor dolomites. A basal Eau Claire sandstone member, the Elmhurst Sandstone, sits at 2983 ft MD and is comprised of 127 ft of fine to medium grained sandstone with interbedded siltstones and gray shales. The thickness of the Eau Claire formation varies regionally from less than 300 ft in western Illinois to more than 1,000 ft in southeastern Illinois. Locally, the Eau Claire is 404 ft thick at the MCI MW 1 well,

with 350 ft of the formation characterized as confining zone for the Marquis Biocarbon Project site. The confining zone is defined by the top of the Eau Claire (2706 ft MD at MCI MW 1) through an 11-foot-thick shale in the upper Elmhurst (3043–3054 ft MD) as shown in Figure 1-9. Confining zone properties were confirmed based on core analysis from MCI MW 1 well.

Injection Zone: Mt. Simon Formation

The main injection zone for the Marquis Biocarbon project is the Mt. Simon Sandstone, consisting of alternating intervals of well- and poorly sorted sands with variable grain size and shale content. Within the study area, the lower portion of the Elmhurst Sandstone is included as part of the injection zone because the Mt. Simon sands, and lower Elmhurst sands are considered hydraulically connected from the base of the intra-Elmhurst shale down (Golden StrataServices, 1984). The Elmhurst Sandstone is fine to medium grained, fossiliferous, and contains interbedded gray shale.

The Mt. Simon sandstone extends throughout Illinois and reduces considerably in thickness from the northeast to southwest. The Mt. Simon sands measure approximately 2500 ft thick in the northwest and decrease to less than 500 feet thick in the southwest, as shown in Figure 1-7. Several Precambrian highs present throughout the basin, which resulted in the non-deposition of the Mt. Simon Sandstone in selected areas. A regional structural contour map for the top of the Mt. Simon Sandstone is shown in Figure 1-8.

From direct measurements and sampling in the characterization well at the project site, the Mt. Simon Sandstone is 3,110 ft MD and 1,760 ft thick and has a shallow dip of 28 ft per mile (0.05% grade) to the southeast. This data corroborates the maps shown in Figure 1-7 and Figure 1-8. 2-D seismic data show no basement highs or pinch outs in the modeled area.

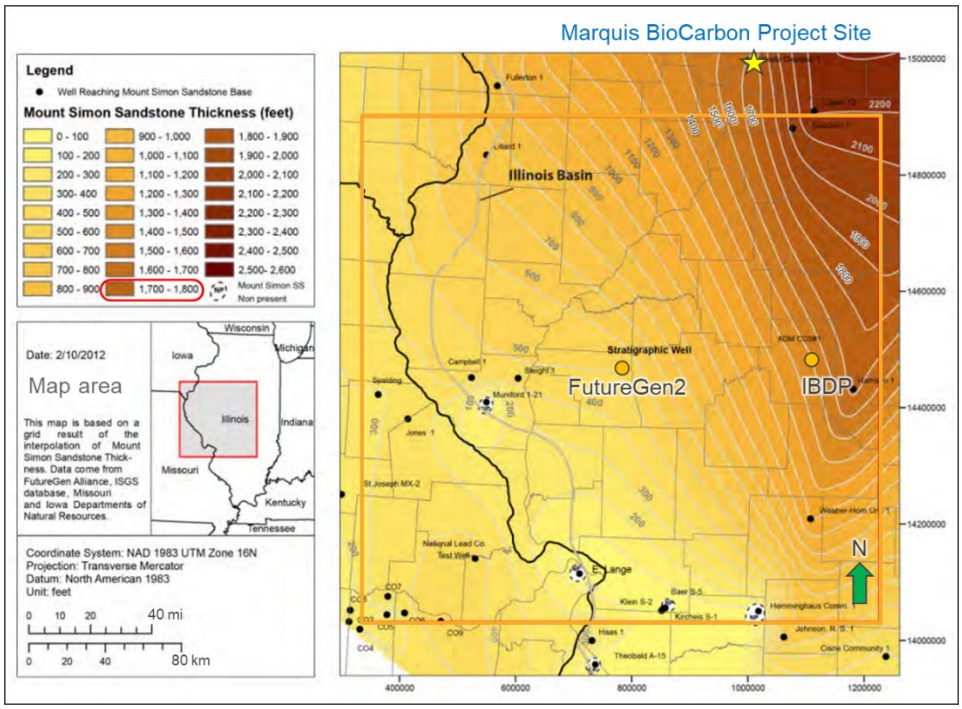


Figure 1-7: Mt. Simon Sandstone thickness map over the west-central portion of the Illinois Basin (modified from FutureGen Alliance, 2013).

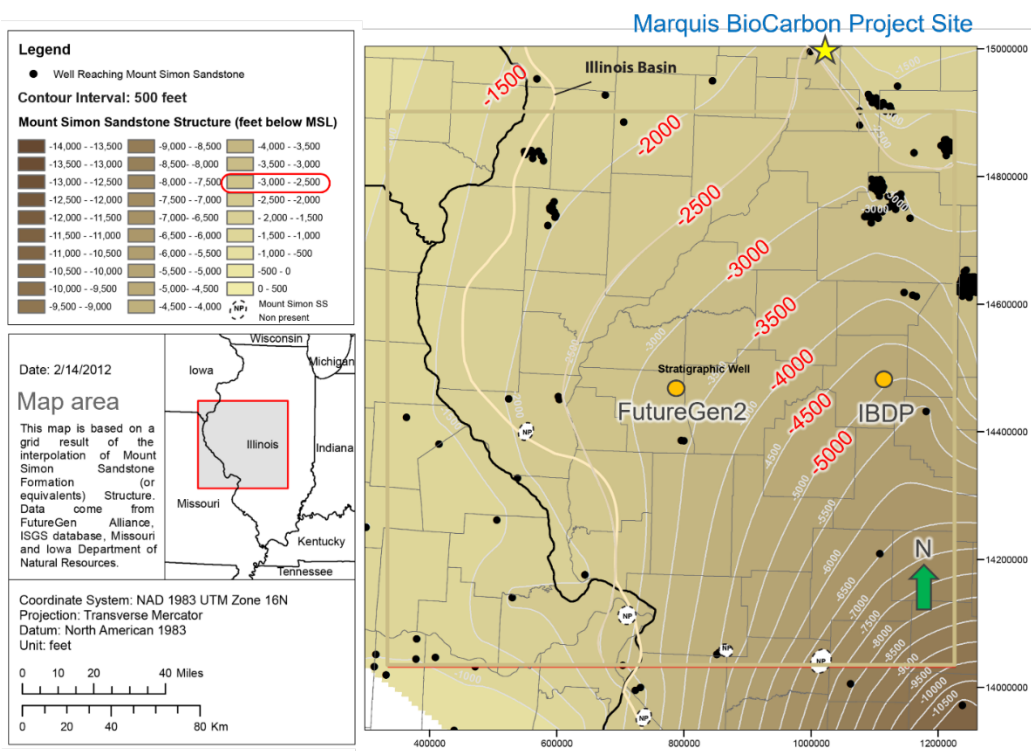


Figure 1-8: Mt. Simon Sandstone elevation depth map over the west-central portion of the Illinois Basin (modified from FutureGen Alliance, 2013).

The Mt. Simon sandstone is subdivided into seven internal zones based on observed responses seen in geophysical and petrophysical data. These zones are numbered top down, as shown below in Figure 1-9. While differently named, these zones are roughly equivalent to Mt. Simon subdivisions used in other studies and at other sites (Fischietto, 2009; FutureGen Alliance, 2013; Freiburg et al., 2014). Generalized reservoir quality of the zones indicates highest quality sands in the lower half of the formation, a middle section of lower-quality sands, and an upper section of higher quality, which is also a trend seen at the regional scale.

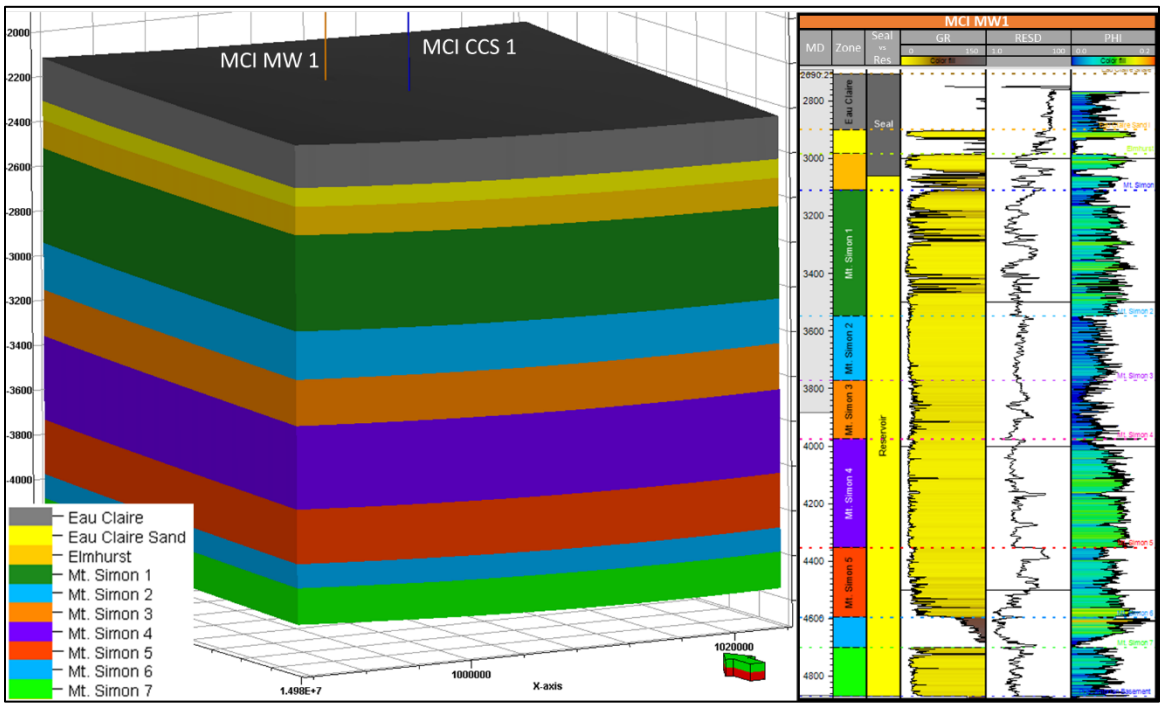


Figure 1-9: Model Zones and corresponding gamma ray, resistivity, and porosity logs. Lower part of the Elmhurst and all the Mt. Simon are considered reservoir, while the upper Elmhurst and Eau Claire shale act as the seal.

To assess site-specific properties for the injection and confining zones, a stratigraphic test well (MCI MW 1) was drilled (Figure 1-4). Multiple sample types were collected for analysis and testing to determine specific qualities of the Mt. Simon and Eau Claire formations at the Marquis Biocarbon Project site, including 6 whole cores, 28 sidewall cores, well logs, and eight dynamic formation tests with fluid samples.

An elemental neutron log was used to determine the specific lithologies present in the confining interval and injection zones by creating a continuous vClay log to use in determining intervals of shales and sands. These results were subsequently cross-checked with whole core and sidewall core samples for verification, and further validated with XRD and XRF data. The most impactful result of incorporating the elemental neutron log for lithologic classification was the

determination that the high gamma ray response near the base of the Mt. Simon, often classified as a shaley interval, is instead an interval of hot sands. This hot sand signature is likely caused by the abundance of Arkosic sands, and is a signature regionally observed near the base of the Mt. Simon formation.

The Mt. Simon Sandstone can be divided into larger blocks associated with the timing and development of the basin that affects depositional settings. Core samples from the project site were integrated with regional studies, resulting in seven distinct depositional packages in the Mt. Simon (Figure 1-9 and 1-10). These environments include eolian sand dunes, fluvial braid plains, and braid deltas that transitioned into shallow marine depositional environments as sea level rose during deposition of the upper Mt. Simon and Eau Claire. Within the regional fluvial braid plain, there are playa (flat "ponding" areas) and eolian (dunal) sedimentary areas (Figure 1-11).

The Mt. Simon consists of sandstones that are generally clean, well-sorted, and porous. Variations in sediment grain size depend on how far sediments were transported from their source and whether they were reworked by wind (eolian sandstone) or water (shallow marine sandstones modified and sorted by wave action). At the Marquis Biocarbon Project site, the lower Mt. Simon consists of conglomerate and very coarse to fine-grained sandstone deposited by braided fluvial channels and eolian systems, as well as arkosic sandstones yielding high gamma ray values in Mt. Simon zone 5 and 6. In the Upper Mt. Simon fluvial, tidal, and shallow marine depositional systems resulted in finer grained sandstone and increased clay content. During the deposition of the Eau Claire, continental shelf and shallow marine systems deposited shales, siltstones, and fine to very-fine grained sandstones with dolomitic and arkosic compositions.

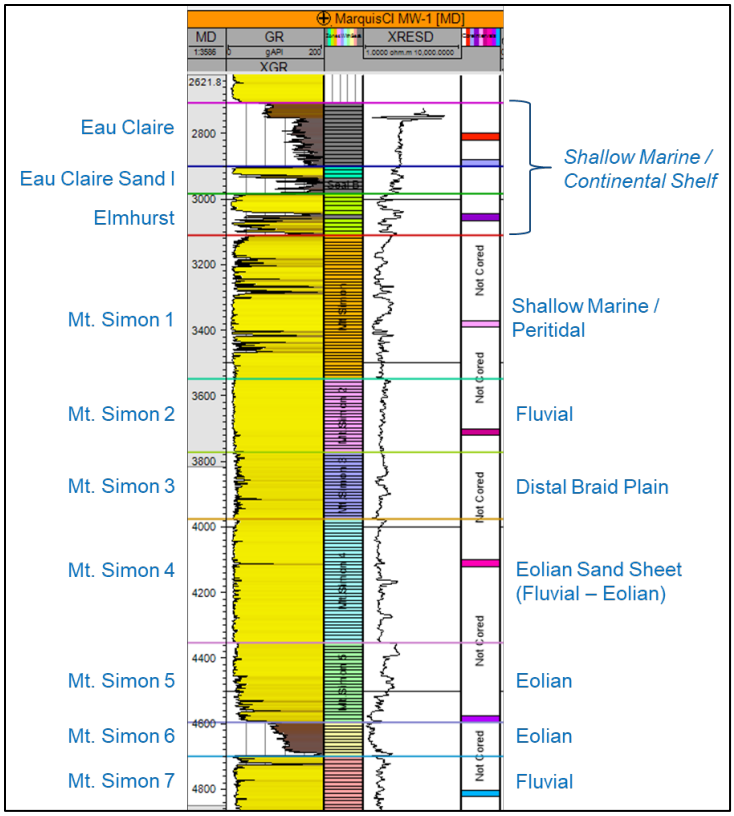


Figure 1-10: Interpreted Mt. Simon depositional environments and corresponding intraformational zones.

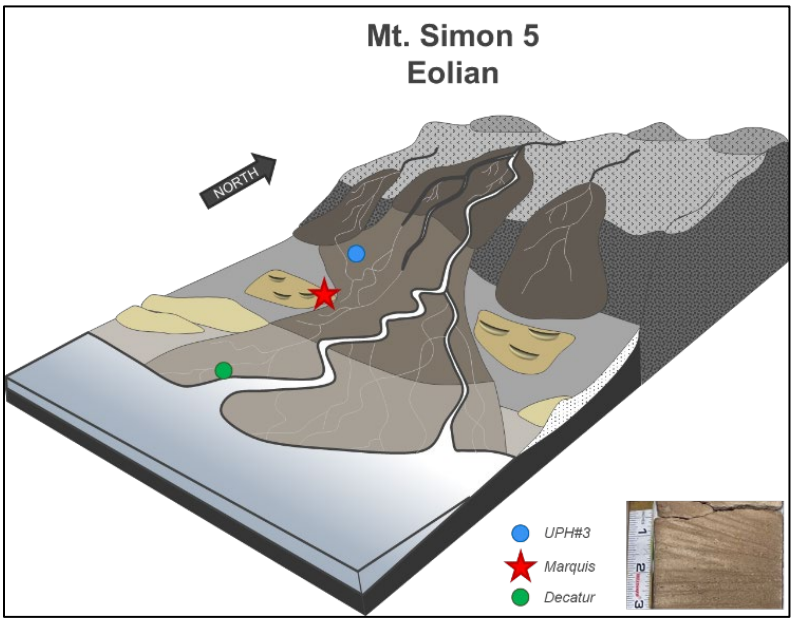


Figure 1-11: Example conceptual schematic drawing of the Mt. Simon Zone 5 representing the eolian depositional environment and interpreted orientations at the Marquis site (not to scale), as well as representative bedding features in whole core (insert) acquired from Mt. Simon Zone 5. Modified from Freiburg et al. (2020).

Porosity and Permeability

Since the injection interval was characterized based on environments of deposition (EOD), EODs were incorporated into the model as objects representing channels and eolian sand deposits. These objects provided a way to constrain facies distribution throughout the model, where environmental controls on the deposition of clean sand and shale could be represented. Facies used were defined with a vClay log to separate the rock into three main types: clean sand, dirty sand, and shale. Each facies had a unique distribution of porosity values (Figure 1-12), which were utilized during the porosity property modeling process. Clean sand and dirty sand histograms had a distinctly different distribution in the Mt. Simon 2 and Mt. Simon 3 intervals, where normal distributions were centered around means which were shifted several porosity percentage points to the left (lower).

The resulting porosity property was used as a direct input into the permeability property, which was calculated using porosity-permeability transform functions derived from the NMR-based permeability log. The NMR-based permeability values were cross-checked with core-measured permeability and a strong correlation was shown. Further details can be found in the AoR and Corrective Action Plan (Permit Section 2). The porosity-permeability function was applied based on flow-based facies, which were defined using a flow-zone-indicator (FZI) log. The FZI data resulted in four additional "flow-based" facies types: High-Flow Sand, Mid-Flow Sand, Low-Flow Sand and Shale. Each lithofacies contained a component of each FZI and were subsequently divided into the corresponding amount of flow facies, which represented variabilities in pore-throat size and directly correlates to flow-potential. Two transforms were defined from this data, an upper transform for the high and medium-flow facies, and a lower transform for the shale and low-flow facies (Figure 1-13). The final permeability property was confirmed with well test results to ensure permeability height achieved in the model matched dynamic observations at the MCI MW1 well.

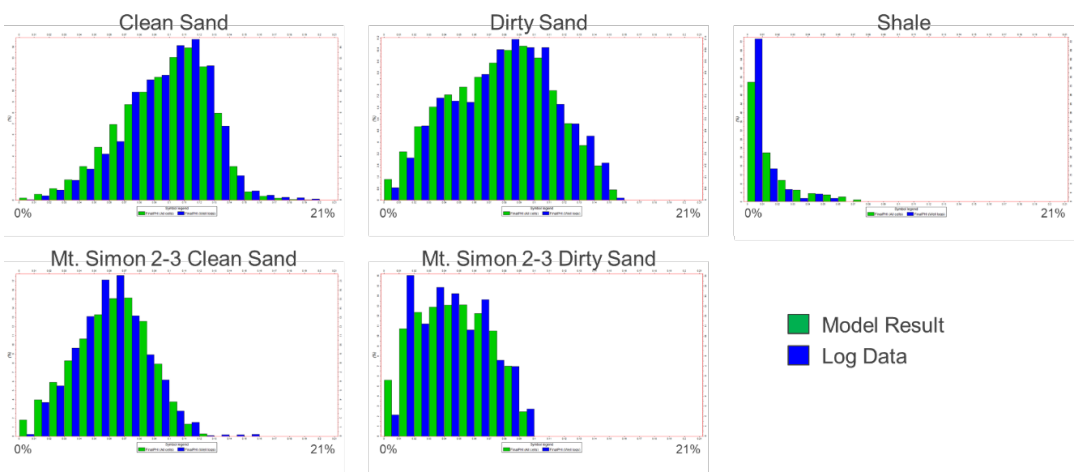


Figure 1-12: Histograms of porosity ranges by facies type showing correlative distributions for the clean sand, dirty sand, and shale facies. Distinctly different distributions for clean sand and dirty sand in Mt. Simons 2 and 3, where normal distribution means are lower.

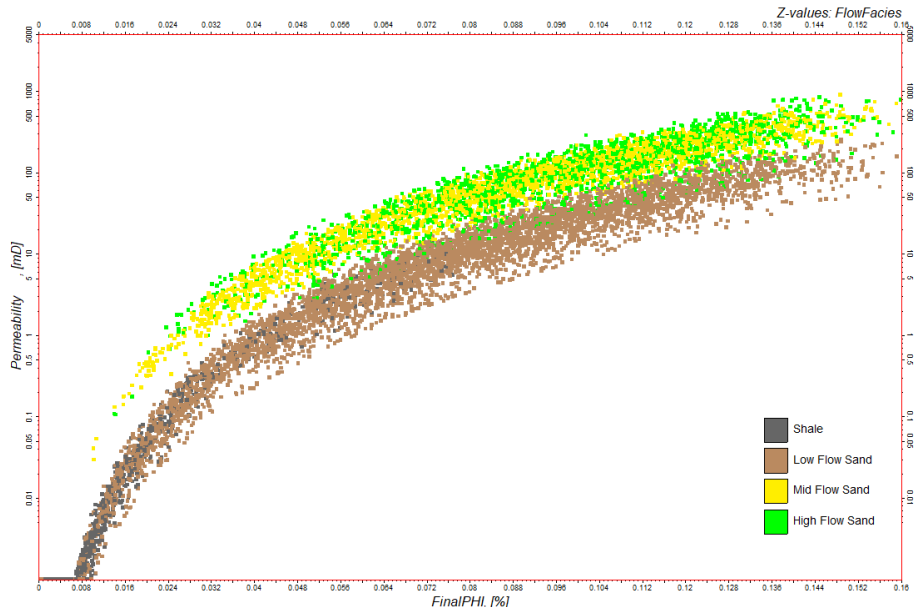


Figure 1-13: Porosity-Permeability cross-plot colored by flow facies showing the utilization of two different transforms, applied by flow-based rock classifications.

Injectivity

As discussed above, the storage capacity of the Mt Simon is sufficient for storage of high volumes of injected CO_2. To calculate the injectivity of the formation, the fracture pressure was measured in the MCI MW1 characterization well. The bottom hole injection pressure cannot exceed 90% of the fracture gradient.

Minifrac tests were performed in the MCI MW 1 characterization well to obtain the fracture pressure. Six tests were conducted: two tests in the Eau Claire Caprock and four in the Mt Simon at different depth intervals. The average fracture propagation pressure gradient of the four tests in the Mt Simon, determined during the analysis of the minifrac and used in the model as the fracture pressure gradient, was 0.76 psi/ft. This fracture gradient was used to constrain the wellbore bottom-hole pressure at the top of the perforation interval in CMG-GEM. The assigned well bottomhole pressure in the model in this case is 2207 psi (3226 ft MD*0.76*90%) following USEPA's guidelines. Using this pressure constraint, the results from the dynamic modeling shows that 7.5 MM tonnes can be injected in 5 years (Figure 1-14). The distribution of the injected CO_2 over time is shown in Figure 1-15. CO_2 does not penetrate the caprock at the end of injection. The plume diameter is predicted to be 0.1 mile to 1 mile in the x direction and 0.1 to 1.4 miles in the y direction across the injection interval (Figure 1-16).

The Area Of Review (AoR) is determined by using the average plume sizes for all layers in the model at the end of the 5-year injection period which corresponds to layer 153. The CO_2 saturation in that layer at the end of injection period was selected to define AoR. Further details can be found in the AoR and Corrective Action Plan (Permit Section 2).

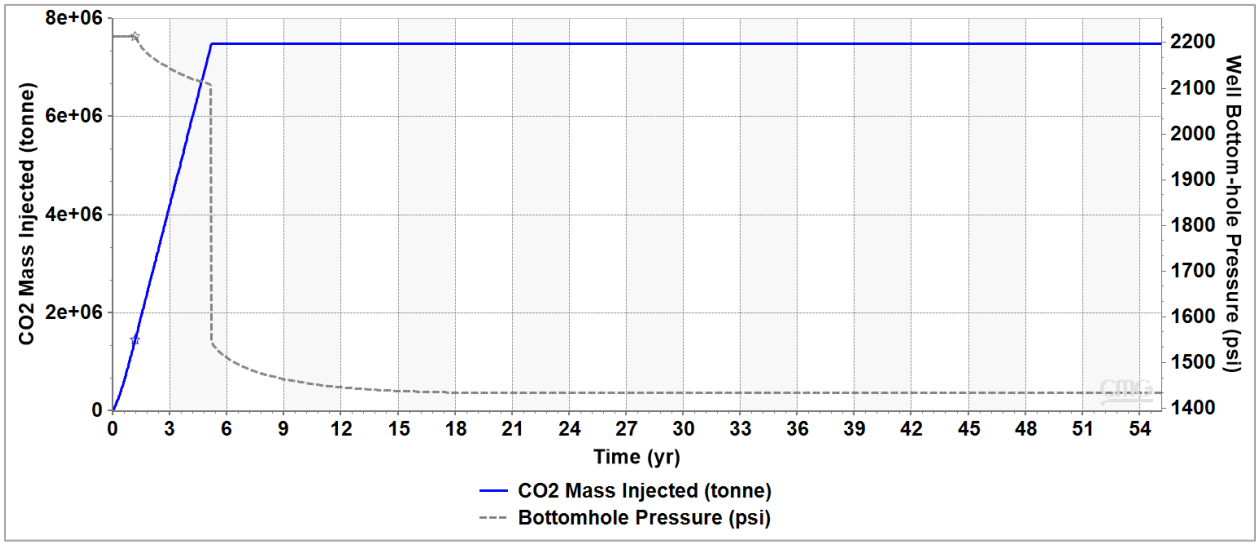


Figure 1-14: Plot of Cumulative CO_2 injection (blue) and Bottom Hole Pressure (grey).

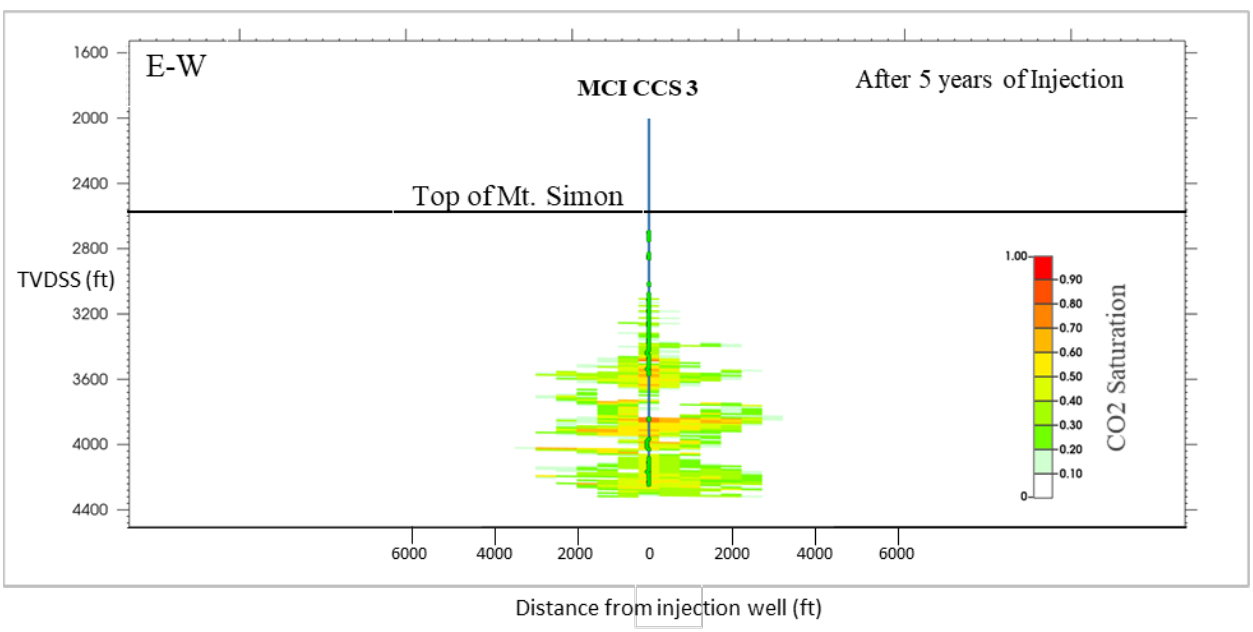


Figure 1-15: Development of CO_2 plume after 5 years of injection.

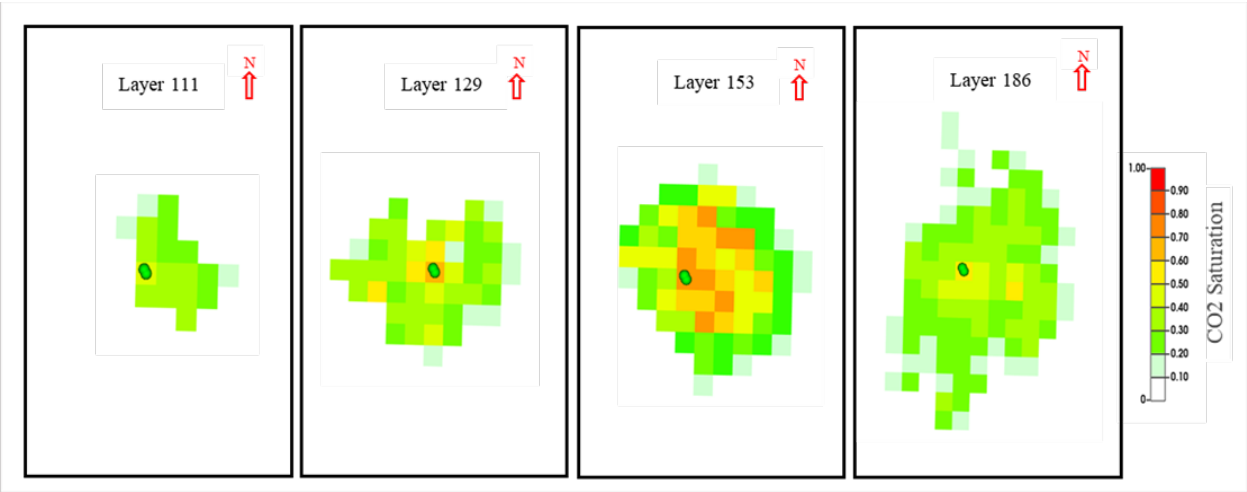


Figure 1-16: CO_2 plume in plan view for selected layers.

Uncertainty

The base case modeling shown above uses parameters derived from field data acquired in the characterization well. To assess potential variations in these parameters an uncertainty analysis has been completed which models the CO_2 plume for modified scenarios. These scenarios are utilized to ensure that the range of uncertainty in the subsurface is considered and covered within the scope of the injection and monitoring plans. The scenarios explored for the Marquis Biocarbon Project are shown in Table 1-5. Each scenario resulted in its own Static Earth Model (SEM) realization, and subsequent dynamic simulation. High and low side case runs were performed in addition to the base case to access the effects of varying porosity/permeability relationships on CO_2 plume and AoR. The permeability vs porosity plot for each case in the Mt Simon is shown Figure 1-17. Both the high and low cases were imported from the Petrel geological (SEM) model into CMG. Every parameter was the same as the base case except for porosity and permeability. The plot illustrates that there is an inverse relationship between porosity and permeability, where in the high case we have high porosity and low permeability and vice versa for the low case. Therefore, in the high case more CO_2 can be stored in a smaller CO_2 plume diameter, due to a greater pore volume.

Scenario	Scenario Objective	Plume Implication	Summary of Property Adjustments
High Side	Highest injectable volume while maintaining AoR constraints	Largest volume, smallest plume	Higher porosity, decreased permeability
Base Case	Base case volumes	Base case plume	Base case properties
Low Side	Lowest injectable volume to maintain AoR constraints	Lowest volume, largest plume	Lower porosity, increased permeability

Table 1-5: Summary of alternative subsurface scenarios for the Marquis Biocarbon Project.

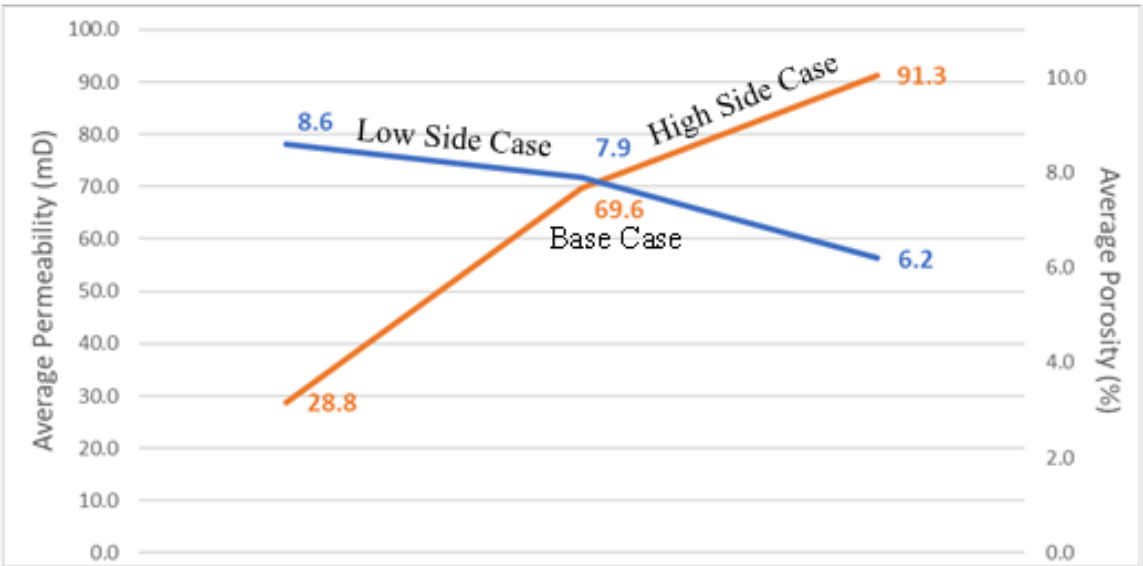


Figure 1-17: Porosity and permeability relationships for High Side Case (orange line) and Low Side Case (blue line). The numbers on the orange are permeability values, number on the blue line are porosity values.

The plume side views for the base, high side and low side cases after 3 years of injection are compared in Figure 1-18. The low side case scenario results in a larger overall plume diameter compared to the other two cases. Figure 1-19 shows the CO_2 plume in map view at layer 153, at the end of injection and 5 and 10 years after the injection stops for the base case scenario.

The results of the sensitivity analysis (high side case and low side case) shown in Figure 1-20 for the CO_2 plume at layer 153 shows that the AoR is smaller compared to base case scenario at the end of the injection and post injection periods. It is also shown in Figure 2-35. that the plume size in the high and low side scenarios remains mainly unchanged after 1 year post injection.

These results indicate that there is low uncertainty around the AoR extent for varying geological parameters. Further details are discussed in the AoR and Corrective Action Plan (Permit Section 2) and the Post Injection Site Closure Plan (Permit Section 9).

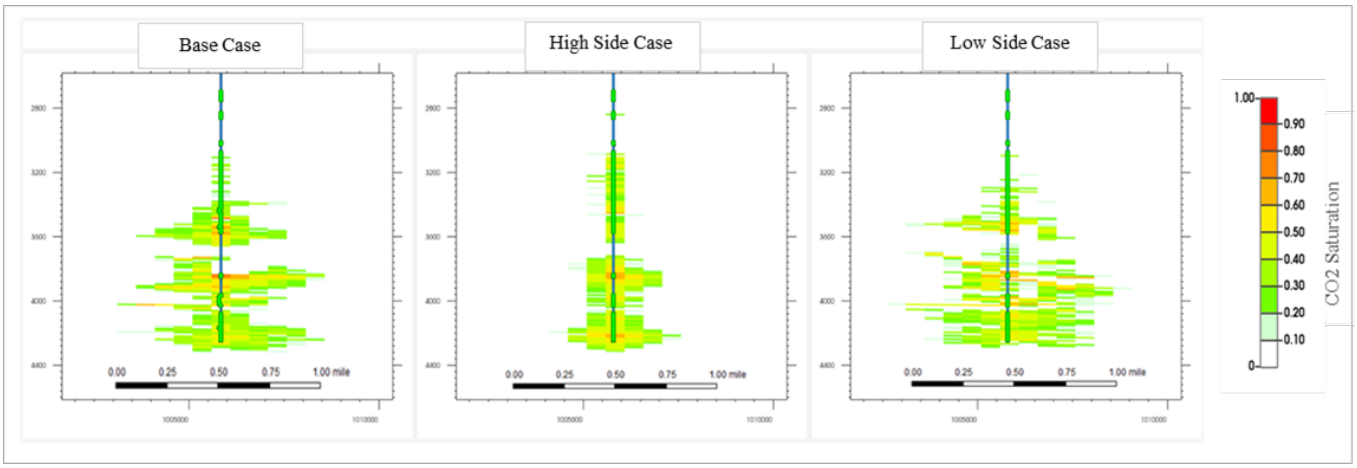


Figure 1-18: CO_2 plume at wellbore cross section after 3 years of injection. The left plume diagram represents the base case, middle represents the High Side Case, and the right plume diagram represents the Low Side Case.

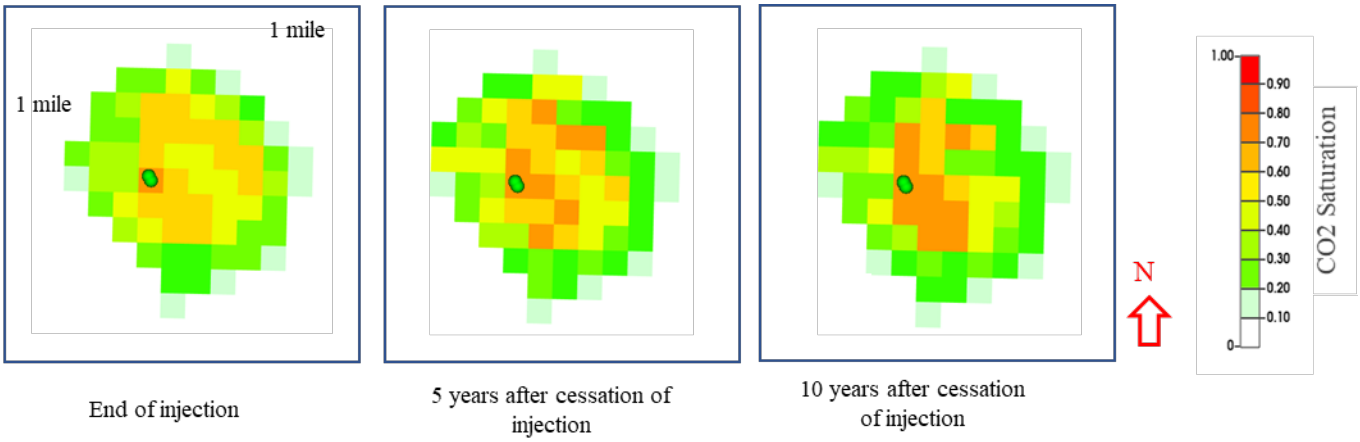


Figure 1-19: CO_2 plume at layer 153 (used to delineate AoR) for the base case at the end of injection, 5 years after injection stopped, and 10 years after injection stopped.

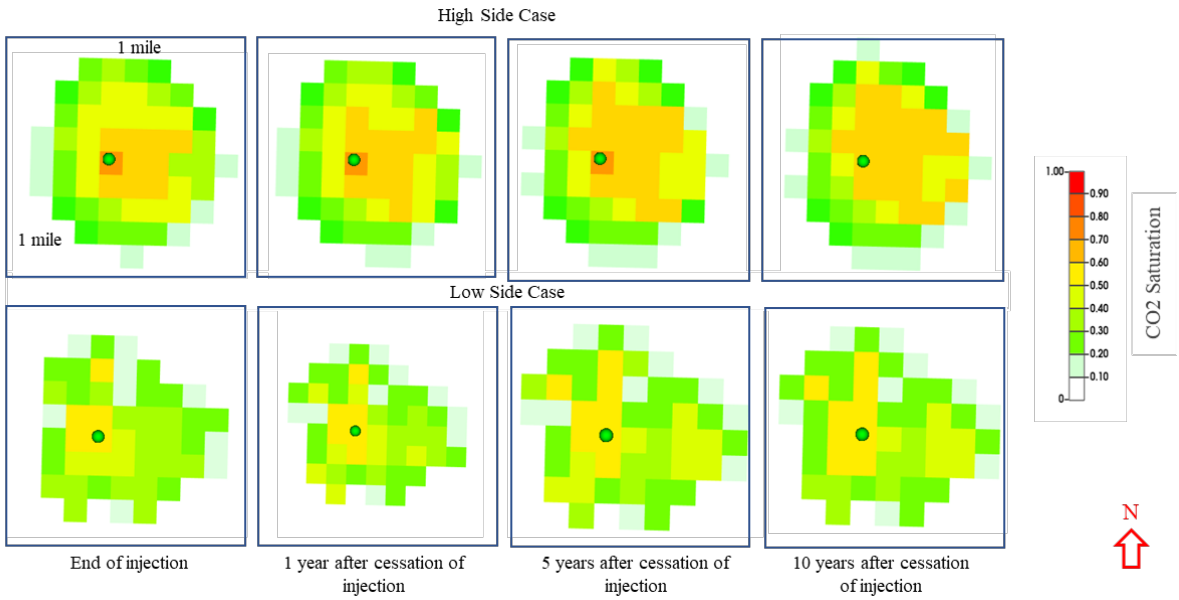


Figure 1-20: CO_2 plume at layer 153 (used to delineate AoR) at the end of injection, 1, 5 and 10 years after injection stopped for the High Side Case (top row) and Low Side Case (bottom row).

1.2.5 Geomechanical and Petrophysical Information [40 CFR 146.82(a)(3)(iv)]

A comprehensive suite of geomechanical and petrophysical data were acquired in the characterization well, MCI MW 1. A full description is given in the Pre-Operational Testing Program (Permit Section 5). In summary, minifrac tests were conducted in the Eau Claire shale confining zone and Mt Simon Sandstone to measure geomechanical properties such as formation breakdown pressure (FBP), fracture propagation pressure (FPP), instantaneous shut-in pressure (ISIP), and fracture closure pressure. Tested intervals are shown in Table 5-8 of the Pre-Operational Testing Program.

These data are used to calculate the fracture propagation pressure in the Mt Simon and Eau Claire caprock described above in section 1.2.4.

1.2.6 Seismic History [40 CFR 146.82(a)(3)(v)]

The seismic history for the area was characterized using publicly available data from the United States Geological Survey (USGS). In Illinois, most of the seismicity occurs in the southern and southeastern part of Illinois where two seismic zones, Wabash Valley, and New Madrid, are located. Central Illinois is an area that has been historically low in earthquakes and induced seismicity (Figure 1-21). Statewide, the largest earthquake had a magnitude of 5.4 and occurred on April 18, 2008, in the southeastern part of the State; it caused minor structural damage. The most recent known earthquake near the Marquis Biocarbon Project occurred in 2004, approximately 25.0 miles northeast of the site (Figure 1-22). This event had a magnitude of 4.2

and an approximate depth of 6.2 mi in basement rock (USGS, 2021). Most of the seismic events in Illinois occurred at depths shallower than 1.9 mi (Figure 1-22).

Based on regional seismic hazard maps published by the USGS (2014), the Marquis Biocarbon Project site is in a low-risk region for an occurrence of a site-specific earthquake. There is a 2% probability that the level of horizontal shaking, or peak ground acceleration (PGA), due to seismic activity will exceed 8–10% of the acceleration due to gravity within 50 years (Figure 1-23).

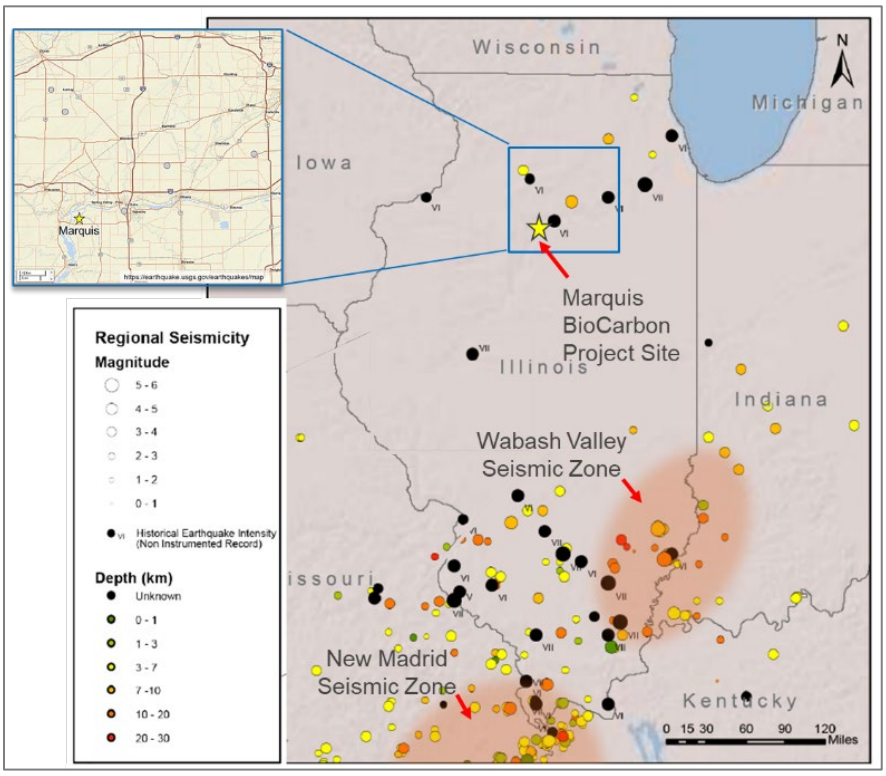


Figure 1-21: Regional Historic Earthquakes. Modified after FutureGen Alliance, 2013. Close-up map shown in subsequent figure.

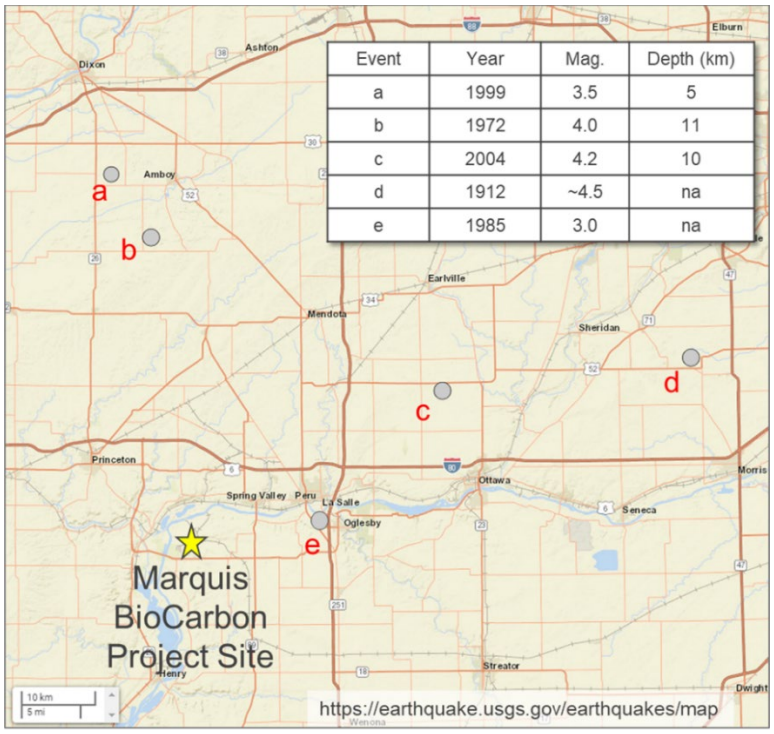


Figure 1-22: Local earthquakes since 1900 (modified from USGS, 2021).

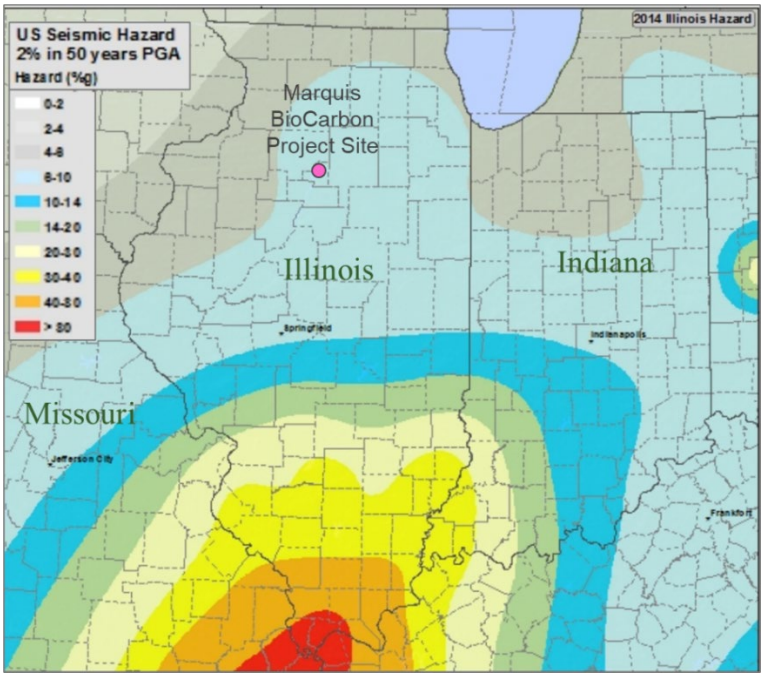


Figure 1-23: 2014 Regional seismic hazard Map for Illinois (USGS, 2014).

1.2.7 Hydrologic and Hydrogeologic Information [40 CFR 146.82(a)(3)(vi), 146.82(a)(5)]

Figure 1-2 shows the stratigraphic succession at the Marquis Biocarbon Project site MCI MW 1 well, along with the hydrostratigraphy. The subsurface hydrologic data analyzed in this study was acquired from the MCI MW 1 well and other regional wells and studies. The characterization data types, and depth coverages are detailed in the Pre-Operational Testing Program (Permit Section 5). Publicly available geologic and hydrologic data in the region, as well as well data, were compiled from well databases held by the Illinois State Geological Survey (ISGS).

The lowermost USDW is defined locally as the Gunter Sandstone of the Prairie du Chien Group (Knox Supergroup) based on salinity samples acquired from MCI MW 1 well. At the MCI MW 1 well, the base of the Gunter Sandstone is 963 ft above the top of the Mt. Simon. USDWs in the project site range in depth from the Gunter Sandstone to shallow, near-surface glacial till aquifers. Regional groundwater flows westward toward the Illinois River (Brower, 1989). Large producing wells in the area may alter this general flow direction as their drawdown cones traverse across the area of the well site. A map showing water wells within the AoR, and a table of the corresponding well information are provided in the AoR and Corrective Action Plan (Permit Section 2).

1.2.8 Geochemistry [40 CFR 146.82(a)(6)]

Aqueous and solid-phase geochemical data are available for the project site. These data were acquired during the installation of the MCI MW 1 characterization well. The geochemical data were obtained to determine:

- the deepest USDW at the project site.
- baseline geochemical data for the project site that can be used to evaluate the migration of CO_2 and brine waters at the site.
- current geochemical equilibrium conditions to evaluate the saturation relationship between the dissolved and solid-phase minerals at the site.
- geochemical reactions that may occur from the injection of CO_2.

Fluid samples were collected from eight locations/depths using drill stem testing (DST) during the drilling of the MCI MW 1 well and a single sample was collected via pumping during the hydraulic testing following drilling the well to total depth. Four samples collected via DST were collected from four separate water-bearing geologic formations above the caprock (St. Peter, New Richmond, Gunter and Galesville Sandstones) to determine the deepest USDW. In addition, the sample from the Galesville Sandstone provides a baseline condition for the geochemistry in the first water-bearing zone above the caprock, which can be compared against to determine if CO_2 or reservoir fluids are moving through the caprock. Four additional fluid samples were collected via DST over the depth of the Mt. Simon Sandstone to determine the vertical heterogeneity of the geochemistry throughout the injection reservoir. A single water sample of

the composite Mt. Simon Sandstone was collected during the reservoir testing to provide an "average" geochemical composition of the reservoir. This sample was collected after approximately 150,000 gallons of water had been pumped from the reservoir; therefore, there is confidence in the representativeness of this sample. These samples also provide baseline geochemical conditions of the injection reservoir and were used to with the geochemical equilibrium models to determine the potential for minerals to precipitate from solution or dissolve from the matrix with the addition of CO_2.

The water samples collected above the caprock and from the injection reservoir were analyzed for major cations and anions, trace metals, and general geochemical properties (i.e., pH, total dissolved solids [TDS], alkalinity, etc.). Figure 1-24 displays the chloride and TDS concentrations of from the samples collected from the MCI MW 1 characterization well. The data indicate that the chloride and TDS concentrations generally increase with depth and demonstrate that the Gunter Sandstone represents the deepest USDW at the site with a TDS concentration of 665 mg/L. Below the Gunter Sandstone, the TDS concentration increases to 23,526 mg/L in the Galesville Sandstone.

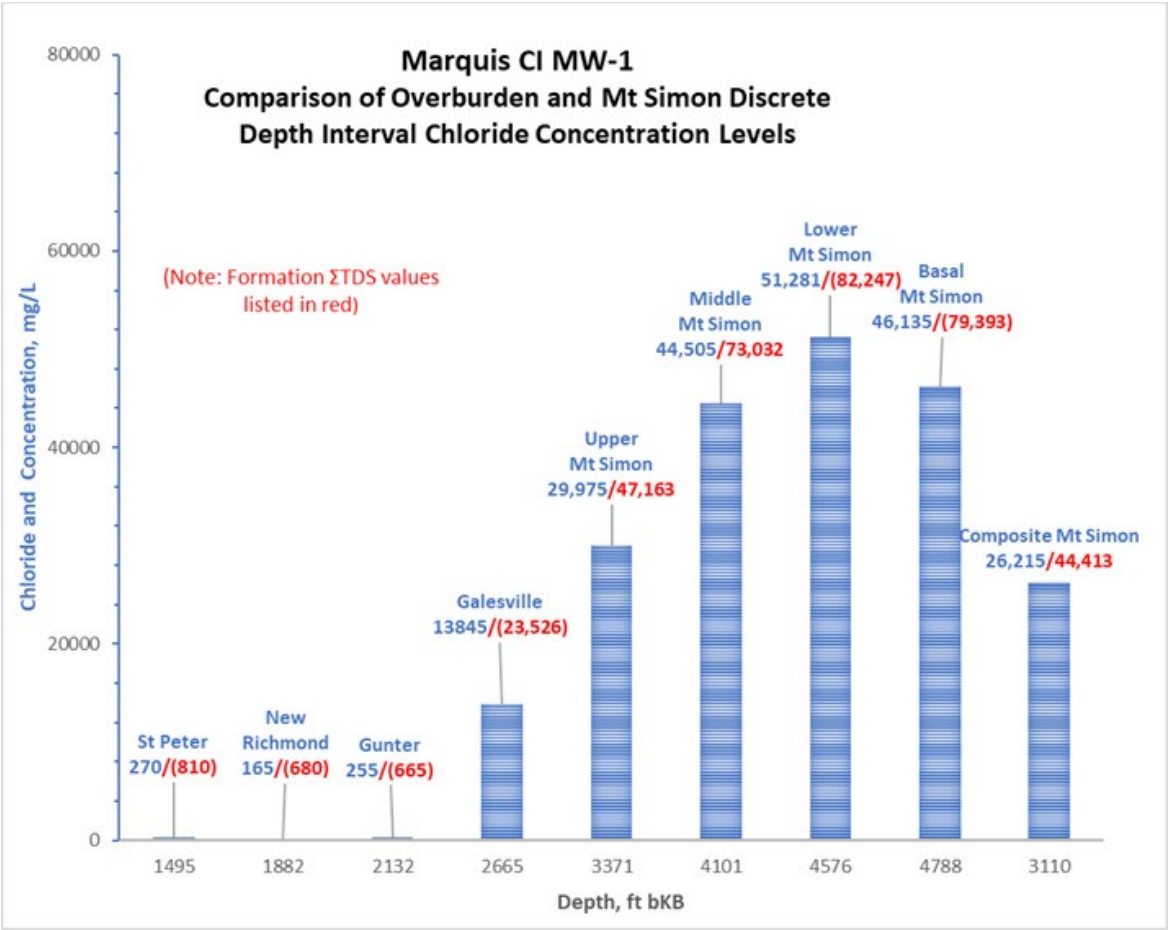


Figure 1-24: Chloride and TDS concentrations in the water/brine samples collected from the MCI MW 1 characterization well.

1.2.9 Other Information (Including Surface Air and/or Soil Gas Data, if Applicable)

At this time, no soil gas or atmospheric monitoring have been planned as part of the Testing and Monitoring Plan (Permit Section 7.0). However, the Testing and Monitoring Plan has been designed to be adaptive to evolving project risks over the life of the project. Should project risks change or should CO_2 migrate beyond the confining layer during the injection or PISC phases of the project soil gas or atmospheric monitoring may be considered. No changes to the Testing and Monitoring or PISC and Site Closure Plan will be implemented without consultation with the UIC Program Director (UIC Director).

1.2.10 Site Suitability [40 CFR 146.83]

An extensive set of subsurface data have been acquired at the site which supports site suitability. Seismic data, core and log data from the MCI MW 1 well do not indicate any concerns regarding confining zone integrity, and it is unlikely that a secondary confinement zone will be required. The Eau Claire formation at the Marquis Biocarbon Project site has several confining shale intervals in the upper Elmhurst Submember and above. Lab-measured permeability values were less than 0.01 mD in several core samples throughout the Eau Claire, and log and seismic data do not show a presence of faulting, significant fracturing, basement highs or regional pinch out.

The Marquis Biocarbon project site is an example of a prime sequestration site for CO_2 possessing all the needed characteristics and not suffering from any detrimental attributes.

1.3 Permit Section 2.0: AoR and Corrective Action

The AoR and Corrective Action Plan is submitted to meet the requirements of Plan 40 CFR 146.82(a)(13), 146.84(b) and 40 CFR 146.84(c).

The plan describes the computational modeling approach and results. The objective of the computational modeling is to track the CO_2 plume size and shape, area of pressure buildup, and determine an AoR for CO_2 injection at the Marquis Biocarbon Project site. The Static Earth Model is a 3D geocellular model that represents the porosity and permeability of different stratigraphic formations, most notably, the intended CO_2 storage formation and overlying confining layer. This type of model was selected as it offers the best options for quantifying, representing, and visualizing the subsurface geologic interpretations for the site. The purpose of this model is to represent available pore volume and enable the estimation of CO_2 storage capacity. Primarily, this geologic model serves as the framework (in terms of delineating zones, surfaces, permeability, and porosity) for computational modeling of CO_2 injection.

The computational modeling to simulate CO_2 injection into the saline aquifer was performed using a 3D multiphase flow simulator CMG-GEM 2016 version (CMG-GEM, 2016). In addition to the geological framework imported from the SEM, additional parameters, such as relative permeability data, initial conditions, phase behavior model, and well and perforation parameters, were added to the computational model to complete the dynamic modeling. CMG-GEM is an

equation-of-state based compositional simulator that models the phase behavior of brine and CO_2 plumes during the injection and post-injection phases of a project. Multiple phases were accounted for in the computational model including aqueous, gas, and supercritical phases.

Modeling multiphase flow processes in porous media, with all components as discussed above, enables:

- Estimation of pressure buildup in the storage formation – confining layer system
- CO_2 phase behavior at storage reservoir condition
- CO_2 saturation to determine plume extent in the storage formation (Mt. Simon Sandstone)
- Ensure confining layer sealing capabilities

The estimated CO_2 saturation map and pressure buildup from modeling multiphase flow processes will predict CO_2 movement during the injection and post injection periods and delineate the AoR.

1.4 Permit Section 3.0: Financial Responsibility

The Financial Responsibility Plan is submitted to meet the requirements of 40 CFR 146.82(a)(14) and 146.85.

1.5 Permit Section 4.0: Injection Well Construction

1.5.1 Proposed Stimulation Program [40 CFR 146.82(a)(9)]

No completion stimulation is planned at this time because the reservoir quality is expected to be adequate for the planned injection volumes.

1.5.2 Construction Procedures [40 CFR 146.2(a)(12)]

A single, newly drilled injection well (MCI CCS 3) will be constructed at the Marquis Biocarbon Project site to meet the requirements of 40 CFR 146.82(a)(9) and (11). Based on information from the Illinois State Geological Survey (ISGS), no oil or gas zones are anticipated to be encountered at this location.

1.5.3 Casing and Cementing

The well will be designed using carbon steel for the casing and tubulars that are not expected to be in contact with a mixture of the injectate (CO_2) and water. That is, the conductor, surface, and intermediate casing sections will all be carbon steel. The deep casing string will be constructed with corrosion-resistant chrome (CR13) across the reservoir and caprock to total depth (TD) and carbon steel from above the caprock to surface. This section of the wellbore is expected to have intermittent exposure to CO_2-formation water mixed fluids especially in the initial phases of

injection and intermittently when well workovers are performed throughout the life of the project. Although the expected water content of the injectate stream will be less than 50 parts per million (ppm), the injection tubing string and flow-wetted injection tree components will be composed of corrosion resistant materials.

The MCI CCS 3 well will include the following casing strings: a 30-inch diameter conductor string set at a depth of approximately 80 ft; a 20-inch diameter surface string set at a depth of approximately 350 feet (ft); a 13 3/8-inch diameter intermediate string set at a depth of approximately 2,750 ft; and a 9 5/8-inch-long string set at a depth of approximately 4,950 ft. All casing strings will be cemented to surface. Any potential changes to the final well design will be discussed with the UIC Director or representative.

The deepest underground source of drinking water (USDW) was confirmed from the fluid sampling program during the characterization phase and was determined to be the Gunter Sandstone formation. Intermediate casing will be set through the Gunter and into the top of the Eau Claire caprock which will provide an additional layer of protection to the USDW.

The cemented casing strings (four in total) for the proposed MCI CCS 3 well will all be cemented back to surface. The surface strings will be cemented using Class A, H, or G cement while the intermediate string will be cemented using Class H or G cement. The injection string will be installed using Schlumberger's EverCRETE (or equivalent) as the tail mix across the injection reservoir and caprock intervals with Class G or H as the lead above the caprock. Casing details are shown in Table 1-6 and a summary of cement types is shown in Table 1-7.

Casing String Name	Open Hole Size (in.)	Outside Diameter (in.)	Setting Depth (ft rGL)	Weight (lb/ft)	Wall Thickness (in.)	Grade	Connection
Conductor	+/-36"	30	80	118	0.375	X-42	Welded
Surface	26"	20	350	94	0.438	J/K-55	Buttress or Long Round Thread
Intermediate	17-1/2"	13.375	2750	54.5	0.38	J/K-55	Buttress or Long Round Thread
Long String	12-1/4"	9.625	4970	40	0.395	L-80 (0-2750') L-8013Cr (2750' – TD)	Premium
Injection Tubing	n/a	4.5	3200	11.6	0.25	L-8013Cr	Premium

Table 1-6: Casing details.

Casing String	Appx. Depth Range (ft, MD)	Cement Type
Surface	0-350	Class A, G, or H
Intermediate	0-2,750	Class G or H

Deep	0-4,900	CO_2-Resistant tail slurry /Class G or H: Pozzolan blend lead slurry

Table 1-7: Cement program for the CO_2 MCI CCS 3 well.

After the well has been completed, a cement bond log – variable density log (CBL-VDL) and advanced ultrasonic cement evaluation log will be run of the entire depth of the long casing string shortly after completion of the MCI CCS 3 well to confirm that the casing string was properly cemented. A baseline temperature measurement will also be acquired from surface to total depth (TD) to provide initial temperature conditions over the well.

The annular fluid will be a dilute salt solution such as potassium chloride (KCl), sodium chloride (NaCl), or similar. The fluid will be mixed on site from dry salt and good quality (clean) fresh water, or it will be acquired pre-mixed. The fluid will also be filtered to ensure that solids do not interfere with the packer or other components of the annular protection system. The likely density of the annular fluid will be approximately 9.2 ppg. Final choice of the type of fluid will depend on availability and wellbore conditions.

1.6 Permit Section 5.0: Pre-Operational Logging and Testing

The Pre-Operational Logging and Testing Plan is submitted to meet the requirements of 40 CFR 146.82(a)(8) and 40 CFR 146.87.

This plan describes the pre-operational formation testing program implemented to characterize the chemical and physical features of the injection zone and confining zone at the Marquis Biocarbon Project. The data set from MCI MW 1 well drilled and tested in the 4th Quarter of 2021 (Permit No. 010858) will form the base of the pre-operational data set. A thorough logging and testing plan was completed including wireline logging, side wall cores and whole core, fluid sampling and injection testing. This data set will be augmented as necessary by data acquired in the MCI CCS 3 well.

Details of the logging and testing program for the MCI CCS 3 well are described in section 5. These in include borehole deviation surveys, wireline logging, fluid sampling and coring, as well as any additional data required by the UIC Director.

1.7 Permit Section 6.0: Well Operations

1.7.1 Operational Procedures [40 CFR 146.82(a)(10)]

This section describes the source of the CO_2 that will be delivered to the storage site, its chemical and physical properties, flow rate, and the anticipated pressure and temperature of the CO_2 at the pipeline outlet. In addition, this section provides the monitoring that will be performed on the MCI CCS 3 well to confirm that it does not provide a conduit from the storage formation to above confining zone water sources, USDW sources, or the surface.

The design basis is to capture and inject the CO_2 produced at the ethanol-production facility. The computational model was completed for the maximum annual injection rate of 1,500,000 MT and a maximum surface injection pressure of 1685 psi (90% of the fracture propagation pressure). The operational parameters of the MCI CCS 3 well are provided in Table 1-8.

Parameters/Conditions	**Limit or Permitted Value**	**Unit**
Maximum Injection Pressure		
Surface	1,685	psig
Downhole (top perforation)	2,207	psig
Average Injection Pressure		
Surface	1,200	psig
Downhole	1,562	psig
Maximum Injection Volume and/or Mass	1,500,000	MT/year
Average Injection Volume and/or Mass	1,200,000	MT/year
Annulus Pressure	150-800	psig
Annulus Pressure/Tubing Differential	100	psig

Table 1-8: Proposed operational procedures.

Based on initial design calculations, the anticipated CO_2 pressure at the pipeline outlet (i.e., at the well site) will be approximately 1,200 psi at an average temperature of 93.2°F (Table 1-9). Variability of the compressor could increase the pressure up to a maximum allowable wellhead pressure of 1,685 psig.

Injection Stream Parameter	Wellhead Specification
Ave Pressure (psi)	1,200
Ave CO_2 Temperature (ºF)	93.2
Ave Mass Flow Rate (MT/yr.)	1,200,000
Density (lb/ft^3)	34-45
Viscosity (cP)	0.073
Molecular Weight	43.99
Source: Trimeric	

Table 1-9: Wellhead injection stream specifications.

Monitoring of the MCI CCS 3 well parameters will be performed to ensure proper operation and compliance with 40 CFR 146.90(b). The wellhead injection pressure will be used to confirm that storage formation pressures remain below the regulated limit while the storage formation pressure will be measured with downhole pressure gauges. The mass injection rate will be continuously monitored to ensure the rate remains below the regulated limit. The annular pressure and temperature will be measured continuously to maintain compliance with the EPA Class VI permit and to monitor the internal mechanical integrity of the well. All monitoring will take place at the locations and frequencies shown in Table 1-10. The operation monitoring data will be connected to the main facility through a supervisory control and data acquisition (SCADA) system.

In addition to the annular monitoring system to evaluate the internal mechanical integrity of the well, a mechanical integrity test will be performed on the well after the tubing has been placed in the well and the packer has been set. External mechanical integrity will be monitored on an annual basis via temperature measurements over the entire depth of the well.

Parameter	Device(s)	Location	Min. Sampling Frequency	Min. Recording Frequency
CO_2 stream pressure (wellhead)	Pressure Gauge	Wellhead	Every 1 min.	Every 1 min.
Mass injection rate	Coriolis Meter	Wellhead	Every 10 sec.	Every 10 sec.
Annular pressure	Pressure Gauge	Wellhead	Every 1 min.	Every 1 min
Annulus fluid volume	Volume	Wellhead	Every 1 min.	Every 1 min
CO_2 stream temperature	Thermocouple	Wellhead	Every 1 min.	Every 1 min.

Notes:

- Sampling frequency refers to how often the monitoring device obtains data from the well for a particular parameter. For example, a recording device might sample a pressure transducer monitoring injection pressure once every two seconds and save this value in memory.
- Recording frequency refers to how often the sampled information gets recorded to digital format (such as a computer hard drive). For example, the data from the injection pressure transducer might be recorded to a hard drive once every minute.

Table 1-10: Sampling devices, locations, and frequencies for continuous monitoring.

1.7.2 Proposed Carbon Dioxide Stream [40 CFR 146.82(a)(7)(iii) and (iv)]

The injection stream will be monitored during the baseline and operational phases of the project (Permit Section 7.2). Prior to the start of the injection phase, the CO_2 stream will be sampled for analysis during regular plant operations to obtain representative CO_2 samples that will serve as a baseline dataset. Once the injection phase commences, samples of the CO_2 injection stream will be collected from the CO_2 delivery pipeline for analysis every three months.

1.8 Permit Section 7.0: Testing and Monitoring

The Testing and Monitoring Plan describes how Marquis Carbon Injection LLC will monitor the site pursuant to 40 CFR 146.82(a)(15) and 146.90.

The Testing and Monitoring Plan has been developed in conjunction with the project risk assessment to reduce the risks associated with CO_2 injection into the subsurface. Goals of the monitoring strategy include:

- Meeting the regulatory requirements of 40 CFR 146.90
- Protecting USDWs
- Ensuring that the MCI CCS 3 well is operating as planned
- Providing data to validate and calibrate the geological and dynamic models used to predict the distribution of CO_2 within the injection zone
- Support AoR re-evaluations over the course of the project

The Testing and Monitoring Plan will be adaptive over time in that the plan can be adjusted to respond:

- As project risks evolve over the course of the project
- If significant differences between the monitoring data and predicted dynamic modeling results are identified
- If key monitoring techniques indicate anomalous results related to well integrity or the loss of containment

Figure 1-4 illustrates the modeled CO_2 plume development over the 5-year injection period as well as the AoR.

The Testing and Monitoring Plan will outline several direct and indirect technologies used throughout the injection and PISC phases of the project that will monitor:

- Daily activities of the injection operations
- Development of the CO_2 and pressure plumes in the storage formation over time
- Well integrity
- CO_2 or brine containment within the injection reservoir
- Groundwater quality in multiple aquifers, including the deepest USDW (Gunter Sandstone) and the deepest water-bearing formation above the caprock (Galesville Sandstone)

Injection operations will be monitored through a range of continuous, daily, and quarterly techniques as detailed in the Well Operations Plan (Permit Section 6.0). Table 1-11 summarizes the proposed operational monitoring for the project.

The well integrity of the MCI CCS 3, MCI MW2, and MCI ACZ 1 wells will be monitored using a range of internal and external mechanical integrity evaluation methods. Initially, a mechanical integrity test (MIT) will be performed on the MCI CCS 3 well following the well completion to confirm internal integrity as per the Pre-Operations Testing Plan (40 CFR 146.82(a)(8), 146.87). External mechanical integrity will be confirmed through annual temperature logging and compared to baseline temperature logging data to identify any deflections from the temperature gradient that could indicate fluid flow behind the casing (40 CFR 146.90 (e)). The same internal and external integrity evaluation methods used with the MCI CCS 3 well will be used on the MCI MW 2 well. However, the annular pressure will be measured daily and adjusted as needed.

Pressure fall-off tests (PFOs) will be conducted in the Mt. Simon Sandstone in the MCI CCS 3 well when they are drilled to establish the hydrogeologic characteristics of the storage formation (Pre-Operational Testing Plan, Permit Section 5). During the injection phase of the project, a PFO will be conducted in the MCI CCS 3 well at least once every five years.

A deep groundwater well will be drilled as part of the Testing and Monitoring Plan for the project. This ‘Above Confining Zone’ (ACZ) well will be drilled to the top of the confining zone, the Eau Claire Formation. MCI ACZ 1 well will be adjacent to the MCI CCS 3 well to

monitor the aquifers above the confining layer. This well will be used for pressure and temperature monitoring as well as periodic fluid sampling in the Galesville Sandstone and the deepest USDW, the Gunter Sandstone. Potential CO_2 or brine migration into the Galesville Sandstone or the deepest USDW will be initially identified through pressure changes in the formation and will be confirmed through aqueous geochemistry data and analysis of stable isotopes (Permit section 5.0).

The shallow groundwater monitoring program consists of four wells (MCI GW 1-4) located on Marquis owned property and within the AoR as shown in Figure 1-4. One of these wells (MCI GW 2) is an existing well, the other three will be new wells. The 3 other existing wells identified outside the CO_2 plume, but within the AoR, are not part of the proposed groundwater monitoring program.

Monitoring Activity	Baseline Data Frequency	Injection Phase Frequency*	Location	Formation top / Depth Range (ft, MD)
Assurance Monitoring:				
Shallow Groundwater Sampling	Once/quarter	Twice/year	MCI GW 1-4 Wells within AoR	@TD
Isotope Analysis	Twice/year	Once/year	MCI GW 1-4 Wells within AoR	@TD
Operational Monitoring:				
CO_2 Stream Analysis	NA	Quarterly	CO_2 Delivery Pipeline	NA
Corrosion Coupon Analysis	NA	Quarterly	CO_2 Delivery Pipeline	NA
Injection Pressure	NA	Continuous	Wellhead	Surface
Mass Injection Rate	NA	Continuous	Wellhead	Surface
Injection Volume (Calculated)	NA	Continuous	Storage Formation	Surface
Annular Pressure	NA	Continuous	Injection Well	Surface
Annular Fluid Volume	NA	Continuous	Injection Well	Surface
Temperature Measurement	Once Once	Annually Annually	Injection Well Deep Monitor Well	0 – TD 0 – TD
PFO Tests	Once	Every 5 years	Wellhead	Surface
Verification Monitoring:				
Fluid Sampling				
Gunter Sandstone Galesville Sandstone Upper Mt. Simon Sandstone	Twice/year Twice/year Twice/year	Twice/year Twice/year Twice/year	ACZ well ACZ well Deep monitor well	2,134 2,651 3,110
Isotope Analysis	Twice/year	Once/year	ACZ Well Deep monitor well	All samples
Pressure – Temperature Sensors Gunter Sandstone Galesville Sandstone Upper Mt. Simon Sandstone	3 months prior to injection Continuous Continuous Continuous	 Continuous Continuous Continuous	 ACZ Well ACZ Well Deep monitor well	 2,134 2,651 3,100
PNC Logging	Once	Once/ year	Deep Monitor well ACZ Well	2,134 – TD 2,134 – TD
Microseismic Monitoring	6 months prior to injection	Continuous	Surface stations	TBD
Time-lapse 3D Surface Seismic Data	Once	Every 5 years and as required.	Surface	

Table 1-11: General schedule and spatial extent for the testing and monitoring activities for the Marquis Biocarbon Project.

MCI MW 2 will be used to monitor pressure and temperature and to take fluid samples from the Mt. Simon Sandstone in the pre-operational, injection, and PISC phases of the project (40 CFR 146.90 (g)). These gauges will continuously record the data and will be retrieved on a quarterly basis for data download. Pulsed neutron capture (PNC) logs will be acquired in the MCI ACZ 1 and MCI MW 2 to identify the intervals and concentration of CO_2 close to the wellbores and possible accumulations of CO_2 above the confining zone (Permit Section 7.8). A second, existing, deep monitoring well (MCI MW 1) will be used for far field monitoring.

Time-lapse 3D seismic data and microseismic monitoring will be used to monitor the development of the CO_2 plume and the associated pressure front through the injection and PISC phases (40 CFR 146.90 (g)). Time-lapse 3D seismic data will be used to indirectly monitor the CO_2 plume development and calibrate the computational modeling results over time (Permit Section 7.8). The seismic will also be used to verify CO_2 containment within the storage formation. This project will monitor related microseismic activity to assist in managing project risks using a surface-based microseismic monitoring array. The microseismic monitoring will be used to accurately determine the locations and magnitudes of injection-induced seismic events (Permit Section 7.8). Refer to Permit Section 7.0 for a full discussion of the Testing and Monitoring Plan.

1.9 Permit Section 8.0: Injection Well Plugging

The Injection Well Plugging Plan describes how Marquis Carbon Injection LLC will plug the injection well (MCI CCS 3) pursuant to 40 CFR 146.82(a)(16) and 146.92.

A Notice of Intent to plug the well will be submitted to the EPA at least 60 days prior to the plugging operations (40 CFR 146.92 (c)). After the project has verified that there are no external well integrity issues, the well will be flushed with buffer fluid to remove any fluids or particulates that may be present in the well. The MCI CCS 3 well casing will be plugged with cement to ensure that it does not provide a conduit outside the injection zone. Table 1-12 shows the intervals that will be plugged as well as the materials and methods that will be used to plug the intervals.

Description	Cemented Interval (ft, MD)	Formation	Plugging Method	Plug Description	
				Type	Quantity
Perforated Interval	3,126−4,900	Mt. Simon Sandstone	Retainer	CO_2-Resistant	681 sacks
9-5/8-in. Casing Column	2,650-2,750	Eau Claire	Balance	Class A	36 sacks
9-5/8-in. Casing Column	250-350	Pennsylvanian	Balance	Class A	36 sacks

Table 1-12: Intervals to be plugged and materials/methods used (40 CFR 146.92 (b)(2 – 4)).

The MCI CCS 3 well casing will be plugged with cement to ensure that it does not provide a conduit outside the injection zone. The injection zone will be plugged using CO_2-resistant cement, a 9-5/8-inch cement retainer constructed with corrosion-resistant materials will be set in the injection casing 100 ft above the top perforation (~ 3,126 ft MD). Cement plugs will also be placed within the injection casing string at the casing shoes of the intermediate and surface strings. One-hundred-foot-thick plugs will be placed between the 250 and 350 ft MD and between 2,650 and 2,750 ft MD. After the top cement plug has been set, the casing sections will be cut off approximately 5 ft below grade, and a steel cap will be welded to the top of the deep casing string. The cap will have the well identification (ID) number, the UIC Class VI permit number, and the date of plug and abandonment inscribed on it. Soil will be backfilled around the well to bring the area around the well back to pre-well installation grade. This area will then be planted with natural vegetation. For more information on the Well Plugging Plan, refer to Permit Section 8.

1.10 Permit Section 9.0: Post-Injection Site Care (PISC) and Site Closure

The PISC and Site Closure Plan describes the activities that Marquis Carbon Injection LLC will perform to meet the requirements of 40 CFR 146.82(a)(18) and 146.93(c).

Marquis Carbon Injection LLC will monitor groundwater quality and track the position of the carbon dioxide (CO_2) plume and pressure front for 5 years after the cessation of injection, which is the anticipated timeline for CO_2 plume and pressure front stabilization.

Based on the modeling of the pressure front as part of the area of review (AoR) delineation, pressure at the MCI CCS 3 well is expected to decrease to pre-injection levels in less than 5 years, as described below. Additional information on the projected post-injection pressure declines and differentials is presented in the permit application and the AoR and Corrective Action Plan (Permit Section 2.0).

1.11 Permit Section 10.0: Emergency and Remedial Response

The Emergency and Remedial Response Plan (ERRP) is submitted to meet the requirements of Plan 40 CFR 146.82(a)(19) and 146.94(a).

The Emergency and Remedial Response Plan (ERRP) provides actions that Marquis Carbon Injection, LLC will take in the event of an emergency and to address movement of CO_2 or formation fluid that may endanger an USDW during the construction, operation, or PISC periods.

If evidence indicates that the injected CO_2 stream, formation fluids, and/or associated pressure front may cause an endangerment to a USDW, the following actions must be performed:

1. Initiate shutdown plan for the MCI CCS 3 well.

2. Take all steps reasonably necessary to identify and characterize any release or migration.
3. Notify the permitting agency/UIC of the emergency event within 24 hours.
4. Implement applicable portions of the approved Emergency Remedial Response Plan (ERRP).

Where the phrase "initiate shutdown plan" is used, the following protocol will be employed: Marquis Carbon Injection, LLC will immediately cease injection. However, in some circumstances, Marquis Carbon Injection, LLC will, in consultation with the UIC Director, determine if a gradual cessation of injection is appropriate. If a non-emergency shutdown of the CO_2 injection system is required, the operator will complete the shutdown in a stepwise approach to prevent over-pressure situations and/or damage to the equipment. Efforts will also be made to maintain the CO_2 in the injection stream in a supercritical phase to prevent special operations during the restart of the system. Also, override of certain relays may be required to properly and safely shutdown the system.

1.12 Injection Depth Waiver and Aquifer Exemption Expansion

The Marquis Biocarbon project is not applying for a depth waiver or an aquifer exemption.

1.13 Other Information

Currently, there are no additional data to submit with this permit application. However, if additional data become available or if the UIC Director requests specific information, those data will be provided to the EPA as an amendment or addendum to this application.

References

CMG-GEM. Advance compositional and GHG reservoir simulator user's guide. Calgary, Alberta2016.

DOE/EIS-0460. Final Environmental Impact Statement for the FutureGen 2.0 Project, Morgan County, Illinois. 2013.

FutureGen Alliance, 2013, Underground Injection Control Permit Applications for FutureGen 2.0 Morgan County Class VI UIC Wells 1, 2, 3, and 4, FG-RPT-017.

Golden StrataServices, 1984, Jones & Laughlin Steel Inc, Hennepin Illinois, UIC Permit Application, UIC-004-WI-JL, EPA Facility ID No. ILD000781591.

Golden StrataServices, 1984B, Full Core Analysis, Appendix 6.0-A, Jones & Laughlin Steel Inc, Hennepin, Illinois.

Goodman, A., Hakala, A., Bromhal, G., Deel, D., Rodosta, T., Frailey, S., Small, M., Allen, D., Romanov, V., Fazio, J., Huerta, N., McIntyre, D., Kutchko, B., Guthrie, G., 2011, U.S. DOE methodology for the development of geologic storage potential for carbon dioxide at the national and regional scale. International Journal of Greenhouse Gas Control, v. 5, p. 242–249.

Goodman, A., Sanguinito, S., Levine, J., 2016. Prospective CO_2 resource estimation methodology: Refinement of existing US-DOE-NETL methods based on data availability, International Journal of Greenhouse Gas Control, v. 54, p. 952–965.

United States Environmental Protection Agency. Geologic Sequestration of Carbon Dioxide: Underground Injection Control (UIC) Program Class VI Well Area of Review Evaluation and Corrective Action Guidance. 2013: 96 p.

United States Geological Survey (USGS), 2014, 2014 Seismic Hazard Map-Illinois. Available at: https://www.usgs.gov/media/images/2014-seismic-hazard-map-illinois

United States Geological Survey (USGS), 2021, Latest Earthquakes [map]. Available at: https://earthquake.usgs.gov/earthquakes/map

Willman, H.B., Atherton, E., Buschbach, T.C., Collinson, C., Frye, J.C., Hopkins, M.E. Lineback, J.A. and Simon, J.A. 1975. Handbook of Illinois Stratigraphy. Champaign, Illinois: Illinois State Geological Survey, Bulletin 95.

4.0 INJECTION WELL CONSTRUCTION PLAN
40 CFR 146.82(a)(8), 146.87

MARQUIS BIOCARBON PROJECT

Facility Information

Facility name:	MARQUIS BIOCARBON PROJECT
Facility contact:	ELIZABETH STEINHOUR DIRECTOR OF ENVIRONMENTAL AFFAIRS 10000 MARQUIS DRIVE, HENNEPIN, IL 61327 815.925.7300 / BETHSTEINHOUR@MARQUISENERGY.COM
Well name:	MCI CCS 3
Well location:	PUTNAM COUNTY, ILLINOIS S2 T32N R2W Latitude: 41.27026520 N, Longitude: 89.30939322 W

Table of Contents

4.0 Injection Well Construction Plan ((146.86 (a)(1)) 3
4.1 Well Design (146.86 (b)) 6
4.1.2 Corrosiveness of the CO_2 stream and formation fluids (146.86 (b)(1)(v)(vi)) 6
4.1.1 Casing/Tubing 8
4.1.2 Tubular Stress Conditions (146.86 (c)) 9
4.1.3 Cement (146.86 (b)) 11
4.1.4 Downhole Completion Equipment (146.86 (a)(2,3) 12
4.1.5 Perforation Strategy 13
4.2 Drilling Contingencies 13
4.3 Annular Fluid System 14
4.4 Stimulation Program 15
4.5 Demonstration of Mechanical Integrity 15
4.6 References 16
Appendix - EverCRETE 17

List of Tables

Table 4-1: Formations of Interest measured in MCI MW 1 well. 3
Table 4-2: Chemical Composition of CO2 stream. 6
Table 4-3: Chemical parameters of Mt. Simon brine used for corrosivity assessment. 7
Table 4-4: Downhole temperatures measured in characterization well, MCI MW 1 7
Table 4-5: Casing details. 9
Table 4-6: Tubular performance details. 9
Table 4-7: Summary of cement types and corresponding casing strings. 11
Table 4-8: Cement program for the CO_2 injection well. 12

List of Figures

Figure 4-1: MCI CCS 3 injection well schematic. 4
Figure 4-2: Plot showing anticipated injection well location for MCI CCS 3 5

4.0 Injection Well Construction Plan ((146.86 (a)(1))

This section describes how a single, newly drilled injection well (MCI CCS 3) will be constructed at the Marquis BioCarbon Project site near Hennepin, Illinois, to meet the requirements of 40 CFR 146.82(a)(9)(11) and 40 CFR 146.86. The well design is discussed in detail in the following sections, including the drilling phase, materials to be used, and the initial expected design. Formation and casing depths for the injection well were determined using data from the MCI MW 1.

No completion stimulation is planned at this time because the expected reservoir quality is sufficient for the planned injection volumes. The maximum injection volume for this project is anticipated to be 1.5 million tonnes (MT)/year. No oil or gas zones are anticipated to be encountered at this location. The only expected zone that may present corrosion issues during the life of the project is the injection zone itself, the Mt. Simon Sandstone, as carbon dioxide (CO_2) is injected over time and mixes with the connate waters to form carbonic acid.

The reservoir modeling section of this application determined that a single, vertical injection well is sufficient to achieve the target CO_2 injection rate. The surveyed location of the well is shown in Figure 4-2. The proposed injection well diagram is shown in Figure 4-1. Table 4-1 details the depths of the geological formations of interest at the site. Refer to the Area of Review (AoR) and Corrective Action Plan (Permit Section 2) for further details on these formations.

Formations	Depth (ft, MD)
Bedrock Top	183
Base of Deepest USDW – Gunter Sandstone	2,147
Caprock Formation – Eau Claire Shale	2,706
Injection Formation – Lower Elmhurst Sandstone–Mt. Simon Sandstone	3,054
Total Depth	4,869

Table 4-1: Formations of Interest measured in *MCI MW 1 well*.

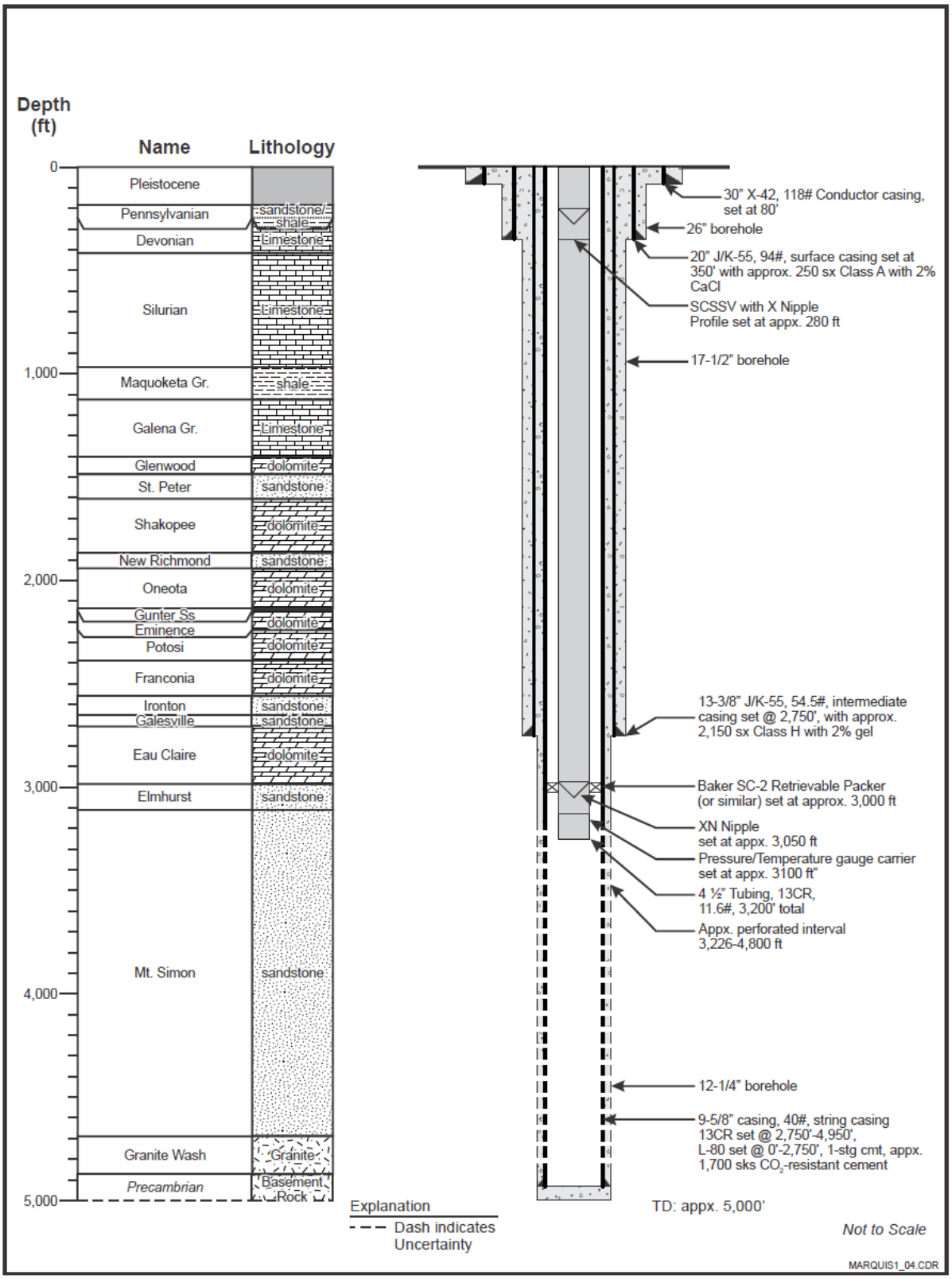


Figure 4-1: MCI CCS 3 injection well schematic.

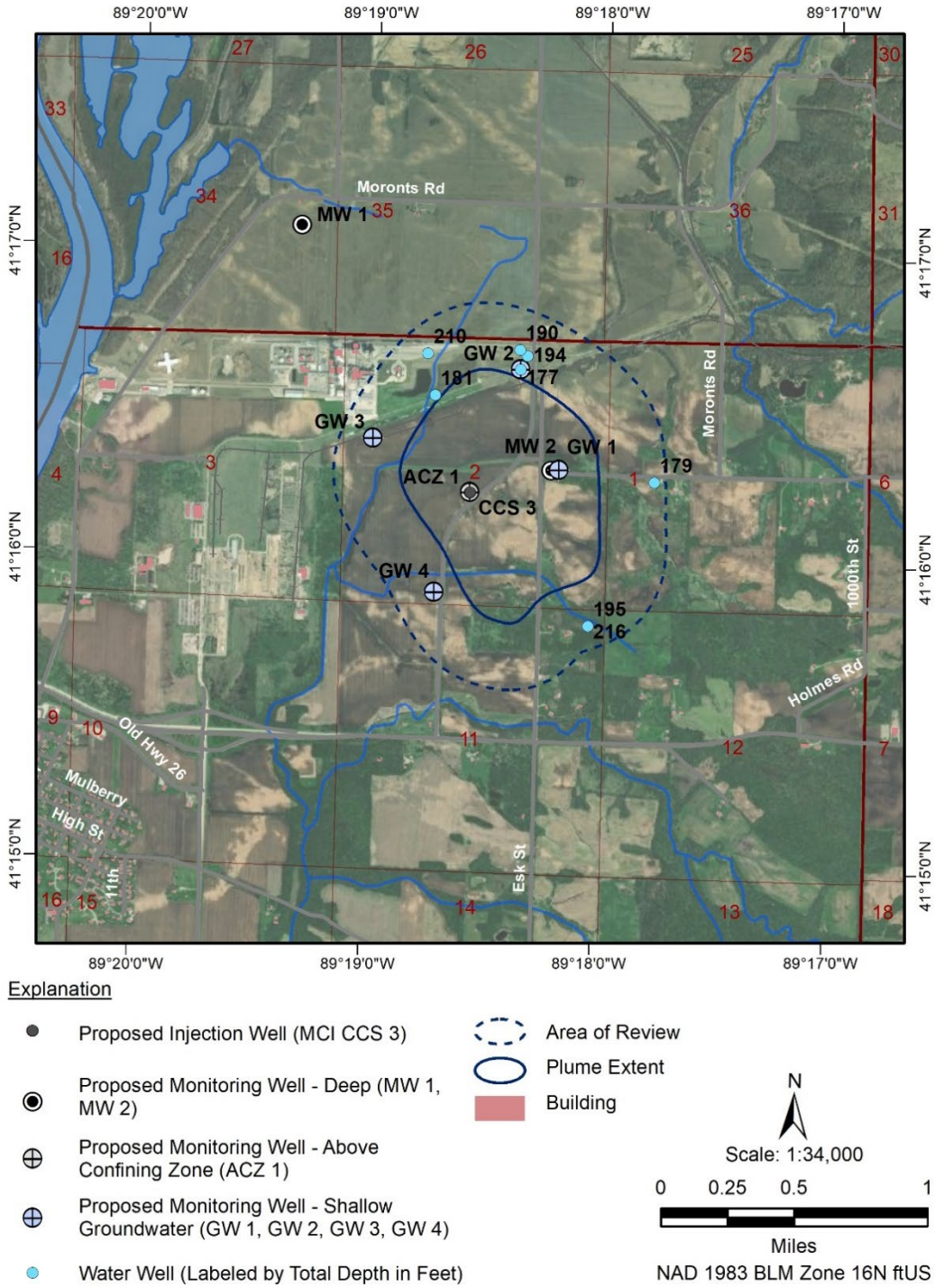


Figure 4-2: Plot showing anticipated injection well location for MCI CCS 3.

4.1 Well Design (146.86 (b))

The proposed well design is shown above in Figure 4-1. The lithology of the injection and confining zones are shown with the injection depth, hole sizes and casing sizes and depths. These are discussed below.

4.1.2 Corrosiveness of the CO_2 stream and formation fluids (146.86 (b)(1)(v)(vi))

The anticipated chemical composition of the CO_2 stream is given in Table 4-2. Based on samples collected during normal operations and a fermentation drop at the ethanol-production facility, the injection stream will be composed of nearly pure CO_2, with a composition of 99.86% CO_2. A fermentation drop is considered the period during fermentation when the worst-case emissions from the scrubbers would be observed. The chemical balance of the remainder of the injection stream will be composed of trace constituents (nitrogen, oxygen, and triethylene glycol [TEG]) with quantities of approximately 0.1%, 0.03%, and 0.3 gallons (gal)/MMSCF, respectively. Dehydration may be performed to reduce the water vapor content in the injection stream. If dehydration is performed, the target water vapor concentration would be <50 parts per million (ppm) to limit the corrosivity of the injection stream. If dehydration is not incorporated into the process stream, water vapor may be present in the injection stream. The injection system has been designed with corrosive-resistant materials that contact the injection stream to prevent corrosion of the components caused by the presence of water vapor. Hydrogen sulfide (H_2S) is not expected to be present in the injection stream; however, analyses will be performed to identify its presence. A target concentration of H_2S will be <20 ppm to reduce corrosivity of the injection stream.

The corrosivity of the injection stream should be limited given the quantities of the minor concentrations of the trace constituents in the injection stream, and the water content will be maintained below the regulated limit of <30 lb/MMSCF for CO2 transport pipeline standards.

Component	Quantity
CO_2	99.86%
Oxygen	0.03%
Nitrogen	0.1%
TEG	<0.3 Gal/MMSCF
Water Vapor	50 ppm
Hydrogen sulfide (H_2S)	<20 ppm

Table 4-2: Chemical Composition of CO2 stream.

Table 4-3 presents the analytical results for parameters that may be used to assess the corrosivity of the formation waters in the Mt. Simon Sandstone. These data represent average results for the brine samples collected from the Mt. Simon Sandstone. The pH, conductivity, and TDS data represent analytical results from a commercial laboratory, the oxidation-reduction potential (ORP) data are field measurements made at the time the brine samples were collected, and the temperature value is the temperature measured at the mid-point of the formation through wireline logging.

Parameter	**Value**
Average pH	6.19
Average Conductivity	121.3 mS/cm
Average TDS	59,575 mg/L
Average ORP	-71.6 mV
Mid-Point Temperature	88.3° F

Table 4-3: Chemical parameters of Mt. Simon brine used for corrosivity assessment.

A summary of the measured downhole temperatures are shown in Table 4-4. Based on these measurements the temperature gradient between the top Eau Claire and base Mt. Simon is 0.0053 F/ft.

Formation name	**Depth (MDKB ft)**	**Temperature (F)**
Top Eau Claire	2,706.0	81.5
Top Mt. Simon	3,110.0	83.6
Base Mt. Simon	4,870.0	93.0

Table 4-4: Downhole temperatures measured in characterization well, MCI MW 1 .

The data indicate that the formation brines are near neutral, but slightly acidic pH and have a moderate salinity content (Conductivity = 121.3 mS/cm and TDS = 59, 575 mg/L). In addition, the ORP measurements suggest that the brines exhibit reducing conditions and the temperature is slightly lower than what might be expected at a depth of approximately 3,990 ft (Mid Mt. Simon). Therefore, the native formation waters of the Mt. Simon Sandstone are not expected to be highly corrosive.

Although neither the CO2 stream or formation waters are expected to be highly corrosive, the injection materials that come in contact with the CO2 stream and/or reservoir brines will be constructed of corrosion-resistant materials, such as Cr13 steel, or similar. For example, the casing string across the Mt. Simon, the packer, and deep portion of the tubing with be constructed with corrosion-resistant materials.

4.1.1 Casing/Tubing

The well will be designed using carbon steel for the casing and tubulars that are not expected to be in contact with a mixture of the injectate (CO_2) and water. That is, the conductor, surface, and intermediate casing sections will all be carbon steel. The deep casing string will be constructed with corrosion-resistant chrome (CR13) across the reservoir and caprock to total depth (TD) and carbon steel from above the caprock to surface. This section of the wellbore is expected to have intermittent exposure to CO_2-formation water mixed fluids especially in the initial phases of injection and intermittently when well workovers are performed throughout the life of the project. Although the expected water content of the injectate stream will be less than 50 parts per million (ppm), the injection tubing string and flow-wetted injection tree components will be composed of corrosion resistant materials.

Specific pressure ratings for the tubulars are provided in Section 4.1.2. However, all selected casing and tubing grades and weights will be adequate for handling anticipated stress loads and pressures throughout the life of the project. The downhole tubulars were analyzed to ensure their ability to withstand the anticipated loads they may undergo. This analysis reviewed loads during installation, drilling, injection, workover, and subsequent abandonment. Additionally, effects due to cyclical loading, temperature, and exposure to wellbore fluids were also assessed. Table 4-3 details the minimum recommended tubulars and descriptions of key loads that were assessed. The design is robust, meeting industry accepted minimum safety factors with significant margin.

The injection well will include the following casing strings: a 30-inch diameter conductor string set at a depth of approximately 80 ft; a 20-inch diameter surface string set at a depth of approximately 350 feet (ft); a 13 3/8-inch diameter intermediate string set at a depth of approximately 2,750 ft; and a 9 5/8-inch-long string set at a depth of approximately 4,950 ft. All casing strings will be cemented to surface. Table 4-5 and Table 4-6 summarize the casing and tubing/packer program for the injection well. Any potential changes to the final well design will be discussed with the UIC Director or representative.

The deepest underground source of drinking water (USDW) was confirmed from the fluid sampling program during the characterization phase and was determined to be the Gunter Sandstone formation. Intermediate casing will be set through the Gunter and into the top of the Eau Claire caprock which will provide an additional layer of protection to the USDW.

Casing String Name	Open Hole Size (in.)	Outside Diameter (in.)	Setting Depth (ft rGL)	Weight (lb/ft)	Wall Thickness (in.)	Grade	Connection
Conductor	+/-36”	30	80	118	0.375	X-42	Welded
Surface	26”	20	350	94	0.438	J/K-55	Buttress or Long Round Thread
Intermediate	17-1/2”	13.375	2,750	54.5	0.38	J/K-55	Buttress or Long Round Thread
Long String	12-1/4”	9.625	4,970	40	0.395	L-80 (0-2750’) L-8013Cr (2750’ – TD)	Premium
Injection Tubing	n/a	4.5	3,200	11.6	0.25	L-8013Cr	Premium

Table 4-5: Casing details.

Casing String Name	Outside Diameter (in.)	Weight (lb/ft)	Grade	Connection	Burst Rating (psi)	Collapse Rating (psi)	Tensile Yield(klbf)
Surface	20	94	J/K-55	BTC	2,108	520	1,480
Intermediate	13.375	54.5	J/K-55	BTC	2,735	1,130	853
Long String	9.625	40	L-80 (0-2750’) 13Cr80 (2750’ – TD)	Premium	5,745	3,090	916
Injection Tubing	4.5	11.6	L-8013Cr	Premium	7,780	6,360	267

Table 4-6: Tubular performance details.

4.1.2 Tubular Stress Conditions (146.86 (c))

Surface

The surface casing will be the first string of casing installed by the drilling rig. The surface casing will be isolated behind two casing strings during injection operations, so the only applicable load conditions are during the installation of the surface casing and during drilling of the intermediate hole section. The highest evaluated burst load occurs when pressure testing the casing, which results in a 4.0 safety factor (SF) and meets design criteria. Axial loading will be minimal due to shallow setting depth, and all evaluated axial load cases result in SF that exceed 10 and meets design criteria. The worst-case collapse loading for the surface casing would be if returns are lost while drilling the intermediate hole interval; however, this results in a 3.4 SF and meets design criteria.

Intermediate

The intermediate casing will be the second string of casing installed by the drilling rig. The intermediate casing will not be exposed to injected fluids due to being isolated behind the long string. All applicable load conditions occur during the installation of the intermediate casing and during drilling of the production hole section. The highest evaluated burst load occurs when pressure testing the casing, which results in a 1.6 SF and meets design criteria. Axial loading will be minimal due to relatively shallow setting depth, and all evaluated axial load cases result in SF that exceed 3. The worst-case collapse loading for the intermediate casing occurs during cementing operations and results in a 1.5 SF which meets design criteria.

Long String

The long string is the final casing string that will be installed and will be exposed to installation and injection load cases. The upper portion of the string will be isolated by a tubing and packer completion allowing for use of carbon steel. The lower portion of the string that will be across the injection zone and caprock will use a corrosion resistant alloy (13Cr) as this string will be providing long term well integrity after the injection phase is completed and the well will be plugged. The highest evaluated burst load occurs when pressure testing the casing, which results in a 3 SF and meets design criteria. During normal operations, the burst loading on the long string casing due to applied annular pressure results (high) in a SF above 6. In the event the tubing develops a leak and maximum injection pressure is applied on a column of annular fluid, the resulting SF is 3.2; however, this will be a short-term event due to safety systems. Axial loading will be minimal due to shallow setting depth and minimal temperature fluctuations. All evaluated axial load cases result in SF that exceed 3. The worst-case collapse loading for the long string casing is a full evacuation to air which results in a SF of 1.4 which meets design criteria. This annulus will be filled with packer fluid (to minimize corrosion) and will be monitored to check for leaks; thus, this evacuated load case is extremely unlikely. A triaxial analysis was also performed based on the data from the MCI MW 1 well, resulting in a minimal SF of 2.4.

Injection Tubing

The injection tubing will be the final string of tubulars installed. The injection tubing will be the primary tubular in contact with injected fluids. During a workover event, the tubing may be removed from the well and can be replaced if any wall loss or damage has taken place. The highest burst load evaluated occurs when the tubing is pressure tested. This load results in a 4.3 SF which meets design criteria. Burst load during normal injection operations (maximum injection pressure, low annular pressure) results in a SF greater than 8. Burst load during injection with an annular pressure loss event results in a SF that exceeds 4. The highest collapse load assessed assumes that the tubing is evacuated during a high annular pressure event, but still results in a SF of 2.8 and meets design criteria. Axial loading will be minimal due to shallow setting depth, low temperatures and all evaluated axial load cases result in SF that exceed 4.

4.1.3 Cement (146.86 (b))

The cemented casing strings (four in total) for the proposed injection well will all be cemented back to surface. The surface strings will be cemented using Class A, H, or G cement while the intermediate string will be cemented using Class H or G cement. The injection string will be installed using Schlumberger's EverCRETE (or equivalent) as the tail mix across the injection reservoir and caprock intervals with Class G or H as the lead above the caprock. Table 4-7 gives a summary of the cement types to be used for each casing string.

Casing String	Appx. Depth Range (MDKB ft)	Cement Type
Surface	0-350	Class A, G, or H
Intermediate	0-2,750	Class G or H
Deep	0-4,900	CO_2-Resistant tail slurry /Class G or H: Pozzolan 50:50 lead slurry

Table 4-7: Summary of cement types and corresponding casing strings.

Class A cements are adequate for providing zonal isolation in behind-pipe environments to prevent the movement of formation fluids between zones. Class A cements have been applied in shallow oil and gas wells and water disposal wells for many decades and are an accepted best practice. In a typical, non-corrosive subsurface environment (i.e., aquifer or oil/gas reservoirs) Class A cement will perform well throughout the service life of the well.

Class G or H cements are generally intended for use in deeper onshore wells and will have improved performance characteristics under higher temperature and pressure conditions, as compared to Class A cements (Guner & Ozturk, 2015).

The deep casing string will be cemented with a slurry similar to Schlumberger's EverCRETE system, which has been widely used in other carbon capture and storage (CCS) applications with reliable results. This cement system is useful in the injected CO_2 environment because it is highly resistant to carbonic acid, has very low permeability, and becomes self-healing when exposed to CO_2 (Schlumberger).

All casing strings will be cemented to surface. Table 4-8 describes the type of cement, estimated volumes, and weight of the mixture in pounds-per-gallon (ppg). Additives may change slightly based on laboratory testing. Volumes may be adjusted based on expected hole enlargement.

Casing String	Casing Depth (MDKB ft)	Cement Description
Surface	350	Lead, Class A w/gel 13.2ppg 104bbls (50% excess) Class A, 15.6 ppg, 54bbls (50% excess)
Intermediate	2,750	Lead, 50/50 Poz:Class H w/gel, 13.2 ppg, 400bbls (25% excess) Tail, Class H, 16.4 ppg, 50bbls (25% excess)
Deep	4,900	Lead, 50/50 Poz:Class H w/gel, 13.2 ppg, 174bbls Tail, CO_2-Resistant, 15.2 ppg, TOC 2700', 165bbls (25% excess)

Table 4-8: Cement program for the CO_2 injection well.

4.1.4 Downhole Completion Equipment (146.86 (a)(2,3)

Completion equipment will exceed the ratings of the injection tubing and will be suitable for the downhole conditions. Completion equipment will be designed such that a tubing plug can be set in the tail pipe below the packer allowing for removal of the upper completion string during workover activities. The downhole completion equipment will include:

- CO_2 compatible packer with tail pipe to allow for Pressure / Temperature gauge and a profile for setting a tubing plug.
- Subsurface safety valve (SCSSV) to allow for shut-in of the well

The 4 ½-inch tubing will be set with a packer inside the long string casing to approximately 3,200 ft. The packer will be set at approximately 3,000 ft, which is about 250 to 275 ft below the top of the Eau Claire Caprock. Tubing tail pipe will be present below the packer to allow installation of a tubing plug and for retrievable memory pressure/temperature gauges to be set throughout the life of the well. A perforated joint of tubing may be required for the use of the pressure/temperature gauges, and this will be determined in the final design. Positive external pressure will be applied to the tubing string throughout the service life of the well from the annular fluid system (Section 4.7).

The final packer selection for this well will be determined prior to completion. However, preliminary plans suggest a packer similar to Baker Hughes' SC-2 retrievable production packer may be used for this application. The Baker SC-2 packer is designed for higher temperature and pressure environments where a high differential pressure (i.e., from above and below) may be present. Although a high-pressure differential will not be observed in this well, the design of this packer provides additional assurance of a positive seal. The exposed components of the packer will be specially constructed from CO_2-resistant materials including CR13 in addition to specially designed polymers for the elements. During the initial startup phase of injection, the

packer may be exposed to CO_2-saturated brine from below until it is fully displaced from the wellbore by the CO_2.

An SCSSV will be deployed in the tubing string at +/-280 ft below surface. The SCSSV will prevent backflow of injected CO_2 up the tubing string back to surface in the unlikely event of loss of containment at surface. An appropriate corrosion-resistant material (stainless steel or Cr13) will be selected as the building material for the SCSSV and will be appropriately sized for the injection tubing string.

4.1.5 Perforation Strategy

The perforated interval of the injection well will encompass selected targets throughout the Mt. Simon (approximately 3,226-4,800 ft). The perforated zones will range from one to six shots per foot (SPF) depending on the evaluation of the wireline logs of the MCI CCS 3. Perforated zones will be selected to balance well performance (i.e., injection pressure) with plume development. Because the Mt. Simon is expected to have some level of heterogeneity the final selected perforation intervals will largely depend on interpreted permeability layers within the Mt. Simon. Modeled perforation intervals based on data from MCI MW 1 well.

4.2 Drilling Contingencies

As mentioned in the previous section, the setting depths for the surface and intermediate casing strings are designed to provide maximum protection for both groundwater and USDWs. There are seven shallow groundwater wells within the AoR above 350 ft, five of which are owned by Marquis and used for ethanol production, and the other three are generally used in the area for agricultural applications.

The main drinking water source in the area are the shallow aquifers at approximately 300 ft measured depth (MD) and provide water to several municipalities in the region. The deepest USDW determined from testing in the MCI MW1 well is the Gunter Sandstone, approximately 2,130 ft MD. Two strings of casing (intermediate and deep) will provide protection to the USDW throughout the life of the project.

The largest drilling issue is anticipated to be the Potosi Dolomite (approximately 2,250 to 2,400 ft MD). This formation is widely known for its vugular, secondary porosity zones that can lead to lost circulation while drilling. Generally, it is thought to be more problematic deeper into the Illinois Basin to the south and east. However, it is a risk that the project will plan to manage at the project site. The Potosi formation did not present drilling problems during the installation of the MCI MW1 well. However, in the event circulation is nearly or completely lost, the plan is to drill ahead without drilling fluid returns through the remainder of the formation if possible. Then, a thixotropic cement slurry will be pumped, likely several slurries, to seal off the lost circulation zones. Once circulation has been fully restored drilling will proceed as planned.

In the event of severe lost circulation issues, a two-stage cement job may be implemented. The differential valve (DV) tool will be set just above the uppermost encountered lost circulation zone.

Although elevated pressures or hydrocarbons are not expected, Blow Out Prevention Equipment (BOPE) will be installed prior to drilling below the surface casing. Periodic drills and training will be performed to ensure the crews are educated in how to react to a well control event.

Other planned contingencies include standard oilfield practices for preventing excessive borehole deviation and a lost drill string. A stiff bottom-hole assembly (BHA), including stabilizers and/or drill collars, will be used to prevent significant deviation from vertical and to minimize the corkscrew tendency of the drill string. Intermittent deviation checks using single shot surveys will be used to verify that wellbore deviation stays below five degrees from vertical. Directional drillers will be contracted in the event consecutive deviation surveys show to be greater than five degrees from vertical to bring the wellbore back to near zero degrees.

Periodically throughout the drilling process the drill string will be pulled back up through the wellbore to ensure the hole is in good working condition, known as "wiper trips." These short trips can prevent the buildup of formation cuttings around the outside of the drill string which can cause the string to become stuck in the hole, in the worst cases. They also ensure the formation of an even mud-cake layer along the walls of the wellbore which aids in better data collection with wireline tools in addition to a smoother installation of casing later in the process.

4.3 Annular Fluid System

The annular fluid will be a dilute salt solution such as potassium chloride (KCl), sodium chloride (NaCl), or similar. The fluid will be mixed on site from dry salt and good quality (clean) fresh water, or it will be acquired pre-mixed. The fluid will also be filtered to ensure that solids do not interfere with the packer or other components of the annular protection system. The likely density of the annular fluid will be approximately 9.2 ppg. Final choice of the type of fluid will depend on availability and wellbore conditions.

The annulus fluid will contain additives and inhibitors including: a corrosion inhibitor, biocide (prevent growth of harmful bacteria), and an oxygen scavenger. Example additives and inhibitors are listed below along with approximate mix rates:

- TETRAHib Plus (corrosion inhibitor for carbon steel tubulars) – 10 gallons (gal) per 100 barrels (bbls) packer fluid
- CORSAF™ SF (corrosion inhibitor for use with 13Cr stainless steel tubulars or a combination of stainless steel and carbon steel tubulars) – 20 gal per 100 bbls packer fluid
- Spec-cide 50 (biocide) – 1 gal per 100 bbls packer fluid

- Oxban-HB (non-sulfite oxygen scavenger) – 10 gal per 100 bbls packer fluid

These products were recommended by and are provided by Tetra Technologies, Inc., of Houston, TX. Actual comparable products and provider may be used other than those described above.

4.4 Stimulation Program

No stimulation program is being planned as the expected injectivity of the Mt. Simon Sandstone should be adequate for the planned injection volumes. A small volume of acid may be required to "clean the perforations" prior to injection but formation breakdown pressure will not be reached during the activity.

4.5 Demonstration of Mechanical Integrity

Pressure testing and logging will be performed to confirm the casing was installed correctly and cemented appropriately.

Please refer to the Pre-Operational Testing Plan (Permit Section 5) and the Testing and Monitoring Plan (Permit Section 7) for additional details on the demonstration of mechanical integrity.

4.6 References

Guner, D., Ozturk, H., 2015. Comparison of Mechanical Behavior of G Class Cements for Different Curing Time. Presented at 24th International Mining Congress and Exhibition of Turkey, 2015.

Schlumberger. EverCRETE system: https://www.slb.com/drilling/drilling-fluids-and-well-cementing/well-cementing/cemcrete-cementing-technology/evercrete-co2-resistant-cement-system.

Appendix - EverCRETE

Transition Technologies

Schlumberger

EverCRETE CO_2-resistant cement system

Extend cement barrier lifetime in reservoirs containing CO_2

Aligned with United Nations Sustainable Development Goals: 12—Responsible consumption and production, 13—Climate action.

CO_2 Reduction:
Serves as barrier for CO_2 storage wells or high CO_2-producing formations. Lowers CO_2 footprint during well construction due to significantly reduced usage of Portland cement.

Temperature:
up to 284 degF [140 degC]

Applications

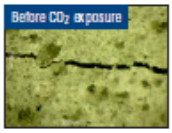
- Carbon capture and storage wells
- Wells in fields that use CO_2 injection for enhanced oil recovery (EOR)
- Primary cementing in CO_2 environments
- Long-term decommissioning objectives for plug and abandonment (P&A) in CO_2 environments

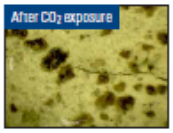
How it improves wells

Because of its intrinsic low permeability, EverCRETE* CO_2-resistant cement system resists cement matrix attack from wet supercritical CO_2 and water saturated with CO_2 conditions. Accelerated reaction kinetics lead to a stabilized matrix within days of exposure to the CO_2 environment, leading to stabilized mechanical properties.

How it works

EverCRETE system blends can be prepared locally using the standard bulk plant. The density can be tailored to well requirements, providing operational flexibility. Unlike other offerings, EverCRETE system is compatible with portland cement. The EverCRETE system can be used as a cement across potential CO_2-producing formations or as the primary barrier in the wellbore for any in situ fluids, with a portland cement-based slurry used as a filler slurry for coverage of remaining casing. It can be prepared and pumped using standard equipment. Additionally, the cement can be engineered with self-healing properties that are reactive to CO_2 exposure.





What it replaces

Portland cement systems are used conventionally for zonal isolation in wells. However, portland cement is thermodynamically unstable in CO_2-rich environments and can degrade rapidly upon exposure to CO_2 in the presence of water. As CO_2-laden water diffuses into the cement matrix, the dissociated acid (H_2CO_3) reacts with the free calcium hydroxide and the calcium silicate hydrate (C-S-H) gel. The reaction products are soluble and migrate out of the cement matrix. Eventually, the compressive strength of the set cement decreases and the permeability and porosity increase, leading to loss of zonal isolation.

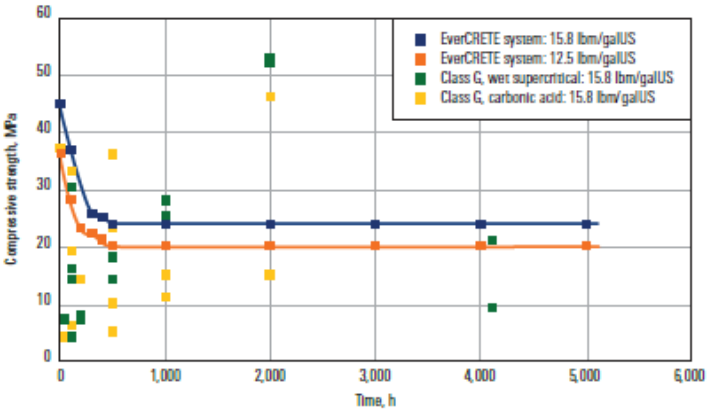
Why it's ideal in any CO_2 environment

Well integrity has been identified as the biggest risk contributing to leakage of CO_2 from underground carbon capture and storage sites. EverCRETE system enables efficient underground storage and keeps greenhouse gases out of the atmosphere.

For wells in fields that use CO_2 injection for EOR or may use it in the future, EverCRETE system reduces the risk of cement sheath degradation and leakage. It can be used to cement new CO_2 injection wells or to plug and abandon injection or production wells at the end of the field life.

In case there is damage to the cement matrix and CO_2 starts to migrate, the self-healing capabilities that can be incorporated in EverCRETE system will repair the crack, reestablishing the integrity of the well and recovering zonal isolation.

EverCRETE system can also be used as a cement across potential CO_2-producing formations or as the primary barrier in the wellbore for in situ fluids after abandonment and permanent decommissioning.



Compressive strength evolution of portland cement and EverCRETE system samples with time in wet supercritical CO_2 fluid and in CO_2 saturated in water at 194 degF [90 degC] under 28 MPa of pressure. After 6 months in CO_2-saturated water, the compressive strength of portland cement is not measurable because most of the samples are highly deteriorated. The stability of the EverCRETE system minimizes the degradation potential of the long-term barrier.

*Mark of Schlumberger
Transition Technologies is a mark of Schlumberger.
Copyright © 2021 Schlumberger. All rights reserved. 21-WCFL-999K3

slb.com/EverCRETE

Class VI UIC Project Plan Submissions

This submission is for:

Project ID: R05-IL-0006

Project Name: Marquis Carbon

Current Project Phase: Pre-Injection Prior to Construction

Testing and Monitoring

Are You Making a Testing and Monitoring Plan Submission at this Time: Yes

Reason for Project Plan Submission: Permit Application Submission

Project Plan Upload

Attach the Testing and Monitoring Plan: https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R05-IL-0006/Phase1-PreConstruction/ProjPlan-06-17-2022-1738/7.--Testing--and--Monitoring--Plan.pdf

Appendices and Supporting Materials Upload

Attach Any Supporting Documentation for the Testing and Monitoring Plan: https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R05-IL-0006/Phase1-PreConstruction/ProjPlan-06-17-2022-1738/7.A--QASP.pdf

https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R05-IL-0006/Phase1-PreConstruction/ProjPlan-06-17-2022-1738/7.A--QASP.pdf

https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R05-IL-0006/Phase1-PreConstruction/ProjPlan-06-17-2022-1738/LQCRM--docs--for--QASP.zip

Injection Well Plugging

Are You Making an Injection Well Plugging Plan Submission at this Time: Yes

Reason for Project Plan Submission: Permit Application Submission

Project Plan Upload

Attach the Injection Well Plugging Plan: https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R05-IL-0006/Phase1-PreConstruction/ProjPlan-06-17-2022-1738/8.--Injection--Well--Plugging--Plan.pdf

Appendices and Supporting Materials Upload

PISC and Site Closure

Are You Making a Post-Injection Site Care and Site Closure Plan Submission at this Time: Yes

Reason for Project Plan Submission: Permit Application Submission

Project Plan Upload

Attach the Post-Injection Site Care and Site Closure Plan: https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R05-IL-0006/Phase1-PreConstruction/ProjPlan-06-17-2022-1738/9.--PISC--and--Site--Closure--Plan.pdf

https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R05-IL-0006/Phase1-PreConstruction/ProjPlan-06-17-2022-1738/9.--PISC--and--Site--Closure--Plan--REV--1.pdf

Appendices and Supporting Materials Upload

Emergency and Remedial Response

Are You Making an Emergency and Remedial Response Plan Submission at this Time: Yes

Reason for Project Plan Submission: Permit Application Submission

Project Plan Upload

Attach the Emergency and Remedial Response Plan: https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R05-IL-0006/Phase1-PreConstruction/ProjPlan-06-17-2022-1738/10.--ERRP.pdf

Appendices and Supporting Materials Upload

Complete Submission

Authorized submission made by: Jared Lee Walker

Comments regarding this submission: Updated PISC and Site Closure

For confirmation a read-only copy of your submission will be emailed to: bethsteinhour@marquisenergy.com

APPENDIX 7.A
QUALITY ASSURANCE AND SURVEILLANCE PLAN

MARQUIS BIOCARBON PROJECT

Facility Information

Facility name: MARQUIS BIOCARBON PROJECT

Facility contact: ELIZABETH STEINHOUR
DIRECTOR OF ENVIRONMENTAL AFFAIRS
10000 MMARQUIS DRIVE, HENNEPIN, IL 61327
815.925.7300 / BETHSTEINHOUR@MARQUISENERGY.COM

Well name: MCI CCS 3

Well location: PUTNAM COUNTY, ILLINOIS
S2 T32N R2W
Latitude: 41.27026520 N, Longitude: 89.30939322 W

This Quality Assurance and Surveillance Plan (QASP) is approved for use and implementation at Marquis Biocarbon Project. The signatures below denote the approval of this document and intent to abide by the procedures outlined within it.

_____ _____
Signature Date

ELIZABETH STEINHOUR
DIRECTOR OF ENVIRONMENTAL
AFFAIRS

_____ _____

Table of Contents

Distribution List 7

A Project Management 8

A.1. Project/Task Organization 8
A.1.1 Key Individuals and Responsibilities 8
A.1.2 Independence from Project QA Manager and Data Gathering 9
A.1.3 QA Project Plan Responsibility 9
A.1.4 Organizational Chart for Key Project Personnel 9

A.2. Problem Definition/Background 9
A.2.1 Reasoning 9
A.2.2 Reasons for Initiating the Project 10
A.2.3 Regulatory Information, Applicable Criteria, Action Limits 10

A.3. Project/Task Description 10
A.3.1 Summary of Work to be Performed and Work Schedule 10
A.3.2 Geographic Locations 13
A.3.3 Resource and Time Constraints 14

A.4. Quality Objectives and Criteria 14
A.4.1 Performance/Measurement Criteria 14
A.4.2 Precision 21
A.4.3 Bias 21
A.4.4 Representativeness 21
A.4.5 Completeness 21
A.4.6 Comparability 21

A.5. Special Training/Certifications 22
A.5.1 Specialized Training and Certifications 22
A.5.2 Training Provider and Responsibility 22

A.6. Documentation and Records 22
A.6.1 Report Format and Package Information 22
A.6.2 Other Project Documents, Records, and Electronic Files 22
A.6.3 Data Storage and Duration 22
A.6.4 QASP Distribution Responsibility 22

B. Data Generation and Acquisition 23

B.1. Sampling Process Design (Experimental Design) 23
B.1.1 Design Strategy 23
B.1.2 Type and Number of Samples/Test Runs 25
B.1.3 Site/Sampling Locations 25
B.1.4 Sampling Site Contingency 26
B.1.5 Activity Schedule 26
B.1.6 Critical/Informational Data 26
B.1.7 Sources of Variability 26

B.2. Sampling Methods 27
B.2.1 Sampling SOPs 27
B.2.2 In-situ Monitoring 29
B.2.3 Continuous Monitoring 29
B.2.4 Sample Homogenization, Composition, Filtration 29
B.2.5 Sample Containers and Volumes 29
B.2.6 Sample Preservation 29
B.2.7 Cleaning/Decontamination of Sampling Equipment 30
B.2.8 Support Facilities 31
B.2.9 Corrective Action, Personnel, and Documentation 31

B.3. Sample Handling and Custody 31
B.3.1 Maximum Hold Time/Time Before Retrieval 31
B.3.2 Sample Transportation 32
B.3.3 Sampling Documentation 32
B.3.4 Sample Identification 32

B.3.5 Sample Chain-of-Custody 32

B.4. Analytical Methods 32
B.4.1 Analytical SOPs 33
B.4.2 Equipment/Instrumentation Needed 33
B.4.3 Method Performance Criteria 33
B.4.4 Analytical Failure 33
B.4.5 Sample Disposal 33
B.4.6 Laboratory Turnaround 33
B.4.7 Method Validation for Nonstandard Methods 33

B.5. Quality Control 35
B.5.1 QC Activities 35
B.5.2 Exceeding Control Limits 36
B.5.3 Calculating Applicable QC Statistics 36

B.6. Instrument/Equipment Testing, Inspection, and Maintenance 37

B.7. Instrument/Equipment Calibration and Frequency 37
B.7.1 Calibration and Frequency of Calibration 37
B.7.2 Calibration Methodology 37
B.7.3 Calibration Resolution and Documentation 38

B.8. Inspection/Acceptance for Supplies and Consumables 38
B.8.1 Supplies, Consumables, and Responsibilities 38

B.9. Non-direct Measurements 38
B.9.1 Seismic Monitoring Methods 38

B.10. Data Management 39
B.10.1 Data Management Scheme 39
B.10.2 Record-keeping and Tracking Practices 39
B.10.3 Data Handling Equipment/Procedures 39
B.10.4 Responsibility 40
B.10.5 Data Archival and Retrieval 40

B.10.6 Hardware and Software Configurations 40
B.10.7 Checklists and Forms 40

C. Assessment and Oversight 40

C.1. Assessments and Response Actions 40
C.1.1 Activities to be Conducted 40
C.1.2 Responsibility for Conducting Assessments 40
C.1.3 Assessment Reporting 40
C.1.4 Corrective Action 41

C.2. Reports to Management 41
C.2.1 QA Status Reports 41

D. Data Validation and Usability 41

D.1. Data Review, Verification, and Validation 41
D.1.1 Criteria for Accepting, Rejecting, or Qualifying Data 41

D.2. Verification and Validation Methods 41
D.2.1 Data Verification and Validation Processes 41
D.2.2 Data Verification and Validation Responsibility 42
D.2.3 Issue Resolution Process and Responsibility 42
D.2.4 Checklist, Forms, and Calculations 42

D.3. Reconciliation with User Requirements 42
D.3.1 Evaluation of Data Uncertainty 42
D.3.2 Data Limitations Reporting 42

References 43

Attachment 1 - Log Quality Control Reference Manuals (LQCRM) ..... **Error! Bookmark not defined.**

List of Tables

Table 1: Distribution List 7
Table 2: Key Individuals and Responsibilities 8
Table 3: Summary of Testing and Monitoring 11
Table 4: Summary of Direct Geochemical Measurements 12
Table 5: Summary of analytical and field parameters for shallow Quaternary groundwater samples. 15
Table 6: Summary of laboratory analytical and field parameters for the deepest USDW, Galesville Sandstone, and Mt. Simon Sandstone groundwater samples. 16
Table 7: Summary of analytical parameters for CO_2 gas stream. All analysis will be performed by a certified third-party laboratory. 17
Table 8: Summary of analytical parameters for corrosion coupons. 17
Table 9: Mass Flow Rate Field Gauge— CO_2 Mass Flow Rate 18
Table 10: Mass Flow Rate Field Gauge— CO_2 Mass Flow Rate 18
Table 11: Pressure Field Gauge —Injection tubing, annulus, pipeline. 19
Table 12: Temperature Field Gauge —Injection tubing, annulus, pipeline. 19
Table 13: Pressure and temperature—bottomhole gauge specifications (PPS25). 19
Table 14: Representative logging tool specifications. Actual tools used will be comparable. 20
Table 15: Actionable testing and monitoring outputs. 20
Table 16: Stabilization criteria of water quality parameters during shallow well purging. 28
Table 17: Preservation, containers, and hold times for aqueous samples. 30
Table 18: Preservation, containers, and hold times for aqueous samples. 30

List of Figures

Figure 1: Marquis Carbon Injection, LLC project organization structure. 9
Figure 2: Marquis Carbon Injection Project area showing location of the injection, deep, above confining zone (ACZ), and shallow groundwater monitoring wells. 13
Figure 3: Example label for groundwater sample bottles. 32
Figure 4: Example of chain-of-custody form for the CO_2 injection stream gas analyses. 34

Figure 5: Example chain-of-custody form for the fluid sample analyses. 35

Distribution List

The following project participants (Table 1) will receive the completed Quality Assurance and Surveillance Plan (QASP) and all future updates for the duration of the project. The Marquis Carbon Injection, LLC Director of Environmental Affairs will be responsible for ensuring that all of those on the distribution list receive the most current copy of the approved QASP. Names in bold are the primary points of contact with addresses listed below.

Name	Organization	Project Role (s)	Contact Information (email / telephone)
Elizabeth Steinhour	Marquis	Director of Environmental Affairs - Lead for Environmental and Quality personnel	bethsteinhour@marquisenergy.com 815-925-7300
Jared Walker	Marquis	Director of Carbon Removal – Lead for Project Manager and MVA Task	jaredwalker@marquisenergy.com 435-241-8214

Table 1: Distribution list.

A Project Management

A.1. Project/Task Organization

A.1.1 Key Individuals and Responsibilities

The project will be led by Marquis Carbon Injection LLC (Marquis). Marquis will retain the services of qualified subcontractors. The performance of the Testing and Monitoring Plan will be shared between Marquis and our designated subcontractor. This QASP describes the methods used to perform the activities listed in the Testing and Monitoring Plan.

The key roles and responsibilities of the personnel involved in implementation of the Testing and Monitoring Plan is listed in Table 2.

Role	Responsibility
Project Manager	The Project Manager (PM) plays a central role in the implementation of all data gathering and analysis for the Project and provides overall coordination and responsibility for all organizational and administrative aspects. The PM is responsible for the planning, funding, schedules, and controls needed to implement project plans and ensure that project participants adhere to the plan.
Quality Representative	The role of the Quality Representative (QR) is to identify quality-affecting processes and to monitor compliance with project requirements. The QR is responsible for establishing and maintaining the project quality assurance plans and monitoring project staff compliance with them. The QR is responsible for ensuring that this Quality Assurance and Surveillance Plan (QASP) meets the project's quality assurance requirements.
Monitoring, Verification, and Accounting Task Lead	Well testing and monitoring activities are the responsibility of the Monitoring, Verification, and Accounting (MVA) Task Lead. The MVA Task Lead is responsible for developing, maintaining, and updating all well testing and monitoring plans, including this QASP.
Subject Matter Experts/Subtask Task Leads	The role of these SMEs is to develop testing and monitoring plans, to collect environmental data specified in those plans using best practices, and to maintain and update those plans as needed. The SMEs, assisted by the MVA Task Lead, are responsible for planning, collecting, and ensuring the quality of testing and monitoring data and managing all necessary metadata and provenance for these data. The SMEs are also often responsible for data analysis, data products and acquisition of independent data quality/peer reviews. The SMEs will be involved in the project as needed. They will be qualified third party individuals.

Table 2: Key individuals and responsibilities.

A.1.2 Independence from Project QA Manager and Data Gathering

To ensure quality assurance, the sample collection process, data analysis and processing will be performed or witnessed by independent third parties outside the management structure in most cases.

A.1.3 QA Project Plan Responsibility

Marquis will be responsible for maintaining and distributing the official, approved QASP. Marquis will periodically review this QASP and consult with EPA when changes to the plan are required.

A.1.4 Organizational Chart for Key Project Personnel

Figure 1 shows the organizational structure of the Marquis BioCarbon project. Marquis will provide a contact list of individuals fulfilling these roles to the UIC Program Director, if required. The project manager and Monitoring, Verification, and Accounting (MVA) task lead are part of the Project Development team, and the Environmental and Quality representatives are part of the Environmental team.

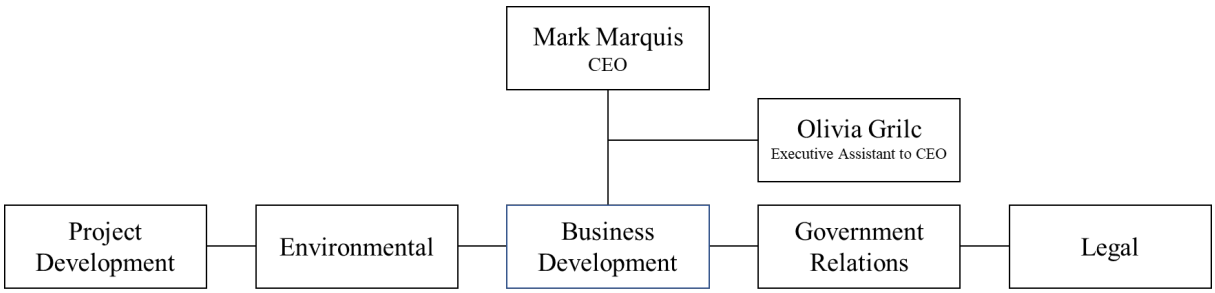


Figure 1: Marquis Carbon Injection, LLC project organization structure.

A.2. Problem Definition/Background

A.2.1 Reasoning

The goals of the Testing and Monitoring Plan (Permit Section 7.0) include:

- Protecting Underground Sources of Drinking Water (USDWs)
- Meeting the regulatory requirements of 40 Code of Federal Regulations (CFR) 146.90
- Ensuring that the injection well is operating as planned
- Providing data to validate and calibrate the geological and dynamic models used to predict the distribution of carbon dioxide (CO_2) within the injection zone

- Support Area of Review (AoR) re-evaluations over the course of the project

These objectives will be met through the collection of pressure/temperature data within and above the storage formation, the collection of groundwater and fluid samples from shallow and deep monitoring wells, wireline logging techniques, pressure/temperature measurements in the tubing and annular space of the injection well and deep monitoring wells, sample collection/analysis of the injection stream, and geophysical monitoring.

This QASP was developed to ensure the quality standards of the Testing and Monitoring Plan to meet the requirements of the EPA Underground Injection Control (UIC) Program for Class VI wells.

A.2.2 Reasons for Initiating the Project

The objective of the Marquis BioCarbon Project is to safely and permanently store injected CO_2 in the Mt. Simon Sandstone. The Testing and Monitoring Plan for this project has been designed to confirm the safe and permanent storage of the CO_2 within the intended storage reservoir.

A.2.3 Regulatory Information, Applicable Criteria, Action Limits

US EPA regulation 40 CFR 146 Subpart H requires owners or operators of Class VI wells to monitor several parameters over the life of the project to ensure that:

- Mechanical integrity of the injection well is maintained
- Fluid migration and the extent of pressure elevation are within the limits described in the permit application
- USDWs are not endangered

Monitoring activities include mechanical integrity tests (MITs), pressure fall-off (PFO) tests during the injection phase of the project, monitoring of shallow and deep groundwater quality, and development of the CO_2 plume and associated pressure front. This document details the measurements that will be required as well as the steps used to ensure that the quality of all data is such that it can be used in the decision-making process over the life of the project.

A.3. Project/Task Description

A.3.1 Summary of Work to be Performed and Work Schedule

Table 3 and Table 4 describe a summary of the testing and monitoring tasks, reasoning, responsible parties, locations, and testing frequency.

Activity	Location(s)	Method	Frequency			Analytical Technique	Lab/Custody	Purpose
			Baseline	Injection Phase	PISC Phase			
CO_2 stream analysis	Post-Compressor	Direct sampling	Once	Quarterly	None	Laboratory analysis	TBD	Monitor injectate
Injection mass rate and volume	Injection wellhead	Flow meter	N/A	Continuous	N/A	Direct measurement	N/A	Monitor injection rate and volume
Injection pressure	Injection Wellhead	Pressure gauge	N/A	Continuous	N/A	Direct measurement	N/A	Monitor injection pressure
Annular pressure	Injection Wellhead	Pressure gauge	N/A	Continuous	N/A	Direct measurement	N/A	Wellbore integrity
Storage formation pressure/temperature	Deep Monitoring Wells	Downhole gauge	N/A	Continuous	Continuous while wells are open	Direct measurement	N/A	Monitor storage and ACZ formations
Corrosion monitoring	Pipeline	Coupon	N/A	Quarterly	N/A	Chemical analysis	TBD	Wellbore integrity
Temperature Measurements	Injection Well Deep Monitor Well	Logging	Once	Annually	Prior to P/A	Direct measurement	N/A	Wellbore integrity
Pulsed Neutron Capture	Deep Monitoring and ACZ Wells	Logging	Once	Annually	Annually while wells are open	Direct measurement	N/A	CO_2 plume development, well Integrity
Pressure fall-off testing	Injection Well	Pressure gauge	N/A	Every 5 years	N/A	Direct measurement	N/A	Reservoir evaluation
Microseismic monitoring	Surface monitoring stations	Seismometer stations	Continuous	Continuous	Continuous	Indirect measurement	N/A	Pressure plume development, confining zone integrity
Time-Lapse 3D Surface Seismic data	Surface	Geophones and seismic sources	Once	Every 4 years	Year 1, Year 5	Indirect measurement	N/A	CO_2 plume development, verify containment

Table 3: Summary of testing and monitoring.

Level	Location(s)	Method	Frequency			Analytical Technique	Lab/Custody	Purpose
			Baseline	Injection Phase	PISC Phase			
Shallow groundwater (Quaternary)	MCI GW 1-4	Dedicated Pump	Quarterly	Semi-Annually	Annually	Laboratory analyses	Table 5	Detection of changes in groundwater quality for a shallow USDW
Deepest USDW	MCI ACZ 1	Bailer	Semi-Annually	Semi-Annually	Annually	Laboratory analyses	Table 6	Detection of changes in quality in the deepest USDW compared to baseline
Galesville Sandstone	MCI ACZ 1	Bailer	Semi-Annually	Annually	Annually	Laboratory analyses	Table 6	Detection of changes in quality in the ACZ aquifer compared to baseline.
In-zone monitoring (Mt. Simon Sandstone)	MCI MW 2	Bailer	Semi-Annually	Semi-Annually	None	Laboratory analyses	Table 6	Detection of changes in quality, geochemistry and CO2 detection in storage formation compared to baseline

Table 4: Summary of direct geochemical measurements.

A.3.2 Geographic Locations

Figure 2 shows the Marquis BioCarbon Project site and monitoring infrastructure.

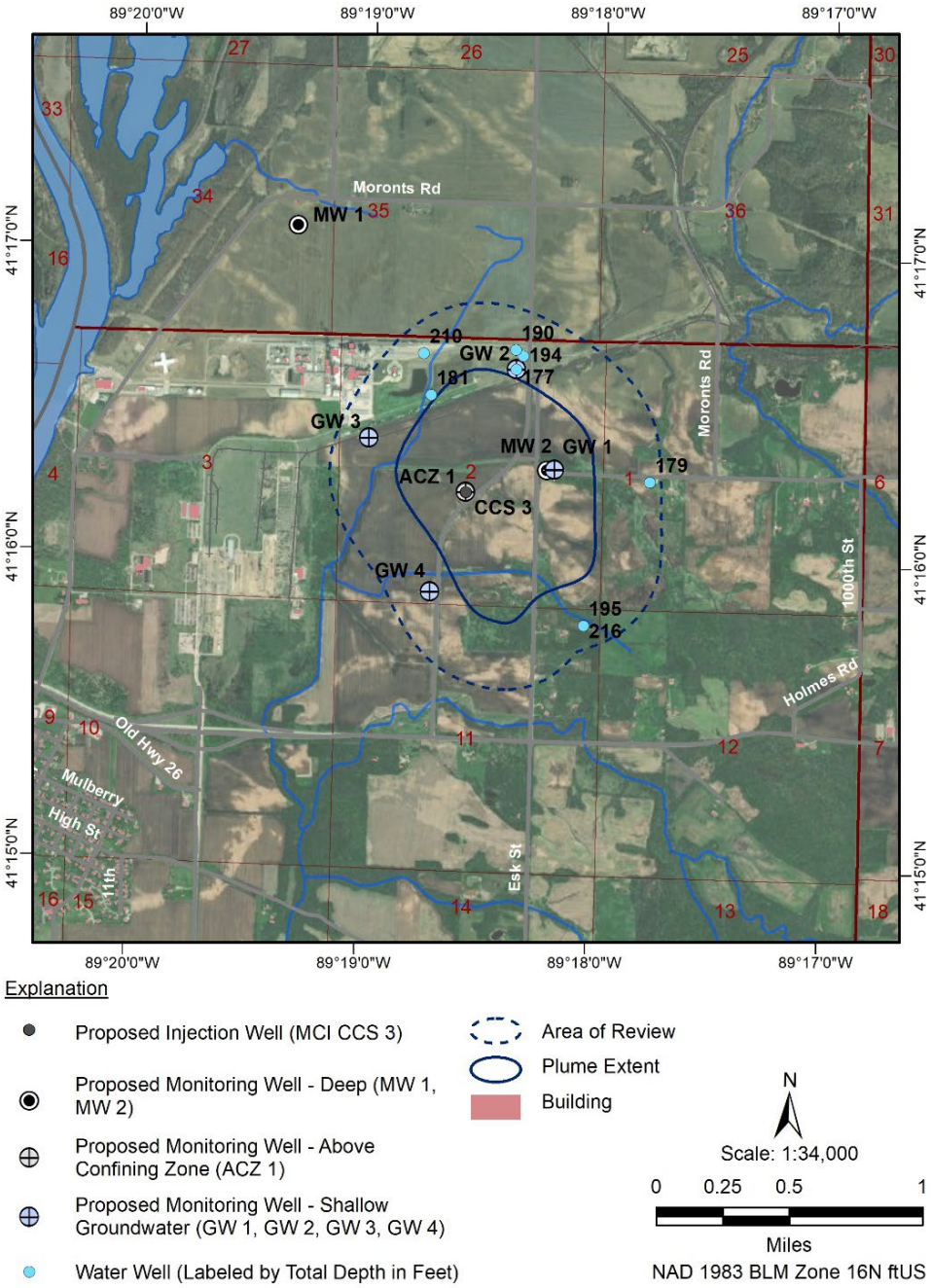


Figure 2: Marquis Carbon Injection Project area showing location of the injection, deep, above confining zone (ACZ), and shallow groundwater monitoring wells.

A.3.3 Resource and Time Constraints

Marquis proposes a 5-year post injection site care (PISC) phase and will continue PISC monitoring for 5 years. Computer Modelling Group (CMG-GEM) simulations will be run throughout the project and matched with actual field data collected under the Testing and Monitoring Plan. The simulations and field testing will confirm that plume stability modeling will be accurate beyond the 5-year period. However, no resource and time constraints have been identified for the Testing and Monitoring Plan beyond the 5-year PISC funding levels.

A.4. Quality Objectives and Criteria

A.4.1 Performance/Measurement Criteria

The overall quality assurance (QA) objective for the testing and monitoring plan is to develop and implement procedures to monitor the CO_2 injection system, development of the CO_2 plume and associated pressure front, and to confirm that CO_2 or other fluids have not migrated beyond the confining layer. This objective will be accomplished through the implementation of the methods provided in Table 3 and Table 4. The tables below (Table 5 to Table 15) detail the specific performance and measurement criteria for each testing and monitoring output.

Parameters	Analytical Methods (*)	Detection Limit/Range	Typical Precisions	QC Requirements
Cations (Na, Ca, Mg, Ba, Sr, Fe, K**)**	ASTM D1976	<1 to 8 mg/L (analyte, dilution, and matrix dependent)	±10%	Daily calibration; blanks, duplicates, and matrix spikes at 10% or greater frequency
Anions (Cl, Br, SO_4**)**	ASTM D4327	0.03 to 0.13 mg/L (analyte, dilution, and matrix dependent)	±15%	Daily calibration; blanks and duplicates at 10% or greater frequency
Dissolved Inorganic Carbon	EPA 9060	0.2 mg/L	±20%	Duplicate measurement; standards at 10% or greater frequency
Total Dissolved Solids	ASTM D5907	12 mg/L	±10%	Balance calibration, duplicate analysis
Alkalinity	ASTM D3875	1 mg/L	±10%	Daily calibration; blanks, duplicates, and matrix spikes at 10% or greater frequency
pH	ASTM D1293	1 to 13 pH units	0/2 pH unit	Daily calibration; blanks, duplicates, and matrix spikes at 10% or greater frequency
Density	ASTM D4052	0.01 g/mL	±10%	Daily calibration; blanks, duplicates and matrix spikes at 10% or greater frequency
Conductivity/Resistivity	ASTM D1125	0 to 100	±1%	Daily calibration; blanks, duplicates, and matrix spikes at 10% or greater frequency
Stable C, H, O Isotopes	CRDS Laser H IRMS for C	200 to 500‰ 50 ppm of DIC	±4‰ ±0.2‰	Duplicates, working standards at 10%
Radiocarbon	AMS	0 to 200 pMC	±0.5 pMC%	Duplicates, working standards at 10%
pH (field)	EPA 150.1	2 to 12 pH units	±0.2 pH unit	User calibration per manufacturer recommendation
Specific conductance (field)	APHA 2510	0 to 200 mS/cm	±1% of reading	User calibration per manufacturer recommendation
Temperature (field)	Thermocouple	-5 to 50°C	±0.2°C	Factory calibration

Table 5: Summary of analytical and field parameters for shallow Quaternary groundwater samples.

* An equivalent method may be employed with the prior approval of the UIC Program Director.

Parameters	Analytical Methods (*)	Detection Limit/Range	Typical Precisions	QC Requirements
Cations: Na, Ca, Mg, Ba, Sr, Fe, K	ASTM D1976	<1 to 8 mg/L (analyte, dilution, and matrix dependent)	±10%	Daily calibration; blanks, duplicates, and matrix spikes at 10% or greater frequency
Anions: Cl, Br, SO_4	ASTM D4327	0.03 to 0.13 mg/L (analyte, dilution, and matrix dependent)	±15%	Daily calibration; blanks and duplicates at 10% or greater frequency
Dissolved Inorganic Carbon	EPA 9060	0.2 mg/L	±20%	Duplicate measurement; standards at 10% or greater frequency
Total Dissolved Solids	ASTM D5907	12 mg/L	±10%	Balance calibration, duplicate analysis
Alkalinity	ASTM D3875	1 mg/L	±10%	Daily calibration; blanks, duplicates, and matrix spikes at 10% or greater frequency
pH	ASTM D1293	1 to 13 pH units	0/2 pH unit	
Density	ASTM D4052	0.01 g/mL	±10%	
Conductivity/Resistivity	ASTM D1125	0 to 100	±1%	
Stable C, H, O Isotopes	CRDS Laser H IRMS for C	200 to 500‰ 50 ppm of DIC	±4‰ ±0.2‰	Duplicates, working standards at 10%
Radiocarbon	AMS	0 to 200 pMC	±0.5 pMC%	Duplicates, working standards at 10%
pH (field)	EPA 150.1	2 to 12 pH units	±0.2 pH unit	User calibration per manufacturer recommendation
Specific conductance (field)	APHA 2510	0 to 200 mS/cm	±1% of reading	User calibration per manufacturer recommendation
Temperature (field)	Thermocouple	-5 to 50°C	±0.2°C	Factory calibration

Table 6: Summary of laboratory analytical and field parameters for the deepest USDW, Galesville Sandstone, and Mt. Simon Sandstone groundwater samples.

* An equivalent method may be employed with the prior approval of the UIC Program Director.

Parameters	Analytical Methods (1)	Detection Limit/Range	Typical Precisions	QC Requirements
CO2 Purity	GC/TCD	0.1-100%	±10 across range	Standard with every sample, duplicate analysis within 10 % of each other
Oxygen	ISBT 4.0 (GC/DID)	1 uL/L to 5,000 uL/L (ppm by volume)	± 10 % of reading	Daily standard within 10 % of calibration, secondary standard after calibration
Nitrogen	ISBT 4.0 GC/DID	1 uL/L to 5,000 uL/L (ppm by volume)	± 10 % of reading	Daily standard within 10 % of calibration, secondary standard after calibration
Hydrogen Sulfide	ISBT 14.0 (GC/SCD)	0.01 uL/L to 50 uL/L (ppm by volume)-dilution dependent	5 - 10 % of reading relative across the range	Daily blank, daily standard within 10 % of calibration, secondary standard after calibration
Water Content	ISBT 11.0 (GC/FID)	0.1 uL/L to 100 uL/L (ppm by volume)-dilution dependent	5 - 10 % of reading relative across the range	Daily blank, daily standard within 10 % of calibration, secondary standard after calibration

Table 7: Summary of analytical parameters for CO_2 gas stream. All analysis will be performed by a certified third-party laboratory.

Parameters	Analytical Methods	Detection Limit/Range	Typical Precisions	QC Requirements
Mass	NACE RP0775-2005	0.005mg	+/-2%	Annual Calibration of Scale (3rd Party Aldinger Co. – Cert #664896F)
Thickness	NACE RP0775-2005	0.001mm	+/-005mm	Factory calibration

Table 8: Summary of analytical parameters for corrosion coupons.

Parameters	Detection Limit/Range
Calibrated working flow rate range	5 to 5,000 MT/day and 4–20 mA
Mass flow rate accuracy	< 0.2%
Mass flow rate resolution	2.6 MT/day
Mass flow rate drift stability	To be determined after first year

Table 9: Mass Flow Rate Field Gauge— CO_2 Mass Flow Rate.

Parameters	Methods	Detection Limit/Range	Typical Precisions	QC Requirements
Compressor discharge pressure	ANSI/NCSL Z540-1-1994	+/- 0.001 psi / 0-3000 psi	+/- 0.01 psi	Calibrated per manufacturer specification
Wellhead Injection Tubing Temperature	ANSI/NCSL Z540-1-1994	+/- 0.001 F / 0-500 F	+/- 0.01 F	Calibrated per manufacturer specification
Annulus Pressure	ANSI/NCSL Z540-1-1994	+/- 0.001 psi / 0-3000 psi	+/- 0.01 psi	Calibrated per manufacturer specification
Wellhead Injection Tubing Pressure	ANSI/NCSL Z540-1-1994	+/- 0.001 psi / 0-3000 psi	+/- 0.01 psi	Calibrated per manufacturer specification
Injection Mass Flow Rate	API MPMS	+/- 0.1000% of rate / 5-5,000 MT/day	+/- 0.01 lbs./hr.	Calibrated per manufacturer specification
Reservoir Pressures Silicon-sapphire	UNKNOWN	+/-0 0.03 psi / 0-6000 PSI	+/- 0.1 psi	Calibrated by manufacturer

Table 10: Mass Flow Rate Field Gauge— CO_2 Mass Flow Rate.

Parameters	Detection Limit/Range
Calibrated working pressure range	0 to 3,000 psi and 4–20 mA
Initial pressure accuracy	< 0.04375%
Pressure resolution	0.001 psi and 0.00001 mA
Pressure drift stability	To be determined after first year

Table 11: Pressure Field Gauge —Injection tubing, annulus, pipeline.

Parameters	Detection Limit/Range
Calibrated working temperature range	0 to 500°F and 4–20 mA
Initial temperature accuracy	< 0.0055 %
Temperature resolution	0.001°F and 0.0001 mA
Temperature drift stability	To be determined after first year

Table 12: Temperature Field Gauge —Injection tubing, annulus, pipeline.

Parameters	Detection Limit/Range
Calibrated working pressure range	Atmospheric to 6,000 psi
Initial pressure accuracy	<+/-0.03 psi over full scale
Pressure resolution	0.0003% psi over full scale
Pressure drift stability	<3 psi per year over full scale
Calibrated working temperature range	257°F
Initial temperature accuracy	<+/-0.9°F
Temperature resolution	0.009°F
Temperature drift stability	<+/-0.1°F per year
Max temperature	257°F

Table 13: Pressure and temperature—bottomhole gauge specifications (PPS25).

Table 15 presents the monitoring methods that will require additional testing or monitoring if exceedances or variances are observed. In the table, the routine measurement method is followed by the additional monitoring that would occur if an exceedance were measured.

	PNC	CBL	USI	Isolation Scanner
Logging speed	1,800 ft/hr.	3,600 ft/hr.	Standard resolution: 2,700 ft/hr. High resolution: 563 ft/hr.	Standard resolution: 2,700 ft/hr. High resolution: 563 ft/hr.
Vertical resolution	15 inches	3 ft	Standard resolution: 0.6 in High speed: 6 in	High resolution: 0.6 in. High speed: 6 in
Investigation	Formation	Casing, annulus, and formation	Casing and annulus	Casing and annulus
Temperature rating	302°F	350°F	350°F	350°F
Pressure rating	15,000 psi	20,000 psi	20,000 psi	20,000 psi

Table 14: Representative logging tool specifications. Actual tools used will be comparable.

Activity or Parameter	Project Action Limit	Detection Limit	Anticipated Reading
MIT—PNC	Action taken when PNC indicates CO_2 outside of expected range	+/- 0.5 SIGMA	Brine saturated ~ 60 CO_2 saturated ~ 8
Temperature Measurement – External Mechanical Integrity	Action taken when temperature measurement displays deflection that varies from baseline logs	+/- 1 °F	Continuous increasing gradient with depth
Internal Mechanical Integrity—Annular Pressure/ Fluid Volume Gauges	>5% pressure loss over 1hour	Refer to Table 10	<5% pressure loss over 1 hour
Surface anddownhole pressure gauges	Action will be taken when pressure outside dfmodeled/expected range	Refer to Table 11 for surface gauges and Table 13 for downhole gauge	Within storage formation: <90% fracture propagation pressure (2,207 psi at 3,226 ft)
Groundwater Chemical Data	Action will be taken if there is analytical evidence that CO_2 has migrated out of the injection zone or AOR	Refer to Table 5 and Table 6.	No presence of CO_2 or chemical indicators of CO_2 outside the injection zone or AoR.
Time-lapse surface seismic data	Detected CO_2 outside theAOR or above the confining zone	Dependent on fluid saturation and formation velocities	CO_2 plume migration similar to modeled outcome

Table 15: Actionable testing and monitoring outputs.

A.4.2 Precision

The specification and precision of each monitoring method is detailed in the tables above. For groundwater sampling, the accuracy of the data will be assessed by the collection and analysis of field blanks to test sampling procedures and matrix spikes to test lab procedures. Field blanks will be taken no less than one per sampling event to determine if the sample bottle is contaminated. Laboratory assessment of analytical precision will be the responsibility of the individual laboratories per their standard operating procedures.

A.4.3 Bias

Laboratory assessment of analytical bias will be the responsibility of the individual laboratories per their standard operating procedures (SOPs) and analytical methodologies. For direct pressure or logging measurements, there is no bias.

A.4.4 Representativeness

For groundwater sampling, data representativeness expresses the degree to which data accurately and precisely represent a characteristic of a population, parameter variations at a sampling point, a process condition, or an environmental condition. The sampling network has been designed to provide data that are representative of site conditions. For the analytical results of individual groundwater samples, representativeness will be estimated by ion charge and mass balances. Ion balances with ±10% error or less will be considered valid. Mass balance assessment will be used in cases where the ion balance is greater than ±10% to help determine the source of error. For a sample and its duplicate, if the relative percent difference (RPD) is greater than 10%, the sample may be considered non-representative.

A.4.5 Completeness

For groundwater sampling, data completeness is a measure of the amount of valid data obtained from a measurement system compared to the amount that was expected to be obtained under normal conditions. It is anticipated that data completeness of 90% for groundwater sampling will be acceptableto meet monitoring goals. For direct pressure, temperature, and flow measurements, it is expected that data will be recorded no less than 90% of the time.

A.4.6 Comparability

Data comparability expresses the confidence with which one data set can be compared to another. The data sets to be generated by this project will be very comparable to future data sets because of the use of standard methods and the level of quality assurance/quality control (QA/QC) effort. Direct pressure, temperature, and logging measurements will be directly comparable to previously obtained baseline or project data.

A.5. Special Training/Certifications

A.5.1 Specialized Training and Certifications

The geophysical survey equipment and wireline logging tools will be operated by trained, qualified, and certified personnel, according to the service company which provides the equipment. The subsequent data will be processed and analyzed according to industry standards. Examples of these are shown in Attachment 1.

No specialized certifications are required for personnel conducting groundwater sampling, but field sampling will be conducted by trained personnel. Groundwater sampling will be conducted by personnel trained to understand and follow the project-specific sampling procedures.

Upon request, the agency will be provided with all laboratory SOPs developed for the specific parameter using the appropriate standard method. Each laboratory technician conducting the analysis on the samples will be trained on the SOP developed for each standard method. The technician's training certification will be included with the biannual report.

A.5.2 Training Provider and Responsibility

Training for personnel will be provided by the operator or by the subcontractor responsible for the data collection activity.

A.6. Documentation and Records

A.6.1 Report Format and Package Information

A semi-annual report from Marquis Carbon Injection, LLC to EPA will contain all required project data, including the testing and monitoring information as specified by the UIC Class VI permit. Data will be provided in electronic or other formats as required by the UIC Program Director.

A.6.2 Other Project Documents, Records, and Electronic Files

Other documents, records, and electronic files such as well logs, test results, or other data will be provided as required by the UIC Program Director.

A.6.3 Data Storage and Duration

Maquis Carbon Injection, LLC or a designated contractor will maintain the required project data as provided elsewhere in the permit.

A.6.4 QASP Distribution Responsibility

The Marquis Carbon Injection, LLC Manager will be responsible for ensuring that all those on the distribution list will receive the most current copy of the approved QASP.

B. Data Generation and Acquisition

B.1. Sampling Process Design (Experimental Design)

During the pre-injection phase, fluid samples will be collected and analyzed for parameters listed in Table 5 and Table 6 of geochemical parameters to establish baseline conditions of the fluids within the target formations. Regular sampling will be performed during the injection and post-injection phases of the project to track the migration of CO_2 through the storage formation and to confirm that CO_2 and other fluids of interest have not migrated out of the storage formation. Analytes will include selected constituents that are:

- Primary and secondary EPA drinking water contaminants.
- Those most responsive in the interaction of CO_2 with the formation fluids and minerals; and
- Those needed for QC.

The full set of selected parameters for each sampling interval is given in Table 5 and Table 6. All samples will be analyzed using a laboratory that meets the requirements under the EPA Environmental Laboratory Accreditation Program. Isotopic analysis will be conducted using established methods. The pressure, temperature, and flowrate of the CO_2 injection stream will be monitored on a continuous basis using instrumentation located in the flowline between the final compression stage and the wellhead. In addition, samples of the injection stream will be collected on a quarterly basis for analysis. The sampling and analysis will be completed to ensure compliance with the approved Class VI permit.

B.1.1 Design Strategy

CO_2 Stream Monitoring Strategy

Regular sampling of the CO_2 stream provides an evaluation of the potential interactions of the CO_2 and other constituents of the injection stream with mineral components and fluids within the storage formation. It can also identify increases in trace components, such as water content, that could accelerate well corrosion and negatively impact well integrity. Minor variation (<5%) is expected in the composition of the injected CO_2 stream which will pass through two scrubbers prior to entering the compressor and the pipeline. As a result, quarterly sampling of the CO_2 injection stream will be sufficient to accurately track the composition of the stream. An initial calibration and validation of the instruments will be performed by the manufacturers and will be verified by the project on a regular basis.

Corrosion Monitoring Strategy

Corrosion coupon analyses will be conducted quarterly to assess the mechanical integrity of the well components that are in contact with the CO_2. The coupons will be assessed for signs of

corrosion and any loss of mass thickness, cracking, pitting, and other signs of corrosion that could be indicative of future well integrity issues. The analysis will be in accordance with National Association of Corrosion Engineers (NACE) Standard RP-0775 (or similar) to determine and document corrosion wear rates.

Shallow Groundwater Monitoring Strategy

One existing and three dedicated shallow groundwater wells in the AoR will be used for shallow groundwater monitoring (Figure 2). These wells penetrate the Quaternary-age deposits to depths less than 300 feet (ft) below ground surface, which is deeper than any drinking water well in the area. Baseline groundwater samples will be acquired from these wells over a 1.5-year period to characterize the seasonal variations in water quality within the AoR prior to the start of CO_2 injection. These groundwater samples will also have their geochemistry and stable isotopes analyzed. Throughout the injection and PISC phases of the project, the results of the aqueous geochemistry and isotope analyses will be compared to the baseline conditions for any indication of CO_2 or brine migration into the shallow groundwater aquifer.

Deep Groundwater Monitoring Strategy

A deep, above confining zone (ACZ) groundwater well will be drilled for the project (40 CFR 146.90 (d)). MCI ACZ 1 will be near the injection well to monitor the aquifers immediately above the confining layer in the event that there is CO_2 or brine migration out of the storage formation along the injection wellbore (Figure 2). This well will allow for pressure and temperature monitoring as well as periodic fluid sampling in the Galesville Sandstone and Gunter Sandstone, the deepest USDW. The well will be equipped with memory-style pressure and temperature gauges in the tubing string, such as Pioneer Petrotech PPS25 or similar, that record data every 60 seconds. The well will be configured in such a way as to isolate these formations such that the gauges measure the pressure and temperature from each interval separately. A bailer system will be used to collect the fluid samples to evaluate geochemical changes in groundwater fluids. Samples will be analyzed for field constituents using a calibrated water quality meter (Horiba U-53, or similar). The geochemical analyses will be performed by Intertek Laboratories, or a similar laboratory. The isotopic analyses will be performed by Isotech Laboratories, or a similar laboratory.

CO_2 or brine migration into the Galesville or Gunter Sandstone will most likely be first identified through pressure changes in the formation. The presence of CO_2 or brine in the overlying aquifers can be further confirmed through aqueous geochemistry data and analysis of isotopes. If deep early-detection monitoring data indicate that CO_2 has migrated out of the primary storage formation, it will trigger external well integrity testing of the injection and deep monitoring wells. It may also trigger a time-lapse three-dimensional (3D) surface seismic survey earlier than initially planned.

Storage Formation Monitoring Strategy

The storage formation will be monitored through pressure and temperature sensors, fluid sampling and analysis, pulsed neutron capture (PNC) logging, time-lapse 3D surface seismic data, and microseismic monitoring to characterize the development of the CO_2 and pressure plumes over the injection and PISC phases of the project. Fluid samples will be collected from the deep monitor well on a biannual basis until the well becomes saturated with CO_2, while the pressure/temperature gauges will be retrieved for data download. PNC logging will be used to determine the CO_2 saturation adjacent to the injection and deep monitoring well. The PNC logging will also confirm that CO_2 has not migrated above the confining layer.

Deep Monitoring Well (MCI MW 2) Sampling

The deep monitoring well (MCI MW 2) will be used to monitor the pressure and CO_2 plume development in the storage formation through the injection phase of the project. Fluid samples will be collected on a semi-annual basis from the Mt. Simon Sandstone to monitor aqueous geochemistry changes within the formation. The well will be swabbed to produce representative formation fluid in the well. During the swabbing process, the swab water will be analyzed in the field using a calibrated water quality meter (Horiba U-53, or similar). After swabbing the well, fluid samples will be collected using a bailer-style system. Samples will be analyzed for constituents that can be used to measure changes in chemistry that would be caused by interaction with the injected CO_2 (Table 4). Intertek Laboratories, or a similar laboratory, will analyze the geochemical species. Isotech, or similar laboratory will be used to perform the isotopic analyses. A set of memory-style pressure and temperature gauges (Petrotech PPS25 or similar) will also be placed in the deep monitoring well to track the pressure response due to CO_2 injection. These gauges will be programmed to collect data every 60 seconds.

B.1.2 Type and Number of Samples/Test Runs

The types, frequencies, and additional details of the sampling and monitoring methods are provided in (Table 3) of this document.

B.1.3 Site/Sampling Locations

Four shallow groundwater well will be used (MCI GW 1-4) as shown in Figure 2, and a deep groundwater monitoring well (MCI ACZ 1) will be drilled. The geochemistry of the storage formation will be monitored using the deep monitoring well (MCI MW 2).

The chemical composition, pressure and temperature, and mass flowrates of the CO_2 injection stream will be monitored downstream of the last stage of compression and upstream of the injection well. At the injection well, the wellhead and storage formation pressure and temperature will be measured along with the annular pressure and volume. In addition, corrosion monitoring will be completed in the pipeline between the compressor and the injection well. PNC logging will be performed in the ACZ 1 well and the deep monitoring well to monitor the CO_2 plume development in the storage formation as well as for potential migration of CO_2 above the confining layer. Temperature measurements will be acquired in

the injection and deep monitoring wells on an annual basis to confirm external mechanical integrity.

B.1.4 Sampling Site Contingency

The shallow groundwater, ACZ, and deep monitoring wells are all located on Marquis property where the Marquis BioCarbon Project is located. Access to the wells is not anticipated to be a problem over the course of the project. The wells are all located on flat farm land not near any residential buildings or any rough terrain. If inclement weather makes site access difficult, sampling schedules will be reviewed, and alternative dates may be selected that would still meet permit-related conditions.

B.1.5 Activity Schedule

Table 3 provides the schedules for the sampling and monitoring activities along with other pertinent details regarding the techniques.

B.1.6 Critical/Informational Data

During data acquisition for the testing and monitoring activities, field and laboratory information will be documented in detail. Information will be recorded in field and laboratory forms and notebooks. Critical information will include the time and date of activity, person(s) performing activity, location of the activity or instrument, field or laboratory instrument calibration data, and field parameter values. For laboratory analyses, much of the critical data will be generated during the analysis and provided to the project in digital and printed formats. Noncritical data may include the appearance and problems with the wells or sampling/monitoring equipment, and weather conditions.

B.1.7 Sources of Variability

Potential sources of variability related to monitoring activities include:

- Natural variations in fluid geochemistry, formation pressure and temperature, and seismic activity
- Variation in fluid geochemistry, formation pressure and temperature, and seismic activity due to project operations
- Changes in groundwater recharge due to rainfall, drought, and snowfall
- Changes in instrument calibration during sampling or analytical activity
- Variations in the staff collecting or analyzing samples
- Differences in environmental conditions during field activities
- Changes in analytical data quality during life of project
- Data entry errors related to maintaining project database

Activities to eliminate, reduce, or reconcile variability related to monitoring activities include:

- Collection of long-term baseline data to observe and document natural variation in monitoring parameters
- Evaluation of data in timely manner after collection to observe anomalies in data that can be addressed through resampling
- Conducting statistical analysis of monitoring data to determine whether variability in a data set is the result of project activities or natural variation
- Checking instrument calibration before, during and after sampling or sample analysis
- Staff training
- The use of standard operating procedures to describe testing and monitoring activities
- Conducting laboratory QA checks using third party reference materials, and/or blind and/or replicate sample checks

B.2. Sampling Methods

Well logging, geophysical monitoring, and pressure/temperature monitoring do not apply to this section.

B.2.1 Sampling SOPs

Groundwater samples will be collected from the shallow groundwater wells using a low-flow sampling method consistent with ASTM D6452-99 (2005) or Puls and Barcelona (1996). If a flow-through cell is not used, field parameters will be measured in grab samples. Groundwater wells will be purged to ensure samples are representative of formation water quality. Static water levels in each well will be determined using an electronic water level indicator before any purging or sampling activities begin. Dedicated pumps (e.g., bladder pumps) will be installed in each monitoring well to minimize potential cross contamination between wells. The pH, temperature, specific conductance, and dissolved oxygen of the purge water will be monitored in the field using portable probes and a flow-through cell consistent with standard methods given sufficient flow rates and volumes. Field chemistry probes will be calibrated at the beginning of each sampling day according to equipment manufacturer procedures using standard reference solutions. When a flow-through cell is used, field parameters will be continuously monitored and will be considered stable when three successive measurements made three minutes apart meet the criteria listed in Table 16.

Field Parameter	Stabilization Criteria
pH	+/- 0.2 units
Temperature	+/- 1°C
Specific Conductance	+/- 3% of reading in µS/cm
Dissolved Oxygen	+/- 10% of reading or 0.3 mg/L whichever is greater

Table 16: Stabilization criteria of water quality parameters during shallow well purging.

After field parameters have stabilized, samples will be collected. Samples requiring filtration will be filtered through 0.45 micrometer (µm) flow-through filter cartridges as appropriate and consistent with ASTM D6564-00. Prior to sample collection, filters will be purged with a minimum of 100 milliliters (mL) of well water (or more if required by the filter manufacturer). For alkalinity and total CO_2 samples, efforts will be made to minimize exposure to the atmosphere during filtration.

Samples will be collected from the ACZ and deep monitoring wells using a bailer system lowered into the wells via slickline. Prior to sample collection, the well will be purged by swabbing the well to remove stagnant fluids and to ensure representative formation fluids are present in the well. The pH, temperature, specific conductance, and dissolved oxygen of the swabbed water will be monitored every swab run in the field using portable probes until the parameters stabilize (Table 16) for three successive runs, and grab samples will be used to collect the samples. Field chemistry probes will be calibrated at the beginning of each sampling day according to equipment manufacturer procedures using standard reference solutions.

After the well has been swabbed, the bailer system will be lowered into the well to collect sufficient volume of the fluid to complete the analyses. The samples will be transferred to the appropriate bottles for each analytical method. Samples that require filtering will be filtered through a 0.45 µm cartridge filter per the procedure.

For the CO_2 stream, samples will be collected from a sampling port located between the final compression stage and the wellhead where the injectate is representative of the stream being injected into the well. The samples will be collected in Department of Transportation (DOT)-rated pressure cylinders that can be sent to an analytical laboratory (e.g., Atlantic Analytical Laboratory) for analysis. A pressure regulator will reduce the pressure of the CO_2 to approximately 250 pounds per square inch (psi) so that the CO_2 is in the gaseous state when collected rather than a super-critical liquid. Cylinders will be purged with sample gas (i.e., CO_2) at least five times prior to sample collection to remove laboratory-added helium gas and ensure a representative sample. During purging, the outlet of the sample cylinder will be connected to a ventilation line and vented to the atmosphere. Appropriate sampling technique is critical for any gas analysis program. Therefore, great care will be taken to ensure that the cylinder is not contaminated by atmospheric

gas, and the sample is representative of the CO_2 in the pipeline.

B.2.2 In-situ Monitoring

In-situ monitoring of groundwater chemistry is not currently planned.

B.2.3 Continuous Monitoring

The pressure and temperature in the deep monitoring wells will be continuously monitored using retrievable data-logging pressure/temperature gauges. These data will be used to calibrate the computational modeling over the life of the project.

B.2.4 Sample Homogenization, Composition, Filtration

Sample homogenization, composition, and filtrations is described in Section B.2.1.

B.2.5 Sample Containers and Volumes

For CO_2 stream monitoring, samples will be collected in a clean sample cylinder rated for the appropriate collection pressure provided by a laboratory such as Atlantic Analytical Laboratory.

CO_2 quarterly gas analysis will include:

- CO_2 Purity (% volume [v]/v, gas chromatograph [GC])
- Oxygen (O_2, parts per million [ppm] v/v)
- Nitrogen (N_2, ppm v/v)
- Hydrogen Sulfide (H_2S ppm v/v)

For shallow and deep fluid samples, all sample bottles will be new. Sample bottles for analytes will be used as received from the vendor or contract analytical laboratory for the analyte of interest. A summary of sample containers is presented in Table 17.

B.2.6 Sample Preservation

For groundwater and other aqueous samples, the preservation methods provided in Table 17 will be used.

Parameters	Preservation/Preparation	Container	Holding Time
Total Metals by ICP Na, Ca, Mg, Ba, Sr, Fe, K	HNO_3 to pH<2, Filter 4-µm	1.5 L Poly	6 months
Anions (Cl, Br, SO_4)	Cool, 4±2°C, no chemical preservation	1 L Poly	28 days
pH	Cool, 4±2°C, no chemical preservation	1 L Poly	None
Alkalinity	Cool, 4±2°C, no chemical preservation	1 L Poly	28 days
Total Dissolved Solids	Cool, 4±2°C, no chemical preservation	1 L Poly	7 days
Specific Gravity	None	1 L Poly	None
Dissolved Inorganic Carbon	None	1 L Poly	7 days
H and O Stable Isotopes	None	50-mLGlass	1 year
C Stable Isotope	Cool, 4±2°C, no chemical preservation	150 mL Poly	14 days
Carbon-14	Cool, 4±2°C, no chemical preservation	150 mL Poly	6 months

Table 17: Preservation, containers, and hold times for aqueous samples.

No preservation will be required for the CO_2 injection stream samples, additional details for the gas sampling are provided in Table 18.

Corrosion coupon sampling only requires that the coupons be physically separated (e.g., sleeves, baggies) during transportation to prevent physical abrasion.

Target Parameters	Volume/Container Material	Preservation Technique	Sample Holding time (max)
CO_2 gas stream	300-ml cylinder	NA	5 Days

Table 18: Preservation, containers, and hold times for aqueous samples.

B.2.7 Cleaning/Decontamination of Sampling Equipment

Dedicated pumps (e.g., bladder pumps) will be installed in each groundwater monitoring well to minimize potential cross contamination between wells. These pumps will remain in each well throughout the project period except for maintenance. Prior to installation, the pumps will be cleaned on the outside with a non-phosphate detergent. Pumps will be rinsed a minimum of three times with deionized water and a minimum of 1 liter (L) of deionized water will be

pumped through the pump and sample tubing. Individual cleaned pumps and tubing will be placed in plastic bags for transport to thefield for installation. All field glassware (pipets, beakers, filter holders, etc.) will be cleaned with tap water to remove any loose dirt and rinsed three times with deionizedwater before use. CO_2 gas stream sampling cylinders will be decontaminated by the analytical lab, and no sampling equipment will be utilized with the corrosion coupons or annual field gauge calibrations.

B.2.8 Support Facilities

Field activities are usually completed in mobile laboratory vehicles or trailers located on site. Fluid sampling may require the use of an air compressor, vacuum pump, generator, filters, and analytical meters (pH, specific conductance, etc.). Sample tubing, connectors and valves required to sample the CO_2 gas stream will be supplied by the analytical lab providing the sampling containers. Sampling will occur within the CO_2 compression building. Similarly, corrosion coupons will be removed from the CO_2 injection line .

Field gauges will be removed from the injection deep monitoring and ACZ wells utilizing existing standard industry tools and equipment (slickline). Deployment and retrieval of the well gauges will be done using procedures and equipment recommended by the vendor, subcontractor, or as is standard per industry practice.

B.2.9 Corrective Action, Personnel, and Documentation

Field staff will be responsible for testing equipment and performing corrective actions on broken or malfunctioning field equipment. If corrective action cannot be taken in the field, then equipment will be returned to the manufacturer for repair or replacement. Significant corrective actions that occur during the sampling and data collection activities that affect analytical results will be documented in field notes.

B.3. Sample Handling and Custody

Well logging, geophysical monitoring, and pressure and temperature monitoring do not apply to this section and are omitted.

Sample holding times will be consistent with standard methods (Table 17). After collection and any necessary preservation, samples will be placed in ice chests in the field and maintained thereafter at approximately 4 degrees Celsius (°C) until analysis. The samples will be maintained at their preservation temperature and sent to the designated laboratory within 24 hours. Analysis of the samples will be completed within the holding time listed in Table 17. As appropriate, alternative sample containers and preservation techniques approved by the UIC Program Director will be used to meet analytical requirements.

B.3.1 Maximum Hold Time/Time Before Retrieval

See Table 17.

B.3.2 Sample Transportation

See description in Section B.2.

B.3.3 Sampling Documentation

Field notes will be collected for all groundwater samples collected. These forms will be retained and archived as reference. The sample documentation is the responsibility of groundwater sampling personnel. A chain-of-custody form will be provided with each CO_2 gas stream sample or fluid sample provided for analysis as shown in Figure 4 and Figure 5.

B.3.4 Sample Identification

All sample bottles will have waterproof labels with information denoting project, sampling date, sampling location, sample identification number, fluid sample, sample type, analyte, volume, filtration used (if any), and preservative used (if any). See Figure 3 for an example of a label.

MarquisCI CS-1 10-16-2022
Metals, 60ml, filtered, HNO_3

Figure 3: Example label for groundwater sample bottles.

B.3.5 Sample Chain-of-Custody

For CO_2 stream analysis, a chain-of-custody form will accompany the sample to the laboratory (Figure 4). The chain-of-custody form will include sample identification (ID), sample collection date/time, sample pressure, and analytical requirements. A chain-of-custody form will accompany the sample through the analytical process. Copies of the chain-of-custody forms will be retained for reference.

For groundwater samples, the chain-of-custody will be documented using a standardized form. A typical form is shown in Figure 5, and a similar form will be used for all groundwater sampling. Copies of the chain-of-custody forms will be provided to the person or lab receiving the samples as well as the person or lab transferring the samples. These forms will be retained and archived to allow simplified tracking of sample status. The chain-of -custody form and record keeping is the responsibility of groundwater sampling personnel.

B.4. Analytical Methods

Well logging, geophysical monitoring, and pressure and temperature monitoring do not apply to this section and are omitted.

B.4.1 Analytical SOPs

Analytical methods are referenced in Table 5 and Table 6. Upon request, Marquis Carbon Injection, LLC will provide the EPA with all laboratory SOPs developed for the specific parameter using the appropriate standard method.

B.4.2 Equipment/Instrumentation Needed

Equipment and instrumentation are specified in the individual analytical methods referenced in Table 5 and Table 6.

B.4.3 Method Performance Criteria

Nonstandard method performance criteria are not anticipated for this project.

B.4.4 Analytical Failure

Each laboratory conducting the analyses in Table 5 through Table 8 will be responsible for appropriately addressing analytical failure according to their individual SOPs.

B.4.5 Sample Disposal

Each laboratory conducting the analyses in Table 5 and Table 6 will be responsible for appropriate sample disposal according to their individual SOPs.

B.4.6 Laboratory Turnaround

Laboratory turnaround will vary by laboratory, but generally turnaround of verified analytical results within one month will be suitable for project needs.

B.4.7 Method Validation for Nonstandard Methods

Nonstandard methods are not anticipated for this project.

The Gold Standard for Gas Analysis

CHAIN OF CUSTODY FORM

ATLANTIC ANALYTICAL LABORATORY, LLC
291 Route 22 East
Salem Industrial Park – Building #2
Lebanon, NJ 08833
(908) 534-5600

CUSTOMER NAME:	PROJECT LOCATION:	COMMENTS:
SAMPLER SIGNATURE:	CUSTOMER SIGNATURE:	

SAMPLING			CUSTOMER CYLINDER NUMBER	SAMPLE IDENTIFICATION (Lot Number, Batch Number, Receiving Number, Part Number, etc.)	ANALYSIS REQUIRED	ON-SITE ANALYSIS
DATE / TIME	CYLINDER NUMBER	CYLINDER SIZE				

Relinquished By:	Date:	Time:	Received By:	Date:	Time:	Comments:
Relinquished By:	Date:	Time:	Received By:	Date:	Time:	Comments:
Relinquished By:	Date:	Time:	Received By:	Date:	Time:	Comments:

Page_____of_____

Form AALCOC Rev 6 25 Jun 2020

Figure 4: Example of chain-of-custody form for the CO_2 injection stream gas analyses.

Intertek

Office:_____
• Job Order Number:_____

NON COMMERCIAL BILL OF LADING

CHAIN OF CUSTODY O SAMPLE TRANSPORTATION RECORD O SAMPLE DISTRIBUTION RECORD O SAMPLE RECEIPT 0

Point of Origin	Intermediary	Destination
Full Name And Address:		
Relinquished By:	Received By:	Received By:
Print:	Print:	Print:
Date:	Date:	Date:
Time:	Time:	Time:

* I hereby declare that the contents of this consignment are fully and accurately described below by the correct technical name(s) (Proper Shipping Name[s]), and are classified, packaged, marked and labeled/placarded, and are in all respects in proper condition for transport according to applicable international and national government regulations.

Delivered By: Intertek / Commercial carrier (circle one)

Inspector/ Driver: _____
Carrier: _____
Air Bill Number: _____
Date Shipped: _____

Customer Product Description
Product 1 :_____
Product 2:_____
Product 3 :_____
Product 4:_____

Note: All volumes must be in Metric units

UN NUMBER	PROPER SHIPPING NAME	HAZARDOUS CLASS NUMBER	PACKING GROUP	PRODUCT NUMBER	NUMBEROF SAMPLES	CONTAINER SIZE	SAMPLE SOURCE	SEAL NUMBER(S)

Figure 5: Example chain-of-custody form for the fluid sample analyses.

B.5. Quality Control

Geophysical monitoring and pressure/temperature monitoring do not apply to this section and are omitted. For wireline log QC, please refer to Attachment 1.

B.5.1 QC Activities

Blanks

For shallow and deep groundwater/brine sampling, a field blank will be collected and analyzed for the inorganic analytes in Table 5 and Table 6 at a frequency of no less than one blank for field event. Field blanks will be exposed to the same field and transport conditions as the groundwater samples. Field blanks will be used to detect contamination resulting from the collection and transportation process.

No field blanks will be collected for the injection stream sampling. Contamination and representative sampling will be determined through the concentrations of nitrogen and helium (that have been spiked into the cylinder) in the sample.

Duplicates

For each fluid sampling round, at least one duplicate sample will be collected from a well. Duplicate samples will be collected from the same source immediately after the original sample in different sample containers and processed as all other samples. Duplicate samples will be used to assess sample heterogeneity and analytical precision.

B.5.2 Exceeding Control Limits

If the sample analytical results exceed control limits (i.e., ion balances > ±10%), further examination of the analytical results will be done by evaluating the ratio of the measured total dissolved solids (TDS) tothe calculated TDS (i.e., mass balance) per the method. The method indicates which ion analyses should be considered suspect based on the mass balance ratio. Suspect ion analyses are then reviewed in the context of historical data and interlaboratory results. If available, suspect ion analyses will then be brought to the attention of the analytical laboratory for confirmation and/or reanalysis. The ion balance will be recalculated, and if the error is still not resolved, the suspect data will be identified and may be given less importance in data interpretations. Additional samples may be collected for repeat analyses to confirm the analytical results.

B.5.3 Calculating Applicable QC Statistics

Charge Balance

The analytical results will be evaluated to determine correctness of analyses based on the anion-cation charge balance calculation. Since fluid samples should be electrically neutral, the chemical analyses should yield equally negative and positive ionic activity. The anion-cation charge balance will be calculated using the formula:

$$\%\ difference = 100\frac{\sum cations - \sum anions}{\sum cations + \sum anions}, \qquad \text{(Equation}$$

where the sums of the ions are represented in milliequivalents per liter and the criteria for acceptable charge balance is ±10%.

Mass Balance

The ratio of the measured TDS to the calculated TDS will be calculated in instances where the chargebalance acceptance criteria are exceeded using the formula:

$$1.0 < \frac{measured\ TDS}{calculated\ TDS} < 1.2\ , \qquad \text{(Equation}$$

where the anticipated values are between 1.0 and 1.2.

Outliers

A determination of one or more statistical outliers is essential prior to the statistical evaluation of

groundwater. This project will use the USEPA's Unified Guidance (March 2009) as a basis for selection of recommended statistical methods to identify outliers in water/brine chemistry data sets as appropriate. These techniques include Probability Plots, Box Plots, Dixon's test, and Rosner's test. The EPA-1989 outlier test may also be used as another screening tool to identify potential outliers.

B.6. Instrument/Equipment Testing, Inspection, and Maintenance

Logging tool equipment will be maintained as per wireline industry best practices (Attachment 1).

All pressure, temperature, and mass flow measurement equipment will be maintained per the manufacturer's specifications. Any necessary calibrations or repairs will also be performed per the manufacturer's specification or by the manufacturer of the equipment.

For fluid sampling, the field equipment will be maintained, factory serviced, and factory calibrated per manufacturer's recommendations. Spare parts that may be needed during sampling will be included in supplies on hand during field sampling.

For all laboratory equipment, testing, inspection, and maintenance will be the responsibility of the analytical laboratory per standard practice, method-specific protocol, or National Environmental Laboratory Accreditation Program (NELAP) requirement.

B.7. Instrument/Equipment Calibration and Frequency

Geophysical monitoring does not apply to this section and is omitted.

B.7.1 Calibration and Frequency of Calibration

Pressure and temperature gauge calibration information will be performed annually. Logging tool calibration will be at the discretion of the service company providing the equipment and following standard industry practices noted in Attachment 1.

For groundwater sampling, the portable field meters or multiprobe sondes used to determine field parameters (e.g., pH, temperature, specific conductance, dissolved oxygen) will be calibrated according to manufacturer recommendations and equipment manuals (i.e., each day before sample collection begins). Recalibration will be performed if any components yield atypical values or fail to stabilize during sampling.

B.7.2 Calibration Methodology

Logging tool calibration methodology will follow standard industry practices in Attachment 1.

The pressure, temperature, and mass flow meters will be calibrated annually.

For groundwater sampling, standards used for calibration are typically 7 and 10 for pH, a potassium chloride solution yielding a value of 1413 microsiemens per centimeter (µS/cm) at

25°C for specific conductance, and a 100% dissolved O_2 solution for dissolved oxygen. Calibration is performed for the pH meters per manufacturer's specifications using a 2-point calibration bounding the range of the sample. For coulometry, sodium carbonate standards (typically yielding a concentration of 4,000 milligrams [mg] CO_2/L) are routinely analyzed to evaluate instrument.

B.7.3 Calibration Resolution and Documentation

Logging tool calibration resolution and documentation will follow standard industry practices in Attachment 1.

Manufacturers of the pressure, temperature, and mass flow equipment will provide calibration certifications for their equipment. If calibration cannot be achieved with the equipment, this piece of equipment will be replaced with a new or calibrated piece of equipment.

For groundwater sampling, calibration values are recorded in daily sampling records and any errors in calibration are noted. For parameters where calibration is not acceptable, redundant equipment may beused so loss of data is minimized.

B.8. Inspection/Acceptance for Supplies and Consumables

B.8.1 Supplies, Consumables, and Responsibilities

Supplies and consumables for field and laboratory operations will be procured, inspected, and accepted as required from vendors approved by Marquis Carbon Injection, LLC, or the respective subcontractor responsible for the data collection activity. Acquisition of supplies and consumables related to groundwater analyses will be the responsibility of the laboratory per established standard methodology or operating procedures.

B.9. Non-direct Measurements

B.9.1 Seismic Monitoring Methods

Data Sources

3D seismic surveys will be conducted at regular intervals during and after CO_2 injection. Each of these surveys will be compared to the baseline survey which was acquired before the start of CO_2 injection. It is important that the only difference between the surveys is the change in acoustic properties of the injection formation caused by the presence of CO_2. Consequently, repeatability of source and receiver types and spacing, source size, and other acquisition parameters between surveys is paramount for an accurate comparison.

Relevance to Project

Time-lapse 3D seismic surveys will be used to track changes in the CO_2 plume in the subsurface. A modeling exercise has been completed to confirm that the planned injected volumes of CO_2 will result in sufficient change in the rock properties of the Mount Simon to be measured with 3D seismic.

Processing and comparing subsequent surveys to a baseline survey will allow the project to monitor plume growth as well as to ensure that the plume does not migrate beyond the confining layer. Computational modeling will be used to predict the CO_2 plume growth and migration over time by combining the processed seismic data with the existing geologic model.

Acceptance Criteria

To ensure survey repeatability, consistent acquisition geometry (receiver line spacing, source line spacing, line direction) is required. The seismic sources (vibroseis trucks) should be the same for each survey, including the number of trucks, their specifications, and the characteristics (sweep parameters) of the seismic energy they generate.

Data processing for each survey should be the same and the baseline seismic survey should be reprocessed alongside each additional repeat seismic survey to ensure consistency.

Resources/Facilities Needed

Marquis Carbon Injection, LLC will subcontract all necessary resources and facilities for the seismic monitoring, in-zone pressure monitoring, and groundwater sampling.

Validity Limits and Operating Conditions

For seismic surveys and computational modeling, intraorganizational checks between trained and experienced personnel will ensure that all surveys and computational modeling are conducted conforming tostandard industry practices.

B.10. Data Management

B.10.1 Data Management Scheme

Marquis Carbon Injection, LLC or a designated contractor will maintain the project data required in the permit. Data will be backed up in electronic format and/or held on secure servers. A separate Data Management Plan will be developed to track and store project data.

B.10.2 Record-keeping and Tracking Practices

All records of gathered data will be securely held and properly labeled for auditing purposes.

B.10.3 Data Handling Equipment/Procedures

All equipment used to store data will be properly maintained and operated according to proper

industry techniques and/or manufacturer's requirements.

B.10.4 Responsibility

The primary project managers will be responsible for ensuring proper data management is maintained.

B.10.5 Data Archival and Retrieval

All data will be held by Marquis Carbon Injection, LLC. These data will be maintained and stored for auditing purposes asdescribed in Section B.10.1.

B.10.6 Hardware and Software Configurations

All Marquis Carbon Injection, LLC and vendor hardware and software configurations will be appropriately interfaced.

B.10.7 Checklists and Forms

Checklists and forms will be procured and generated as necessary.

C. Assessment and Oversight

C.1. Assessments and Response Actions

C.1.1 Activities to be Conducted

Groundwater quality data will be collected at the frequency outlined in Table 4. After completion of sample analysis, results will be reviewed for QC criteria, as noted in Section B.5. If the data quality fails to meet criteria set in Section B.5, samples will be reanalyzed, if still within holding time criteria. If outside of holding time criteria or at the operator's choosing, additional samples may be collected, or sample results may be excluded from data evaluations and interpretations. Evaluation for data consistency will be performed according to procedures described in the EPA 2009 Unified Guidance (EPA, 2009).

C.1.2 Responsibility for Conducting Assessments

Organizations gathering data will be responsible for conducting their internal assessments. All stop-work orders will be handled internally within individual organizations.

C.1.3 Assessment Reporting

All assessment information should be reported to the individual organizations project manager outlined in Section A.1.1.

C.1.4 Corrective Action

All corrective action affecting only an individual organization's data collection responsibility should be addressed, verified, and documented by the individual project managers and communicated to the other project managers as necessary. Corrective actions affecting multiple organizations should be addressed by all members of the project leadership and communicated to other members on the distribution list for the QASP. Assessments may require integration of information from multiple monitoring sources across organizations (operational, in-zone monitoring, above-zone monitoring) to determine whether correction actions are required and/or the most cost-efficient and effective action toimplement. Marquis Carbon Injection, LLC will coordinate multiorganization assessments and corrective actions as warranted based on the severity of the event as described in the Emergency and Remedial Response Plan (Permit Section 10.0).

C.2. Reports to Management

C.2.1 QA Status Reports

QA status reports should not be needed. If any testing or monitoring techniques are changed, the QASP will be reviewed and updated as appropriate in consultation with EPA. Revised QASPs will be distributed by Marquis Carbon Injection, LLC to the full distribution list at the beginning of this document.

D. <u>Data Validation and Usability</u>

D.1. Data Review, Verification, and Validation

D.1.1 Criteria for Accepting, Rejecting, or Qualifying Data

The groundwater/brine and injection stream analytical data validation will include the review of the concentration units, sample holding times, and the review of duplicate, blank and other appropriate QA/QC results. All analytical results will be entered into a database or spreadsheet with periodic data review and analysis. Marquis Carbon Injection, LLC will retain copies of the laboratory analytical test results and/or reports. Analytical results will be reported on a frequency based on the approved UIC permit conditions. In the periodic reports, data will be presented in graphical and tabular formats as appropriate to characterize general system operations and variability with time.

D.2. Verification and Validation Methods

D.2.1 Data Verification and Validation Processes

See Sections D.1.1. and B.5 for data verification and validation processes.

Appropriate statistical software will be used to determine data consistency.

D.2.2 Data Verification and Validation Responsibility

Marquis Carbon Injection, LLC or its designated subcontractor will verify and validate the injection stream and groundwater analytical data.

D.2.3 Issue Resolution Process and Responsibility

Marquis Carbon Injection, LLC or its designated coordinator will provide an overview of the injection stream and groundwater data handling, management, and assessment process. Staff involved in these processes will consult with the coordinator to determine actions that are required to resolve issues.

D.2.4 Checklist, Forms, and Calculations

Checklists and forms will be developed specifically to meet permit requirements.

D.3. Reconciliation with User Requirements

D.3.1 Evaluation of Data Uncertainty

Statistical software will be used to determine groundwater data consistency.

D.3.2 Data Limitations Reporting

The organization-level project managers will be responsible for ensuring that data developed by their respective organizations is presented with the appropriate data-use limitations.

Marquis Carbon Injection, LLC will use the current operating procedure for the use, sharing, and presentation of results and/or data for the Marquis BioCarbon Project. This procedure has been developed to ensure quality, internal consistency and facilitate tracking and record keeping of data end-users and associated publications.

References

APHA, 2005, Standard methods for the examination of water and wastewater (21st edition), AmericanPublic Health Association, Washington, DC.

ASTM, 2010, Method D7069-04 (reapproved 2010), Standard guide for field quality assurance in a ground-water sampling event, ASTM International, 100 Barr Harbor Drive, West Conshohocken, PA.

ASTM, 2010, Method D6911-03 (reapproved 2010), Standard guide for packaging and shipping environmental samples for laboratory analysis, ASTM International, 100 Barr Harbor Drive, WestConshohocken, PA.

ASTM, 2005, Method D6517-00 (reapproved 2005), Standard guide for field preservation of ground-water samples, ASTM International, 100 Barr Harbor Drive, West Conshohocken, PA.

ASTM, 2005, Method D6564-00 (reapproved 2005), Standard guide for field filtration of ground-watersamples, ASTM International, 100 Barr Harbor Drive, West Conshohocken, PA.

ASTM, 2005, Method D6452-99 (reapproved 2005), Standard Guide for Purging Methods for Wells Usedfor Ground-Water Quality Investigations, ASTM International, 100 Barr Harbor Drive, West Conshohocken, PA.

ASTM, 2002, Method D513-11, Standard test methods for total and dissolved carbon dioxide in water,ASTM International, 100 Barr Harbor Drive, West Conshohocken, PA.

ASTM, 2002, Method D6771-02, Standard guide for low-flow purging and sampling for wells and devicesused for ground-water quality investigations, ASTM International, 100 Barr Harbor Drive, West Conshohocken, PA.

Puls, R.W., and M.J. Barcelona, 1996, Low-Flow (Minimal Drawdown) Ground-Water SamplingProcedures. U.S. Environmental Protection Agency, EPA-540/S-95/504.

U.S. Environmental Protection Agency (US EPA), 2009, Statistical analysis of groundwater monitoringdata at RCRA facilities—Unified Guidance, US EPA, Office of Solid Waste, Washington, DC.

U.S. Environmental Protection Agency (US EPA), 1974, Methods for chemical analysis of water andwastes, US EPA Cincinnati, OH, EPA-625-/6-74-003a.

7.0 TESTING AND MONITORING PLAN
40 CFR 146.90

MARQUIS BIOCARBON PROJECT

Facility Information

Facility name:	MARQUIS BIOCARBON PROJECT
Facility contact:	ELIZABETH STEINHOUR DIRECTOR OF ENVIRONMENTAL AFFAIRS 10000 MARQUIS DRIVE, HENNEPIN, IL 61327 815.925.7300 / BETHSTEINHOUR@MARQUISENERGY.COM
Well name:	MCI CCS 3
Well location:	PUTNAM COUNTY, ILLINOIS S2 T32N R2W Latitude: 41.27026520 N, Longitude: 89.30939322 W

Table of Contents

7.0 Testing and Monitoring Plan 5
7.1 Overall Strategy and Approach for Testing and Monitoring 5
7.1.1 Quality Assurance Procedures 14
7.1.2 Reporting Procedures 14
7.2 Carbon Dioxide Stream Analysis (40 CFR 146.90 (a)) 14
7.2.1 Sampling Location and Frequency 14
7.2.2 Analytical Parameters 15
7.2.3 Sampling Method – CO_2 Injection Stream Gases 15
7.2.4 Laboratory to be Used/Chain of Custody and Analysis Procedures 17
7.3 Continuous Recording of Operational Parameters (40 CFR 146.88 (e)(1), 146.89 (b), and 146.90(b)) 18
7.3.1 Monitoring Location and Frequency 18
7.3.2 Monitoring details 19
7.4 Corrosion Monitoring (40 CFR 146.90 (c)) 21
7.4.1 Monitoring Location and Frequency 21
7.4.2 Sample Description 22
7.4.3 Monitoring Details 22
7.5 Above Confining Zone Monitoring (40 CFR 146.90 (d)) 23
7.5.1 Monitoring Location and Frequency 23
7.5.2 Analytical Parameters 25
7.5.3 Monitoring and Sampling Methods 26
7.5.4 Laboratory to be Used/Chain of Custody Procedures 27
7.6 Mechanical Integrity Testing 27
7.6.1 Internal Mechanical Integrity Testing 27
7.6.2 External Mechanical Integrity Testing (40 CFR 146.90 (e)) 29
7.7 Pressure Fall-Off Testing (40 CFR 146.90 (f)) 29
7.7.1 Testing Location and Frequency 30
7.7.2 Testing Details 30
7.8 Carbon Dioxide Plume and Pressure Front Tracking (40 CFR 146.90 (g)) 31
7.8.1 Plume Monitoring Location and Frequency 31
7.8.2 Plume Monitoring Details 33

7.8.3 Pressure-Front Monitoring Location and Frequency 34
7.8.4 Pressure-Front Monitoring Details 35
7.8.5 Time-lapse 3D Seismic Validation using Deterministic Seismic Forward Modeling 35
7.9 References 40
Appendix 7.A Quality Assurance and Surveillance Plan 41

List of Tables

Table 7-1: General schedule and spatial extent for the testing and monitoring activities for the Marquis BioCarbon Project. 13

Table 7-2: Summary of analytes to be measured in the CO_2 stream. 15

Table 7-3: Sampling devices, locations, and frequencies for continuous monitoring. 18

Table 7-4: List of equipment coupon with material of construction. 22

Table 7-5: Monitoring schedule for the ACZ and shallow groundwater monitoring wells during the pre-operational and injection phases of the project. 24

Table 7-6: Summary of analytical and field parameters for groundwater samples. 26

Table 7-7: Preservation methods, container type, and holding times for analyte classes. 27

Table 7-8: Internal mechanical integrity monitoring details. 28

Table 7-9: External mechanical integrity tests. 29

Table 7-10: CO_2 plume monitoring activities. 32

Table 7-11: Pressure plume monitoring activities 34

List of Figures

Figure 7-1: CO_2 plume and associated AoR for the Marquis BioCarbon Project. 7

Figure 7-2: Stratigraphic column from characterization well MCI MW 1 located at the Marquis BioCarbon Project site. 9

Figure 7-3: Example of double-ended sample cylinder (Atlantic Analytical Laboratory, 2021). 16

Figure 7-4: Schematic of gas sampling system using a high-pressure cylinder (Atlantic Analytical Laboratory, 2021). 17

Figure 7-5: Type Corrosion coupon illustration in pipeline (top), types of coupons to be used for corrosion monitoring (below) (Cosasco, 2021). 23

Figure 7-6: 3D seismic baseline outline..... 33

Figure 7-7: Raw 2D seismic gathers with corresponding conditioned pre stack gathers (top). Forward model built from recorded logs (middle). Comparison of measured amplitude with incidence angle for modeled log response and 2D seismic data (bottom)..... 37

Figure 7-8: Change in simulated log response (left) and modeled time-lapse, pre-stack seismic amplitude difference (right) for CO_2 fluid replacement in lower Mt. Simon. 38

Figure 7-9: Change in amplitude versus incidence angle from pre- to post-injection demonstrate a change in the polarity of the seismic event associated with the top of the injection zone (left). AVA attributes derived from post-injection synthetics demonstrate a clear separation of the injection zone from the background trend (right). 39

7.0 Testing and Monitoring Plan

7.1 Overall Strategy and Approach for Testing and Monitoring

This Testing and Monitoring Plan describes how Marquis Carbon Injection, LLC will monitor the site pursuant to 40 CFR 146.90.

The Testing and Monitoring Plan has been developed in conjunction with the project risk assessment to reduce the risks associated with carbon dioxide (CO_2) injection into the subsurface at this site. Goals of the monitoring strategy include:

- Meeting the regulatory requirements of 40 CFR 146.90
- Protecting underground sources of drinking water (USDWs)
- Ensuring that the MCI CCS 3 well is operating as planned
- Providing data to validate and calibrate the geological and dynamic models used to predict the distribution of CO_2 within the injection zone
- Support area of review (AoR) re-evaluations over the course of the project

The Testing and Monitoring Plan will be adaptive over time; the plan can be adjusted to respond:

- As project risks evolve over the course of the project
- If significant differences between the monitoring data and predicted dynamic modeling results are identified
- If key monitoring techniques indicate anomalous results related to well integrity or the loss of containment

Figure 7-1 illustrates the modeled CO_2 plume at the end of the injection period. The AoR and Corrective Action Plan, Permit Section 2, (40 CFR 146.84 (b)) describes the data and computational techniques used to model the development of the CO_2 plume during injection. It describes the data collected in the characterization well (MCI MW 1) and how it was used to build the static earth model (SEM) also incorporating the two-dimensional (2D) seismic data. In addition, it explains how the data collected as part of this Testing and Monitoring Plan will be used to re-evaluate the AoR over the pre-operational and injection phases of the project (40 CFR 146.84 (e)).

Certain outcomes of the testing and monitoring activities described below may trigger action according to the Emergency and Remedial Response Plan, Permit Section 10, (40 CFR 146.94 (a)).

The Testing and Monitoring Plan will utilize several direct and indirect monitoring technologies throughout the injection and post-injection site care (PISC) phases of the project that will monitor:

- Daily activities of the injection operations

- Development of the CO_2 and pressure plumes in the storage formation over time
- Well integrity
- CO_2 or brine containment within the injection reservoir
- Groundwater quality in multiple aquifers, including the deepest USDW (Gunter Sandstone) and the deepest water-bearing formation above the caprock (Galesville Sandstone)

This plan includes two deep monitoring wells: one near the MCI CCS 3 well (MCI MW 2) and a second existing well (MCI MW 1) for far field monitoring.

Injection operations will be monitored through a range of continuous, daily, and quarterly techniques as detailed in the Well Operations Plan, Permit Section 6, (40 CFR 146.82(a)(8), 146.87). The water content and chemical composition of the CO_2 stream will be monitored downstream of the final compression (40 CFR 146.90 (a)). Corrosion coupons composed of the same material as the well components and CO_2-delivery pipeline will be placed in the delivery pipeline and analyzed on a quarterly basis for signs of corrosion and loss of mass that may be indicative of future potential well integrity issues (40 CFR 146.90 (c)).

Continuous recording devices will monitor wellhead injection pressure, temperature, and mass flowrate (40 CFR 146.90 (b)). The injection mass flowrate will be directly measured at the surface to monitor the cumulative mass of injected CO_2 and ensure compliance with the permit injection limits. The storage formation injection volume will be calculated using the mass flowrate combined with the pressure and temperature conditions in the storage formation. The injection volumes will, in turn, be used to update the computational models at regular intervals throughout the injection phase of the project. The annular pressure between the tubing and the injection casing strings and the annular fluid volumes will also be monitored on a continuous basis (40 CFR 146.90 (b)). These data will be linked to a Supervisory Control and Data Acquisition (SCADA) system to record the operations data, control injection rates, and initiate system shutdown, if required. The SCADA system can also be used to adjust the volume of annular fluid, and thereby pressure, in the annular space to meet the operational and regulatory objectives. Bottomhole pressure and temperature will be measured continuously until a steady state of flow is reached using retrievable pressure sensors to establish a wellhead-to-bottomhole pressure correlation that can be used to calculate the reservoir pressure at any time using the wellhead pressure data.

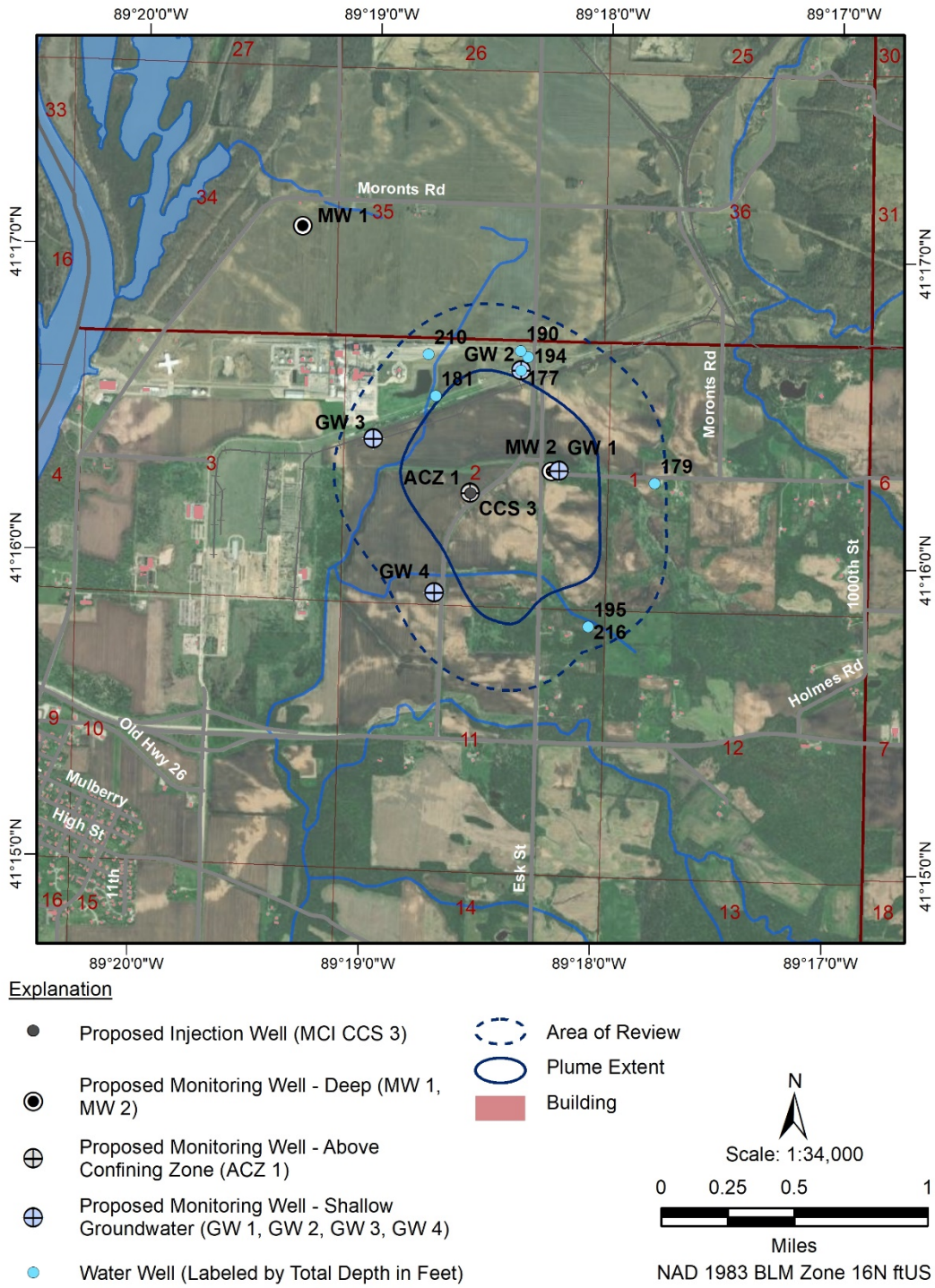


Figure 7-1: CO_2 plume and associated AoR for the Marquis BioCarbon Project.

The well integrity of the injection and deep monitoring wells will be monitored using a range of internal and external mechanical integrity evaluation methods. Initially, a mechanical integrity test (MIT) will be performed on the MCI CCS 3 well following the well completion to confirm internal integrity as per the Pre-Operations Testing Plan, Permit Section 5, (40 CFR 146.82(a)(8), 146.87). External mechanical integrity will be confirmed through annual temperature logging and compared to baseline temperature logging data to identify any deflections from the temperature gradient that could indicate fluid flow behind the casing (40 CFR 146.90 (e)). The same internal and external integrity evaluation methods used with the MCI CCS 3 well will be used on the deep monitoring wells. However, the annular pressure will be measured daily and adjusted as needed.

Pressure fall-off (PFO) tests will be conducted in the Mt. Simon Sandstone in the characterization and injection wells when they are drilled to establish the hydrogeologic characteristics of the storage formation (Permit Section 6.0, Pre-Operational Testing Plan). During the injection phase of the project, a PFO test will be conducted in the MCI CCS 3 well at least once every five years. If there is an injection pressure increase of more than10%, over a period of one month, compared to the computational model, then a PFO test will be conducted sooner (40 CFR 146.90 (f)). The objective of the PFO testing is to periodically monitor for any changes in the near wellbore environment that would impact injectivity or cause injection pressures to increase (EPA, 2013). The formation characteristics obtained through the PFO testing will be compared to the results from previous tests to identify any changes over time and will be used to calibrate the computational models.

A deep groundwater well will be drilled as part of the Testing and Monitoring Plan for the project. This 'Above Confining Zone' (ACZ) well will be drilled to the top of the confining zone, the Eau Claire Formation. MCI ACZ 1 will be adjacent to the MCI CCS 3 well to monitor the aquifers above the confining layer (Figure 7-1). This well will be used for pressure and temperature monitoring as well as periodic fluid sampling in the Galesville Sandstone and the deepest USDW, the Gunter Sandstone. Potential CO_2 or brine migration into the Galesville Sandstone or the deepest USDW will be initially identified through pressure changes in the formation and will be confirmed through aqueous geochemistry data and analysis of stable isotopes (Permit Section 5.0, Pre-Operational Testing Plan). If confirmed, this would trigger external well integrity testing of the injection and deep monitoring wells and may trigger the emergency response actions found in the Emergency and Remedial Response Plan (Permit Section 10.0).

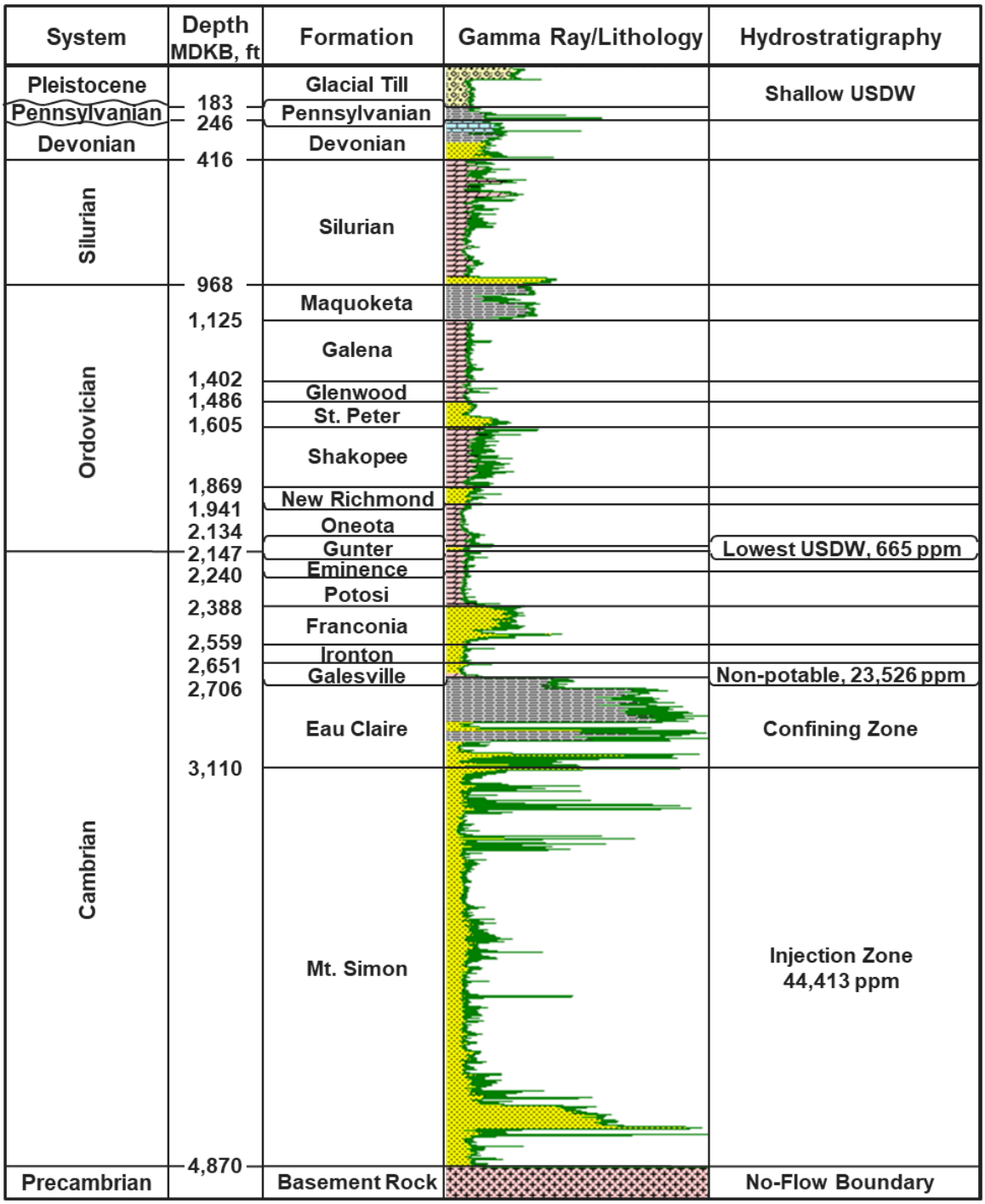


Figure 7-2: Stratigraphic column from MCI MW 1 well located at the Marquis BioCarbon Project site.

The shallow groundwater monitoring program consists of four wells (MCI GW 1-4) located on land owned by Marquis and within the AoR as shown in Figure 7-1. One of these wells (MCI GW 2) is an existing well, the other three will be new wells.

To establish a baseline of the seasonal variation in the aqueous geochemistry of these shallow groundwater wells, sampling will be collected prior to the start of CO_2 injection. Throughout the injection and PISC phases of the project, the results of the aqueous geochemistry and stable isotope analyses will be compared to the baseline conditions for any indication of CO_2 or brine migration into the shallow groundwater aquifer. If indications of CO_2 or brine are found in the shallow groundwater aquifer, it will trigger the emergency response actions found in the Emergency and Remedial Response Plan (Permit Section 10).

Pressure and temperature sensors in the deep monitoring well (MCI MW 2) will be used to measure pressure and temperature variations in the storage formation in the pre-operational, injection, and PISC phases of the project (40 CFR 146.90 (g)). These gauges will continuously record data and will be retrieved on a quarterly basis for data download. This deep monitoring well will also be used to collect fluid samples from the storage formation to monitor for changes in the water chemistry over time and verify when the leading edge of the CO_2 plume reaches the MCI MW 2 well.

Pulsed neutron capture (PNC) logs will be acquired in the deep MCI MW 2 well and ACZ well to identify the intervals and concentration of CO_2 across the injection zone and primary confining zone. This pressure and PNC log data will also be used to calibrate the dynamic modeling over the injection and PISC phases of the project.

Several indirect monitoring techniques will be deployed to monitor the development of the CO_2 plume and the associated pressure front through the injection and post- injection project phases (40 CFR 146.90 (g)). Time-lapse three-dimensional (3D) surface seismic data will be used to qualitatively monitor the CO_2 plume development and calibrate the computational modeling results over time. The time-lapse 3D surface seismic data will also be used to verify CO_2 containment within the Mt. Simon formation. A robust deterministic seismic forward modeling project has been undertaken to demonstrate that this technique can successfully detect subsurface changes associated with CO_2 injection at this site (Section 7.8.5).

Background seismic activity will be monitored continuously using a site-specific microseismic monitoring network designed to optimize the accuracy of the event locations and event magnitudes (Section 8.3). The location of individual stations within this network can be adjusted as required in response to monitoring results or future AoR re-evaluations.

The project site is in an area of Illinois with low rates of seismic activity and risk (Permit Section 1, Project Narrative). The primary goals of continuous background seismicity monitoring are:

- Addressing public and stakeholder concerns related to induced seismicity
- Monitoring the spatial extent of the pressure front from the distribution of seismic events

- Identifying activity that may indicate failure of the confining zone and possible containment loss

Table 7-1 presents the general schedule and spatial extent for the monitoring activities in the baseline and injection phases of the project. Refer to the PISC and Site Closure Plan (Permit Section 9) for discussion of the monitoring plans related to the PISC phase. Changes to the monitoring schedule may occur over time as the project evolves. For instance, if anomalous results are identified in the existing monitoring data, confirmation sampling will be conducted within 10 days and additional monitoring data may be acquired through subsequent investigations into the anomalous results. Likewise, if the CO_2 plume behaves in a stable and predictable manner for many years through the injection phase of the project, some monitoring may be reduced in frequency. Any such changes to the Testing and Monitoring Plan will be made in consultation with the Underground Injection Control (UIC) Program Director (40 CFR 146.90 (j)).

Monitoring Activity	Baseline Data Frequency	Injection Phase Frequency*	Location	Formation top / Depth Range (ft, MD)
Assurance Monitoring:				
Shallow Groundwater Sampling	Once/quarter	Twice/year	GW-1, 2, 3 & 4 wells within AoR	Producing zone
Isotope Analysis	Twice/year	Once/year	GW-1, 2, 3 & 4 wells within AoR	0 – TD
Operational Monitoring:				
CO_2 Stream Analysis	NA	Quarterly	CO_2 Delivery Pipeline	NA
Corrosion Coupon Analysis	NA	Quarterly	CO_2 Delivery Pipeline	NA
Injection Pressure	NA	Continuous	Wellhead	Surface
Mass Injection Rate	NA	Continuous	Wellhead	Surface
Injection Volume (Calculated)	NA	Continuous	Storage Formation	Surface
Annular Pressure	NA	Continuous	Injection Well	Surface
Annular Fluid Volume	NA	Continuous	Injection Well	Surface
Temperature Measurement	Once Once	Annually Annually	Injection Well Deep Monitor Well	0 – TD 0 – TD
PFO Tests	Once	Every 5 years	Wellhead	Surface
Verification Monitoring:				
Fluid Sampling				
Gunter Sandstone	Twice/year	Twice/year	ACZ well	2,134
Galesville Sandstone	Twice/year	Twice/year	ACZ well	2,651
Upper Mt. Simon Sandstone	Twice/year	Twice/year	Deep monitor well	3,110
Isotope Analysis	Twice/year	Once/year	ACZ Well Deep monitor well	All samples
Pressure – Temperature Sensors	3 months prior to injection			

Monitoring Activity	Baseline Data Frequency	Injection Phase Frequency*	Location	Formation top / Depth Range (ft, MD)
Gunter Sandstone Galesville Sandstone Upper Mt. Simon Sandstone	Continuous Continuous Continuous	Continuous Continuous Continuous	ACZ Well ACZ Well Deep monitor well	2,134 2,651 3,100
PNC Logging	Once	Once/ year	Deep Monitor well ACZ Well	2,134 – TD 2,134 – TD
Microseismic Monitoring	6 months prior to injection	Continuous	Surface stations	TBD
Time-lapse 3D Surface Seismic Data	Once	Every 5 years and as required.	Surface	
*Minimum frequency				

Table 7-1: General schedule and spatial extent for the testing and monitoring activities for the Marquis BioCarbon Project.

7.1.1 Quality Assurance Procedures

Data quality assurance and surveillance protocols adopted by the project have been designed to facilitate compliance with the requirements specified in 40 CFR 146.90 (k). Quality assurance (QA) requirements for direct measurements within the injection zone, above the confining zone, and within the shallow USDW aquifer are described in the Quality Assurance and Surveillance Plan (QASP) that is attached to this document (Appendix 7.1). These measurements will be performed based on best industry practices and the QA protocols recommended by the service contractors selected to perform the work.

7.1.2 Reporting Procedures

Marquis Carbon Injection, LLC will report the results of all testing and monitoring activities to the EPA in compliance with the requirements under 40 CFR 146.91.

7.2 Carbon Dioxide Stream Analysis (40 CFR 146.90 (a))

Marquis Carbon Injection, LLC will analyze the CO_2 stream during the injection phase of the project to provide data representative of its chemical characteristics and to meet the requirements of 40 CFR 146.90 (a).

This section describes the measurements and sampling methodologies that will be used to monitor the chemical characteristics of the CO_2 injection stream.

7.2.1 Sampling Location and Frequency

Prior to injection, the CO_2 stream will be sampled at the wellhead during regular plant operations to obtain representative CO_2 samples that will serve as a baseline dataset. Currently, there is no plan to add tracers to the CO_2 stream.

Very little variation (<5%) is expected in the composition of the CO_2 that comes from the fermentation process CO_2 scrubbers due to the consistency of the process. In addition, the CO_2 stream will pass through two scrubbers prior to entering the compressor and the pipeline. As such, quarterly sampling of the CO_2 injection stream will be sufficient to accurately track the composition of the stream. In the first year of injection, samples will be taken at three monthly intervals after the start of injection. If a change greater than 10% from the average baseline conditions in any of the components in the CO_2 stream is noted during the quarterly sampling, a second sample will be obtained for verification. If the verification sample confirms that there is a change in the concentration of one of the constituents that would negatively impact the injection process, the CO_2 stream will then be sampled monthly until the cause of the change is found, and a new baseline can be formed.

7.2.2 Analytical Parameters

Samples of the injection stream will be collected for chemical analysis. Based on data obtained from historic sampling / testing, the samples will be analyzed for CO_2, H_2O, N_2, O_2, C_2H_5OH, CH_3CHO and H_2S. A determination has not been made as to the CO_2 compression system that will be used to inject the off gases into the MCI CCS 3 well. If the compressor design requires the use of a gas dehydration system to remove moisture from the gas stream, the testing may also include triethylene glycol (TEG) which is often used in the dehydration process (Table 7-2). Prior to injection, baseline samples of the injection stream will be collected in a sampling station that can purge and collect samples in a container that can be sealed prior to transfer to an accredited the laboratory. The species included for analysis may be expanded depending on the results of those analyses. Gas concentration analyses will be performed by a laboratory that holds a National Environmental Laboratory Accreditation and uses standardized procedures for gas chromatography, mass spectrometry, detector tubes, and photoionization. Samples of the CO_2 stream will be collected on a quarterly basis for chemical analysis.

Group	Constituent	Rational	Method[1]	CO_2 Spec
Gases	CO_2	Major constituent of CO_2 stream	ISBT 2.0	99%+
	N_2	Minor constituent of CO_2 stream	ISBT 4.0	<1 percent
	O_2	Indicator of atmospheric contamination	ISBT 4.0	<20 ppm
	H_2S	Minor constituent of CO_2 stream	ISBT 14.0	<20 ppm
	TEG	Carry-through gas from the dehydration system	TBD	None
Note 1: An equivalent method may be used with prior approval of the UIC Program Director.				

Table 7-2: Summary of analytes to be measured in the CO_2 stream.

7.2.3 Sampling Method – CO_2 Injection Stream Gases

Grab samples of the CO_2 stream will be obtained for analysis of the components present in the injection stream. Samples of the CO_2 stream will be collected at a location in the system where the material is representative of the material injected (i.e., between the compression system and the MCI CCS 3 well), using a ¼-inch sampling port in the flowline which are standard fitting sizes on double-ended sample cylinders provided by any nationally accredited environmental laboratory (Figure 7-3). Quick-connect fittings are attached to the cylinder's ¼-inch national pipe thread (NPT) fittings, and the cylinder is easily connected into the system. The CO_2 stream flows from the pipeline by opening a ball valve, through a pressure reducer, into the cylinder. The

pressure regulator will reduce the pressure of the CO_2 stream to approximately 250 pounds per square inch (psi) so that the CO_2 is in the gaseous state when collected rather than a super-critical liquid. The three-way valve upstream from the cylinder allows for greater control of the pressure in the system. Cylinders will be purged with sample gas (i.e., CO_2) at least five times prior to sample collection to remove laboratory-added helium gas and ensure a representative sample. During purging, the outlet of the sample cylinder will be connected to a ventilation line and vented to the atmosphere. Proper sampling technique is critical for any gas analysis program. Therefore, great care will be taken to ensure that the cylinder is not contaminated by atmospheric gas and the sample is representative of the CO_2 in the pipeline. A standard sampling procedure is shown below in Figure 7-4. Samples will be shipped to the lab after collection in accordance with the standard operating procedures (SOPs) found in Section B2 of the QASP (Appendix 7.1). Further details related to sampling methods can be found in Section B2 of the QASP.

Figure 7-3: Example of double-ended sample cylinder (Atlantic Analytical Laboratory, 2021).

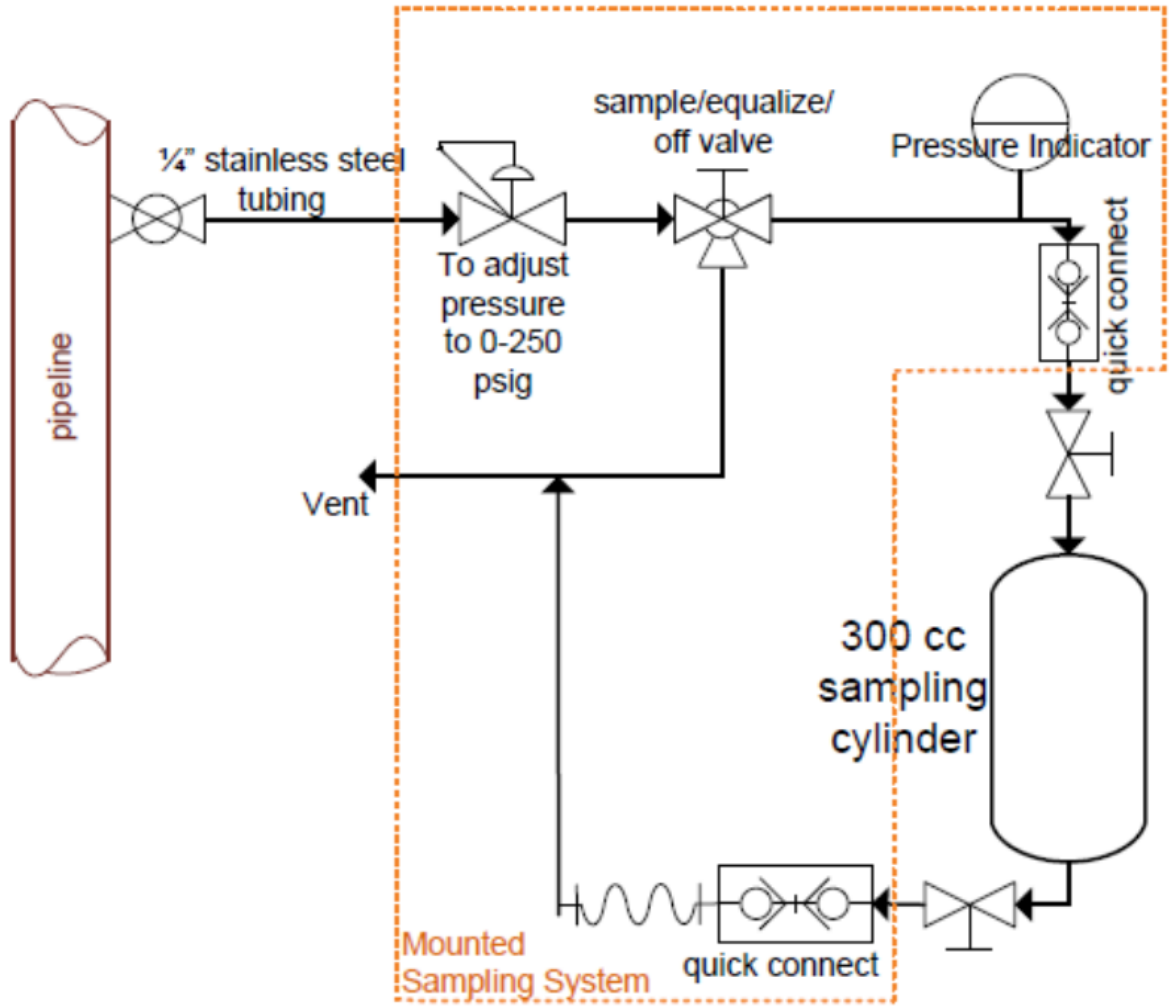


Figure 7-4: Schematic of gas sampling system using a high-pressure cylinder (Atlantic Analytical Laboratory, 2021).

7.2.4 Laboratory to be Used/Chain of Custody and Analysis Procedures

A nationally accredited environmental laboratory will analyze the CO_2 stream samples. The third-party laboratory will follow standard sample handling and chain-of-custody guidance (EPA 540-R-09-03, or equivalent). Details can be found in the QASP (Appendix 7.A).

7.3 Continuous Recording of Operational Parameters (40 CFR 146.88 (e)(1), 146.89 (b), and 146.90(b))

Marquis Carbon Injection, LLC will install and use continuous recording devices to monitor injection pressure, mass injection rate, and volume (calculated); the pressure on the annulus between the tubing and the long string casing; the annulus fluid volume added; and the temperature of the CO_2 stream, as required at 40 CFR 146.88 (e)(1), 146.89 (b), and 146.90 (b). The details are described in the following sections.

7.3.1 Monitoring Location and Frequency

Marquis Carbon Injection, LLC will perform the activities identified in Table 7-3 to monitor operational parameters and verify internal mechanical integrity of the MCI CCS 3 well. All monitoring will take place at the locations and frequencies shown in Table 7-3. All of the data recorded on a continuous basis will be connected to the main facility through a SCADA system. The hourly average value of the parameter being continuously monitored and logged shall be recorded for purposes of reporting. If the electronic data logging system is out of service, field monitoring of manual gauges and annulus pressure will be recorded at least twice per shift (i.e., every 4 hours) for periods when the MCI CCS 3 well is operational.

Parameter	Device(s)	Location	Min. Sampling Frequency	Min. Recording Frequency
CO_2 stream pressure (injection stream)	Pressure Gauge	Wellhead	Every 1 min.	Every 1 min.
Injection pressure (storage formation)	Pressure Gauge	Wellhead	Every 1 min.	Every 1 min.
Mass injection rate	Coriolis Meter	Wellhead	Every 10 sec.	Every 10 sec.
Annular pressure	Pressure Gauge	Wellhead	Every 1 min.	Every 1 min
Annulus fluid volume	Volume	Wellhead	Every 1 min.	Every 1 min
CO_2 stream temperature	Thermocouple	Wellhead	Every 1 min.	Every 1 min.
Injection temperature (storage formation)	Temperature Gauge	Tubing within injection zone	Every 1 min.	Every 1 min.
Notes: Sampling frequency refers to how often the monitoring device obtains data from the well for a particular parameter. For example, a recording device might sample a pressure transducer monitoring injection pressure once every two seconds and save this value in memory. Recording frequency refers to how often the sampled information gets recorded to digital format (such as a computer hard drive). For example, the data from the injection pressure transducer might be recorded to a hard drive once every minute.				

Table 7-3: Sampling devices, locations, and frequencies for continuous monitoring.

7.3.2 Monitoring Details

7.3.2.1 Continuous Recording of Injection Pressure

The CO_2 injection pressure will be monitored on a continuous basis at the wellhead of the MCI CCS 3 well to ensure that injection pressures do not exceed 90% of the fracture propagation pressure of the injection zone (40 CFR 146.88 (a)). Further details are found in the Well Operations Plan (Permit Section 6.0). If injection pressure exceeds 90% of the injection zone fracture pressure, then the injection process will be automatically shut down in accordance with the Well Operations Program.

A dynamic flow calculation will be made to correlate the wellhead pressure to the bottomhole pressure, and this calculation will be used for the initial injection conditions. The bottomhole gauges will be removed when a steady state of flow is achieved,

Any anomalies outside of the normal operating specifications may indicate that an issue has occurred with the well, such as a loss of mechanical integrity or blockage in the tubing or may be caused by a change in injection flowrate. Anomalous pressure measurements would trigger the need for further investigation of the cause of the change (40 CFR 146.89 (b)). The wellhead injection pressure will also be used to calibrate the computational modeling throughout the injection phase of the project.

The wellhead pressure of the injected CO_2 will be continuously measured by an electronic pressure transducer with analog output mounted on the CO_2 line associated with the MCI CCS 3 well. The transmitter will be electronically connected to the SCADA system located in the Control Building, which can shut down the system or change the flowrate depending on the pressures measured at the wellhead. The transducer will be calibrated prior to the start of injection operations, and annually thereafter.

7.3.2.2 Continuous Recording of Injection Mass Flowrate

The mass flowrate of CO_2 injected into the well will be measured by a Coriolis mass flow meter. This flow meter will be placed in the CO_2 delivery line near the well. The meter will have an analog output (Micro Motion Coriolis Flow and Density Meter Elite Series or similar). Two flow meters will be supplied; this will provide one spare flow meter to allow for flow meter servicing and calibration. The flow meter will be connected to the SCADA system for continuous monitoring and control of the CO_2 injection rate into the well. Using two flow meters will allow confirmation of accurate flow measurements. The mass flow meters will be calibrated annually.

7.3.2.3 Injection Volume

The injection volume into the reservoir will be calculated on a continuous basis based on the injection mass and the pressure and temperature conditions in the storage formation. The volume calculated will be used in the computational models to determine storage formation capacity and flow.

7.3.2.4 Continuous Recording of Annular Pressure

As described in the Well Operations Program, the pressure on the annulus between the injection tubing and the long-string casing will be measured by an electronic pressure transducer with analog output, such as a Foxboro I/A Series® IAP20 or similar, that is mounted on the wing valve/annular fluid line connected to the wellhead of the MCI CCS 3 well. The transmitter will be connected to the well control system and the SCADA system to regulate the annular pressure.

Annular pressures are expected to vary up to 20% during normal operations due to atmospheric and CO_2 stream temperature fluctuations. The annular pressure gauge will be calibrated annually and the transducer will be recalibrated according to the manufacturer's recommendations.

7.3.2.5 Continuous Recording of Annulus Fluid Volume

As described in the Well Operations Program, the volume of the annulus fluid between the injection tubing and the long-string casing will be measured using the accumulator levels and the brine reservoir level on the well control system. The accumulator levels will be measured using a level transmitter (Temposonics linear-position sensor R-series Model RH or equivalent). The brine reservoir level will be measured using a level transmitter (Omega LVCN414 series or equivalent). The transmitters will be connected to the well control system and to the SCADA system.

The annular fluid volume is expected to fluctuate as atmospheric and injection stream temperatures change. These changes are expected to be most dramatic during startup and shutdown operations.

7.3.2.6 Continuous Recording of CO_2 Stream Temperature

The temperature of the CO_2 injection stream will be continuously measured using an electronic thermocouple. The thermocouple will be mounted in a temperature well in the CO_2 line at a location close to the pressure transmitter near the wellhead. The transmitter will be electronically connected to the SCADA system. The transmitter will be calibrated prior to the start of injection operations and calibrated annually. The thermocouple for measuring surface injection temperature will be recalibrated annually or it will be replaced with a calibrated thermocouple.

7.3.2.7 Bottomhole Pressure and Temperature

Bottomhole pressure and temperature will be monitored prior to and during injection until steady state of flow is reached. The downhole pressure data will be used to establish a correlation between the storage formation pressure and the wellhead pressure for more accurate estimates of downhole pressure throughout injection. These data will also be used with the mass flow rate to calculate the volume injection rate of the CO_2 into the reservoir.

Two retrievable electronic pressure/temperature gauges, such as Pioneer Petrotech Services Model PPS25, or similar, will be set on a plug at the bottom of the tubing string. The gauges can record and store 1,000,000 sets of pressure/temperature data points. They will be recovered from the well via slickline and the data downloaded. Two gauges are used to confirm consistent measurements and provide backup if required. First, the relationship between wellhead pressure and formation pressure will be defined. Then this will be used as a point of compliance for maintaining injection pressure below 90% of formation fracture propagation pressure as per 40 CFR 146.88 (a). The downhole pressure and temperature data will also be used to calibrate the dynamic model.

The pressure/temperature gauges will be checked for visible damage each time they are removed from the wells. If no issues are apparent with the data or the physical appearance of the gauges, they will be recalibrated every three years, per the manufacturer's recommendation.

7.4 Corrosion Monitoring (40 CFR 146.90 (c))

To meet the requirements of 40 CFR 146.90 (c), Marquis Carbon Injection, LLC will monitor well materials (Table 7-4) and components during the operational period for loss of mass, thickness, cracking, pitting, and other signs of corrosion to ensure that the well components meet the minimum standards for material strength and performance. This section presents the procedures that will be followed to monitor the corrosion of well materials used in the casing and tubing. For Class VI injection wells, corrosion monitoring of the well materials is required on a quarterly basis (40 CFR 146.90 (c)).

7.4.1 Monitoring Location and Frequency

The corrosion coupons will be retrieved and analyzed every three months after the start of injection. If the coupons show evidence of corrosion, the MCI CCS 3 well itself can be assessed for signs of corrosion using well logging techniques such as multi-finger caliper logging or an ultrasonic casing evaluation tool.

Equipment Coupon	Material of Construction
Pipeline	Corrosion resistant material
Wellhead (non flow-wetted)	Carbon Steel Alloy
Long String Casing	Cr-13 Steel Alloy
Flow-wetted surface equipment (Injection Tree)	Corrosion resistant material
Injection Tubing	Corrosion resistant material
Packer and SCSSV	Corrosion resistant material

Table 7-4: List of equipment coupon with material of construction.

7.4.2 Sample Description

The coupons will be made from the same materials as the long string casing and tubing (Table 7-4). Prior to placement of the corrosion coupons in the CO_2 stream, they will be weighed and measured for thickness, width, and length as a baseline measurement.

7.4.3 Monitoring Details

Corrosion monitoring of well materials will be conducted using coupons placed in the CO_2 pipeline (Figure 7-5). The coupons will be made of the same material as the long string of casing and other well and piping materials. The coupons will be removed quarterly and assessed for corrosion using American Society for Testing and Materials (ASTM) G1-03: Standard Practice for Preparing, Cleaning, and Evaluating Corrosion Test Specimens (ASTM, 2017). This method measures the corrosivity of steel to both aqueous and non-aqueous liquids. Upon removal, coupons will be inspected visually for evidence of corrosion, which may include pitting, cracking, and loss of mass or thickness. The weight and size (thickness, width, length) of the coupons will also be measured and recorded each time they are removed and compared to the baseline measurements. Corrosion rate will be calculated as the weight loss during the exposure period divided by the duration (i.e., weight loss method).

If data from the coupon monitoring suggest there is the potential for corrosion of the well materials, the MCI CCS 3 well will be evaluated using wireline tools such as a multi-finger caliper or ultrasonic casing evaluation tool. The frequency of running these tubing and casing inspection logs will be contingent on the corrosion data from the coupon monitoring program. Wireline tools are lowered into the well to directly measure properties of the well casing that indicate corrosion. As the name implies, multi-finger calipers have several fingers and are capable of recording information measured by each finger so that the data can be used to produce highly detailed 3D images of the well. Ultrasonic tools are capable of measuring wall thickness in addition to the inner diameter of the well tubular. Consequently, these tools can also provide information about the outer surface of the casing.

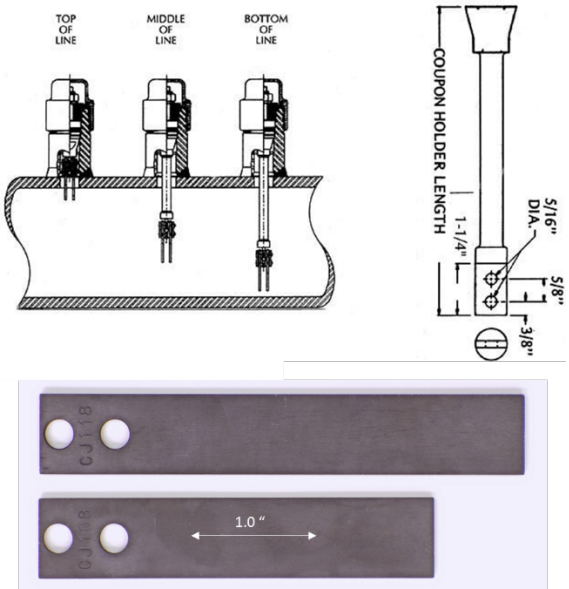


Figure 7-5: Type Corrosion coupon illustration in pipeline (top), types of coupons to be used for corrosion monitoring (below) (Cosasco, 2021).

7.5 Above Confining Zone Monitoring (40 CFR 146.90 (d))

Marquis Carbon Injection LLC will monitor groundwater quality and geochemical conditions above the confining zone during the operational period to meet the requirements of 40 CFR 146.90 (d).

7.5.1 Monitoring Location and Frequency

A deep groundwater well will be drilled as part of the Testing and Monitoring Plan for the project. This ACZ well (MCI ACZ 1) will be drilled to the top of the confining zone, the Eau Claire. It will be drilled adjacent to the MCI CCS 3 well to monitor for any CO_2 leakage or brine migration into the deep ACZ aquifers (Figure 7-1).

Table 7-5 shows the proposed deep ACZ monitoring methods, depths, and frequencies. In addition to the data collected for the Pre-Operational Testing Program (Permit Section 5.0), fluids from the Gunter Sandstone and the Galesville Sandstone will be sampled twice prior to the start of CO_2 injection to determine if there is any natural variability in the fluids in these formations.

Baseline shallow groundwater samples will be collected from four groundwater wells within the AoR (Figure 7-1) on a quarterly schedule starting prior to the start of injection to characterize the seasonal variations in shallow groundwater quality within the AoR (40 CFR 146.90 (d)).

Target Formation	Monitoring Activity	Depth (ft, MD)	Baseline Frequency	Injection Phase Frequency

Shallow Groundwater Wells	Groundwater Geochemistry	0 - TD	Once / quarter	Q2/ end Q3
Shallow Groundwater Wells	Stable Isotopes	0 - TD	Once / quarter	Q2
Gunter Sandstone	Pressure/ Temperature	2.134	Continuous	Continuous (Every minute)
Gunter Sandstone	Groundwater Geochemistry	2.134	Once / quarter	Q2/ end Q3
Gunter Sandstone	Stable Isotopes	2.134	Once / quarter	Q2
Galesville Sandstone	Pressure/ Temperature	2.651	Continuous	Continuous (Every minute)
Galesville Sandstone	Groundwater Geochemistry	2.651	Once / quarter	Q2/ end Q3
Galesville Sandstone	Stable Isotopes	2.651	Once / quarter	Q2/ end Q3

Table 7-5: Monitoring schedule for the ACZ and shallow groundwater monitoring wells during the pre-operational and injection phases of the project.

Migration of CO_2 or brine into the ACZ aquifers will likely first be identified through pressure changes in the aquifers. An increasing pressure trend in either aquifer would suggest that leakage across the confining layer is occurring. While any increasing trend in pressure or temperature will be evaluated, an increase in pressure or temperature greater than 5% above baseline values will warrant additional monitoring and inspections to rule out the possibility of fluid leakage out of the storage formation. Such an increase in pressure or temperature would initiate more frequent fluid sampling and analysis for geochemical parameters from the aquifer with the pressure/temperature increase. An increase in pressures or temperatures in one of the deep ACZ aquifers may also trigger additional external well integrity investigations in the injection or deep monitor well.

The accumulation of CO_2 or brine in an overlying aquifer will likely result in the following changes:

- Aqueous geochemistry parameters such as pH and alkalinity
- Reaction of cements, mineral surface coatings, and clay particles with the CO_2 may liberate cations and anions into the aqueous phase
- Oxygen and carbon isotopes may be used to differentiate between existing CO_2 sources (if present) within the AoR and the injected CO_2

If anomalous changes in the aqueous geochemistry are observed in the ACZ monitoring zones, new samples will be obtained from the affected aquifer to verify the changes. The frequency with which fluid samples are obtained from each of the ACZ aquifers for analysis will be increased. As a precautionary measure, the fluid sampling frequency for the shallow groundwater monitoring wells will also be increased. If the injected CO_2 has a unique isotopic signature from the existing isotopes in the overlying aquifers, a new round of samples will be collected for

isotopic analysis from the affected aquifer. Anomalous changes may also trigger the need for additional well integrity testing in both the deep monitoring well and the MCI CCS 3 well to ensure that no well integrity issues have developed since the last set of external MITs.

7.5.2 Analytical Parameters

Table 7-6 identifies the geochemical parameters to be monitored and the analytical methods to be used on all fluid samples collected from the ACZ well, shallow groundwater wells, and the deep monitoring well. Fluid samples collected from these wells will be analyzed for cations, trace metals, anions, pH, alkalinity, total dissolved solids (TDS), density, dissolved inorganic carbon, and conductivity/resistivity. The cations, anions, TDS, density, and conductivity/resistivity provide details of the overall geochemistry of these aquifers. Changes in these parameters during the injection phase of the project may provide an indication of CO_2 or brine movement above the confining layer. While pH and alkalinity may be indicators of CO_2 migration above the confining layer, the dissolved inorganic carbon analysis could provide direct evidence of CO_2 migration into these formations. Stable isotopes of C (in dissolved inorganic carbon), O, and H may provide an indication of fluid or CO_2 migration into the deep ACZ aquifers and may also provide information about the origin of any migrating fluids. The presence of Carbon-14 may provide an indication of CO_2 migration into the deep ACZ aquifers as any naturally occurring Carbon-14 originally in these aquifers would have decayed long ago.

The relative benefit of each analytical measurement will be evaluated throughout the design and initial injection testing phase of the project to identify the analytes best suited to meeting project monitoring objectives under site-specific conditions. If some analytical measurements are shown to be of limited use, they will be removed from the analyte list and not carried forward through the operational phases of the project. Any modification to the parameter list in Table 7-6 will be made in consultation with the UIC Program Director.

There are no plans to use tracers during operations. However, as the monitoring plan is designed to be adaptive as project risks evolve over time, this decision may be re-assessed later.

Parameters	Analytical Methods
Cations (Na, Ca, Mg, Ba, Sr, Fe, K)	ASTM D1976
Anions (Cl, Br, SO_4)	ASTM D4327
pH	ASTM D1293
Alkalinity	ASTM D3875
Total Dissolved Solids (TDS)	ASTM D5907
Density	ASTM D4052
Dissolved Inorganic Carbon	ASTM D513-11
Conductivity/Resistivity	ASTM D1125
Stable Isotopes of C, O, and H	ASTM STP 573
Carbon-14	

Table 7-6: Summary of analytical and field parameters for groundwater samples.

7.5.3 Monitoring and Sampling Methods

Pressure and temperature sensors will be placed in the tubing strings of the ACZ monitoring well to allow measurement of these parameters within the Gunter Sandstone and Galesville Sandstone. The wells will be configured to isolate these formations, so gauges measure the pressures/temperatures of these geologic formations separately. The gauges will be memory-style gauges (Pioneer Petrotech PPS25 or similar), that record and store data within the gauge. The gauges will be programmed to measure and record pressure and temperature every minute and would be set in the well three months prior to the start of injection to obtain baseline data. A pair of gauges will be placed in each zone to limit the possibility of data loss, and the gauges will be retrieved so that the data can be downloaded on a quarterly basis. The gauges will be placed back in the well after the data download.

For fluid sampling, a bailer or pump system will be used to collect the water samples. Prior to sample collection the well will be purged to remove stagnant water from the well and ensure representative water is collected from the formation. The amount of water that will be purged will be determined by the volume of water and/or field parameter stabilization. The fluid purged from the well will be monitored for field parameters, such as pH, specific conductance, and temperature, using a calibrated water quality meter (Horiba U-53, or similar). Once these parameters stabilize, it will be an indication that representative formation fluid is in the well at the time the sample is collected.

Preservation, preparation methods, container type, and holding times for the analyte classes are presented in Table 7-7. The analytical methods for the metals require acidification with nitric acid, and the samples will be filtered. The remainder of the analyses do not require preparation or preservation other than chilling the samples. The samples will be collected in either glass or

polyethylene bottles ranging in size from 50 milliliters (mL) to 1.5 liters (L). Hold times from the analytes range from 7 days for TDS to 1 year for the oxygen and hydrogen isotopes.

Parameters	Preservation/Preparation	Container	Holding Time
Total Metals by ICP Na, Ca, Mg, Ba, Sr, Fe, K	HNO_3 to pH<2, Filter 4-µm	1.5 L Poly	6 months
Anions Cl, Br, SO_4	Cool, 4±2°C, no chemical preservation	1 L Poly	28 days
pH	Cool, 4±2°C, no chemical preservation	1 L Poly	None
Alkalinity	Cool, 4±2°C, no chemical preservation	1 L Poly	28 days
Total Dissolved Solids	Cool, 4±2°C, no chemical preservation	1 L Poly	7 days
Specific Gravity	None	1 L Poly	None
Dissolved Inorganic Carbon	None	1 L Poly	7 days
H and O Stable Isotopes	None	50 mL Glass	1 year
C Stable Isotopes	Cool, 4±2°C, no chemical preservation	150 mL Poly	14 days
Carbon-14	Cool, 4±2°C, no chemical preservation	150 mL Poly	6 months

Table 7-7: Preservation methods, container type, and holding times for analyte classes.

7.5.4 Laboratory to be Used/Chain of Custody Procedures

The geochemical analyses will be performed by Intertek Laboratories and the isotopic analyses will be performed by Isotech Laboratories. These laboratories may be substituted with other accredited laboratories with equivalent capabilities without modification to the Testing and Monitoring Plan. Samples will be tracked using appropriately formatted chain-of-custody forms. See the QASP for additional information (Appendix 7.A).

7.6 Mechanical Integrity Testing

7.6.1 Internal Mechanical Integrity Testing

Internal mechanical integrity refers to the integrity or seal within the long casing string between the long casing string, tubing, and packer. The quality of this seal can be confirmed with an MIT and annular pressure monitoring. Both methods will be used during the injection phase of this project to monitor and confirm internal mechanical integrity. Table 7-8 presents the details for conducting the annular pressure MIT and the annular pressure monitoring.

Testing/Monitoring Method	Frequency	Location of Monitoring	Parameters Measured
Annular Pressure MIT	After completion or workover	Tubing/casing annulus	Ability to hold pressure testing
Annular Pressure Monitoring	Continuous	Tubing/casing annulus	Pressure, temperature, annular fluid volume

Table 7-8: Internal mechanical integrity monitoring details.

After the packer, tubing, and downhole equipment have been re-installed, the tubing/casing annulus will be filled with a corrosion-inhibited fluid, such as a potassium chloride (KCl) solution with additives. The temperature of the annular space will be allowed to stabilize, and an annular pressure MIT test will be conducted to ensure that there are no leaks in the tubing, casing, or packer. This approach is also described in the Pre-Operation Testing Program (Permit Section 5.0). The annular pressure test will be performed by pumping additional annular fluid into the annulus to increase the pressure to a pressure that exceeds the maximum injection pressure. The annular pressure will be monitored for a minimum of thirty-minutes (EPA, 2008). A change in pressure less than 3% of applied surface pressure would indicate normal internal mechanical integrity. If a pressure loss greater than 3% is observed, the cause of the poor mechanical integrity will be identified and corrected. Following the annular pressure test, the annular pressure will be relieved by releasing the fluid to a vessel for volumetric measurement. The volume of the recovered liquid returned from the annulus is expected to be proportional to the volume of the annulus and the amount of pressurization.

The annular pressure test will be repeated any time the packer has been released, for instance, during well workovers. An annular pressure test may also be repeated if there is an indication of lost internal integrity.

In addition to the annular pressure MIT, the annular pressure will be continuously monitored throughout the injection period in conjunction with the annular pressure monitoring and control system to ensure internal mechanical integrity. Once injection commences, injection pressure, annular pressure, and annular fluid volumes will be monitored continuously to ensure that internal well integrity and proper annular pressure is maintained.

If a change in the annular pressure or annular fluid volume displays a change of greater than 20% from baseline conditions, the cause of the change will be investigated. Note that changes in the temperature of the injection stream can result in changes in the temperature of the annular space and variations in annular pressure. Initial investigations would focus on correlations between the temperature of the injection stream and the variations in annular pressure.

7.6.2 External Mechanical Integrity Testing (40 CFR 146.90 (e))

Marquis Carbon Injection, LLC will conduct external integrity testing annually to meet the requirements of 146.89(c) and 146.90(e).

7.6.2.1 Testing Location and Frequency

External mechanical integrity refers to the absence of fluid movement through channels between the long casing string and the borehole or the intermediate casing string. Migration of fluids through this zone could result in contamination of USDWs; therefore, the external integrity of the MCI CCS 3 well will be confirmed throughout the injection phase of the project.

Temperature measurements will be acquired in the MCI CCS 3 well to monitor and ensure external mechanical integrity of the well. A baseline temperature measurement will be acquired in the MCI CCS 3 well after the well has been completed and the temperatures have returned to static conditions. Following the baseline log, temperature measurements will be acquired annually after the start of injection. The log will be run during a period without CO_2 injection and will be conducted over the entire well with the tool being conveyed through tubing above the packer. Temperature logging will also be used to monitor the external mechanical integrity of the deep monitoring wells on an annual basis (Table 7-9).

Test	Well	Depth Range (ft, MD)	Schedule
Temperature Measurements	Injection	0 – 3,100 (Upper Mt. Simon)	Annually
	Deep monitor	0 – 3,100 (Upper Mt. Simon)	Annually
Oxygen Activation Log	Injection	0 – 3,100 (Upper Mt. Simon)	As required
	Deep monitor	0 – 3,100 (Upper Mt. Simon)	As required

Table 7-9: External mechanical integrity tests.

7.6.2.2 Testing Details

The data from each annual logging event will be compared to the baseline log to determine if there are any inconsistencies between the logs. If inconsistencies appear, the cause of the deviations will be determined, and an oxygen-activation log will be performed over the zone where the inconsistency was found to substantiate results of the temperature measurements.

7.7 Pressure Fall-Off Testing (40 CFR 146.90 (f))

Marquis Carbon Injection, LLC will perform PFO tests during the injection phase as described below to meet the requirements of 40 CFR 146.90(f).

PFO testing involves the measurement and analysis of pressure data from a well after it has been shut-in. PFO tests provide the following information:

- Confirmation of hydrogeologic reservoir properties such as injectivity and average permeability
- Formation damage (skin) near the wellbore, which can be used to diagnose the need for well remediation/rehabilitation
- Changes in reservoir performance over time, such as long-term pressure buildup in the storage formation, that may indicate formation damage
- Average reservoir pressure that can be used to calibrate modeled predictions of reservoir pressure to verify that the operation is responding as modeled/predicted

7.7.1 Testing Location and Frequency

PFO testing will be performed in the MCI CCS 3 well once every five years during the injection operations. However, additional PFO testing may be performed opportunistically if the system is shut down for a maintenance event, and the fall-off data may be collected and analyzed. In addition, data from these tests can be used to determine the duration of shut-in desired for the scheduled PFO testing. The scheduled PFO tests will likely be performed during scheduled shutdown events to prevent additional system downtime.

7.7.2 Testing Details

A PFO test has a period of injection followed by a period of shut in. The bottom-hole pressure is then monitored and recorded for sufficient time during both phases of the testing to make a valid observation of the pressure fall-off curve. The optimal duration for the shut-in periods will be determined through the opportunistic PFO test completed prior to the first scheduled PFO. To reduce the wellbore storage effects attributable to the pipeline and surface equipment, the well will be shut-in at the wellhead nearly instantaneously with direct coordination with the injection facility operator. The programed injection rate will be maintained for a minimum of one week prior to the PFO. Additional data from the month prior to shut-in will also be included in the analysis of the PFO test. Downhole and wellhead pressure gauges will be used to record and monitor bottomhole pressures during the injection period and the fall-off period. Specifications for the pressure gauges are provided in the QASP.

Reservoir pressures will be measured to capture the change in bottom-hole pressure throughout the test period; this includes the rapidly changing pressures immediately following cessation of injection. The fall-off period will continue until radial flow conditions are observed as indicated by stabilization of the surface pressure and the plateau of the pressure derivative curve. The PFO test may also be truncated if boundary effects are encountered or if radial flow conditions are not observed. In addition to the radial flow regime, other flow regimes may be observed from the PFO test including spherical flow, linear flow, and fracture flow. The shut-in period of the fall off test is expected to last at least five days, but data collected during the opportunistic PFO test

will be used to assess the duration of this phase of the test. Analysis of PFO test data will be done using transient-pressure analysis techniques that are consistent with EPA guidance for conducting PFO tests (EPA, 1998, 2002).

Pressure gauges that are used for the purpose of the PFO test will be calibrated according to the recommendations of the manufacturer and current calibration certificates will be provided with the test results to EPA.

A report containing the PFO data and interpretation of the reservoir ambient pressure will be submitted to the permitting agency within 90 days of the test.

7.8 Carbon Dioxide Plume and Pressure Front Tracking (40 CFR 146.90 (g))

Marquis Carbon Injection, LLC will employ direct and indirect methods to track the extent of the CO_2 plume and the presence or absence of elevated pressure during the operation period to meet the requirements of 40 CFR 146.90 (g).

7.8.1 Plume Monitoring Location and Frequency

Table 7-10 presents a summary of the methods that Marquis Carbon Injection, LLC will use to monitor the location of the CO_2 plume, including the activities, locations, and frequencies. The parameters to be analyzed as part of fluid sampling in the injection zone and associated analytical methods are presented in Table 7-3. The corresponding QA procedures for these methods are presented in the QASP.

Fluid samples will be obtained for analysis from the Mt. Simon Sandstone intervals in accordance with the Pre-Operational Testing Plan. The final sampling interval will be determined after the MCI CCS 3 well has been drilled and the well logs have been analyzed.

PNC logs will be used to identify difference in reservoir fluids near the wells and will be used to aid in monitoring the migration of the injected CO_2. PNC logs operate by generating a pulse of high energy neutrons, subsequently measuring the neutron decay over time and across a wide energy spectrum (Conner et al., 2017).

Target Formation	Monitoring Activity	Monitoring Location(s)	Spatial Coverage	Frequency
Direct Plume Monitoring				
Upper Mt. Simon Sandstone	Fluid sampling	Deep monitor	3,100 – TD ft	Twice/ year until CO_2 breakthrough
Upper Mt. Simon Sandstone	Isotope analysis	Deep monitor	3,100 – TD ft	Once/ year until CO_2 breakthrough
Lower Mt. Simon Sandstone	Fluid sampling	Deep monitor	4,700 ft	Twice/ year until CO_2 breakthrough
Galesville, Eau Claire, and Mt. Simon Formations	PNC logging	Deep monitor ACZ-1	2,600 – TD ft 2,600 – TD ft 2,500 – TD ft	Once/ year Once/ year
Indirect Plume Monitoring				
Galesville, Eau Claire, and Mt. Simon Formations	Time-lapse 3D seismic	Surface	Over project AoR	Every 5 years or 4 million tons injected and as required.

Table 7-10: CO_2 plume monitoring activities.

Baseline PNC logs will be acquired in the deep monitoring, and ACZ monitoring well prior to the start of CO_2 injection. During injection, they will be acquired in both wells twice each year.

Time-lapse 3D surface seismic is proposed as the primary indirect technique to monitor the development of the CO_2 plume during and after injection. A pre-injection baseline 3D seismic survey will be acquired in early 2022 (Figure 7-6). The same seismic survey will then be acquired again at regular intervals, during and after the injection period and will be compared

back to the baseline survey. Various specific processing techniques (Calvert, 2005) will highlight the location of the CO_2 at the time of each subsequent survey acquisition.

At this time, no continuous CO_2 plume monitoring has been planned for the project. Likewise, no phased or adaptive monitoring has been planned for the project in terms of expanding the monitoring network. However, if the AoR is reassessed over the injection phase of the project, the Testing and Monitoring Plan will also be reassessed.

Figure 7-6: 3D seismic baseline outline.

7.8.2 Plume Monitoring Details

As CO_2 is injected into the Mt. Simon Sandstone, the geochemistry of the fluids and C, O, and H isotopes in the formation are expected to change. Geochemical modelling will be used to predict the geochemical changes to the Mt. Simon Sandstone fluids once data from the Pre-Operational Testing has been analyzed. The results of the geochemical and isotope analysis will be delivered in the form of laboratory reports. Section 7.5 of this document details the sampling procedures that will be used. Table 7-6 summarizes the analytical and field parameters for the fluid sampling. Table 7-7: Preservation methods, container type, and holding times for analyte classes. summarizes the methods, containers, and preparation methods for the fluid sampling. Further information can also be found in the QASP (Appendix 7.A). The project will stop taking fluid samples from the upper Mt. Simon Sandstones once free phase CO_2 is encountered at the sampling ports.

PNC logging will be used to monitor the distribution and saturation of CO_2 adjacent to the wellbores in the ACZ and monitoring wells. The PNC logs will be acquired through the Galesville Sandstone to confirm the absence of CO_2 accumulations along the wellbore above the confining layer.

Technical details on PNC logging tools can be found in the QASP (Appendix 7.A).

Time-lapse 3D surface seismic data will be used to qualitatively monitor the CO_2 plume development and calibrate the computational modeling results over time. The planned 3D seismic surveys are specifically designed for the Marquis Biocarbon Project site. The previously acquired 2D seismic surveys provided insight into site-specific seismic characteristics, including seismic signal attenuation and the impact of background noise associated with the daily operations of the industrial plant. The 3D acquisition parameters will provide significant uplift in data quality beyond what is normally expected from 3D geometry over 2D.

The results of the geochemical and isotope analysis, PNC logging, and time-lapse 3D surface seismic data will all be integrated to develop a comprehensive understanding of the CO_2 plume development over time. PNC logging and time-lapse 3D surface seismic data can be incorporated into the SEM for comparison to the computational modelling predictions at different points in time. The data can be used to constrain the computational modelling results and produce better plume predictions over the course of the project.

If the CO_2 plume monitoring data diverges significantly from the modelled plume predictions, it may result in a reassessment of the AoR as per the AoR and Corrective Action Plan.

7.8.3 Pressure-Front Monitoring Location and Frequency

Table 7-11 presents the methods that Marquis Carbon Injection, LLC will use to monitor the position of the pressure front, including the activities, locations, and frequencies.

QA procedures for these methods are presented in the QASP. The pressure/temperature sensors will be programmed to measure and record pressure and temperature readings every minute. The gauges will be retrieved for data download on a quarterly basis. A pair of gauges will be place in each zone to limit the possibility of data loss.

Target Formation	Monitoring Activity	Monitoring Location(s)	Spatial Coverage	Frequency
Direct pressure front monitoring				
Upper Mt. Simon Sandstone	Pressure Monitoring	Deep Monitor Well	3,100 – 3,500 ft	Continuous
Indirect pressure front monitoring				
Eau Claire and Mt. Simon Formations, and Precambrian Basement	Microseismic Monitoring	Surface Stations	TBD through modelling	Continuous

Table 7-11: Pressure plume monitoring activities

Microseismic data will be recorded from a surface-based network of sensors on a continuous basis. These data will be sent to a cloud-based service via a cellular connection for data processing and archive. Baseline microseismic data will be acquired for four to six months prior to the start of injection operations.

No phased or adaptive monitoring has been planned for the project in terms of expanding the monitoring network. However, if the AoR is reassessed over the injection phase of the project, the Testing and Monitoring Plan will be reassessed (Permit Section 7.0).

7.8.4 Pressure-Front Monitoring Details

Pressure/temperature sensors will be placed on the tubing string of the deep monitor well to monitor the pressures in the upper Mt. Simon intervals (Table 7-11). The gauges will be memory-style gauges, such as Pioneer Petrotech PPS25 or similar, that would record and store the data within the gauge. Refer to the QASP for technical information on the potential pressure/ temperature gauges (Appendix 7.A). The gauges will be placed back in the well after the data download.

The pressure/temperature data will be stored as time stamped data pairs. It is expected that the pressures in the Mt. Simon Sandstone monitoring interval will begin to increase once injection operations begin. These data will be used to calibrate the computational modelling results over the injection and PISC phases of the project. Calibrating the computational model with pressure and temperature data from the storage formation will lead to more accurate predictions of pressure plume behavior over time. The AoR and Corrective Action Plan further describes how the pressure and temperature data will be used to calibrate the computational modelling, and how it might be used to trigger an early reassessment of the AoR (Permit Section 2.0).

The proposed microseismic monitoring array will have multiple surface stations. The number and physical locations of these stations will be determined using a network design process. Each standalone station will likely consist of a seismometer, digitizer, solar panel with battery backup, and a cell modem/ antenna. Triggered data will be processed to provide event magnitude and location information and results will be reviewed by a data processor and event data will be received by the project daily. The event locations will be incorporated in the SEM. Microseismic activity will provide qualitative information on the spatial extent of pressure plume over time.

7.8.5 Time-lapse 3D Seismic Validation using Deterministic Seismic Forward Modeling

A robust deterministic seismic forward modeling project has been undertaken to demonstrate that this technique can indirectly detect subsurface changes associated with CO_2 injection at this site. This modeling project was performed using data acquired at the project site, including Vertical Seismic Profile (VSP) data and wireline logging data recorded in the MCI MW 1 well and 2D seismic data from line MI-IL-4-21.

The initial phase of the project included conditioning the 2D seismic data and integrating the VSP results. Incident angle gathers are derived through ray tracing and an averaged amplitude decay curve was derived. Importantly, this is averaged spatially across 200 pre-stack gathers and temporally over the Mt. Simon (600-900 ms two-way time). This provides a measured, *in situ* amplitude versus offset (AVO) response independent of potential signal contamination.

Using the recorded sonics (compressional and shear) and bulk density logs, a 1.5D, full elastic wave equation forward model was built. This model was conditioned in a manner consistent to the 2D seismic and comparable angle gathers were derived. The corresponding amplitude decay curve was extracted and compared to the 2D seismic equivalent (Figure 7-7).

The modeled (from logs) and measured (from 2D seismic) amplitude decay curves compare very favorably. This implies that we can use seismic data acquired at this site in pre-stack seismic inversion studies to predict subsurface rock properties and how they will change over time as a result on CO_2 injection.

The final phase of the modeling exercise was twofold. A fluid replacement modeling workflow adjusts the pre-injection, recorded sonics (compressional and shear) and bulk density logs to simulate the expected log response after replacement of a portion of the formation water with CO_2. AVO synthetic gathers are then generated using the measured, pre-injections logs and the simulated, post-injection logs. The difference in these pre- and post-injection AVO synthetics quantifies the time-lapse seismic response that can be anticipated with injection of CO_2.

Figure 7-8 illustrates the difference in pre- and post-injection log and seismic amplitude responses for injection into the lower members of the Mt. Simon. This modeling was done for three zones in the Mt. Simon to capture the possible change in seismic response over the entire formation. A measurable change in both the logs and seismic response after fluid substitution of CO_2 is clearly visible in Figure 7-8. Injection into the upper and middle members of the formation gave similar results.

The synthetic, pre-stack gathers were processed to produce angle gathers via a workflow that is applicable to any future processing of the 3D seismic survey. These modeled, processed synthetic responses are presented to show the anticipated effect of injecting CO_2 on the seismic amplitude versus angle (AVA) response. Figure 7-9 captures these modeled changes for injection into the lower members of the Mt. Simon. Injection into the upper and middle portions of the Mt. Simon yielded analogous results. Based on this quantitative analysis, a measurable change in both polarity of the seismic event associate with the top of the injection zone and pre-stack seismic response is expected.

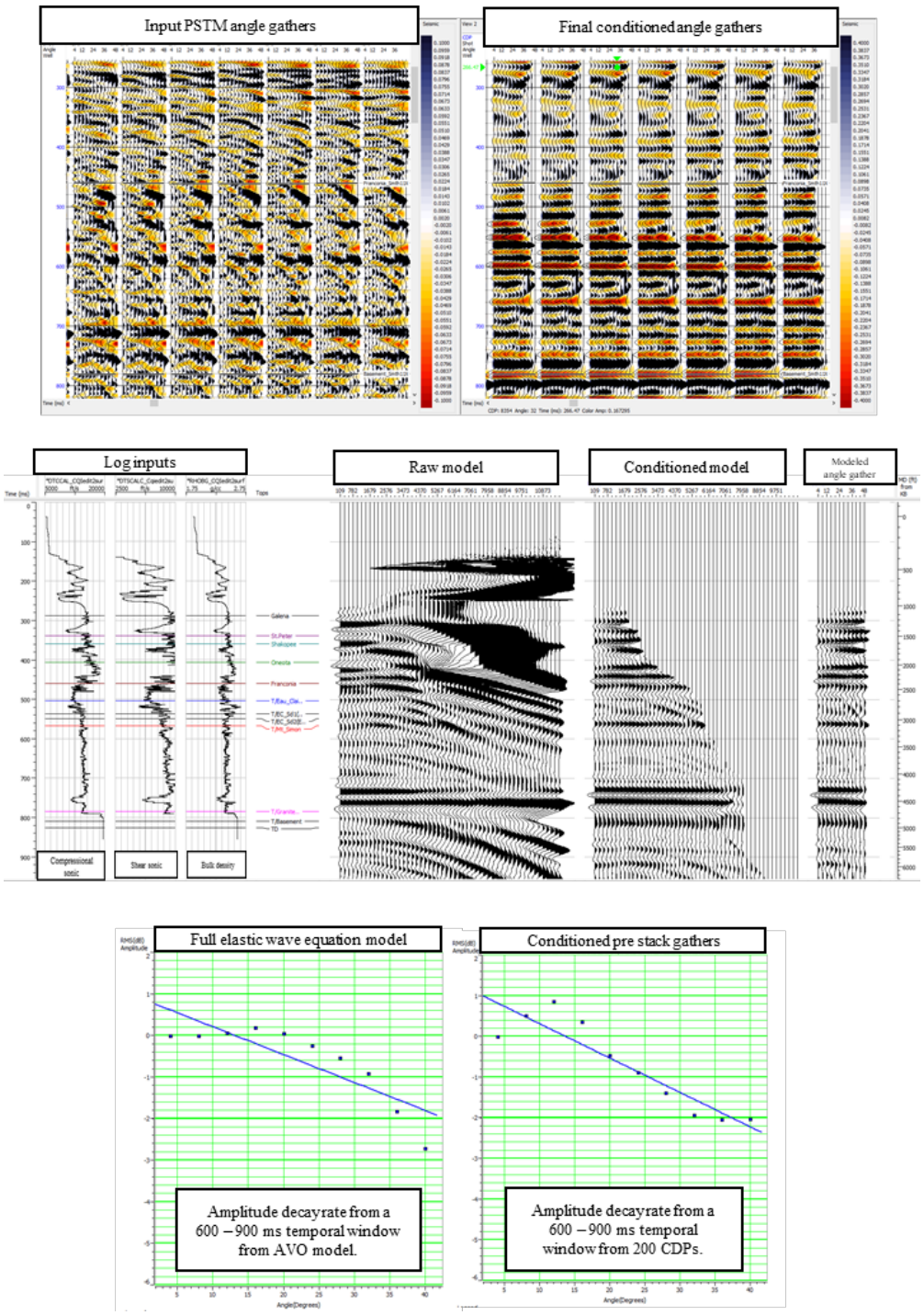


Figure 7-7: Raw 2D seismic gathers with corresponding conditioned pre stack gathers (top). Forward model built from recorded logs (middle). Comparison of measured amplitude with incidence angle for modeled log response and 2D seismic data (bottom).

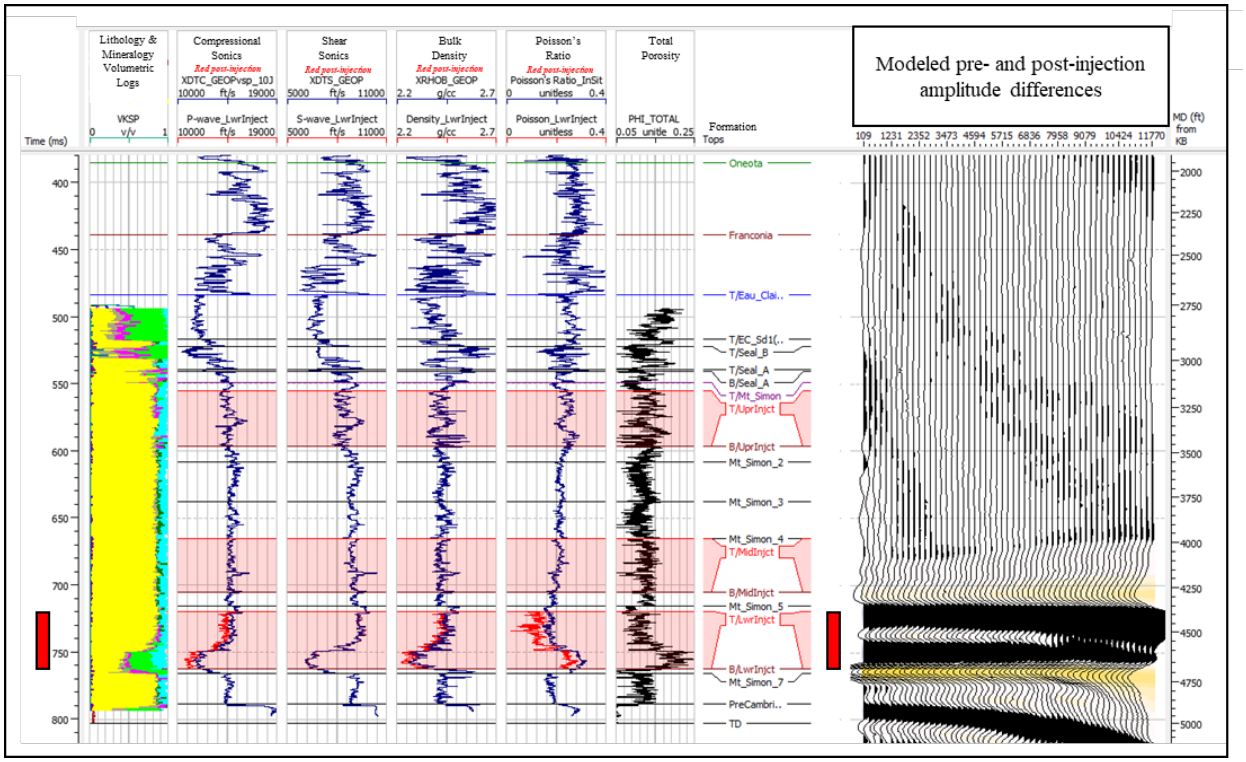


Figure 7-8: Change in simulated log response (left) and modeled time-lapse, pre-stack seismic amplitude difference (right) for CO_2 fluid replacement in lower Mt. Simon.

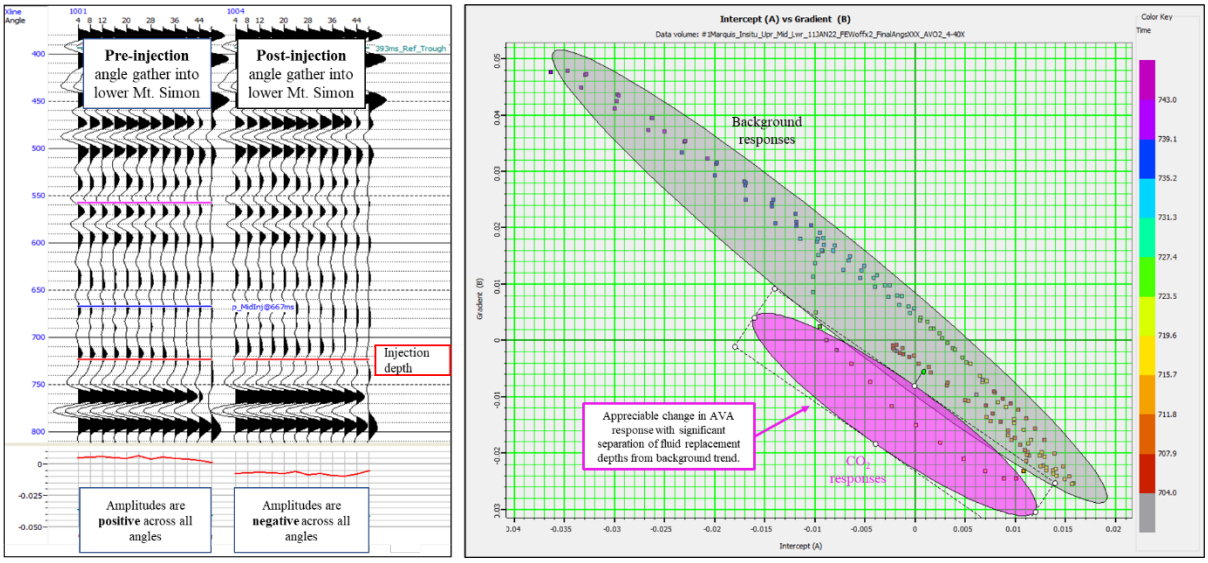


Figure 7-9: Change in amplitude versus incidence angle from pre- to post-injection demonstrate a change in the polarity of the seismic event associated with the top of the injection zone (left). AVA attributes derived from post-injection synthetics demonstrate a clear separation of the injection zone from the background trend (right).

This modeling exercise shows that the injection of CO_2 into the proposed intervals appreciably changes the velocities and densities of the formation and thus the seismic response. Changes in the seismic amplitudes and AVO/AVA attributes provide a direct quantification of the changes resulting from CO_2 injection and plume growth. The results of this modeling study strongly indicate that four-dimensional (4D) seismic monitoring is a viable and robust means of long-term monitoring for this site.

7.9 References

American Society of Testing and Materials, 2017. Standard Practice for Preparing, Cleaning, and Evaluating Corrosion Test Specimens, G1-03. 9 p.

Atlantic Analytical Laboratory, 2021. https://atlanticanalytical.com/

Bauer, R. A., Carney, M., & Finley, R. J., 2016. Overview of microseismic response to CO_2 injection into the Mt. Simon saline reservoir at the Illinois Basin-Decatur Project. International Journal of Greenhouse Gas Control, 54(Part 1), 378-388. https://doi.org/10.1016/j.ijggc.2015.12.015.

Calvert, R., 2005, Insights and methods for 4D reservoir monitoring and characterization: SEG, EAGE/SEG Distinguished Instructor Short Course, no. 8.

Conner, A. et al. Developing Best Practices for Evaluating Fluid Saturations with Pulsed Neutron Capture Logging Across Multiple Active CO_2-EOR Fields, Energy Procedia, Volume 114, 2017, Pages 3636-3648, ISSN 1876-6102.

Cosasco, 2021. https://www.cosasco.com/

EPA (United States Environmental Protection Agency). 2002. "UIC Pressure Falloff Testing Guideline." EPA Region 6, August 8, Third Revision; http://www.epa.gov/region6/water/swp/uic/guideline.pdf.

EPA (United States Environmental Protection Agency). 2008. "Determination of Mechanical Integrity of Injection Wells." EPA Region 5, February, https://www.epa.gov/sites/default/files/2015-09/documents/r5-deepwell-guidance5-determation-mechanical-integrity-200802.pdf

Lumley, D. (2019). The Role of Geophysics in Carbon Capture and Storage. In T. Davis, M. Landrø, & M. Wilson (Eds.), Geophysics and Geosequestration (pp. 11-53). Cambridge: Cambridge University Press. doi:10.1017/9781316480724.003

Malehmir, Alireza & Bellefleur, Gilles & Koivisto, Emilia & Juhlin, Christopher. (2017). Pros and cons of 2D vs 3D seismic mineral exploration surveys. First Break. 35. 49-55. 10.3997/1365-2397.35.8.89805.

Nanometrics, 2021, https://www.nanometrics.ca/

United States Environmental Protection Agency, 2013. Geologic Sequestration of Carbon Dioxide: Underground Injection Control (UIC) Program Class VI Well Testing and Monitoring Guidance, EPA 816-R-13-001. 142 p.

United States Environmental Protection Agency, 2011. Contract Laboratory Program Guidance for Field Samplers, EPA 540-R-09-03. 84 p.

Appendix 7.A Quality Assurance and Surveillance Plan

The Quality Assurance and Surveillance Plan is presented in a separate document accompanying this permit application.

8.0 INJECTION WELL PLUGGING PLAN
40 CFR 146.92 (b)

MARQUIS BIOCARBON PROJECT

Facility Information

Facility name: MARQUIS BIOCARBON PROJECT

Facility contact: ELIZABETH STEINHOUR
DIRECTOR OF ENVIRONMENTAL AFFAIRS
10000 MARQUIS DRIVE, HENNEPIN, IL 61327
815.925.7300 / BETHSTEINHOUR@MARQUISENERGY.COM

Well Name: MCI CCS 3

Well location: PUTNAM COUNTY, ILLINOIS
S2 T32N R2W
Latitude: 41.27026520 N, Longitude: 89.30939322 W

Table of Contents

8.0 Injection Well Plugging Plan 3
8.1 Plugging Plan for the MCI CCS 3 Injection Well 3
8.2 Tests or Measures for Determining Bottom-Hole Reservoir Pressure 3
8.3 Planned External Mechanical Integrity Tests 3
8.4 Plugging Plan 4
8.5 Detailed Pre-Plugging Procedure 6
8.6 Detailed Plugging and Abandonment Procedure (Post-Injection) 7

List of Tables

Table 8-1: Planned MITs. 4
Table 8-2: Intervals to be plugged and materials/methods used (40 CFR 146.92 (b)(2 – 4)). 6
Table 8-3: Information on proposed well plugs 6

8.0 Injection Well Plugging Plan

8.1 Plugging Plan for the MCI CCS 3 Injection Well

The MCI CCS 3 well plugging plan described in this section, details the methods and materials that will be used to plug and abandon the MCI CCS 3 injection well in accordance with 40 CFR 146.92. The well construction details for the MCI CCS 3 injection well are provided in the Injection Well Construction Plan (Permit Section 4) of this application; this includes the casing and cement used in the completion of the well. These details will be used to determine an appropriate approach to plugging the MCI CCS 3 well to prevent migration of fluids upwards through the abandoned well. The Post-Injection site Care and Closure (PISC) Plan (Permit Section 9) describes tests that will be performed prior to well abandonment to confirm the well has maintained mechanical integrity throughout the injection phase of the project.

The Class VI permit, in accordance with 40 CFR 146.92, requires that specific data be collected prior to plugging an injection well. The bottom-hole pressure must be determined and the mechanical integrity of the well casing must be confirmed prior to plugging and abandoning the well. The procedures that will be used to generate these data are described in the following sections.

8.2 Tests or Measures for Determining Bottom-Hole Reservoir Pressure

Bottom-hole pressure measurements will be conducted prior to plugging and abandonment of the MCI CCS 3 well as required by 40 CFR 146.92(a). These measurements will be used to determine several parameters required during the plugging and abandonment of the MCI CCS 3 well, including the pressure required to squeeze the cement from the well casing into the storage formation, the need for well control such as the weight of brine required to prevent the well from flowing, and the required blowout preventor (BOP) stack during the pre-abandoment workover activities. The bottom-hole reservoir pressure will also be used to confirm the blend of cement to be used to plug the well.

8.3 Planned External Mechanical Integrity Tests

External mechanical integrity tests (MITs) will be conducted prior to plugging the MCI CCS 3 well as required by 40 CFR 146.92(a). The mechanical integrity of the well must be demonstrated after the injection phase of the project has been completed and prior to plugging the well to ensure conduits between the injection zone and the underground sources of drinking water (USDWs) have not developed. The external mechanical integrity will be evaluated by acquiring a temperature measurement in the MCI CCS 3 well (Table 8-1).

Test Description	Location

Temperature measurement	MCI CCS 3
Oxygen-Activation Log (Contingency)	MCI CCS 3

Table 8-1: Planned Mechanical Integrity Tests.

Throughout the injection phase of the project, the external mechanical integrity of the MCI CCS 3 well will be confirmed through regular temperature measurements in accordance with the Testing and Monitoring plan (Permit Section 7). A final temperature measurement will be acquired over the entire MCI CCS 3 well after the tubing has been pulled and prior to the plugging and abandonment process (40 CFR 146.92 (b)(2)). The temperature data will be evaluated for anomalies and compared to previous temperature measurements acquired during the pre-operational and injection phases of the project for any indications that the storage formation fluids have migrated outside of the storage formation.

The post-injection temperature data are expected to display a similar temperature gradient above the confining zone as the previous measurements. If the temperature gradient deviates less than 10% between the post-injection data and previous data, the well will be considered to have maintained external mechanical integrity. A temperature gradient change greater than 10% would suggest an external mechanical integrity issue, and an oxygen-activation log will be acquired to corroborate the results of the temperature log. If a loss in external mechanical integrity is discovered, corrective action will be taken prior to proceeding to the plugging and abandonment. The response actions to such a situation are described in the Emergency and Remedial Response Plan (Permit Section 10).

8.4 Plugging Plan

A Notice of Intent to plug the well will be submitted to the EPA at least 60 days prior to the plugging operations (40 CFR 146.92 (c)). Section 8.5 details the pre-plugging procedures that will be completed prior to plugging the well, and Section 8.6 contains a detailed description of the plugging procedures.

After the the project has verified that there are no external well integrity issues, the well will be flushed with a buffer fluid to remove any fluids or particulates that may be present in the well (Section 8.6). The weight of the buffer fluid will be determined from the final reservoir pressure measurement and will be chemically compatible with the formation fluids and solids to reduce the potential of corrosion of the well materials. A minimum of three casing volumes will be circulated without exceeding the fracture pressure of the Mt. Simon Sandstone.

The MCI CCS 3 well casing will be plugged with cement to ensure that it does not provide a conduit outside the injection zone. Table 8-2 and Table 8-3 present the intervals that will be plugged as well as the materials and methods that will be used to plug the intervals. The cement volume required for each plug was calculated using the inside diameter of the deep casing string (8.835 inches), the length of the zone to be plugged (1,555 feet [ft]), and the yield of the cement slurry (1.18 ft^3/sack for Class A or G or H and 1.07 ft^3/sack for the carbon dioxide [CO_2]-

resistant cement). The injection zone will be plugged using CO_2-resistant cement with a retainer/squeeze method or other method approved by the UIC Director. A 9-5/8-inch cement retainer constructed with corrosion-resistant materials will be set in the injection casing 100 ft above the top perforation (~ 3,126 ft measured depth [MD]). These depths may be re-evaluated once the MCI CCS 3 well has been drilled and formation depths have been established with greater certainty. Approximately 681 sacks of CO_2-resistant cement will be used to plug the injection interval; this includes a 10% excess volume to be squeezed through the perforations into the Mt. Simon Sandstone. It requires approximately 0.44 sack of cement to seal one foot of perforated casing (including the 10% excess), and this value may be used to estimate for amount of cement needed for different perforation scenarios.

The pressure used to squeeze the cement will be determined from the bottom-hole pressure data measured before beginning the plugging and abandonment process. The injection pressure of the cement will not exceed the fracture pressure of the Mt. Simon Sandstone. If it appears that the injection pressure will exceed the fracture pressure, and the total amount of cement has not been pumped into the injection zone, cement pumping will cease. After allowing the pressure to decrease to an acceptable level, cement pumping will be attempted again. A rapid increase in pressure on the tubing would indicate that the perforations have been sealed with cement, and no additional cement will be added to the zone or the plug.

In addition, cement plugs will be placed within the injection casing string at the casing shoes of the intermediate and surface strings. One hundred-foot-thick plugs will be placed between the 250 and 350 ft MD and between 2,650 and 2,750 ft MD using a balance method (Section 8.6). Approximately 36 sacks of Class A or G or H cement will be used for each of these plugs.

After the the top cement plug has been set, the casing sections will be cut off approximately 5 ft below grade, and a steel cap will be welded to the top of the deep casing string. The cap will have the well identification (ID) number, the UIC Class VI permit number, and the date of plug and abandonment inscribed on it. Soil will be backfilled around the well to bring the area around the well back to pre-well installation grade. This area will then be planted with natural vegetation.

The methods and materials described in the preceding paragraph are based upon current understanding of the geology at the site and current well designs. If necessary, the plans will be updated to reflect latest well designs. The new designs, materials, and methods will be described in the Notice of Intent to Plug submitted at least 60 days prior to the plugging of the well (40 CFR 146.92 (c)).

After the completion of the plugging activities, a plugging report will be submitted to the UIC Director describing the methods and tests that were performed on the well during plugging. This report will be submitted to the UIC Director within 60 days of completing the plugging activities (40 CFR 146.92 (d)).

Description	Cemented Interval (ft, MD)	Formation	Plugging Method	Plug Description	
				Type	Quantity
Perforated Interval	3,126−4,900	Mt. Simon Sandstone	Retainer	CO_2-Resistant	681 sacks
9-5/8-in. Casing Column	2,650-2,750	Eau Claire	Balance	Class A	36 sacks
9-5/8-in. Casing Column	250-350	Pennsylvanian	Balance	Class A	36 sacks

Table 8-2: Intervals to be plugged and materials/methods used (40 CFR 146.92 (b)(2 – 4)).

Plug Information	Plug #1	Plug #2	Plug #3
Diameter of boring in which plug will be placed (in.)	8.835	8.835	8.835
Depth to bottom of tubing or drill pipe (ft)	3,126	2,750	350
Sacks of cement to be used (each plug)	681*	36	36
Slurry volume to be pumped (ft^3)	728*	43	43
Slurry weight (lb./gal)	15.2	15.9	15.9
Slurry Yield (ft^3/sack)	1.07	1.18	1.18
Calculated top of plug (ft)	3,126	2,650	250
Bottom of plug (ft)	4,781	2,750	350
Type of cement or other material	CO_2- Resistant	Class A	Class A
Method of emplacement (e.g., balance method, retainer method, or two-plug method)	Retainer	Balance	Balance

Table 8-3: Information on proposed well plugs.

8.5 Detailed Pre-Plugging Procedure

1. Notify EPA 60 days in advance of plugging via letter of intent, and 48 hours prior to commencing field operations. Ensure proper notifications and permits are in place and given to all regulatory agencies for rig move.

2. Ensure all permits for Plug & Abandonment (P&A) procedure and work plan have been approved and work authorized by the EPA. With the injection well falling under the EPA Class VI Permit jurisdiction, State and Local agencies do not require notifications.

3. Ensure that advance pre-site inspection has been performed and the rig company has visited the site and is capable of transporting rig, tanks and ancillary equipment to perform P&A operations. Notify all key third parties of expected work scope, and ensure third-party contracts for work are in place prior to move in.

4. Provide on-site and at well location of all copies of permits prior to initiating operations. Monitor and ensure all permit conditions of approval have been met.

5. Confirm all necessary forms for Owner are on the rig, i.e., permits, safety meetings, trip sheets, etc.

8.6 Detailed Plugging and Abandonment Procedure (Post-Injection)

1. Conduct and document a safety meeting.

2. Conduct bottom hole pressures and MITs. See Sections 8.2 and 8.3.

3. Move-in (MI) rig and ancillary equipment onto MCI CCS 3 well site and rig up (RU). Nipple up and test BOPs, pressure test equipment and ensure proper operation.

4. Check wellhead tubing and casing pressures.

5. Record bottom-hole pressure from downhole gauge (if final pressure has not already been determined) and calculate kill fluid density.

6. Fill tubing with kill weight brine as determined by the final pressure measurement. Inject two tubing volumes of kill weight brine. Monitor tubing and casing pressure for 1 hour. Release from packer with tubing string and circulate one hole volume with kill weight brine.

    a. If the well is not dead or the pressure cannot be bled off of tubing, RU slickline and set plug in lower profile nipple below packer. Pick on tubing to remove tubing seals from packer and circulate tubing and annulus with kill weight fluid.

7. Release packer and pull out of hole with tubing laying it down. NOTE: Ensure that the well is over-balanced so there is no backflow due to formation pressure and there are at least two well control barriers in place at all times.

8. Trip into hole with work string with 9-5/8 inch cement retainer to a depth of 3,126 ft and set retainer to cement the perforated portion of the well, and prepare for cement plugging operations. Pump 681 sacks of CO_2-resistant cement (slurry weight of 15.2 pounds per gallon [lb/gal] through the retainer while maintaining bottom-hole pressure below fracture pressure). If it appears that the injection pressure will exceed the fracture pressure and the total amount of cement has not been pumped into the injection zone,

cement pumping will cease. After allowing the pressure to reduce to an acceptable level, cement pumping will be attempted again. A rapid increase in pressure on the tubing would indicate that the perforations have been sealed with cement, and no additional cement will be added to the zone or plug.

9. Trip tubing string out of well and remove stinger from end of tubing.

10. Trip tubing string to a depth of 2,750 ft and prepare to set second cement plug. Pump 36 sacks of Class A cement with 50% POZ (slurry weight of 14.7 lb/gal) using a balance method to cement between a depth of 2,650 and 2,750 ft.

11. Trip tubing string to a depth of 350 ft and prepare to set third cement plug. Pump approximately 36 sacks of Class A cement to fill the casing from a depth of 350 to 250 ft.

12. Cut the casing string off at 5 ft below grade and weld a steel plate, (with well ID, permit number, and date of abandonment on it) to the casing strings.

13. Backfill the excavation.

14. Rig down and move off service rig and any remaining exquipment.

The procedures described above are subject to modification during execution as necessary to ensure a plugging operation that protects worker safety and is effective to protect USDWs. Any significant modifications due to unforeseen circumstances will be described in the Plugging Report. The Plugging Report will be submitted to the EPA within 60 days after plugging is completed (40 CFR 146.92 (d)).

9.0 POST-INJECTION SITE CARE AND SITE CLOSURE PLAN
40 CFR 146.93(a)

MARQUIS BIOCARBON PROJECT

Facility Information

Facility name:	MARQUIS BIOCARBON PROJECT
Facility contact:	ELIZABETH STEINHOUR DIRECTOR OF ENVIRONMENTAL AFFAIRS 10000 MARQUIS DRIVE, HENNEPIN, IL 61327 815.925.7300 / BETHSTEINHOUR@MARQUISENERGY.COM
Well name:	MCI CCS 3
Well location:	PUTNAM COUNTY, ILLINOIS S2 T32N R2W Latitude: 41.27026520 N, Longitude: 89.30939322 W

Table of Contents

9.0 Post-Injection Site Care and Site Closure (PISC) Plan 5
9.1 Introduction 5
9.2 Pre- and Post-Injection Pressure Differential [40 CFR 146.93(a)(2)(i)] 5
9.3 Predicted Position of the CO_2 Plume and Associated Pressure Front at Site Closure (40 CFR 146.93(a)(2)(ii)) 6
9.4 Post-Injection Monitoring Plan (40 CFR 146.93(b)(1)) 10
9.4.1 Monitoring Above the Confining Zone 14
9.4.2 CO_2 Plume and Pressure Front Tracking (40 CFR 146.93(a)(2)(iii)) 16
9.4.3 Schedule for Submitting Post-Injection Monitoring Results (40 CFR 146.93(a)(2)(iv)) 18
9.5 Alternative Post-Injection Site Care Timeframe (40 CFR 146.93(c)) 19
9.5.1 Computational Modeling Results – 40 CFR 146.93(c)(1)(i) 19
9.5.2 Predicted Timeframe for Pressure Decline – 40 CFR 146.93(c)(1)(ii) 21
9.5.3 Predicted Rate of Plume Migration – 40 CFR 146.93(c)(1)(iii) 21
9.5.4 Confining Zone Characterization – 40 CFR 146.93(c)(1)(vii) 21
9.5.5 Assessment of Fluid Movement Potential – 40 CFR 146.93(c)(1)(viii)-(ix) 22
9.5.6 Location of USDWs – 40 CFR 146.93(c)(1)(x) 22
9.6 Non-Endangerment Demonstration Criteria 23
9.6.1 Introduction and Overview 23
9.6.2 Summary of Existing Monitoring Data 23
9.6.3 Summary of Computational Modeling History 23
9.6.4 Evaluation of Reservoir Pressure 24
9.6.5 Evaluation of CO_2 Plume 25
9.6.6 Evaluation of Emergencies or Other Events 25
9.7 Site Closure Plan 25
9.7.1 Plugging Monitoring Wells 26
9.7.2 Site Closure Report 30
9.7.3 Quality Assurance and Surveillance Plan (QASP) 31
References 32

List of Tables

Table 9-1: Summary of monitoring activities in the PISC phase of the project. 11

Table 9-2: Monitoring of ground water quality and geochemical changes above the confining zone. 14

Table 9-3: Summary of analytical and field parameters for ground water samples. 15

Table 9-4: Sampling and recording frequencies for continuous monitoring in the MCI ACZ 1 well. 16

Table 9-5: Post-injection phase CO_2 plume monitoring. 17

Table 9-6: Post-injection phase pressure-front monitoring. 18

Table 9-7: Intervals to be plugged and methods used when plugging the MCI MW 2 well. 28

Table 9-8: Intervals to be plugged and methods used when plugging the MCI ACZ 1 well. 28

Table 9-9: Materials used for plugging the MCI MW 2 well. 29

Table 9-10: Materials used for plugging the MCI ACZ 1 well 30

List of Figures

Figure 9-1: Pressure predictions at the MCI CCS 3 well based on Layer 153 with an elevation of 3,833 TVDSS, ft from the computation model for the 5-year injection phase and a post injection period of 50 years. 5

Figure 9-2: Map showing the modeled CO_2 plume footprint, AoR, and existing and proposed project wells within the AoR. 7

Figure 9-3: Cross section of the CO_2 plume at the end of the injection phase and at 3 and 5 years after the cessation of injection. 8

Figure 9-4: Predicted pressure plume response at the end of the injection phase and after 1, and 5 years after the cessation on injection. The pressure build-up cut-off is 150 psi. 9

Figure 9-5: Stratigraphic column from characterization well MCI MW 1 located at the Marquis BioCarbon Project site. 13

Figure 9-6: Plot of porosity and permeability relationships for High Side Case (orange line) and Low Side Case (blue line). The numbers on the orange are permeability values, number on the blue line are porosity values. The porosity permeability relationship for the base case was calculated from the ratio between permeability and porosity at the intersection of the curves. ... 20

Figure 9-7: CO_2 plume at layer 153 (used to delineate AoR) at the end of injection, 1, 5 and 10 years after injection stopped for the High Side Case (top row) and Low Side Case (bottom row). 20

9.0 Post-Injection Site Care and Site Closure (PISC) Plan

9.1 Introduction

This Post-Injection Site Care and Site Closure (PISC) plan describes the activities that Marquis Carbon Injection LLC will perform to meet the requirements of 40 CFR 146.93. Marquis Carbon Injection LLC will monitor groundwater quality and track the position of the carbon dioxide (CO_2) plume and pressure front for 5 years after the cessation of injection, which is the anticipated timeline for CO_2 plume and pressure front stabilization.

9.2 Pre- and Post-Injection Pressure Differential [40 CFR 146.93(a)(2)(i)]

Based on the modeling of the pressure front as part of the area of review (AoR) delineation, pressure at the MCI CCS 3 well is expected to decrease to pre-injection levels in less than 5 years, as described below. Additional information on the projected post-injection pressure declines and differentials is presented in the permit application and the AoR and Corrective Action Plan (Permit Section 2).

Figure 9-1 shows the modeling results of pressure behavior during the injection phase of the project and a 50-year post-injection period for Layer 153 within the computational model which is used to delineate the AoR for the project. Refer to the AoR and Corrective Action Plan (Permit Section 2) for more information on the delineation of the AoR. In the post injection phase, pressures at the MCI MW 2 and MCI CCS 3 (monitoring and injection) wells decrease to pre-injection levels in less than 5 years.

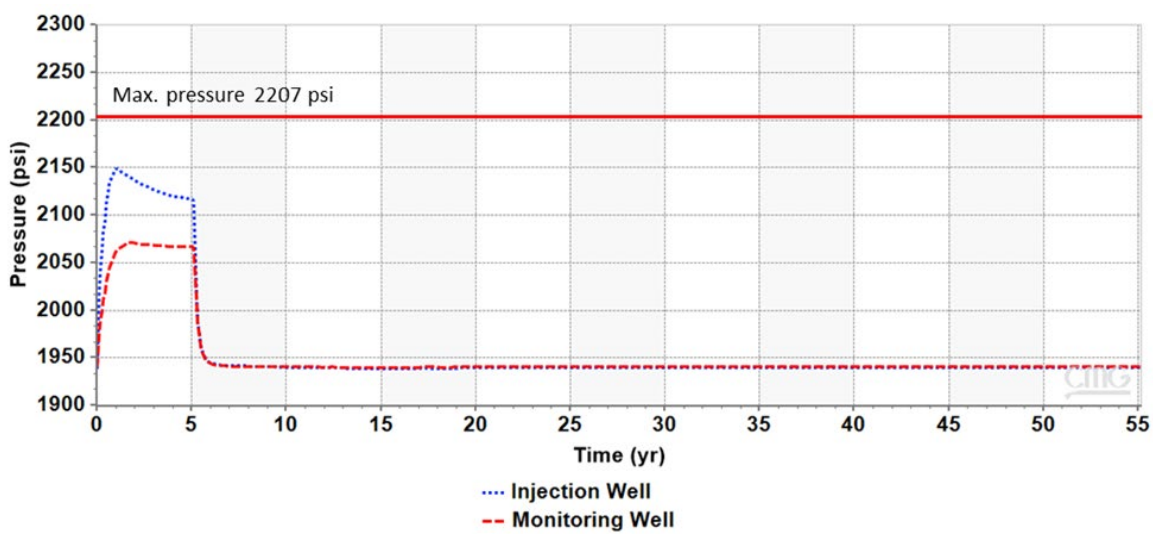


Figure 9-1: Pressure predictions at the MCI CCS 3 well based on Layer 153 with an elevation of 3,833 TVDSS, ft from the computation model for the 5-year injection phase and a post injection period of 50 years.

9.3 Predicted Position of the CO_2 Plume and Associated Pressure Front at Site Closure (40 CFR 146.93(a)(2)(ii))

Figure 9-2 shows the predicted extent of the CO_2 plume at the end of the PISC timeframe that represents the maximum extent of the CO_2 plume in relation to the AoR. This map is based on the final AoR delineation modeling results submitted pursuant to 40 CFR 146.84.

Figure 9-3 shows the predicted extent of the CO_2 plume at the end of the injection phase and at 3 and 5 years after the cessation of injection. The figures demonstrate the stability of the CO_2 plume during the PISC phase. Figure 9-4 shows a cross section of the pressure buildup around the MCI CCS 3 well at the end of the injection phase and at 3 and 5 years after the cessation of injection using a pressure build-up cut-off of 150 pounds per square inch (psi) to delineate the pressure front. The pressure front decreases rapidly after the injection period ends and decreases to the pre-injection pressure in less than 5 years.

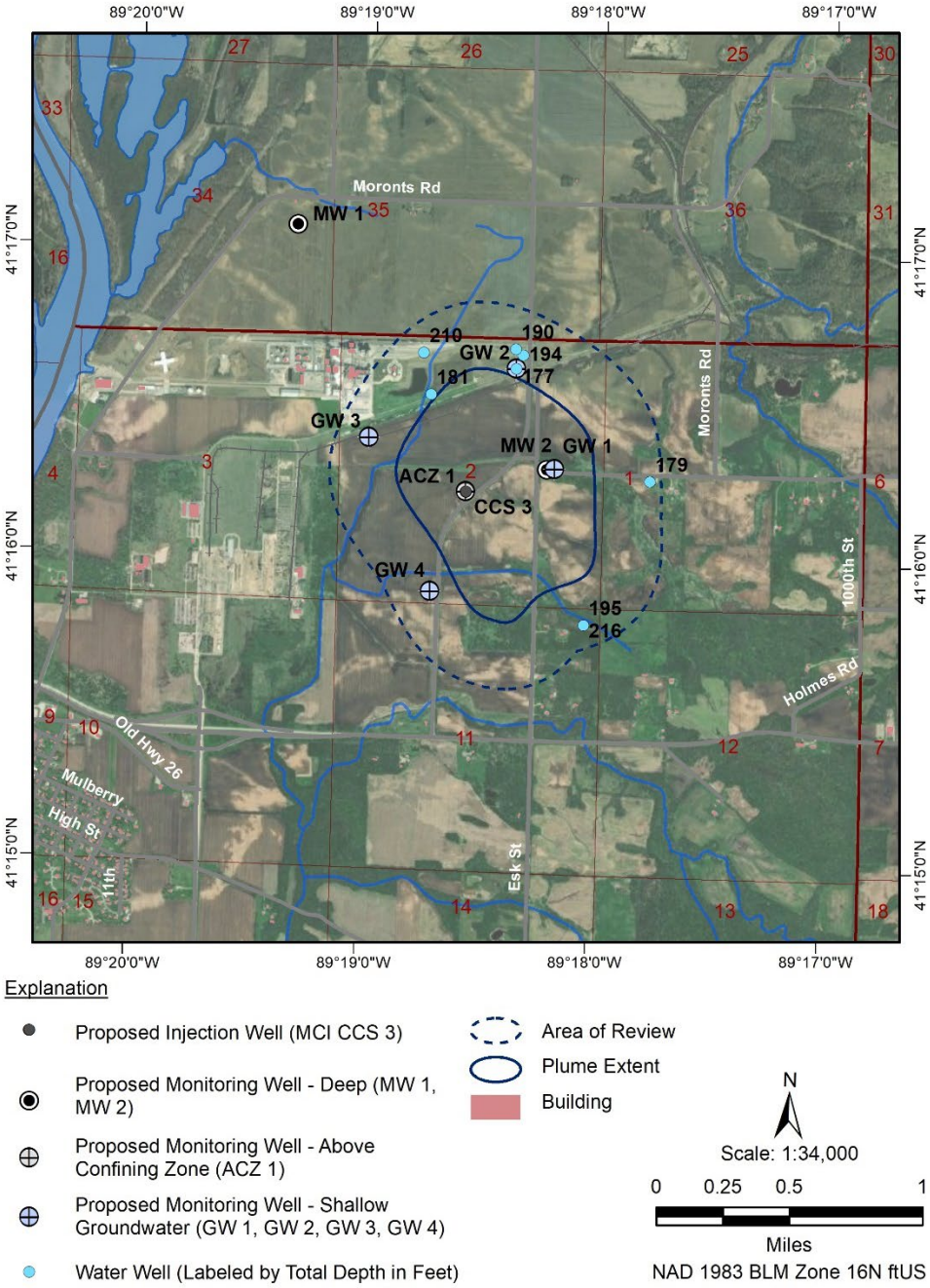


Figure 9-2: Map showing the modeled CO_2 plume footprint, AoR, and existing and proposed project wells within the AoR.

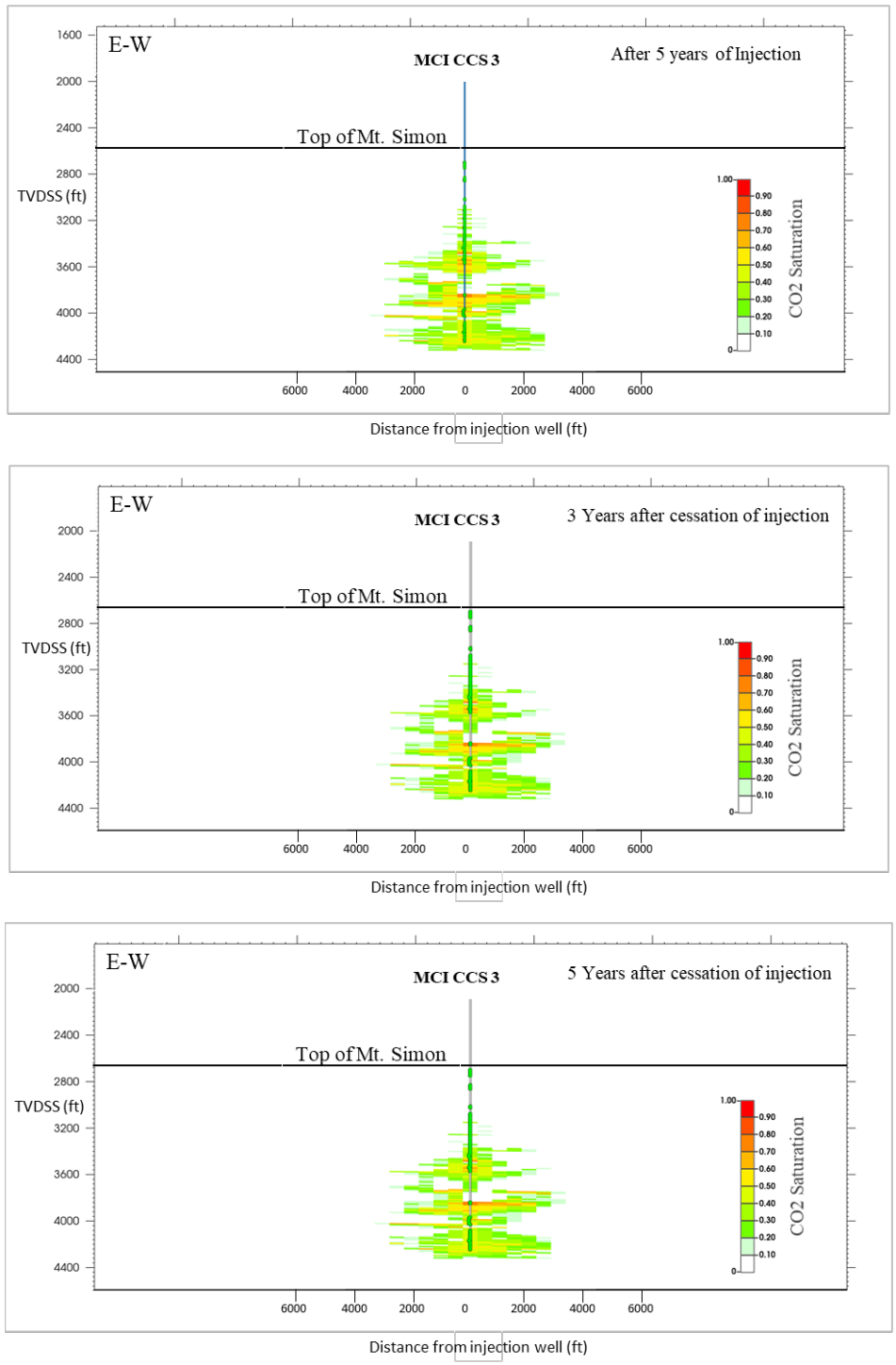


Figure 9-3: Cross section of the CO_2 plume at the end of the injection phase and at 3 and 5 years after the cessation of injection.

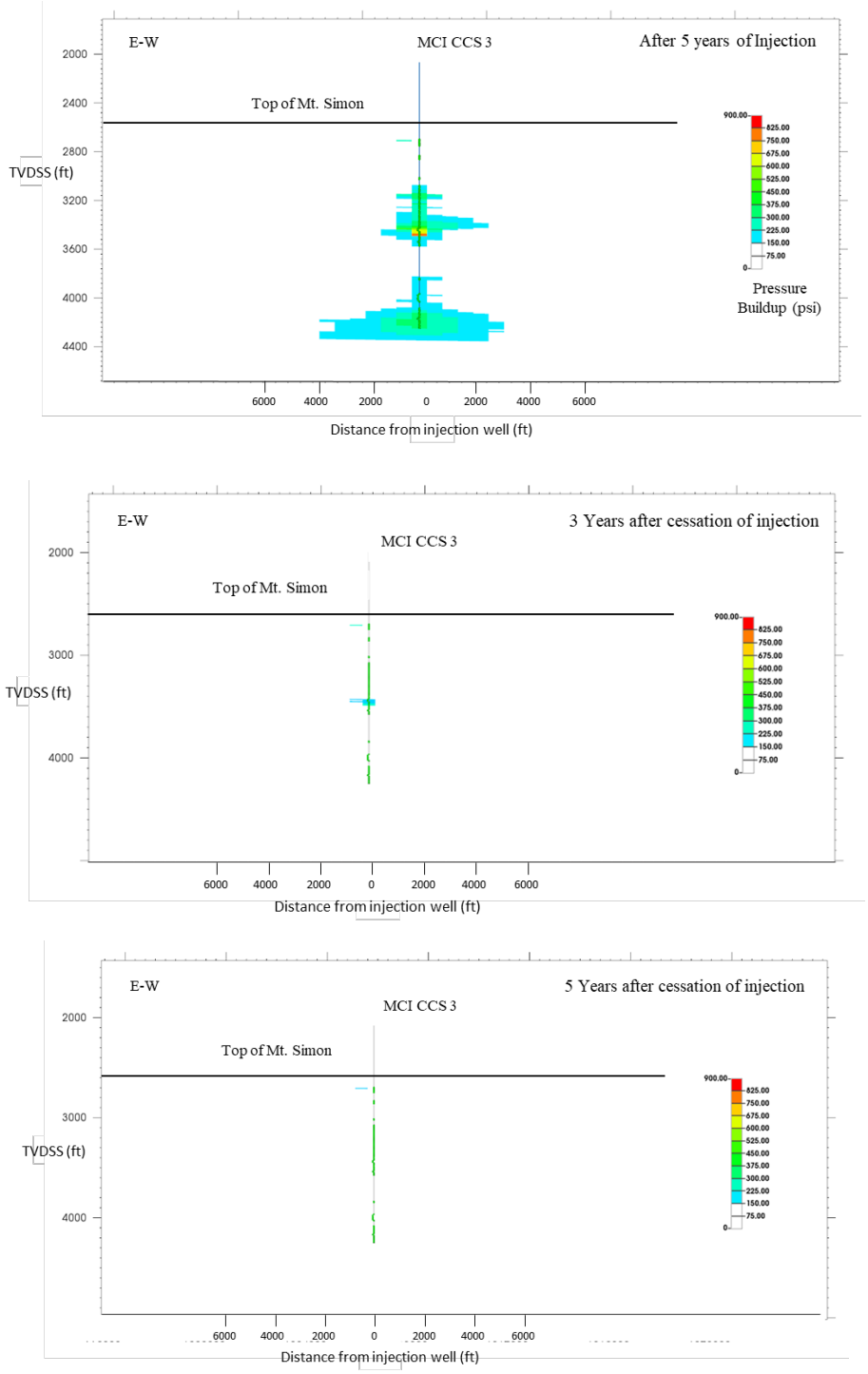


Figure 9-4: Predicted pressure plume response at the end of the injection phase and after 1, and 5 years after the cessation on injection. The pressure build-up cut-off is 150 psi.

9.4 Post-Injection Monitoring Plan (40 CFR 146.93(b)(1))

Performing groundwater monitoring, storage zone pressure monitoring, and geophysical monitoring as described in the following sections during the post-injection phase will meet the requirements of 40 CFR 146.93(b)(1). The results of all post-injection monitoring will be submitted semi-annually in Year 1 of the PISC and annually in subsequent years.

A quality assurance and surveillance plan (QASP) for all testing and monitoring activities during the injection and post-injection phases is provided in Appendix 7.A of the Testing and Monitoring Plan (Permit Section 7).

Table 9-1 summarizes the monitoring activities that will take place during the PISC phase of the project. The project will continue to monitor the well integrity of the MCI CCS 3 and MCI MW 2 wells on a yearly basis using temperature measurements to ensure that there is no migration of CO_2 up the wellbores. In addition, the annular pressures and fluid volumes in the MCI CCS 3 well will be monitored on a continuous basis until the well is plugged and abandoned. Annular pressure in the deep monitoring well will be monitored daily until the well is plugged and abandoned. Refer to the Well Operations Plan and the Testing and Monitoring Plan for more information on the well integrity and operational monitoring plans (Permit Sections 6 and 7, respectively).

Pulsed neutron capture (PNC) logging will continue in the MCI MW 2 well and the above confining zone (ACZ) monitoring well (MCI ACZ-1) in the second quarter of each year of the PISC phase. This will allow the project to continue to characterize the vertical plume development in the Mt. Simon Sandstone in the MCI MW 2 well and further verify that CO_2 is not migrating past the confining zone and into the ACZ aquifers, thereby endangering underground sources of drinking water (USDWs). Refer to the Testing and Monitoring Plan for more information on the PNC logging plans in the injection phase of the project (Permit Section 7).

The project will continue to monitor pressures within the Mt. Simon Sandstone in the MCI MW 2 well and pressure at the top of the Mt. Simon Sandstone in the MCI CCS 3 well until it is abandoned. The pressure within the Mt. Simon Sandstone is expected to begin to dissipate once CO_2 injection ceases based on the computational modelling. The Mt. Simon Sandstone pressure measurements are expected to verify the pressure decrease, and the data will be used to history match the computational modelling in the PISC phase.

Monitoring Activity	PISC Frequency*	Location	Depth Range (ft, MD)
Assurance Monitoring:			
Shallow Groundwater Sampling	Twice/year	GW-1, 2, 3 & 4 wells within AoR	Producing zone
Isotope Analysis	Twice/year	GW-1, 2, 3 & 4 wells within AoR	0 – TD
Operational Monitoring:			
Annular Pressure	Continuous	MCI CCS 3 well	Surface
Annular Fluid Volume	Continuous	MCI CCS 3 well	Surface
Annular Pressure	Daily	MCI MW 2 well	Surface
Temperature Measurement	Annually Annually	MCI CCS 3 well MCI MW 2 well	0 – TD 0 – TD
Verification Monitoring:			
Fluid Sampling			
Gunter Sandstone Galesville Sandstone Upper Mt. Simon Sandstone	Twice/year Twice/year Twice/year	MCI ACZ 1 well MCI ACZ 1 well MCI MW 2 well	2,134 2,651 3,110
Isotope Analysis	Twice/year	MCI ACZ 1 well MCI MW 2 well	All samples
Pressure – Temperature Sensors			
Gunter Sandstone Galesville Sandstone Upper Mt. Simon Sandstone	Continuous Continuous Continuous	MCI ACZ 1 Well MCI ACZ 1 Well MCI MW 2 well	2,134 2,651 3,100
PNC Logging	Once/ year	MCI MW 2 well MCI ACZ 1 well	2,134 – TD 2,134 – TD
Microseismic Monitoring	Continuous	Surface stations	TBD
Time-lapse 3D Surface Seismic Data	Every 5 years and as required.	Surface	

Table 9-1: Summary of monitoring activities in the PISC phase of the project.

Pressures will also continue to be monitored in the Galesville Sandstone and the deepest USDW to confirm the continued containment of CO_2 within the storage formation (Figure 9-5). Fluid

samples will be taken from the Galesville Sandstone and deepest USDW once a year for geochemical and isotopic analysis to further verify CO_2 containment. Shallow groundwater fluid samples will also be obtained each year from the shallow groundwater wells, MCI GW 1-4, for geochemical and isotopic analysis.

Microseismic activity is expected to return to background (pre-injection) levels once the injection phase of the project is complete and the associated pressure plume begins to dissipate. The microseismic monitoring would then be phased out in the first six to twelve months of the PISC phase. This will be evaluated in the first months of the PISC phase of the project, and no decisions will be made without consultation with the Underground Injection Control (UIC) Program Director (UIC Director).

The project proposes to acquire two time-lapse three-dimensional (3D) surface seismic surveys in the PISC phase of the project. One will be acquired within one year of the end of the injection phase or at the start of the PISC phase of the project. The final survey will be acquired in the final year of the PISC phase of the project. The objectives of these two surveys include:

- Verification of continued CO_2 containment in the storage formation
- Demonstration of the stability of the CO_2 plume after the injection phase of the project
- Providing data for the calibration and verification of the computational modelling

These data will be used to demonstrate non-endangerment of USDWs at the end of the PISC phase (Section 5.0).

Marquis companies own the land on which the injection, deep monitoring, and ACZ wells are located. Marquis also owns the land on which the shallow groundwater wells used for monitoring are located. The wells are on flat farmland not near residential areas. Access to the wells is not anticipated to be an issue for the PISC phase of the project.

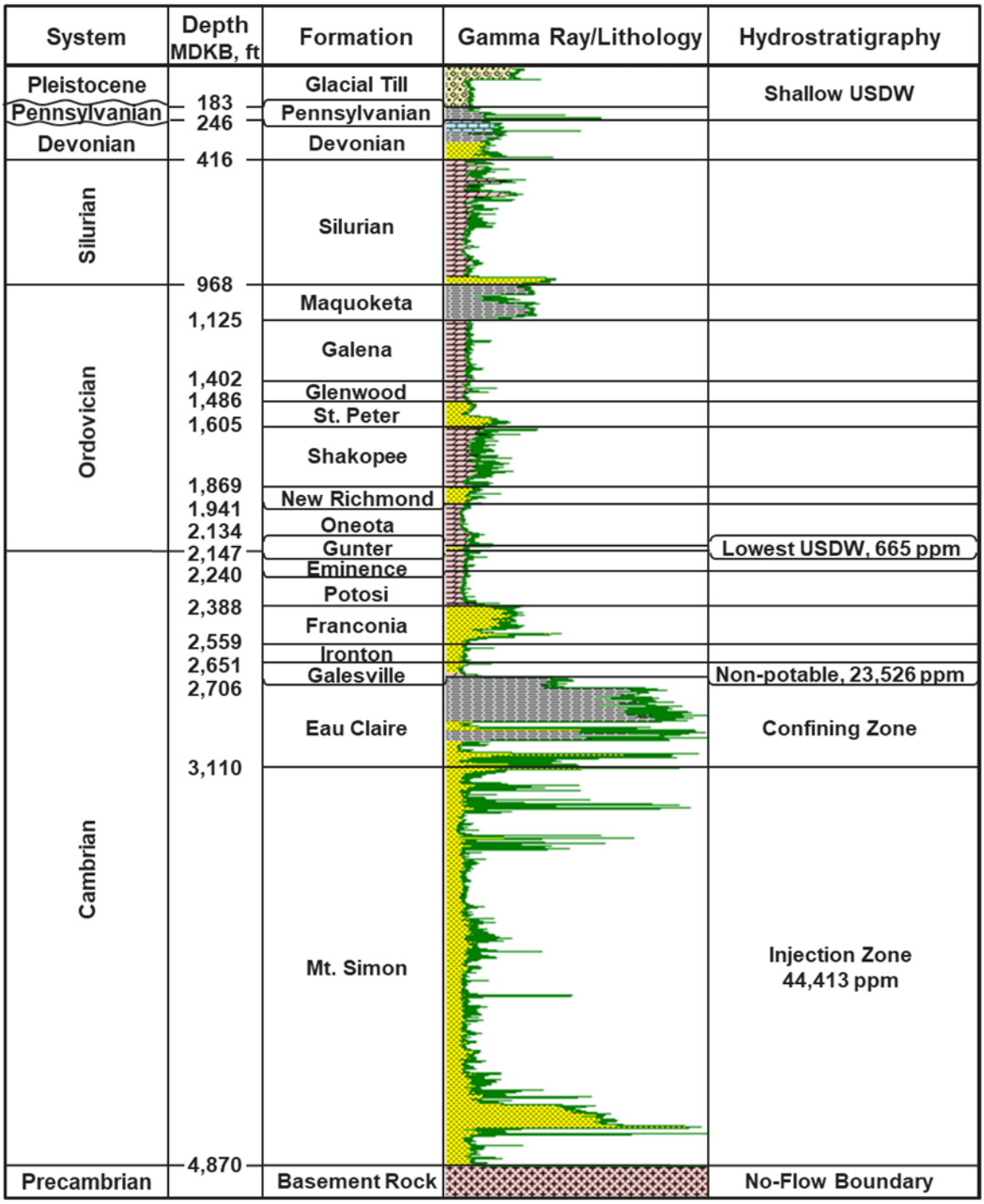


Figure 9-5: Stratigraphic column from MCI MW 1 well located at the Marquis BioCarbon Project site.

9.4.1 Monitoring Above the Confining Zone

The monitoring plan for the PISC is designed to be adaptive and respond to evolving project risks over time. At this point in the project, no phased monitoring has been planned for the MCI ACZ 1 well; however, this may be assessed later as the project progresses. No changes will be made to the PISC without informing the UIC Director (40 CFR 146.93 (a)(3)).

Table 9-2 presents the proposed MCI ACZ 1 and groundwater monitoring wells monitoring methods, locations, and frequencies. For fluid sampling, a bailer system or like method that maintains the formation pressure of the sample will be used to collect water samples to be analyzed for dissolved inorganic carbon, alkalinity, pH, and isotopic parameters. Samples for all other analytes will be collected with an open-ended bailer. Prior to sample collection the well will be swabbed to remove stagnant water and ensure representative water is collected from the formation. The fluid swabbed from the well will be monitored for field parameters, such as pH, specific conductance, and temperature, using a calibrated water quality meter (Horiba U-53, or similar). Once these parameters stabilize, it will be an indication that representative formation fluid is in the well at the time the sample is collected.

Target Formation	Monitoring Activity	Monitoring Location(s)	Spatial Coverage	Frequency
Shallow Groundwater	Groundwater geochemistry and stable isotopes	Select Shallow groundwater wells in AoR	88 – 246 ft, MD	Q2/ year after injection ceases
Gunter Sandstone	Groundwater geochemistry and stable isotopes	MCI ACZ-1	TBD	Q2/ year after injection ceases
Galesville Sandstone	Groundwater geochemistry and stable isotopes	MCI ACZ-1	~2,670 ft, MD	Q2/ year after injection ceases
Galesville Sandstone	PNC Logging	MCI ACZ-1	2,500 – 2,800 ft, MD	Q2/ year after injection ceases

Table 9-2: Monitoring of ground water quality and geochemical changes above the confining zone.

Table 9-3 identifies the initial groundwater parameters to be monitored and the analytical methods that will be used for the samples in the baseline analysis of the data. During the pre-injection and injection phases, the project will assess which subset of analytes are most responsive to interactions with CO_2, so the list of analytes will be reduced in the future (Permit Section 7). However, no changes will be implemented without consultation with the UIC Director.

Parameters	Analytical Methods
Cations (Na, Ca, Mg, Ba, Sr, Fe, K)	ASTM D1976
Anions (Cl, Br, SO_4)	ASTM D4327
pH	ASTM D1293
Alkalinity	ASTM D3875
Total Dissolved Solids (TDS)	ASTM D5907
Density	ASTM D4052
Dissolved Inorganic Carbon	ASTM D513-11
Conductivity/Resistivity	ASTM D1125
Stable Isotopes of C, O, and H	ASTM STP 573
Carbon-14	

Table 9-3: Summary of analytical and field parameters for ground water samples.

A nationally certified laboratory will be selected for the groundwater sampling and analysis. The sampling and analytical measurements will be performed in accordance with project quality assurance requirements. Samples will be tracked using appropriately formatted chain-of-custody forms. See the QASP for additional information (Permit Section 7, Appendix 7.A).

The results of the geochemical and isotope analysis will be delivered in the form of laboratory reports. If anomalous changes in the aqueous geochemistry are observed in the ACZ monitoring zones, new samples will be obtained from the affected aquifer and sent for analysis to verify the changes.

If anomalous changes are confirmed (greater than 5% deviation from baseline values as described in the Testing and Monitor Plan [Section 7.5]), the frequency with which fluid samples are obtained from the ACZ aquifers for analysis will be increased. As a precautionary measure, the fluid sampling frequency for the shallow groundwater monitoring wells will also be increased in consultation with the UIC Director. If the injected CO_2 has a unique isotopic signature from the existing isotopes in the overlying aquifers, a new round of samples will be collected for isotopic analysis from the affected aquifer. Confirmed anomalous changes may also trigger the need for additional well integrity testing in both the MCI MW 2 well and the MCI CCS 3 well to ensure that no well integrity issues have developed since the last set of external mechanical integrity tests. A combination of anomalous pressure, geochemical, and well integrity testing results may result in the decision to acquire a time-lapse surface seismic survey before the survey scheduled in year five of the PISC to determine the size of the leakage accumulation (Table 9-1).

Table 9-4 presents information about the continuous monitoring devices to be used in the deepest USDW and the Galesville Sandstone. The pressure/temperature data will be stored as time

stamped data pairs. Migration of CO_2 or brine into the MCI ACZ 1 well will likely first be identified through pressure changes in the aquifers. An increasing pressure trend in either aquifer would suggest that leakage across the confining layer is occurring. While any increasing trend in pressure or temperature will be evaluated, an increase in pressure or temperature greater than 5% above baseline values will warrant additional monitoring and inspections to rule out the possibility of fluid leakage out of the storage formation. Such an increase in pressure or temperature would initiate more frequent fluid sampling and analysis for geochemical parameters from the aquifer with the pressure/temperature increase. An increase in pressures or temperatures in the MCI ACZ 1 well may also trigger additional external well integrity investigations in the MCI CCS 3 or MCI MW 2 well.

Parameter	Device(s)	Location	Min. Sampling Frequency	Min. Recording Frequency
Pressure	Pressure Gauge	Deepest USDW Galesville Sandstone	Every 1 min.	Every 1 min.
Temperature	Temperature Gauge	Deepest USDW Galesville Sandstone	Every 1 min.	Every 1 min.

Notes:
- Sampling frequency refers to how often the monitoring device obtains data from the well for a particular parameter. For example, a recording device might sample a pressure transducer monitoring injection pressure once every two seconds and save this value in memory.
- Recording frequency refers to how often the sampled information gets recorded to digital format (such as a computer hard drive). For example, the data from the injection pressure transducer might be recorded to a hard drive once every minute.

Table 9-4: Sampling and recording frequencies for continuous monitoring in the MCI ACZ 1 well.

9.4.2 CO_2 Plume and Pressure Front Tracking (40 CFR 146.93(a)(2)(iii))

Marquis Carbon Injection LLC will employ direct and indirect methods to track the extent of the CO_2 plume and the presence or absence of elevated pressure.

Table 9-5 presents the direct and indirect methods that will be used to monitor the CO_2 plume including the activities, locations, and frequency of sampling.

Fluid sampling will be performed as described in Section B.2 of the QASP; sample handling and custody will be performed as described in B3 of the QASP; and quality control will be ensured using the methods described in B5 of the QASP. Quality assurance procedures for seismic monitoring methods are presented in B9 of the QASP (Permit Section 7, Appendix 7.A).

Target Formation	Monitoring Activity	Monitoring Location(s)	Spatial Coverage	Frequency
Direct Plume Monitoring				
Galesville, Eau Shale, and Mt. Simon Formations	Pulsed Neutron Logging	Deep monitor well	2,600 – 4,800 ft, MD	Q2/ Year
Indirect Plume Monitoring				
Galesville, Eau Shale, and Mt. Simon Formations	Time-lapse 3D Surface Seismic Data	Over project AoR	To be confirmed prior to survey	Q2, Year 1 Q2, Year 5

Table 9-5: Post-injection phase CO_2 plume monitoring.

The PNC logs will be received as log ascii standard (LAS) files and interpreted products that can be imported into the static earth model (SEM). PNC logging will be used to monitor the distribution and saturation of CO_2 adjacent to the wellbore in the MCI MW 2 well. The PNC logs will be acquired through the Galesville Sandstone in the MCI MW 2 well to confirm the absence of CO_2 accumulations along the wellbores above the confining layer. Technical details on PNC logging tools can be found in the QASP (Permit Section 7, Appendix 7.A).

Surface seismic data are delivered in a variety of formats including acquisition and processing reports and raw data files from a variety of points in the processing flow. In the context of time-lapse analysis, an assessment will be provided on the differences between the baseline and time-lapse surveys as well as data files that can be incorporated into the SEM. The injection of CO_2 and expansion of the plume is expected to change the acoustic impedance of the Mt. Simon Sandstone over time. These acoustic impedance changes will be used to track the CO_2 plume during the PISC phase of the project. The time-lapse surface seismic data will also be monitored for changes that may suggest that CO_2 has migrated past the confining layer.

Table 9-6 presents the direct and indirect methods that will be used to monitor the pressure front. The pressure/temperature sensors will be programmed to measure and record pressure and temperature readings every 60 sec. The gauges will be retrieved for data download on a quarterly basis. A pair of gauges will be placed in each zone to limit the possibility of data loss. The final monitoring interval in the upper Mt. Simon Sandstone will be determined after the MCI CCS 3 well has been drilled and the well logs have been analyzed (Pre-Operational Testing Program, Permit Section 5). Two pressure sensors will also be set at the MCI CCS 3 well to measure the pressure fall-off at the top of the Mt. Simon Sandstone until the well is abandoned. The pressure/temperature data will be stored as time-stamped data pairs that can used for history matching in the computational model.

Target Formation	Monitoring Activity	Monitoring Location(s)	Spatial Coverage	Frequency
Direct Pressure-Front Monitoring				
Upper Mt. Simon Sandstone	Pressure Monitoring	MCI MW 2	3,100 – 3,500 ft, MD Exact TBD	Continuous
Top Mt. Simon Sandstone	Pressure Monitoring	MCI CCS 3 well	3,100 ft, MD	Continuous
Indirect Pressure-Front Monitoring				
Eau Claire and Mt. Simon Formations, and Precambrian Basement	Microseismic Monitoring	5 Surface Stations	AoR	Continuous

Table 9-6: Post-injection phase pressure-front monitoring.

The results of the geochemical and isotope analysis, PNC logging, and time-lapse 3D surface seismic data will all be integrated to develop a comprehensive understanding of the CO_2 plume development over time. PNC logging and time-lapse 3D surface seismic data can be incorporated into the SEM for comparison to the computational modelling predictions at different points in time. Based on the current computational modelling results, the CO_2 plume is predicted to stabilize (Figure 9-3), and the pressure plume is predicted to rapidly decrease to pre-injection levels within the proposed 5-year PISC phase. Time-lapse 3D surface seismic surveys acquired during Year 1 and Year 5 of the PISC phase will characterize the stabilization of the CO_2 plume. The pressure data from the MCI MW 2 and MCI CCS 3 wells will verify the decline in formation pressures predicted by the computational modelling.

The increase in pressure in a storage formation is one of the primary drivers for CO_2 and brine migration beyond the confining layer and potentially endangering USDWs. The rapid decrease in pressure in the Mt. Simon Sandstone coupled with the ACZ monitoring and absence of evidence for CO_2 migration beyond the confining layer will demonstrate the non-endangerment of USDWs within the AoR (Section 9.5).

9.4.3 Schedule for Submitting Post-Injection Monitoring Results (40 CFR 146.93(a)(2)(iv))

All PISC monitoring data and results collected using the methods described above will be submitted in reports to the EPA. In the first year of the PISC phase, reports will be submitted on a semi-annual basis. After the first year of the PISC phase, reports will be submitted annually. The reports will contain information and data generated during the reporting period (i.e., well-based monitoring data, sample analysis, and the results from updated site models). The initial Year 1 report will be submitted within eight months after the date that injection stops or alternatively on a data agreed upon with the UIC Director.

9.5 Alternative Post-Injection Site Care Timeframe (40 CFR 146.93(c))

Marquis Carbon Injection LLC will conduct post-injection monitoring for a five-year period following the cessation of injection operations. A justification for this alternative PISC timeframe is provided below.

9.5.1 Computational Modeling Results – 40 CFR 146.93(c)(1)(i)

Figure 9-3 shows the cross section of the predicted CO_2 plume extent and demonstrates the CO_2 plume stability during alternative PISC timeframe. Figure 9-4 illustrates a cross section of the predicted pressure front during the post-injection period. The pressure front declines quickly during the post-injection period. Figure 9-1 shows, the predicted pressure at the MCI CCS 3 well reaches pre-injection pressure in less than the proposed 5-year PISC timeframe. Given the fast CO_2 plume stabilization and rapid pressure decrease in the Mt. Simon Sandstone predicted by the computational modeling, a 5-year PISC is appropriate to ensure USDW protection.

This was further supported by a sensitivity analysis to test the effects of varying the porosity and permeability relationships on the CO_2 plume shape and pressure behavior (Figures 9-6 and 9-7). High side and low side case runs, testing two porosity permeability relationships in addition to the base case were performed. The permeability vs porosity plot for each case in the Mt Simon is shown Figure 9-6. The results of the sensitivity analysis indicate that the CO_2 plume shape is similar in both cases compared to the base case scenario (Figure 9-7). Details related to this sensitivity analysis are discussed further in AoR and Corrective Action Plan Section (Permit Section 2.6.7).

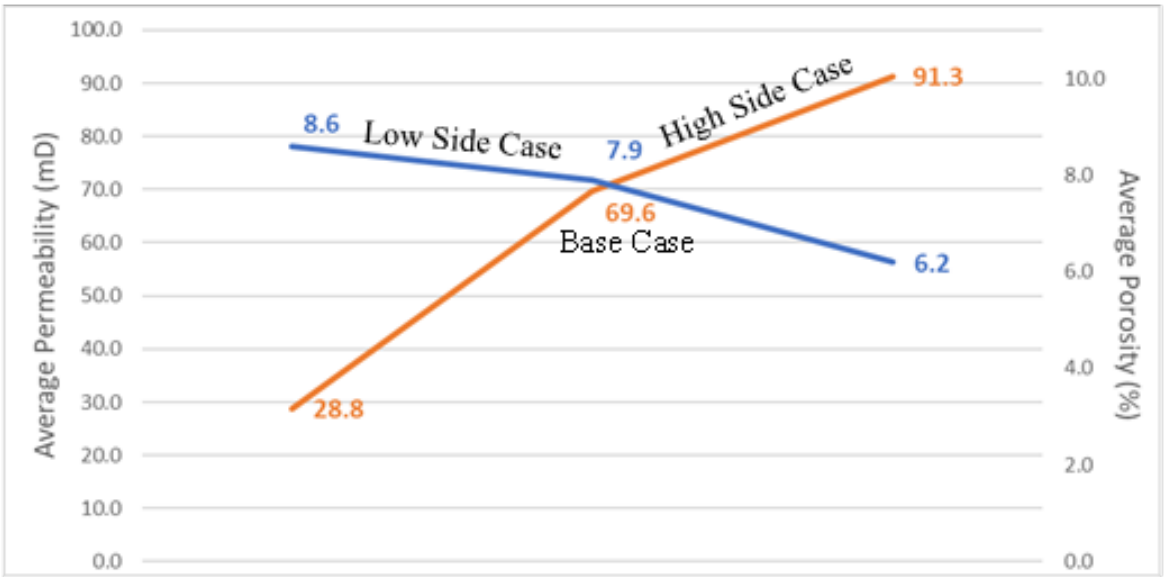


Figure 9-6: Plot of porosity and permeability relationships for High Side Case (orange line) and Low Side Case (blue line). The numbers on the orange are permeability values, number on the blue line are porosity values. The porosity permeability relationship for the base case was calculated from the ratio between permeability and porosity at the intersection of the curves.

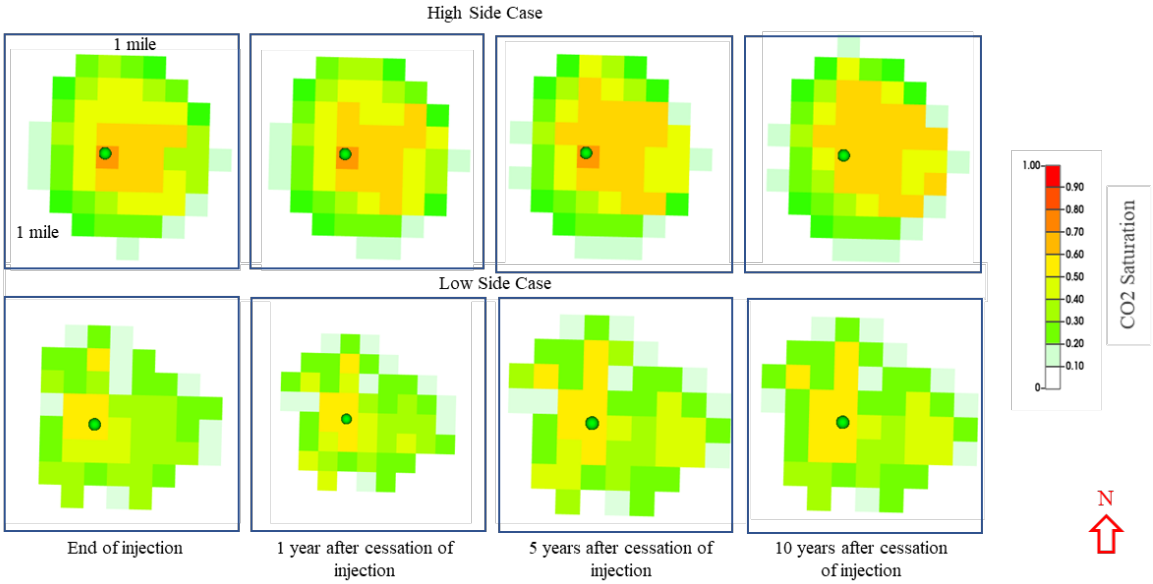


Figure 9-7: CO_2 plume at layer 153 (used to delineate AoR) at the end of injection, 1, 5 and 10 years after injection stopped for the High Side Case (top row) and Low Side Case (bottom row).

9.5.2 Predicted Timeframe for Pressure Decline – 40 CFR 146.93(c)(1)(ii)

Figure 9-4 shows the cross section of the pressure front during the post injection phase. Additional plots and figures, showing the pressure front during the injection period, can be found in the AoR and Corrective Action Plan Section (Permit Section 2). The maximum spatial extent of the pressure front occurs at the end of the injection period. Figure 9-1 shows the predicted pressure buildup and decline at the MCI CCS 3 well through the injection phase and for 50 years of the post-injection period. The pressure declines immediately following cessation of injection and is predicted to be heterogenous between the MCI CCS 3 and MCI MW 2 wells (Figure 9-1). The details related to sensitivity analysis can be found in the AoR and Corrective Action Plan Section (Permit Section 2). A comparison of the pressure time series from the sensitivity analysis demonstrates that the pressure buildup during the injection phase and rapid decline during the PISC phase are similar to the base case scenario for different porosity permeability relationships (Figure 9-8).

Continuous pressure measurements will be acquired from the Mt. Simon Sandstone through the injection and PISC phases of the project (Testing and Monitoring Plan, Permit Section 7). The pressure data obtained during the injection phase of the project will be used to update the computational modelling every six months as per the reporting requirements in 40 CFR 146.91. Pressure data acquired during the PISC phase of the project are expected to verify the rapid decline in pressure in the Mt. Simon Sandstone predicted by the computational modelling.

9.5.3 Predicted Rate of Plume Migration – 40 CFR 146.93(c)(1)(iii)

Figure 9-3 shows the cross section of the CO_2 plume remains relatively stable from the end of the injection period to Year 3 and Year 5 of the PISC phase. Additional figures illustrating the predicted CO_2 plume expansion during the injection period are provided in the AoR and Corrective Action Plan Section (Permit Section 2). The average CO_2 plume extent was utilized to define the AoR. The details related to sensitivity analysis are presented in the AoR and Corrective Action Plan Section (Permit Section 2.6.7). The results from the sensitivity analysis show that the CO_2 plume shape remains a similar or smaller size and shape for the different modeled porosity permeability relationships (Figure 9-7).

9.5.4 Confining Zone Characterization – 40 CFR 146.93(c)(1)(vii)

The Eau Claire Formation is the primary confining unit for the project. The base of the Eau Claire Formation is comprised of the sandy Elmhurst Member where some CO_2 mobility is expected over time. However, the Eau Claire Formation has known thick and continuous shale intervals (Eau Claire Shale) above the Elmhurst Member, which have been confirmed as having good sealing capacity with core analysis (Permit Section 5). The Pre-Operational Testing Plan details the characterization that has been completed for the Eau Claire Shale (Permit Section 5).

This included assessing the mineralogy, geomechanics, and capillary pressure within the Eau Claire Shale.

The properties of the Eau Claire Formation were distributed within a static reservoir model and then imported into the computational model. Figure 9-3 shows the cross section of the plume map at the end of the injection period and for Years 3 and 5 of the PISC phase. Additional figures illustrating the CO_2 plume behavior during a 50-year post-injection period have been included in the AoR and Corrective Action Plan Section (Permit Section 2). Computational modeling results show that there would be no CO_2 penetration into the Eau Claire Shale during the injection and post-injection modeling period due to the low permeability of the Eau Claire Shale.

9.5.5 Assessment of Fluid Movement Potential – 40 CFR 146.93(c)(1)(viii)-(ix)

There is no evidence of geological conduits within the AoR. Also, within the AoR there are no existing wells that penetrate either the injection zone or the confining layer, so no corrective action is required.

The MCI CCS 3 well will be constructed according to the USEPA Class VI regulations, and several measures will be incorporated in the well design to ensure protection of the USDWs at the site following the injection period (Injection Well Construction Plan, Permit Section 4). The long casing string and packer will be constructed of corrosion-resistant alloys (CR13) across the injection reservoir and confining zone to reduce the chances of casing degradation over the long term. Similarly, a CO_2-resistant cement will be pumped behind the deep string casing across the injection reservoir and confining zone. Following completion of the injection phase of the project and monitoring efforts, the MCI CCS 3 well will be plugged and abandoned according to the EPA Class VI guidelines, including the use of CO_2-resistant cement across the storage formation (Injection Well Plugging Plan, Permit Section 8).

During the injection and PISC phases of the project, the well integrity of the MCI CCS 3 and MCI MW 2 wells will be monitored through several internal and external monitoring techniques (Section 9.3, Permit Section 7). Annular pressures and fluid volumes will be monitored in the MCI CCS 3 well on a continuous basis until the MCI CCS 3 well is abandoned. Annular pressures in the MCI MW 2 well will be monitored daily. Temperature logging is the primary external mechanical integrity test that will be used to monitor the MCI CCS 3 and MCI MW 2 wells on an annual basis.

9.5.6 Location of USDWs – 40 CFR 146.93(c)(1)(x)

At the Marquis BioCarbon Project site, the Mt. Simon Sandstone is not considered a USDW based on salinity samples acquired from MCI MW 1 with total dissolved solids (TDS) concentrations greater than 10,000 milligrams per liter (mg/L) or 10,000 parts per million (ppm).

The lowermost USDW is defined locally as the Gunter Sandstone of the Prairie du Chien Group (Knox Supergroup). At the MCI MW 1 well, the base of the Gunter Sandstone is 963 feet (ft) above the top of the Mt. Simon. USDWs in the project site range from the Gunter Sandstone (deepest USDW) to shallow, near-surface glacial till aquifers.

9.6 Non-Endangerment Demonstration Criteria

Prior to approval of the end of the post-injection phase, Marquis Carbon Injection LLC will submit a demonstration of non-endangerment of USDWs to the UIC Director, per 40 CFR 146.93(b)(2) and (3).

The owner or operator will issue a report to the UIC Director. This report will make a demonstration of USDW non-endangerment based on the evaluation of the site monitoring data used in conjunction with the project's computational model. The report will detail how the non-endangerment demonstration evaluation uses site-specific conditions to confirm and demonstrate non-endangerment. The report will include all relevant monitoring data and interpretations upon which the non-endangerment demonstration is based, model documentation and all supporting data, and any other information necessary for the UIC Director to review the analysis. The report will include the following sections:

9.6.1 Introduction and Overview

A summary of relevant background information will be provided, including the operational history of the injection project, the date of the non-endangerment demonstration relative to the post-injection period outlined in this PISC and Site Closure Plan, and a general overview of how monitoring and modeling results will be used together to support a demonstration of USDW non-endangerment.

9.6.2 Summary of Existing Monitoring Data

A summary of all previous monitoring data collected at the site, pursuant to the Testing and Monitoring Plan (Permit Section 7) and this PISC and Site Closure Plan, including data collected during the injection and post-injection phases of the project, will be submitted to help demonstrate non-endangerment. Data submittals will be in a format acceptable to the UIC Director [40 CFR 146.91(e)], and will include a narrative explanation of monitoring activities, including the dates of all monitoring events, changes to the monitoring program over time, and an explanation of all monitoring infrastructure that has existed at the site. Data will be compared with baseline data collected during site characterization [40 CFR 146.82(a)(6) and 146.87(d)(3)].

9.6.3 Summary of Computational Modeling History

The results of computational modeling used for AoR delineation and for demonstration of an

alternative PISC timeframe will be compared to the monitoring data collected during the injection and PISC phases of the project. The monitoring data used to update and calibrate the computational modeling and to demonstrate non-endangerment of USDWs will include:

- Pressure monitoring data from the Mt. Simon Sandstone, Galesville Sandstone, and the deepest USDW
- Microseismic data
- PNC logs that characterize CO_2 saturations and vertical plume development along the well bores
- Time-lapse 3D seismic data

Data generated during the PISC period will be used to help show that the computational model accurately represents the storage site and can be used as a proxy to determine the CO_2 and pressure plume's properties and size. Marquis Carbon Injection LLC will demonstrate this degree of accuracy by comparing the monitoring data obtained during the PISC period against the model's predicted properties such as plume location, rate of movement, and pressure decay. The validation of the computational model with the large volume of available data will be a significant element to support the non-endangerment demonstration. The validation of the computational modeling results over the areas and zones where monitoring data have been collected will help to ensure confidence in those areas of the model where surface infrastructure precludes the collection of time-lapse 3D surface seismic data or the installation of monitoring wells.

9.6.4 Evaluation of Reservoir Pressure

During the PISC phase, the computational modeling predicts that the pressure in the Mt. Simon Sandstone will steadily decrease toward the pre-injection static pressure. One of the primary forces driving CO_2 or brine migration out of the storage formation is a pressure increase in the storage formation. Figure 9-1 illustrates the rapid decrease in pressure back to pre-injection levels in the Mt. Simon Sandstone once the injection phase of the project ends; and pressure decline toward pre-injection levels is one factor indicative of USDW non-endangerment.

The project will monitor pressure in the Mt. Simon Sandstone in the MCI MW 2 well and at the top of the Mt. Simon Sandstone in the MCI CCS 3 well with downhole pressure gauges (Table 9-6). The measured pressure will be compared to the pressure predicted by the computational model at the same depth. Agreement between the actual and the predicted values will help validate the accuracy of the model and further demonstrate non-endangerment.

9.6.5 Evaluation of CO_2 Plume

During the injection and PISC phases of the project, the extent of the CO_2 plume will be evaluated by PNC logging in the MCI MW 2 well and time-lapse 3D surface seismic surveys.

PNC logging will be used to monitor the distribution and saturation of CO_2 adjacent to the wellbore in the MCI MW 2 well. The PNC logging results can be compared against the model's predicted plume vertical extent at a specific point location at a specified time interval. A good correlation between the two data sets will help provide strong evidence in validating the model's ability to model the CO_2 plume. Time-lapse 3D surface seismic data will be acquired at longer time intervals to track the development of the CO_2 plume over a larger spatial extent. Both data types will be used to verify the computational model's ability to predict the CO_2 behavior in the PISC phase of the project and support a demonstration of non-endangerment of USDWs at the end of the project.

9.6.6 Evaluation of Emergencies or Other Events

Mobilized brine from the storage formation may also pose a risk to USDWs. The geochemical data collected from the MCI ACZ 1 well will be used to demonstrate that the storage formation fluids have not migrated above the confining formation during the injection or PISC phases of the project. If these fluids have not migrated beyond the confining zone during the injection or PISC phases of the project, then they are not anticipated to pose a risk to USDWs after the PISC phase. To demonstrate non-endangerment, results of the fluid sampling in the deepest USDW from the injection and PISC phases will be compared to the pre-injection baseline samples. This comparison will support a demonstration that no significant changes in the fluid properties of the overlying formations have occurred and that storage formation fluids have not moved through the confining layer, and therefore the CO_2 and/or brine would not represent an endangerment to any USDWs.

Section 9.4.6 describes the quality of the well construction for the wells that penetrate the confining zone for this project. The Well Construction Plan and the Well Plugging Plan are presented in Permit Sections 4 and 8, respectively. No other wells penetrate the confining zone within the AoR.

9.7 Site Closure Plan

Marquis Carbon Injection LLC will conduct site closure activities to meet the requirements of 40 CFR 146.93(e) as described below. Marquis Carbon Injection LLC will submit a final Site Closure Plan and notify the permitting agency at least 120 days prior of its intent to close the site. Once the permitting agency has approved closure of the site, Marquis Carbon Injection LLC will plug or transfer to another permit the MCI MW 1, MCI MW 2, and MCI ACZ 1 wells and submit a site closure report to EPA. The activities, as described below, represent the planned

activities based on information provided to EPA. The actual site closure plan may employ different methods and procedures. A final Site Closure Plan will be submitted to the UIC Director for approval with the notification of the intent to close the site.

9.7.1 Plugging Monitoring Wells

Prior to plugging the wells, the external integrity of each well will be confirmed by running a temperature log over the entire length of the casing (total depth [TD] to surface). The temperature log will be acquired just before plugging the well and will be compared to previously run temperature logs to ensure that no deflections have developed that may indicate a problem with external well integrity. In addition, PNC logs will be run in the wells following the injection period to confirm that CO_2 has not migrated out of the injection zone.

The Well Plugging Plan for the MCI CCS 3 well can be found in Permit Section 8. The same approach that was used to plug the MCI CCS 3 well will be used to plug the MCI MW 1, MCI MW 2, and MCI ACZ 1 wells. Plugging and abandonment of the MCI MW 1, MCI MW 2, and MCI ACZ 1 wells will meet all requirements set forth by the Class VI regulations. The perforated zone of the well will be plugged using a retainer method and the upper portions of the well will be cemented with a balance method. In addition, the portion of the casing within the storage formation in the deep MCI MW 2 well will be plugged using CO_2-resistant cement. All the wells will have the casing cut off 5 ft below grade and a steel cap will be welded to the top of the deep casing string. The cap will have the well identification (ID) number and the date of plugging and abandonment inscribed on it. The following provides a detailed plan for plugging the MCI MW 1, MCI MW 2, and MCI ACZ 1 wells at the Marquis BioCarbon Project site.

1. Conduct and document a safety meeting.
2. Move-in (MI) rig and ancillary equipment onto well site and rig up (RU). Nipple up and test blow out preventors (BOPs), pressure test equipment and ensure proper operation.
3. Check wellhead tubing and casing pressures.
4. Record bottom-hole pressure from downhole gauge (if final pressure has not already been determined) and calculate kill fluid density.
5. Fill tubing with kill weight brine as determined by the final pressure measurement. Inject two tubing volumes of kill weight brine. Monitor tubing and casing pressure for 1 hour.
6. If the well is not dead or the pressure cannot be bled off the tubing, rig up slickline and set plug in lower profile nipple below packer. Unstab the tubing and circulate tubing and annulus with kill weight fluid until well is dead.

7. Release packer and pull out of hole with tubing laying it down. NOTE: Ensure that the well is over-balanced so there is no backflow due to formation pressure and there are always at least two well control barriers in place.
8. Trip into hole with work string with 5-1/2-inch cement retainer to approximately 100 ft above the top perforation, set retainer to cement the perforated portion of the well, and prepare for cement plugging operations. Pump the specified number of sacks of cement through the retainer while maintaining bottom-hole pressure below fracture pressure. If it appears that the injection pressure will exceed the fracture pressure and the total amount of cement has not been pumped into the injection zone, cement pumping will cease. After allowing the pressure to reduce to an acceptable level, cement pumping will be attempted again. A rapid increase in pressure on the tubing would indicate that the perforations have been sealed with cement, and no additional cement will be added to the zone or plug.
9. If a second perforated zone is present in the well, repeat Step 8 for upper perforated zone.
10. Trip tubing string out of well and remove stinger from end of tubing.
11. Trip tubing string to a depth of approximately 300 ft and prepare to set second cement plug. Pump 12 sacks of Class A cement (slurry weight of 15.9 pounds per gallon [lb/gal]) using a balance method to cement between a depth of 200 and 300 ft.
12. Trip tubing string to a depth of 100 ft and prepare to set third cement plug. Pump approximately 12 sacks of Class A cement to fill the casing from a depth of 100 ft to near surface.
13. Cut the casing string off at 5 ft below grade and weld a steel plate, (with well ID, permit number, and date of abandonment on it) to the casing strings.
14. Backfill the excavation.
15. Rig down and move off service rig and any remaining equipment.

Tables 9-7 and 9-8 provide the methods that will be used to set the plugs in each of the monitoring wells, and Tables 9-9 and 9-10 provide the materials that will be used during the plugging process. The volume of the casing to be cemented was calculated using the inside diameter of the 5-1/2-inch casing string (4.892 inches), and the length of the casing to be cemented. Note that an additional 10% volume was used when calculating the cement needed to cement the perforated zones.

Zone of Interest	Cemented Depth (ft, MD)	Formation	Plugging Method	Plug Description	
				Type	Quantity
Perforated Interval	Various between 3,165−4,050	Mt. Simon Sandstone	Retainer	CO_2-Resistant	132 sacks
5-1/2-in. Casing Column	200-300	Pennsylvanian	Balance	Class A	12 sacks
5-1/2-in. Casing Column	0-100	Pleistocene Drift	Balance	Class A	12 sacks

Table 9-7: Intervals to be plugged and methods used when plugging the MCI MW 2 well.

Zone of Interest	Cemented Depth (ft, MD)	Formation	Plugging Method	Plug Description	
				Type	Quantity
Galesville Perforated Interval	2,425-2,595	Galesville Sandstone	Retainer	Class A	37 sacks
Deepest USDW Interval	1,337-1,482	Deepest USDW	Retainer	Class A	33 sacks
5-1/2-in. Casing Column	200-300	Pennsylvanian	Balance	Class A	12 sacks
5-1/2-in. Casing Column	0-100	Pleistocene Drift	Balance	Class A	12 sacks

Table 9-8: Intervals to be plugged and methods used when plugging the MCI ACZ 1 well.

Plug Information	Plug #1	Plug #2	Plug #3
Diameter of boring in which plug will be placed (in.)	4.892	4.892	4.892
Depth to bottom of tubing or drill pipe (ft, MD)	3,065	300	100
Sacks of cement to be used (each plug)	132	12	12
Slurry volume to be pumped (ft^3)	142	13.1	13.1
Slurry weight (lb./gal)	15.2	15.9	15.9
Slurry Yield (ft^3/sack)	1.07	1.18	1.18
Calculated top of plug (ft, MD)	3,065	200	0
Bottom of plug (ft, MD)	4,050	300	100
Type of cement or other material	CO_2- Resistant	Class A	Class A
Method of emplacement (e.g., balance method, retainer method, or two-plug method)	Retainer	Balance	Balance

Table 9-9: Materials used for plugging the MCI MW 1 well.

Following the plugging and abandonment of the monitoring wells, the above ground infrastructure, such as wellheads, monitoring equipment, etc., will be removed, and the area around the wells will be regraded to follow the natural topography of the surrounding area (currently agricultural fields). The ground will be replanted with either native vegetation or be converted back to agricultural land.

Plug Information	Plug #1	Plug#2	Plug #3	Plug #4
Diameter of boring in which plug will be placed (in.)	4.892	4.892	4.892	4.892
Depth to bottom of tubing or drill pipe (ft)	2,325	1,237	300	100
Sacks of cement to be used (each plug)	37	33	12	12
Slurry volume to be pumped (ft^3)	39	35.2	13.1	13.1
Slurry weight (lb./gal)	15.2	15.2	15.9	15.9
Slurry Yield (ft^3/sack)	1.07	1.07	1.18	1.18
Calculated top of plug (ft)	2,325	1,237	200	0
Bottom of plug (ft)	2,595	1,482	300	100
Type of cement or other material	CO_2-Resistant	CO_2-Resistant	Class A	Class A
Method of emplacement (e.g., balance method, retainer method, or two-plug method)	Retainer	Retainer	Balance	Balance

Table 9-2: Materials used for plugging the MCI ACZ 1 well.

9.7.2 Site Closure Report

A site closure report will be prepared and submitted within 90 days following site closure, documenting the following:

- Plugging of the monitoring wells (and the MCI CCS 3 well if it has not previously been plugged)
- Location of sealed MCI CCS 3 well on a plat of survey that has been submitted to the local zoning authority
- Notifications to state and local authorities as required by 40 CFR 146.93(f)(2)
- Records regarding the nature, composition, and volume of the injected CO_2, and post-injection monitoring records.
- Groundwater monitoring wells may be converted to use as groundwater wells as appropriate.

Marquis Carbon Injection LLC will record a notation to the property's deed on which the MCI CCS 3 well was located that will indicate the following:

- That the property was used for CO_2 sequestration
- The name of the local agency to which a plat of survey with MCI CCS 3 well location was submitted
- The volume of fluid injected
- The formation into which the fluid was injected, and the period over which the injection occurred.

The site closure report will be submitted to the permitting agency and maintained by the owner or operator for a period of 10 years following site closure. Additionally, the owner or operator will maintain the records collected during the post-injection period for a period of 10 years after which these records will be delivered to the UIC Director.

9.7.3 Quality Assurance and Surveillance Plan (QASP)

The QASP is presented in the Appendix A of the Testing and Monitoring Plan (Permit Section 7.0).

References

Enick RM, Klara SM. CO_2 solubility in water and brine under reservoir conditions. Chemical Engineering Communications 90(1):23-33 (1990).

FutureGen Alliance, 2013, Underground Injection Control Permit Applications for FutureGen 2.0 Morgan County Class VI UIC Wells 1, 2, 3, and 4, FG-RPT-017.

Golden StrataServices, 1984, Jones & Laughlin Steel Inc, Hennepin Illinois, UIC Permit Application, UIC-004-WI-JL, EPA Facility ID No. ILD000781591.

Land CS. Calculation of imbibition relative permeability for two-and three-phase flow from rock properties. Society of Petroleum Engineers Journal 8(02):149-56 (1968).

Li YK, Nghiem LX. Phase equilibria of oil, gas and water/brine mixtures from a cubic equation of state and Henry's law. The Canadian Journal of Chemical Engineering 64(3):486-96(1986).

Nghiem L, Shrivastava V, Tran D, Kohse B, Hassam M, Yang C. Simulation of CO_2 storage in saline aquifers. In: SPE/EAGE Reservoir Characterization & Simulation Conference: European Association of Geoscientists & Engineers. p. cp-170-00063 (2009).

Raziperchikolaee S, Alvarado V, Yin S. Effect of hydraulic fracturing on long-term storage of CO_2 in stimulated saline aquifers. Applied energy 102:1091-104 (2013).

9.0 POST-INJECTION SITE CARE AND SITE CLOSURE PLAN
40 CFR 146.93(a)

MARQUIS BIOCARBON PROJECT

Facility Information

Facility name:	MARQUIS BIOCARBON PROJECT
Facility contact:	ELIZABETH STEINHOUR DIRECTOR OF ENVIRONMENTAL AFFAIRS 10000 MARQUIS DRIVE, HENNEPIN, IL 61327 815.925.7300 / BETHSTEINHOUR@MARQUISENERGY.COM
Well name:	MCI CCS 3
Well location:	PUTNAM COUNTY, ILLINOIS S2 T32N R2W Latitude: 41.27026520 N, Longitude: 89.30939322 W

Table of Contents

9.0 Post-Injection Site Care and Site Closure (PISC) Plan 5
9.1 Introduction 5
9.2 Pre- and Post-Injection Pressure Differential [40 CFR 146.93(a)(2)(i)] 5
9.3 Predicted Position of the CO_2 Plume and Associated Pressure Front at Site Closure (40 CFR 146.93(a)(2)(ii)) 6
9.4 Post-Injection Monitoring Plan (40 CFR 146.93(b)(1)) 10
9.4.1 Monitoring Above the Confining Zone 14
9.4.2 CO_2 Plume and Pressure Front Tracking (40 CFR 146.93(a)(2)(iii)) 16
9.4.3 Schedule for Submitting Post-Injection Monitoring Results (40 CFR 146.93(a)(2)(iv)) 18
9.5 Alternative Post-Injection Site Care Timeframe (40 CFR 146.93(c)) 19
9.5.1 Computational Modeling Results – 40 CFR 146.93(c)(1)(i) 19
9.5.2 Predicted Timeframe for Pressure Decline – 40 CFR 146.93(c)(1)(ii) 21
9.5.3 Predicted Rate of Plume Migration – 40 CFR 146.93(c)(1)(iii) 21
9.5.4 Site-Specific Trapping Processes – 40 CFR 146.93(c)(1)(iv)-(vi) 21
9.5.5 Confining Zone Characterization – 40 CFR 146.93(c)(1)(vii) 23
9.5.6 Assessment of Fluid Movement Potential – 40 CFR 146.93(c)(1)(viii)-(ix) 23
9.5.7 Location of USDWs – 40 CFR 146.93(c)(1)(x) 24
9.6 Non-Endangerment Demonstration Criteria 24
9.6.1 Introduction and Overview 24
9.6.2 Summary of Existing Monitoring Data 24
9.6.3 Summary of Computational Modeling History 25
9.6.4 Evaluation of Reservoir Pressure 25
9.6.5 Evaluation of CO_2 Plume 26
9.6.6 Evaluation of Emergencies or Other Events 26
9.7 Site Closure Plan 27
9.7.1 Plugging Monitoring Wells 27
9.7.2 Site Closure Report 32
9.7.3 Quality Assurance and Surveillance Plan (QASP) 33
References 34

List of Tables

Table 9-1: Summary of monitoring activities in the PISC phase of the project. 12

Table 9-2: Monitoring of ground water quality and geochemical changes above the confining zone. 14

Table 9-3: Summary of analytical and field parameters for ground water samples. 15

Table 9-4: Sampling and recording frequencies for continuous monitoring in the MCI ACZ 1 well. 16

Table 9-5: Post-injection phase CO_2 plume monitoring. 17

Table 9-6: Post-injection phase pressure-front monitoring. 18

Table 9-7: Intervals to be plugged and methods used when plugging the MCI MW 2 well. 30

Table 9-8: Intervals to be plugged and methods used when plugging the MCI ACZ 1 well. 30

Table 9-9: Materials used for plugging the MCI MW 2 well. 31

Table 9-10: Materials used for plugging the MCI ACZ 1 well 32

List of Figures

Figure 9-1: Pressure predictions at the injection well based on Layer 153 with an elevation of 3,833 TVDSS, ft from the computation model for the 5-year injection phase and a post injection period of 50 years. 5

Figure 9-2: Map showing the modeled CO2 plume footprint, AoR, and existing and proposed project wells within the AoR. 7

Figure 9-3: Cross section of the CO2 plume at the end of the injection phase and at 3 and 5 years after the cessation of injection. 8

Figure 9-4: Predicted pressure plume response at the end of the injection phase and after 1, and 5 years after the cessation on injection. The pressure build-up cut-off is 150 psi. 9

Figure 9-5: Stratigraphic column from characterization well MCI MW 1 located at the Marquis BioCarbon Project site. 13

Figure 9-6: Plot of porosity and permeability relationships for High Side Case (orange line) and Low Side Case (blue line). The numbers on the orange are permeability values, number on the

blue line are porosity values. The porosity permeability relationship for the base case was calculated from the ratio between permeability and porosity at the intersection of the curves.... 20

Figure 9-7: CO2 plume at layer 153 (used to delineate AoR) at the end of injection, 1, 5 and 10 years after injection stopped for the High Side Case (top row) and Low Side Case (bottom row). 20

Figure 9-8: CO2 dissolved in brine, CO2 residually trapped in brine during injection, supercritical CO2 and liquid CO2 as a percentage of total CO2 moles injected during the injection and post-injection periods. 22

9.0 Post-Injection Site Care and Site Closure (PISC) Plan

9.1 Introduction

This Post-Injection Site Care and Site Closure (PISC) plan describes the activities that Marquis Carbon Injection LLC will perform to meet the requirements of 40 CFR 146.93. Marquis Carbon Injection LLC will monitor groundwater quality and track the position of the carbon dioxide (CO_2) plume and pressure front for 5 years after the cessation of injection, which is the anticipated timeline for CO_2 plume and pressure front stabilization.

9.2 Pre- and Post-Injection Pressure Differential [40 CFR 146.93(a)(2)(i)]

Based on the modeling of the pressure front as part of the area of review (AoR) delineation, pressure at the MCI CCS 3 well is expected to decrease to pre-injection levels in less than 5 years, as described below. Additional information on the projected post-injection pressure declines and differentials is presented in the permit application and the AoR and Corrective Action Plan (Permit Section 2).

Figure 9-1 shows the modeling results of pressure behavior during the injection phase of the project and a 50-year post-injection period for Layer 153 within the computational model which is used to delineate the AoR for the project. Refer to the AoR and Corrective Action Plan (Permit Section 2) for more information on the delineation of the AoR. In the post injection phase, pressures at the MCI MW 2 and MCI CCS 3 (monitoring and injection) wells decrease to pre-injection levels in less than 5 years.

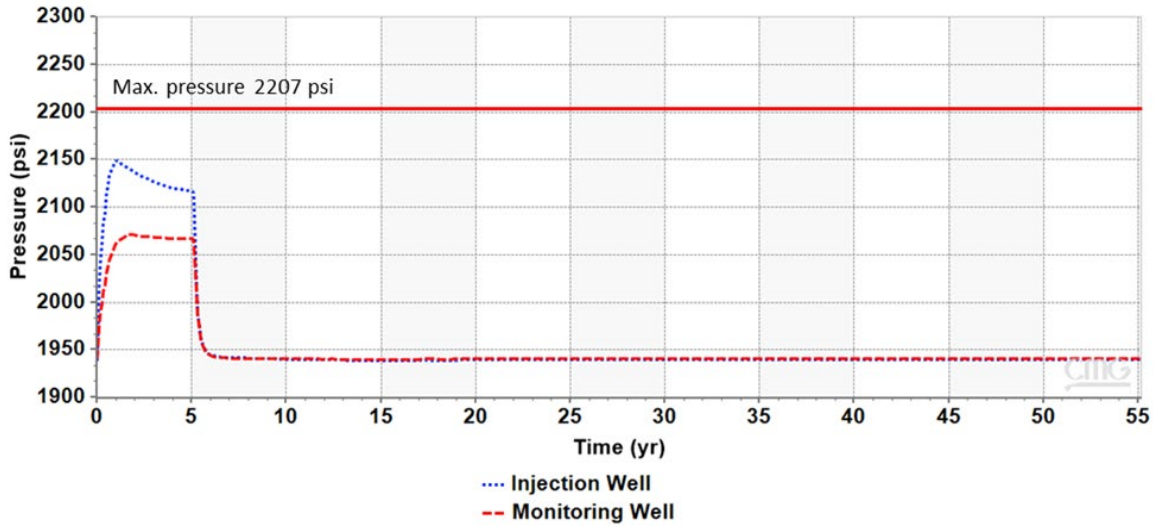


Figure 9-1: Pressure predictions at the MCI CCS 3 well based on Layer 153 with an elevation of 3,833 TVDSS, ft from the computation model for the 5-year injection phase and a post injection period of 50 years.

9.3 Predicted Position of the CO_2 Plume and Associated Pressure Front at Site Closure (40 CFR 146.93(a)(2)(ii))

Figure 9-2 shows the predicted extent of the CO_2 plume at the end of the PISC timeframe that represents the maximum extent of the CO_2 plume in relation to the AoR. This map is based on the final AoR delineation modeling results submitted pursuant to 40 CFR 146.84.

Figure 9-3 shows the predicted extent of the CO_2 plume at the end of the injection phase and at 3 and 5 years after the cessation of injection. The figures demonstrate the stability of the CO_2 plume during the PISC phase. Figure 9-4 shows a cross section of the pressure buildup around the MCI CCS 3 well at the end of the injection phase and at 3 and 5 years after the cessation of injection using a pressure build-up cut-off of 150 pounds per square inch (psi) to delineate the pressure front. The pressure front decreases rapidly after the injection period ends and decreases to the pre-injection pressure in less than 5 years.

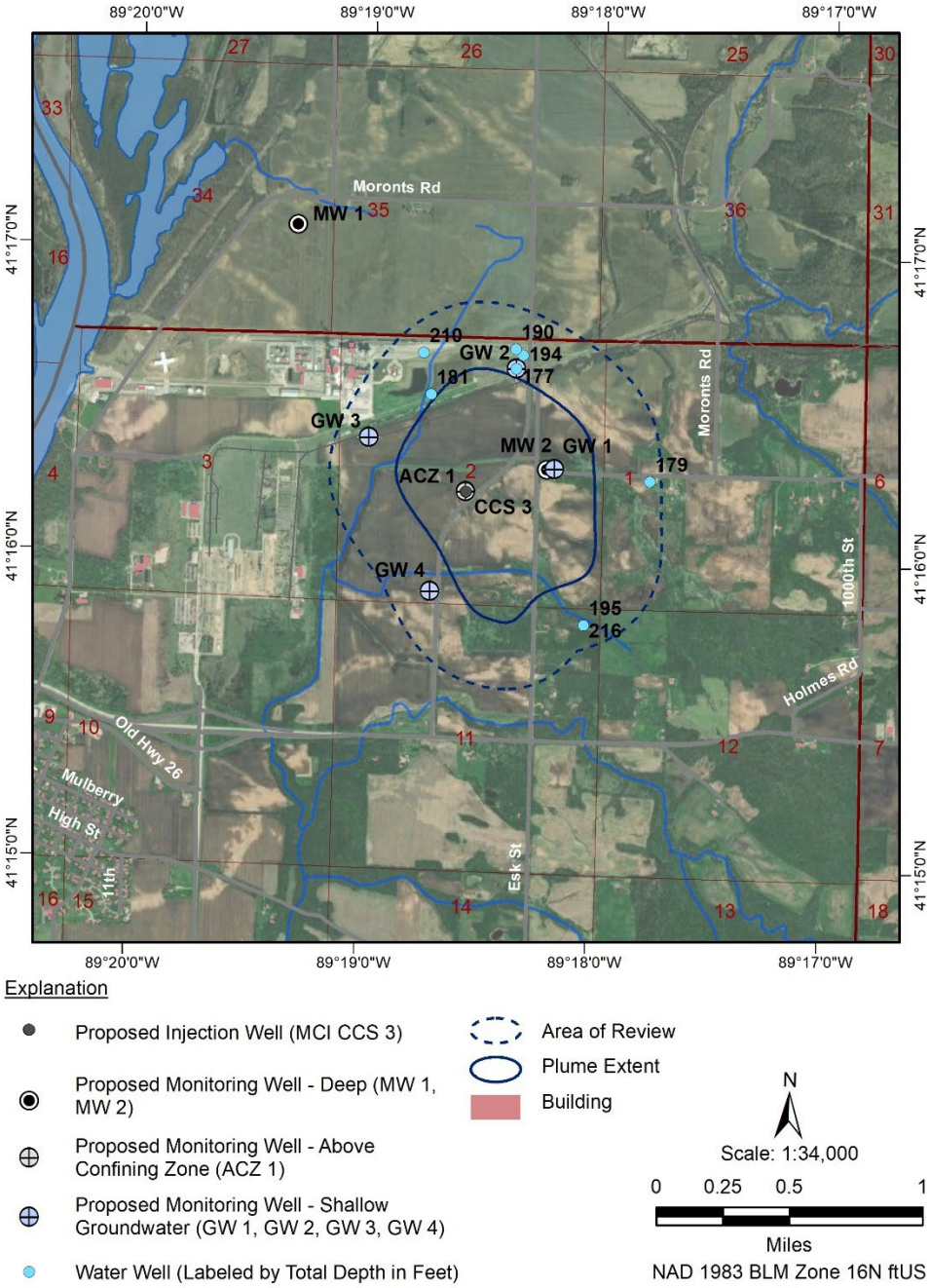


Figure 9-2: Map showing the modeled CO_2 plume footprint, AoR, and existing and proposed project wells within the AoR.

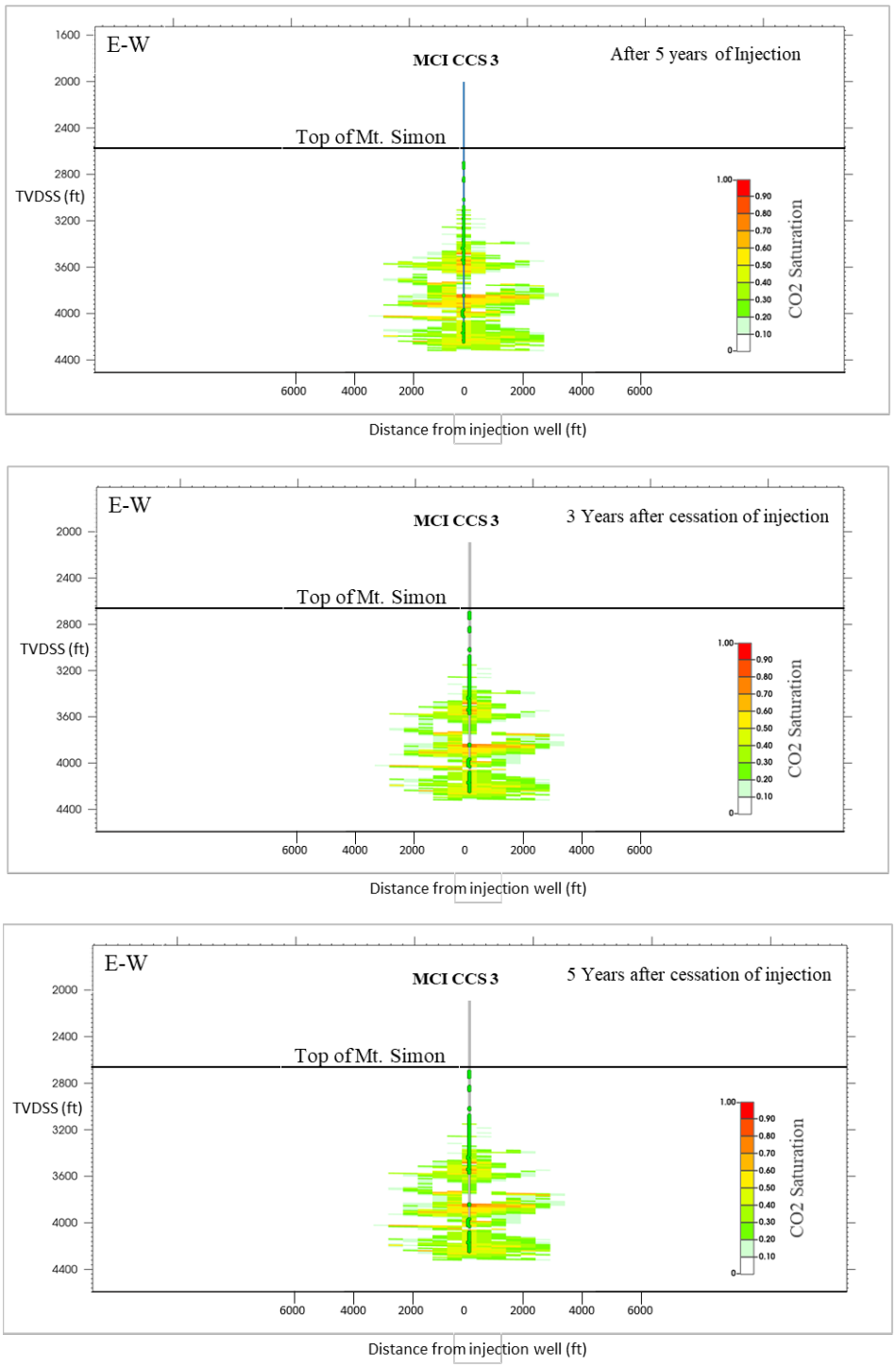


Figure 9-3: Cross section of the CO_2 plume at the end of the injection phase and at 3 and 5 years after the cessation of injection.

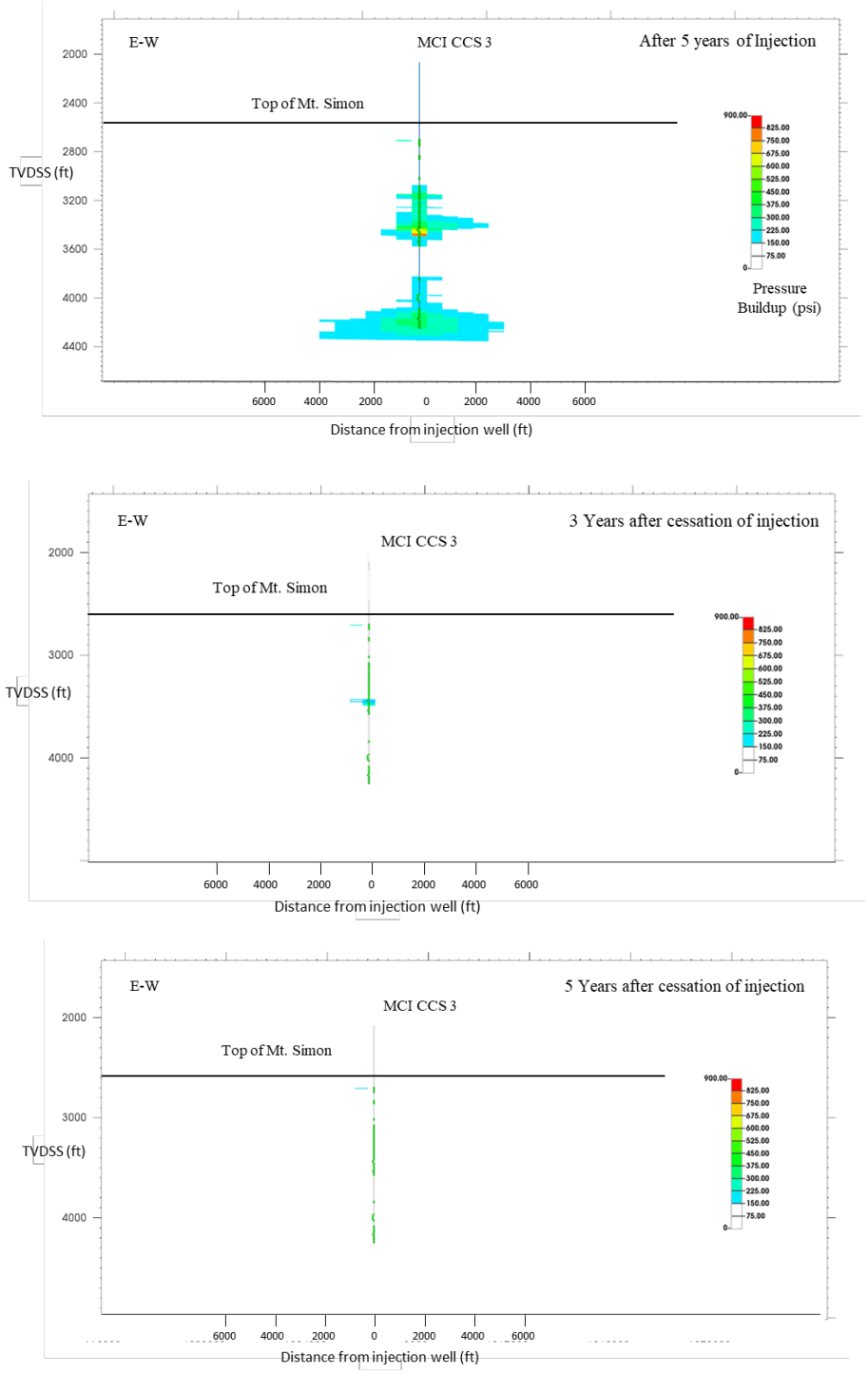


Figure 9-4: Predicted pressure plume response at the end of the injection phase and after 1, and 5 years after the cessation on injection. The pressure build-up cut-off is 150 psi.

9.4 Post-Injection Monitoring Plan (40 CFR 146.93(b)(1))

Performing groundwater monitoring, storage zone pressure monitoring, and geophysical monitoring as described in the following sections during the post-injection phase will meet the requirements of 40 CFR 146.93(b)(1). The results of all post-injection monitoring will be submitted semi-annually in Year 1 of the PISC and annually in subsequent years.

A quality assurance and surveillance plan (QASP) for all testing and monitoring activities during the injection and post-injection phases is provided in Appendix 7.A of the Testing and Monitoring Plan (Permit Section 7).

Table 9-1 summarizes the monitoring activities that will take place during the PISC phase of the project. The project will continue to monitor the well integrity of the MCI CCS 3 and MCI MW 2 wells on a yearly basis using temperature measurements to ensure that there is no migration of CO_2 up the wellbores. In addition, the annular pressures and fluid volumes in the MCI CCS 3 well will be monitored on a continuous basis until the well is plugged and abandoned. Annular pressure in the deep monitoring well will be monitored daily until the well is plugged and abandoned. Refer to the Well Operations Plan and the Testing and Monitoring Plan for more information on the well integrity and operational monitoring plans (Permit Sections 6 and 7, respectively).

Pulsed neutron capture (PNC) logging will continue in the MCI MW 2 well and the above confining zone (ACZ) monitoring well (MCI ACZ-1) in the second quarter of each year of the PISC phase. This will allow the project to continue to characterize the vertical plume development in the Mt. Simon Sandstone in the MCI MW 2 well and further verify that CO_2 is not migrating past the confining zone and into the ACZ aquifers, thereby endangering underground sources of drinking water (USDWs). Refer to the Testing and Monitoring Plan for more information on the PNC logging plans in the injection phase of the project (Permit Section 7).

The project will continue to monitor pressures within the Mt. Simon Sandstone in the MCI MW 2 well and pressure at the top of the Mt. Simon Sandstone in the MCI CCS 3 well until it is abandoned. The pressure within the Mt. Simon Sandstone is expected to begin to dissipate once CO_2 injection ceases based on the computational modelling. The Mt. Simon Sandstone pressure measurements are expected to verify the pressure decrease, and the data will be used to history match the computational modelling in the PISC phase.

Monitoring Activity	PISC Frequency*	Location	Depth Range (ft, MD)
Assurance Monitoring:			
Shallow Groundwater Sampling	Twice/year	GW-1, 2, 3 & 4 wells within AoR	Producing zone
Isotope Analysis	Twice/year	GW-1, 2, 3 & 4 wells within AoR	0 – TD
Operational Monitoring:			
Annular Pressure	Continuous	MCI CCS 3 well	Surface
Annular Fluid Volume	Continuous	MCI CCS 3 well	Surface
Annular Pressure	Daily	MCI MW 2 well	Surface
Temperature Measurement	Annually Annually	MCI CCS 3 well MCI MW 2 well	0 – TD 0 – TD
Verification Monitoring:			
Fluid Sampling			
Gunter Sandstone Galesville Sandstone Upper Mt. Simon Sandstone	Twice/year Twice/year Twice/year	MCI ACZ 1 well MCI ACZ 1 well MCI MW 2 well	2,134 2,651 3,110
Isotope Analysis	Twice/year	MCI ACZ 1 well MCI MW 2 well	All samples
Pressure – Temperature Sensors			
Gunter Sandstone Galesville Sandstone Upper Mt. Simon Sandstone	Continuous Continuous Continuous	MCI ACZ 1 Well MCI ACZ 1 Well MCI MW 2 well	2,134 2,651 3,100
PNC Logging	Once/ year	MCI MW 2 well MCI ACZ 1 well	2,134 – TD 2,134 – TD

Microseismic Monitoring	Continuous	Surface stations	TBD
Time-lapse 3D Surface Seismic Data	Every 5 years and as required.	Surface	

Table 9-1: Summary of monitoring activities in the PISC phase of the project.

Pressures will also continue to be monitored in the Galesville Sandstone and the deepest USDW to confirm the continued containment of CO_2 within the storage formation (Figure 9-5). Fluid samples will be taken from the Galesville Sandstone and deepest USDW once a year for geochemical and isotopic analysis to further verify CO_2 containment. Shallow groundwater fluid samples will also be obtained each year from the shallow groundwater wells, MCI GW 1-4, for geochemical and isotopic analysis.

Microseismic activity is expected to return to background (pre-injection) levels once the injection phase of the project is complete and the associated pressure plume begins to dissipate. The microseismic monitoring would then be phased out in the first six to twelve months of the PISC phase. This will be evaluated in the first months of the PISC phase of the project, and no decisions will be made without consultation with the Underground Injection Control (UIC) Program Director (UIC Director).

The project proposes to acquire two time-lapse three-dimensional (3D) surface seismic surveys in the PISC phase of the project. One will be acquired within one year of the end of the injection phase or at the start of the PISC phase of the project. The final survey will be acquired in the final year of the PISC phase of the project. The objectives of these two surveys include:

- Verification of continued CO_2 containment in the storage formation
- Demonstration of the stability of the CO_2 plume after the injection phase of the project
- Providing data for the calibration and verification of the computational modelling

These data will be used to demonstrate non-endangerment of USDWs at the end of the PISC phase (Section 5.0).

Marquis companies own the land on which the injection, deep monitoring, and ACZ wells are located. Marquis also owns the land on which the shallow groundwater wells used for monitoring are located. The wells are on flat farmland not near residential areas. Access to the wells is not anticipated to be an issue for the PISC phase of the project.

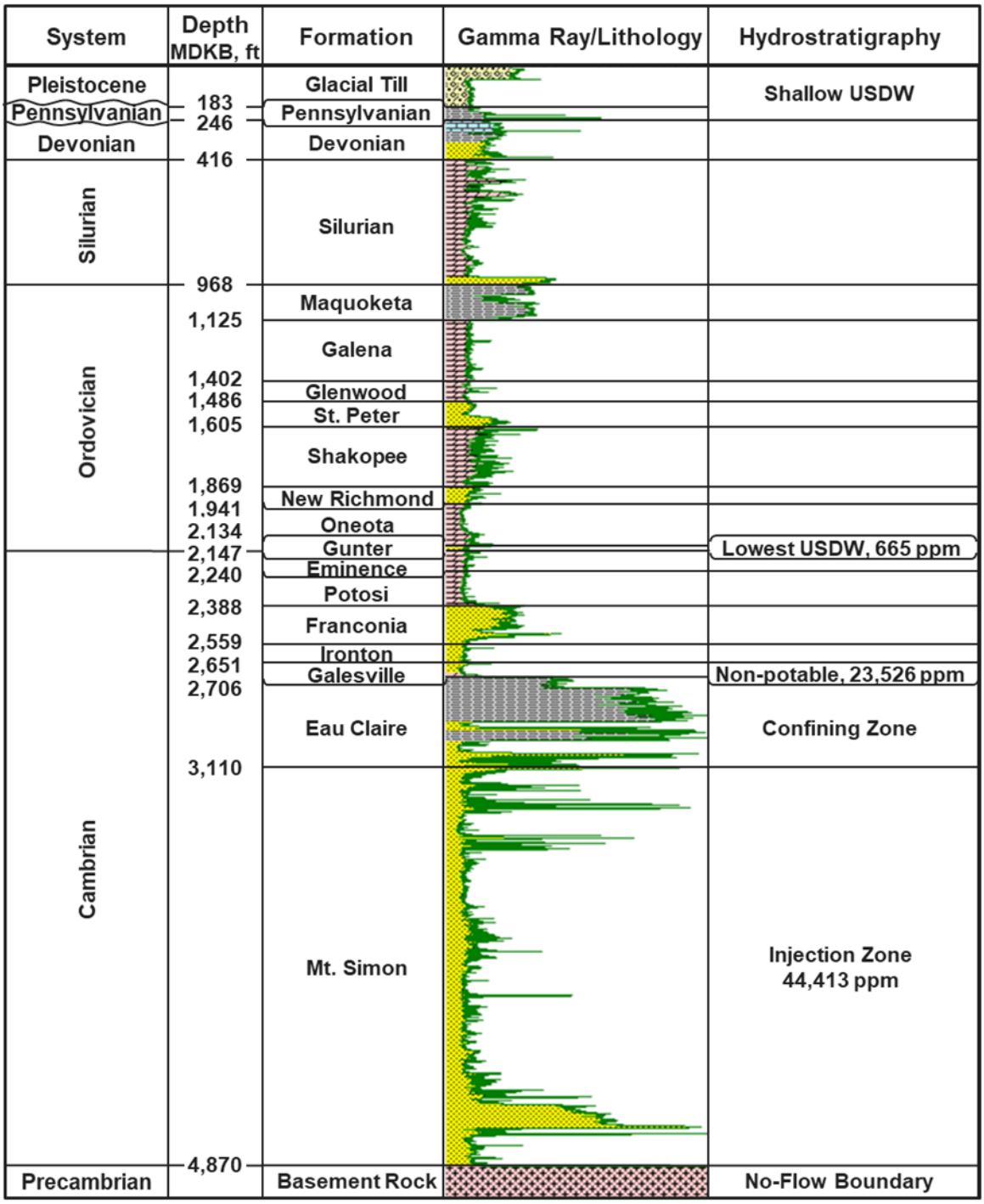


Figure 9-5: Stratigraphic column from MCI MW 1 well located at the Marquis BioCarbon Project site.

9.4.1 Monitoring Above the Confining Zone

The monitoring plan for the PISC is designed to be adaptive and respond to evolving project risks over time. At this point in the project, no phased monitoring has been planned for the MCI ACZ 1 well; however, this may be assessed later as the project progresses. No changes will be made to the PISC without informing the UIC Director (40 CFR 146.93 (a)(3)).

Table 9-2 presents the proposed MCI ACZ 1 and groundwater monitoring wells monitoring methods, locations, and frequencies. For fluid sampling, a bailer system or like method that maintains the formation pressure of the sample will be used to collect water samples to be analyzed for dissolved inorganic carbon, alkalinity, pH, and isotopic parameters. Samples for all other analytes will be collected with an open-ended bailer. Prior to sample collection the well will be swabbed to remove stagnant water and ensure representative water is collected from the formation. The fluid swabbed from the well will be monitored for field parameters, such as pH, specific conductance, and temperature, using a calibrated water quality meter (Horiba U-53, or similar). Once these parameters stabilize, it will be an indication that representative formation fluid is in the well at the time the sample is collected.

Target Formation	Monitoring Activity	Monitoring Location(s)	Spatial Coverage	Frequency
Shallow Groundwater	Groundwater geochemistry and stable isotopes	Select Shallow groundwater wells in AoR	88 – 246 ft, MD	Q2/ year after injection ceases
Gunter Sandstone	Groundwater geochemistry and stable isotopes	MCI ACZ-1	TBD	Q2/ year after injection ceases
Galesville Sandstone	Groundwater geochemistry and stable isotopes	MCI ACZ-1	~2,670 ft, MD	Q2/ year after injection ceases
Galesville Sandstone	PNC Logging	MCI ACZ-1	2,500 – 2,800 ft, MD	Q2/ year after injection ceases

Table 9-2: Monitoring of ground water quality and geochemical changes above the confining zone.

Table 9-3 identifies the initial groundwater parameters to be monitored and the analytical methods that will be used for the samples in the baseline analysis of the data. During the pre-injection and injection phases, the project will assess which subset of analytes are most responsive to interactions with CO_2, so the list of analytes will be reduced in the future (Permit Section 7). However, no changes will be implemented without consultation with the UIC Director.

Parameters	Analytical Methods
Cations (Na, Ca, Mg, Ba, Sr, Fe, K)	ASTM D1976
Anions (Cl, Br, SO_4)	ASTM D4327
pH	ASTM D1293
Alkalinity	ASTM D3875
Total Dissolved Solids (TDS)	ASTM D5907
Density	ASTM D4052
Dissolved Inorganic Carbon	ASTM D513-11
Conductivity/Resistivity	ASTM D1125
Stable Isotopes of C, O, and H	ASTM STP 573
Carbon-14	

Table 9-3: Summary of analytical and field parameters for ground water samples.

A nationally certified laboratory will be selected for the groundwater sampling and analysis. The sampling and analytical measurements will be performed in accordance with project quality assurance requirements. Samples will be tracked using appropriately formatted chain-of-custody forms. See the QASP for additional information (Permit Section 7, Appendix 7.A).

The results of the geochemical and isotope analysis will be delivered in the form of laboratory reports. If anomalous changes in the aqueous geochemistry are observed in the ACZ monitoring zones, new samples will be obtained from the affected aquifer and sent for analysis to verify the changes.

If anomalous changes are confirmed (greater than 5% deviation from baseline values as described in the Testing and Monitor Plan [Section 7.5]), the frequency with which fluid samples are obtained from the ACZ aquifers for analysis will be increased. As a precautionary measure, the fluid sampling frequency for the shallow groundwater monitoring wells will also be increased in consultation with the UIC Director. If the injected CO_2 has a unique isotopic signature from the existing isotopes in the overlying aquifers, a new round of samples will be collected for isotopic analysis from the affected aquifer. Confirmed anomalous changes may also trigger the need for additional well integrity testing in both the MCI MW 2 well and the MCI CCS 3 well to ensure that no well integrity issues have developed since the last set of external mechanical integrity tests. A combination of anomalous pressure, geochemical, and well integrity testing results may result in the decision to acquire a time-lapse surface seismic survey before the survey scheduled in year five of the PISC to determine the size of the leakage accumulation (Table 9-1).

Table 9-4 presents information about the continuous monitoring devices to be used in the deepest USDW and the Galesville Sandstone. The pressure/temperature data will be stored as time

stamped data pairs. Migration of CO_2 or brine into the MCI ACZ 1 well will likely first be identified through pressure changes in the aquifers. An increasing pressure trend in either aquifer would suggest that leakage across the confining layer is occurring. While any increasing trend in pressure or temperature will be evaluated, an increase in pressure or temperature greater than 5% above baseline values will warrant additional monitoring and inspections to rule out the possibility of fluid leakage out of the storage formation. Such an increase in pressure or temperature would initiate more frequent fluid sampling and analysis for geochemical parameters from the aquifer with the pressure/temperature increase. An increase in pressures or temperatures in the MCI ACZ 1 well may also trigger additional external well integrity investigations in the MCI CCS 3 or MCI MW 2 well.

Parameter	Device(s)	Location	Min. Sampling Frequency	Min. Recording Frequency
Pressure	Pressure Gauge	Deepest USDW Galesville Sandstone	Every 1 min.	Every 1 min.
Temperature	Temperature Gauge	Deepest USDW Galesville Sandstone	Every 1 min.	Every 1 min.

Notes:
- Sampling frequency refers to how often the monitoring device obtains data from the well for a particular parameter. For example, a recording device might sample a pressure transducer monitoring injection pressure once every two seconds and save this value in memory.
- Recording frequency refers to how often the sampled information gets recorded to digital format (such as a computer hard drive). For example, the data from the injection pressure transducer might be recorded to a hard drive once every minute.

Table 9-4: Sampling and recording frequencies for continuous monitoring in the MCI ACZ 1 well.

9.4.2 CO_2 Plume and Pressure Front Tracking (40 CFR 146.93(a)(2)(iii))

Marquis Carbon Injection LLC will employ direct and indirect methods to track the extent of the CO_2 plume and the presence or absence of elevated pressure.

Table 9-5 presents the direct and indirect methods that will be used to monitor the CO_2 plume including the activities, locations, and frequency of sampling.

Fluid sampling will be performed as described in Section B.2 of the QASP; sample handling and custody will be performed as described in B3 of the QASP; and quality control will be ensured using the methods described in B5 of the QASP. Quality assurance procedures for seismic monitoring methods are presented in B9 of the QASP (Permit Section 7, Appendix 7.A).

Target Formation	Monitoring Activity	Monitoring Location(s)	Spatial Coverage	Frequency
Direct Plume Monitoring				
Galesville, Eau Shale, and Mt. Simon Formations	Pulsed Neutron Logging	Deep monitor well	2,600 – 4,800 ft, MD	Q2/ Year
Indirect Plume Monitoring				
Galesville, Eau Shale, and Mt. Simon Formations	Time-lapse 3D Surface Seismic Data	Over project AoR	To be confirmed prior to survey	Q2, Year 1 Q2, Year 5

Table 9-5: Post-injection phase CO_2 plume monitoring.

The PNC logs will be received as log ascii standard (LAS) files and interpreted products that can be imported into the static earth model (SEM). PNC logging will be used to monitor the distribution and saturation of CO_2 adjacent to the wellbore in the MCI MW 2 well. The PNC logs will be acquired through the Galesville Sandstone in the MCI MW 2 well to confirm the absence of CO_2 accumulations along the wellbores above the confining layer. Technical details on PNC logging tools can be found in the QASP (Permit Section 7, Appendix 7.A).

Surface seismic data are delivered in a variety of formats including acquisition and processing reports and raw data files from a variety of points in the processing flow. In the context of time-lapse analysis, an assessment will be provided on the differences between the baseline and time-lapse surveys as well as data files that can be incorporated into the SEM. The injection of CO_2 and expansion of the plume is expected to change the acoustic impedance of the Mt. Simon Sandstone over time. These acoustic impedance changes will be used to track the CO_2 plume during the PISC phase of the project. The time-lapse surface seismic data will also be monitored for changes that may suggest that CO_2 has migrated past the confining layer.

Table 9-6 presents the direct and indirect methods that will be used to monitor the pressure front. The pressure/temperature sensors will be programmed to measure and record pressure and temperature readings every 60 sec. The gauges will be retrieved for data download on a quarterly basis. A pair of gauges will be placed in each zone to limit the possibility of data loss. The final monitoring interval in the upper Mt. Simon Sandstone will be determined after the MCI CCS 3 well has been drilled and the well logs have been analyzed (Pre-Operational Testing Program, Permit Section 5). Two pressure sensors will also be set at the MCI CCS 3 well to measure the pressure fall-off at the top of the Mt. Simon Sandstone until the well is abandoned. The pressure/temperature data will be stored as time-stamped data pairs that can used for history matching in the computational model.

Target Formation	Monitoring Activity	Monitoring Location(s)	Spatial Coverage	Frequency
Direct Pressure-Front Monitoring				
Upper Mt. Simon Sandstone	Pressure Monitoring	MCI MW 2	3,100 – 3,500 ft, MD Exact TBD	Continuous
Top Mt. Simon Sandstone	Pressure Monitoring	MCI CCS 3 well	3,100 ft, MD	Continuous
Indirect Pressure-Front Monitoring				
Eau Claire and Mt. Simon Formations, and Precambrian Basement	Microseismic Monitoring	5 Surface Stations	AoR	Continuous

Table 9-6: Post-injection phase pressure-front monitoring.

The results of the geochemical and isotope analysis, PNC logging, and time-lapse 3D surface seismic data will all be integrated to develop a comprehensive understanding of the CO_2 plume development over time. PNC logging and time-lapse 3D surface seismic data can be incorporated into the SEM for comparison to the computational modelling predictions at different points in time. Based on the current computational modelling results, the CO_2 plume is predicted to stabilize (Figure 9-3), and the pressure plume is predicted to rapidly decrease to pre-injection levels within the proposed 5-year PISC phase. Time-lapse 3D surface seismic surveys acquired during Year 1 and Year 5 of the PISC phase will characterize the stabilization of the CO_2 plume. The pressure data from the MCI MW 2 and MCI CCS 3 wells will verify the decline in formation pressures predicted by the computational modelling.

The increase in pressure in a storage formation is one of the primary drivers for CO_2 and brine migration beyond the confining layer and potentially endangering USDWs. The rapid decrease in pressure in the Mt. Simon Sandstone coupled with the ACZ monitoring and absence of evidence for CO_2 migration beyond the confining layer will demonstrate the non-endangerment of USDWs within the AoR (Section 9.5).

9.4.3 Schedule for Submitting Post-Injection Monitoring Results (40 CFR 146.93(a)(2)(iv))

All PISC monitoring data and results collected using the methods described above will be submitted in reports to the EPA. In the first year of the PISC phase, reports will be submitted on a semi-annual basis. After the first year of the PISC phase, reports will be submitted annually. The reports will contain information and data generated during the reporting period (i.e., well-based monitoring data, sample analysis, and the results from updated site models). The initial Year 1 report will be submitted within eight months after the date that injection stops or alternatively on a data agreed upon with the UIC Director.

9.5 Alternative Post-Injection Site Care Timeframe (40 CFR 146.93(c))

Marquis Carbon Injection LLC will conduct post-injection monitoring for a five-year period following the cessation of injection operations. A justification for this alternative PISC timeframe is provided below.

9.5.1 Computational Modeling Results – 40 CFR 146.93(c)(1)(i)

Figure 9-3 shows the cross section of the predicted CO_2 plume extent and demonstrates the CO_2 plume stability during alternative PISC timeframe. Figure 9-4 illustrates a cross section of the predicted pressure front during the post-injection period. The pressure front declines quickly during the post-injection period. Figure 9-1 shows, the predicted pressure at the MCI CCS 3 well reaches pre-injection pressure in less than the proposed 5-year PISC timeframe. Given the fast CO_2 plume stabilization and rapid pressure decrease in the Mt. Simon Sandstone predicted by the computational modeling, a 5-year PISC is appropriate to ensure USDW protection.

This was further supported by a sensitivity analysis to test the effects of varying the porosity and permeability relationships on the CO_2 plume shape and pressure behavior (Figures 9-6 and 9-7). High side and low side case runs, testing two porosity permeability relationships in addition to the base case were performed. The permeability vs porosity plot for each case in the Mt Simon is shown Figure 9-6. The results of the sensitivity analysis indicate that the CO_2 plume shape is similar in both cases compared to the base case scenario (Figure 9-7). Details related to this sensitivity analysis are discussed further in AoR and Corrective Action Plan Section (Permit Section 2.6.7).

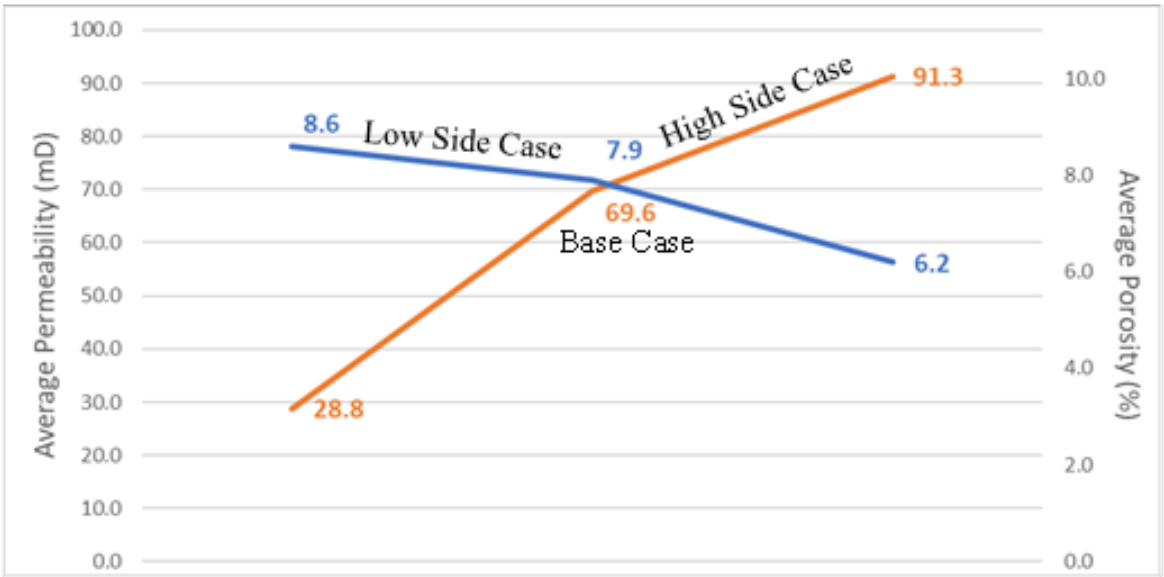


Figure 9-6: Plot of porosity and permeability relationships for High Side Case (orange line) and Low Side Case (blue line). The numbers on the orange are permeability values, number on the blue line are porosity values. The porosity permeability relationship for the base case was calculated from the ratio between permeability and porosity at the intersection of the curves.

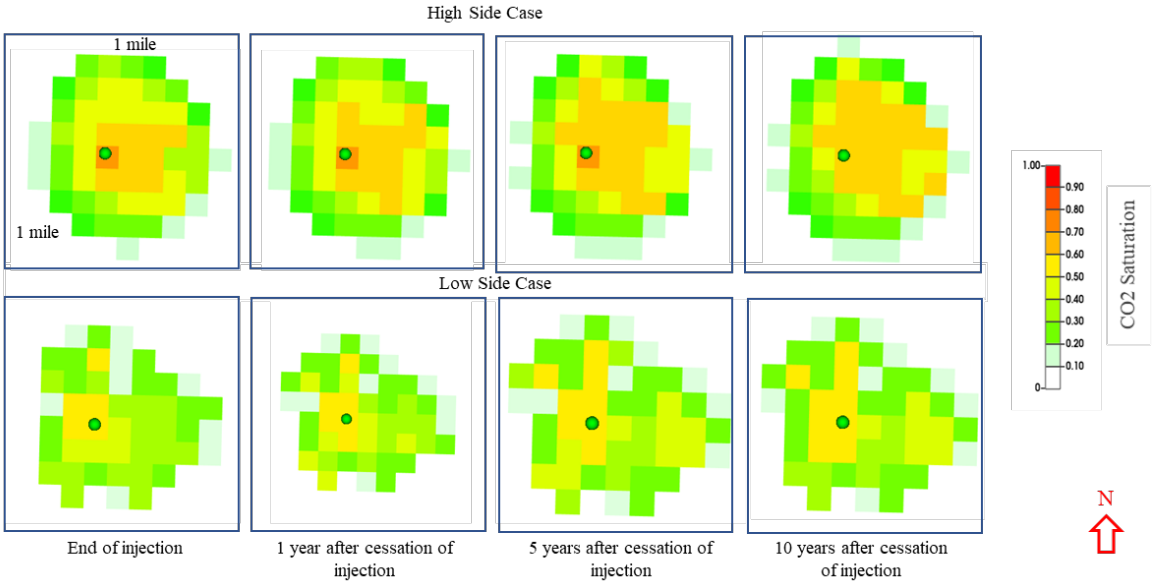


Figure 9-7: CO_2 plume at layer 153 (used to delineate AoR) at the end of injection, 1, 5 and 10 years after injection stopped for the High Side Case (top row) and Low Side Case (bottom row).

9.5.2 Predicted Timeframe for Pressure Decline – 40 CFR 146.93(c)(1)(ii)

Figure 9-4 shows the cross section of the pressure front during the post injection phase. Additional plots and figures, showing the pressure front during the injection period, can be found in the AoR and Corrective Action Plan Section (Permit Section 2). The maximum spatial extent of the pressure front occurs at the end of the injection period. Figure 9-1 shows the predicted pressure buildup and decline at the MCI CCS 3 well through the injection phase and for 50 years of the post-injection period. The pressure declines immediately following cessation of injection and is predicted to be heterogenous between the MCI CCS 3 and MCI MW 2 wells (Figure 9-1). The details related to sensitivity analysis can be found in the AoR and Corrective Action Plan Section (Permit Section 2). A comparison of the pressure time series from the sensitivity analysis demonstrates that the pressure buildup during the injection phase and rapid decline during the PISC phase are similar to the base case scenario for different porosity permeability relationships (Figure 9-8).

Continuous pressure measurements will be acquired from the Mt. Simon Sandstone through the injection and PISC phases of the project (Testing and Monitoring Plan, Permit Section 7). The pressure data obtained during the injection phase of the project will be used to update the computational modelling every six months as per the reporting requirements in 40 CFR 146.91. Pressure data acquired during the PISC phase of the project are expected to verify the rapid decline in pressure in the Mt. Simon Sandstone predicted by the computational modelling.

9.5.3 Predicted Rate of Plume Migration – 40 CFR 146.93(c)(1)(iii)

Figure 9-3 shows the cross section of the CO_2 plume remains relatively stable from the end of the injection period to Year 3 and Year 5 of the PISC phase. Additional figures illustrating the predicted CO_2 plume expansion during the injection period are provided in the AoR and Corrective Action Plan Section (Permit Section 2). The average CO_2 plume extent was utilized to define the AoR. The details related to sensitivity analysis are presented in the AoR and Corrective Action Plan Section (Permit Section 2.6.7). The results from the sensitivity analysis show that the CO_2 plume shape remains a similar or smaller size and shape for the different modeled porosity permeability relationships (Figure 9-7).

9.5.4 Site-Specific Trapping Processes – 40 CFR 146.93(c)(1)(iv)-(vi)

The computational modelling assessed the residual and solubility trapping process during the injection phase and for a 50-year post-injection period. The CO_2 solubility in brine was modeled as a phase equilibrium process, which is computed by the equality of fugacity in the gas and aqueous phase (Li and Nghiem, 1986). The fugacity of gaseous components soluble in the aqueous phase was calculated using Henry's law. The Henry's law constants are a function of pressure and temperature and accurately estimate CO_2 solubility into the aqueous phase (Enick and Klara, 1990; Nghiem et al., 2009). Increasing brine salinity causes the fraction of dissolved

CO2 to decrease marginally. The amount of CO_2 trapped as residual gas in the aquifer is determined by the Land model (Land, 1968). One of the parameters that controls the amount of trapped gas by relative permeability hysteresis is the maximum residual gas saturation, which is a function of the formation pore structure (Raziperchikolaee et al., 2013). Due to the thickness and permeability variations of the Mt. Simon Sandstone, significant amounts of CO_2 can be residually trapped. Residual trapping increases during the post-injection time period.

Figure 9-16 shows the moles of dissolved CO_2, the moles of trapped CO_2, the moles of supercritical CO_2 and the moles of liquid CO_2 as a percentage of total CO_2 moles injected during the injection and post-injection periods. Due to lower temperatures at shallower depths, liquid phase is present.

As the CO_2 becomes immobilized through solubility and residual trapping, the risk of CO_2 migration out of the storage formation decreases. Ultimately, this will serve to demonstrate the non-endangerment of USDWs. Mineralization is unlikely to play a significant role as a major trapping mechanism for the project.

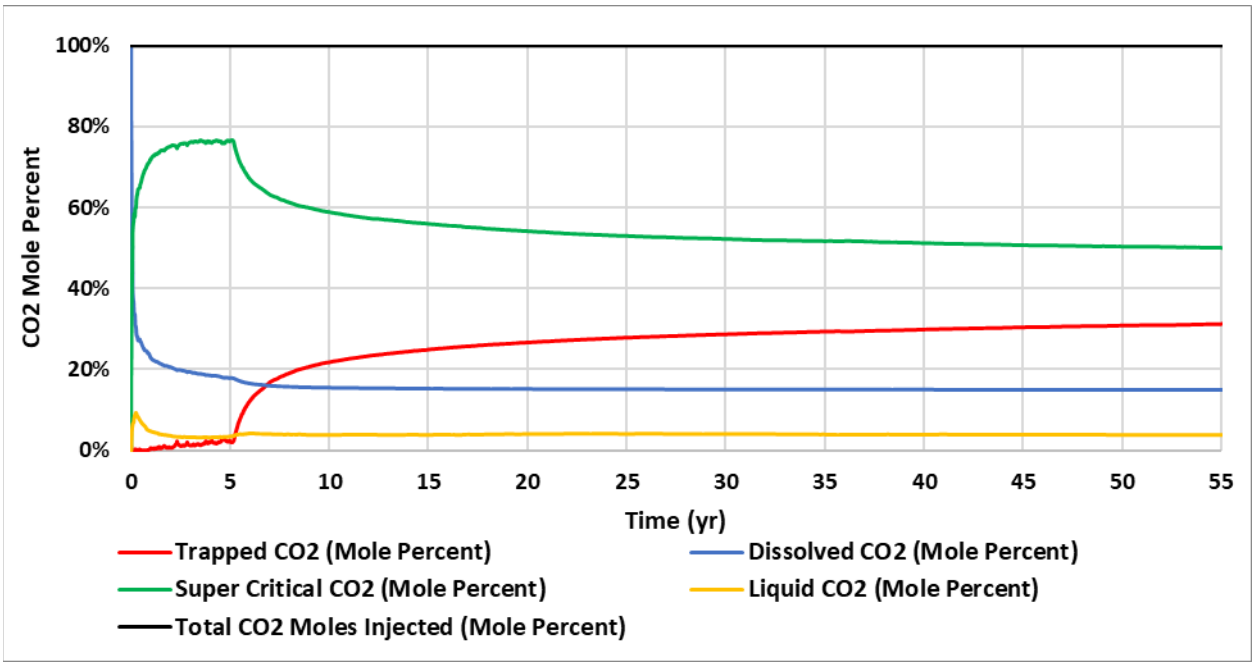


Figure 9-8: CO_2 dissolved in brine, CO_2 residually trapped in brine during injection, supercritical CO_2 and liquid CO_2 as a percentage of total CO_2 moles injected during the injection and post-injection periods.

9.5.5 Confining Zone Characterization – 40 CFR 146.93(c)(1)(vii)

The Eau Claire Formation is the primary confining unit for the project. The base of the Eau Claire Formation is comprised of the sandy Elmhurst Member where some CO_2 mobility is expected over time. However, the Eau Claire Formation has known thick and continuous shale intervals (Eau Claire Shale) above the Elmhurst Member, which have been confirmed as having good sealing capacity with core analysis (Permit Section 5). The Pre-Operational Testing Plan details the characterization that has been completed for the Eau Claire Shale (Permit Section 5). This included assessing the mineralogy, geomechanics, and capillary pressure within the Eau Claire Shale.

The properties of the Eau Claire Formation were distributed within a static reservoir model and then imported into the computational model. Figure 9-3 shows the cross section of the plume map at the end of the injection period and for Years 3 and 5 of the PISC phase. Additional figures illustrating the CO_2 plume behavior during a 50-year post-injection period have been included in the AoR and Corrective Action Plan Section (Permit Section 2). Computational modeling results show that there would be no CO_2 penetration into the Eau Claire Shale during the injection and post-injection modeling period due to the low permeability of the Eau Claire Shale.

9.5.6 Assessment of Fluid Movement Potential – 40 CFR 146.93(c)(1)(viii)-(ix)

There is no evidence of geological conduits within the AoR. Also, within the AoR there are no existing wells that penetrate either the injection zone or the confining layer, so no corrective action is required.

The MCI CCS 3 well will be constructed according to the USEPA Class VI regulations, and several measures will be incorporated in the well design to ensure protection of the USDWs at the site following the injection period (Injection Well Construction Plan, Permit Section 4). The long casing string and packer will be constructed of corrosion-resistant alloys (CR13) across the injection reservoir and confining zone to reduce the chances of casing degradation over the long term. Similarly, a CO_2-resistant cement will be pumped behind the deep string casing across the injection reservoir and confining zone. Following completion of the injection phase of the project and monitoring efforts, the MCI CCS 3 well will be plugged and abandoned according to the EPA Class VI guidelines, including the use of CO_2-resistant cement across the storage formation (Injection Well Plugging Plan, Permit Section 8).

During the injection and PISC phases of the project, the well integrity of the MCI CCS 3 and MCI MW 2 wells will be monitored through several internal and external monitoring techniques (Section 9.3, Permit Section 7). Annular pressures and fluid volumes will be monitored in the MCI CCS 3 well on a continuous basis until the MCI CCS 3 well is abandoned. Annular pressures in the MCI MW 2 well will be monitored daily. Temperature logging is the primary

external mechanical integrity test that will be used to monitor the MCI CCS 3 and MCI MW 2 wells on an annual basis.

9.5.7 Location of USDWs – 40 CFR 146.93(c)(1)(x)

At the Marquis BioCarbon Project site, the Mt. Simon Sandstone is not considered a USDW based on salinity samples acquired from MCI MW 1 with total dissolved solids (TDS) concentrations greater than 10,000 milligrams per liter (mg/L) or 10,000 parts per million (ppm). The lowermost USDW is defined locally as the Gunter Sandstone of the Prairie du Chien Group (Knox Supergroup). At the MCI MW 1 well, the base of the Gunter Sandstone is 963 feet (ft) above the top of the Mt. Simon. USDWs in the project site range from the Gunter Sandstone (deepest USDW) to shallow, near-surface glacial till aquifers.

9.6 Non-Endangerment Demonstration Criteria

Prior to approval of the end of the post-injection phase, Marquis Carbon Injection LLC will submit a demonstration of non-endangerment of USDWs to the UIC Director, per 40 CFR 146.93(b)(2) and (3).

The owner or operator will issue a report to the UIC Director. This report will make a demonstration of USDW non-endangerment based on the evaluation of the site monitoring data used in conjunction with the project's computational model. The report will detail how the non-endangerment demonstration evaluation uses site-specific conditions to confirm and demonstrate non-endangerment. The report will include all relevant monitoring data and interpretations upon which the non-endangerment demonstration is based, model documentation and all supporting data, and any other information necessary for the UIC Director to review the analysis. The report will include the following sections:

9.6.1 Introduction and Overview

A summary of relevant background information will be provided, including the operational history of the injection project, the date of the non-endangerment demonstration relative to the post-injection period outlined in this PISC and Site Closure Plan, and a general overview of how monitoring and modeling results will be used together to support a demonstration of USDW non-endangerment.

9.6.2 Summary of Existing Monitoring Data

A summary of all previous monitoring data collected at the site, pursuant to the Testing and Monitoring Plan (Permit Section 7) and this PISC and Site Closure Plan, including data collected during the injection and post-injection phases of the project, will be submitted to help demonstrate non-endangerment. Data submittals will be in a format acceptable to the UIC

Director [40 CFR 146.91(e)], and will include a narrative explanation of monitoring activities, including the dates of all monitoring events, changes to the monitoring program over time, and an explanation of all monitoring infrastructure that has existed at the site. Data will be compared with baseline data collected during site characterization [40 CFR 146.82(a)(6) and 146.87(d)(3)].

9.6.3 Summary of Computational Modeling History

The results of computational modeling used for AoR delineation and for demonstration of an alternative PISC timeframe will be compared to the monitoring data collected during the injection and PISC phases of the project. The monitoring data used to update and calibrate the computational modeling and to demonstrate non-endangerment of USDWs will include:

- Pressure monitoring data from the Mt. Simon Sandstone, Galesville Sandstone, and the deepest USDW
- Microseismic data
- PNC logs that characterize CO_2 saturations and vertical plume development along the well bores
- Time-lapse 3D seismic data

Data generated during the PISC period will be used to help show that the computational model accurately represents the storage site and can be used as a proxy to determine the CO_2 and pressure plume's properties and size. Marquis Carbon Injection LLC will demonstrate this degree of accuracy by comparing the monitoring data obtained during the PISC period against the model's predicted properties such as plume location, rate of movement, and pressure decay. The validation of the computational model with the large volume of available data will be a significant element to support the non-endangerment demonstration. The validation of the computational modeling results over the areas and zones where monitoring data have been collected will help to ensure confidence in those areas of the model where surface infrastructure precludes the collection of time-lapse 3D surface seismic data or the installation of monitoring wells.

9.6.4 Evaluation of Reservoir Pressure

During the PISC phase, the computational modeling predicts that the pressure in the Mt. Simon Sandstone will steadily decrease toward the pre-injection static pressure. One of the primary forces driving CO_2 or brine migration out of the storage formation is a pressure increase in the storage formation. Figure 9-1 illustrates the rapid decrease in pressure back to pre-injection levels in the Mt. Simon Sandstone once the injection phase of the project ends; and pressure decline toward pre-injection levels is one factor indicative of USDW non-endangerment.

The project will monitor pressure in the Mt. Simon Sandstone in the MCI MW 2 well and at the top of the Mt. Simon Sandstone in the MCI CCS 3 well with downhole pressure gauges (Table 9-6). The measured pressure will be compared to the pressure predicted by the computational model at the same depth. Agreement between the actual and the predicted values will help validate the accuracy of the model and further demonstrate non-endangerment.

9.6.5 Evaluation of CO_2 Plume

During the injection and PISC phases of the project, the extent of the CO_2 plume will be evaluated by PNC logging in the MCI MW 2 well and time-lapse 3D surface seismic surveys.

PNC logging will be used to monitor the distribution and saturation of CO_2 adjacent to the wellbore in the MCI MW 2 well. The PNC logging results can be compared against the model's predicted plume vertical extent at a specific point location at a specified time interval. A good correlation between the two data sets will help provide strong evidence in validating the model's ability to model the CO_2 plume. Time-lapse 3D surface seismic data will be acquired at longer time intervals to track the development of the CO_2 plume over a larger spatial extent. Both data types will be used to verify the computational model's ability to predict the CO_2 behavior in the PISC phase of the project and support a demonstration of non-endangerment of USDWs at the end of the project.

9.6.6 Evaluation of Emergencies or Other Events

Mobilized brine from the storage formation may also pose a risk to USDWs. The geochemical data collected from the MCI ACZ 1 well will be used to demonstrate that the storage formation fluids have not migrated above the confining formation during the injection or PISC phases of the project. If these fluids have not migrated beyond the confining zone during the injection or PISC phases of the project, then they are not anticipated to pose a risk to USDWs after the PISC phase. To demonstrate non-endangerment, results of the fluid sampling in the deepest USDW from the injection and PISC phases will be compared to the pre-injection baseline samples. This comparison will support a demonstration that no significant changes in the fluid properties of the overlying formations have occurred and that storage formation fluids have not moved through the confining layer, and therefore the CO_2 and/or brine would not represent an endangerment to any USDWs.

Section 9.4.6 describes the quality of the well construction for the wells that penetrate the confining zone for this project. The Well Construction Plan and the Well Plugging Plan are presented in Permit Sections 4 and 8, respectively. No other wells penetrate the confining zone within the AoR.

9.7 Site Closure Plan

Marquis Carbon Injection LLC will conduct site closure activities to meet the requirements of 40 CFR 146.93(e) as described below. Marquis Carbon Injection LLC will submit a final Site Closure Plan and notify the permitting agency at least 120 days prior of its intent to close the site. Once the permitting agency has approved closure of the site, Marquis Carbon Injection LLC will plug or transfer to another permit the MCI MW 1, MCI MW 2, and MCI ACZ 1 wells and submit a site closure report to EPA. The activities, as described below, represent the planned activities based on information provided to EPA. The actual site closure plan may employ different methods and procedures. A final Site Closure Plan will be submitted to the UIC Director for approval with the notification of the intent to close the site.

9.7.1 Plugging Monitoring Wells

Prior to plugging the wells, the external integrity of each well will be confirmed by running a temperature log over the entire length of the casing (total depth [TD] to surface). The temperature log will be acquired just before plugging the well and will be compared to previously run temperature logs to ensure that no deflections have developed that may indicate a problem with external well integrity. In addition, PNC logs will be run in the wells following the injection period to confirm that CO_2 has not migrated out of the injection zone.

The Well Plugging Plan for the MCI CCS 3 well can be found in Permit Section 8. The same approach that was used to plug the MCI CCS 3 well will be used to plug the MCI MW 1, MCI MW 2, and MCI ACZ 1 wells. Plugging and abandonment of the MCI MW 1, MCI MW 2, and MCI ACZ 1 wells will meet all requirements set forth by the Class VI regulations. The perforated zone of the well will be plugged using a retainer method and the upper portions of the well will be cemented with a balance method. In addition, the portion of the casing within the storage formation in the deep MCI MW 2 well will be plugged using CO_2-resistant cement. All the wells will have the casing cut off 5 ft below grade and a steel cap will be welded to the top of the deep casing string. The cap will have the well identification (ID) number and the date of plugging and abandonment inscribed on it. The following provides a detailed plan for plugging the MCI MW 1, MCI MW 2, and MCI ACZ 1 wells at the Marquis BioCarbon Project site.

1. Conduct and document a safety meeting.
2. Move-in (MI) rig and ancillary equipment onto well site and rig up (RU). Nipple up and test blow out preventors (BOPs), pressure test equipment and ensure proper operation.
3. Check wellhead tubing and casing pressures.
4. Record bottom-hole pressure from downhole gauge (if final pressure has not already been determined) and calculate kill fluid density.

5. Fill tubing with kill weight brine as determined by the final pressure measurement. Inject two tubing volumes of kill weight brine. Monitor tubing and casing pressure for 1 hour.
6. If the well is not dead or the pressure cannot be bled off the tubing, rig up slickline and set plug in lower profile nipple below packer. Unstab the tubing and circulate tubing and annulus with kill weight fluid until well is dead.
7. Release packer and pull out of hole with tubing laying it down. NOTE: Ensure that the well is over-balanced so there is no backflow due to formation pressure and there are always at least two well control barriers in place.
8. Trip into hole with work string with 5-1/2-inch cement retainer to approximately 100 ft above the top perforation, set retainer to cement the perforated portion of the well, and prepare for cement plugging operations. Pump the specified number of sacks of cement through the retainer while maintaining bottom-hole pressure below fracture pressure. If it appears that the injection pressure will exceed the fracture pressure and the total amount of cement has not been pumped into the injection zone, cement pumping will cease. After allowing the pressure to reduce to an acceptable level, cement pumping will be attempted again. A rapid increase in pressure on the tubing would indicate that the perforations have been sealed with cement, and no additional cement will be added to the zone or plug.
9. If a second perforated zone is present in the well, repeat Step 8 for upper perforated zone.
10. Trip tubing string out of well and remove stinger from end of tubing.
11. Trip tubing string to a depth of approximately 300 ft and prepare to set second cement plug. Pump 12 sacks of Class A cement (slurry weight of 15.9 pounds per gallon [lb/gal]) using a balance method to cement between a depth of 200 and 300 ft.
12. Trip tubing string to a depth of 100 ft and prepare to set third cement plug. Pump approximately 12 sacks of Class A cement to fill the casing from a depth of 100 ft to near surface.
13. Cut the casing string off at 5 ft below grade and weld a steel plate, (with well ID, permit number, and date of abandonment on it) to the casing strings.
14. Backfill the excavation.
15. Rig down and move off service rig and any remaining equipment.

Tables 9-7 and 9-8 provide the methods that will be used to set the plugs in each of the monitoring wells, and Tables 9-9 and 9-10 provide the materials that will be used during the plugging process. The volume of the casing to be cemented was calculated using the inside diameter of the 5-1/2-inch casing string (4.892 inches), and the length of the casing to be

cemented. Note that an additional 10% volume was used when calculating the cement needed to cement the perforated zones.

Zone of Interest	Cemented Depth (ft, MD)	Formation	Plugging Method	Plug Description	
				Type	Quantity
Perforated Interval	Various between 3,165−4,050	Mt. Simon Sandstone	Retainer	CO_2-Resistant	132 sacks
5-1/2-in. Casing Column	200-300	Pennsylvanian	Balance	Class A	12 sacks
5-1/2-in. Casing Column	0-100	Pleistocene Drift	Balance	Class A	12 sacks

Table 9-7: Intervals to be plugged and methods used when plugging the MCI MW 2 well.

Zone of Interest	Cemented Depth (ft, MD)	Formation	Plugging Method	Plug Description	
				Type	Quantity
Galesville Perforated Interval	2,425-2,595	Galesville Sandstone	Retainer	Class A	37 sacks
Deepest USDW Interval	1,337-1,482	Deepest USDW	Retainer	Class A	33 sacks
5-1/2-in. Casing Column	200-300	Pennsylvanian	Balance	Class A	12 sacks
5-1/2-in. Casing Column	0-100	Pleistocene Drift	Balance	Class A	12 sacks

Table 9-8: Intervals to be plugged and methods used when plugging the MCI ACZ 1 well.

Plug Information	Plug #1	Plug #2	Plug #3
Diameter of boring in which plug will be placed (in.)	4.892	4.892	4.892
Depth to bottom of tubing or drill pipe (ft, MD)	3,065	300	100
Sacks of cement to be used (each plug)	132	12	12
Slurry volume to be pumped (ft^3)	142	13.1	13.1
Slurry weight (lb./gal)	15.2	15.9	15.9
Slurry Yield (ft^3/sack)	1.07	1.18	1.18
Calculated top of plug (ft, MD)	3,065	200	0
Bottom of plug (ft, MD)	4,050	300	100
Type of cement or other material	CO_2- Resistant	Class A	Class A
Method of emplacement (e.g., balance method, retainer method, or two-plug method)	Retainer	Balance	Balance

Table 9-9: Materials used for plugging the MCI MW 1 well.

Following the plugging and abandonment of the monitoring wells, the above ground infrastructure, such as wellheads, monitoring equipment, etc., will be removed, and the area around the wells will be regraded to follow the natural topography of the surrounding area (currently agricultural fields). The ground will be replanted with either native vegetation or be converted back to agricultural land.

Plug Information	Plug #1	Plug#2	Plug #3	Plug #4
Diameter of boring in which plug will be placed (in.)	4.892	4.892	4.892	4.892
Depth to bottom of tubing or drill pipe (ft)	2,325	1,237	300	100
Sacks of cement to be used (each plug)	37	33	12	12
Slurry volume to be pumped (ft^3)	39	35.2	13.1	13.1
Slurry weight (lb./gal)	15.2	15.2	15.9	15.9
Slurry Yield (ft^3/sack)	1.07	1.07	1.18	1.18
Calculated top of plug (ft)	2,325	1,237	200	0
Bottom of plug (ft)	2,595	1,482	300	100
Type of cement or other material	CO_2-Resistant	CO_2-Resistant	Class A	Class A
Method of emplacement (e.g., balance method, retainer method, or two-plug method)	Retainer	Retainer	Balance	Balance

Table 9-2: Materials used for plugging the MCI ACZ 1 well.

9.7.2 Site Closure Report

A site closure report will be prepared and submitted within 90 days following site closure, documenting the following:

- Plugging of the monitoring wells (and the MCI CCS 3 well if it has not previously been plugged)
- Location of sealed MCI CCS 3 well on a plat of survey that has been submitted to the local zoning authority
- Notifications to state and local authorities as required by 40 CFR 146.93(f)(2)
- Records regarding the nature, composition, and volume of the injected CO_2, and post-injection monitoring records.
- Groundwater monitoring wells may be converted to use as groundwater wells as appropriate.

Marquis Carbon Injection LLC will record a notation to the property's deed on which the MCI CCS 3 well was located that will indicate the following:

- That the property was used for CO_2 sequestration
- The name of the local agency to which a plat of survey with MCI CCS 3 well location was submitted
- The volume of fluid injected
- The formation into which the fluid was injected, and the period over which the injection occurred.

The site closure report will be submitted to the permitting agency and maintained by the owner or operator for a period of 10 years following site closure. Additionally, the owner or operator will maintain the records collected during the post-injection period for a period of 10 years after which these records will be delivered to the UIC Director.

9.7.3 Quality Assurance and Surveillance Plan (QASP)

The QASP is presented in the Appendix A of the Testing and Monitoring Plan (Permit Section 7.0).

References

Enick RM, Klara SM. CO_2 solubility in water and brine under reservoir conditions. Chemical Engineering Communications 90(1):23-33 (1990).

FutureGen Alliance, 2013, Underground Injection Control Permit Applications for FutureGen 2.0 Morgan County Class VI UIC Wells 1, 2, 3, and 4, FG-RPT-017.

Golden StrataServices, 1984, Jones & Laughlin Steel Inc, Hennepin Illinois, UIC Permit Application, UIC-004-WI-JL, EPA Facility ID No. ILD000781591.

Land CS. Calculation of imbibition relative permeability for two-and three-phase flow from rock properties. Society of Petroleum Engineers Journal 8(02):149-56 (1968).

Li YK, Nghiem LX. Phase equilibria of oil, gas and water/brine mixtures from a cubic equation of state and Henry's law. The Canadian Journal of Chemical Engineering 64(3):486-96(1986).

Nghiem L, Shrivastava V, Tran D, Kohse B, Hassam M, Yang C. Simulation of CO_2 storage in saline aquifers. In: SPE/EAGE Reservoir Characterization & Simulation Conference: European Association of Geoscientists & Engineers. p. cp-170-00063 (2009).

Raziperchikolaee S, Alvarado V, Yin S. Effect of hydraulic fracturing on long-term storage of CO_2 in stimulated saline aquifers. Applied energy 102:1091-104 (2013).

10. EMERGENCY AND REMEDIAL RESPONSE PLAN
40 CFR 146.94(a)

MARQUIS BIOCARBON PROJECT

Facility Information

Facility name:	MARQUIS BIOCARBON PROJECT
Facility contact:	ELIZABETH STEINHOUR DIRECTOR OF ENVIRONMENTAL AFFAIRS 10000 MARQUIS DRIVE, HENNEPIN, IL 61327 815.925.7300 / BETHSTEINHOUR@MARQUISENERGY.COM
Well name:	MCI CCS 3
Well location:	PUTNAM COUNTY, ILLINOIS S2 T32N R2W Latitude: 41.27026520 N, Longitude: 89.30939322 W

Table of Contents

10.0 Emergency and Remedial Response Plan 3
10.1 Introduction 3
10.2 Local Resources and Infrastructure 3
10.3 Potential Risk Scenarios 6
10.4 Emergency Identification and Response Actions 6
10.4.1 Well Integrity Failure 7
10.4.2 Injection Well Monitoring Equipment Failure 9
10.4.3 Potential Brine or CO_2 Leakage to USDW 11
10.4.4 Natural Disaster 13
10.4.5 Induced Seismic Event 15
10.5 Response Personnel and Equipment 17
10.6 Emergency Communications Plan 18
10.7 Plan Review 19
10.8 Staff Training and Exercise Procedures 19
Appendix 10.A – FEP Risk Assessment 20

List of Tables

Table 10-1: Degrees of risk for emergency events. 6
Table 10-2: Response actions to an emergency associated with well integrity failure. 8
Table 10-3: Response actions to an emergency associated with well equipment failure. 10
Table 10-4: Response actions to an emergency associated with potential Brine or CO_2 leakage to a USDW. 12
Table 10-5: Response actions to an emergency associated with a natural disaster. 14
Table 10-6: Induced seismicity protocol for seismic events located with an epicenter within the AoR. 16
Table 10-7: Site-specific emergency contact list. 17
Table 10-8: Key local, state, and other authority's emergency contact list. 18

List of Figures

Figure 10-1: Map of the site resources and infrastructure. 5

10.0 Emergency and Remedial Response Plan

10.1 Introduction

This Emergency and Remedial Response Plan (ERRP) describes actions that Marquis Carbon Injection, LLC will take to address movement of the injection fluid or formation fluid in a manner that may endanger an underground source of drinking water (USDW) during the construction, operation, or post-injection site care periods.

If Marquis Carbon Injection, LLC obtains evidence that the injected carbon dioxide (CO_2) stream and/or associated pressure front may cause an endangerment to a USDW, Marquis Carbon Injection, LLC will perform the following actions:

1. Initiate shutdown plan for the MCI CCS 3 well.
2. Take all steps reasonably necessary to identify and characterize any release.
3. Notify the permitting agency/UIC Program Director (UIC Director) of the emergency event within 24 hours.
4. Implement applicable portions of the approved ERRP.

Where the phrase "initiate shutdown plan" is used, the following protocol will be employed: Marquis Carbon Injection, LLC will immediately cease injection. However, in some circumstances, Marquis Carbon Injection, LLC will, in consultation with the UIC Program Director, determine if a gradual cessation of injection is appropriate. If a non-emergency shutdown of the CO_2 injection system is required, the operator will complete the shutdown in a stepwise approach to prevent over-pressure situations and/or damage to the equipment. Efforts will also be made to maintain the CO_2 in the injection stream in a supercritical phase to prevent special operations during the restart of the system. Also, override of certain relays may be required to properly and safely shutdown the system.

10.2 Local Resources and Infrastructure

Resources in the vicinity of the Marquis BioCarbon Project that may be affected as a result of an emergency event at the project site include: USDWs, seven existing and three new shallow groundwater wells, and public traffic on Prairie Industrial Parkway.

Two major aquifer systems serve as the primary public water supply in Putnam County and vicinity: the Quaternary and Pennsylvania aquifers. The village of Hennepin obtains its groundwater supply at depths up to 135 feet [ft]. The Quaternary aquifer system consists of shallow, glacial deposits overlying the bedrock. The Pennsylvanian aquifer system, up to 250 ft deep in the project area, contains variable water quality that is generally utilized when the Quaternary aquifer supplies are insufficient.

Nearby surface-water features include the Illinois River to the west and north and unnamed northern tributaries to Coffee Creek. Groundwater supply wells are scattered across the area,

with depths typically shallower than 300 ft. A description of the active and inactive wells in this area is provided in the Area of Review (AoR) and Corrective Action Plan.

The land in the vicinity of the MCI CCS 3 well consists primarily of cropland with sparse residential or agricultural buildings. There are no public buildings, such as schools or hospitals in the vicinity of the MCI CCS 3 well. Additionally, there are no residential groundwater wells within the AoR. Industrial buildings owned by the Marquis ethanol-production facility are located 0.5 miles to the northwest of the injection site. These buildings and facilities are partially inside the AoR. Developed land is present 1.5 miles to the southwest in Hennepin, and other industrialized land uses in the area include an abandoned electrical coal plant to the north and an open pit quarry to the northeast.

Future infrastructure related to the Marquis BioCarbon Project site will consist of pipelines, the MCI CCS 3 well, the MCI MW 2, and above confining zone (MCI ACZ 1) wells, and the associated CO_2 compression facilities.

Resources and infrastructure addressed in this plan are shown in

Figure 10-1.

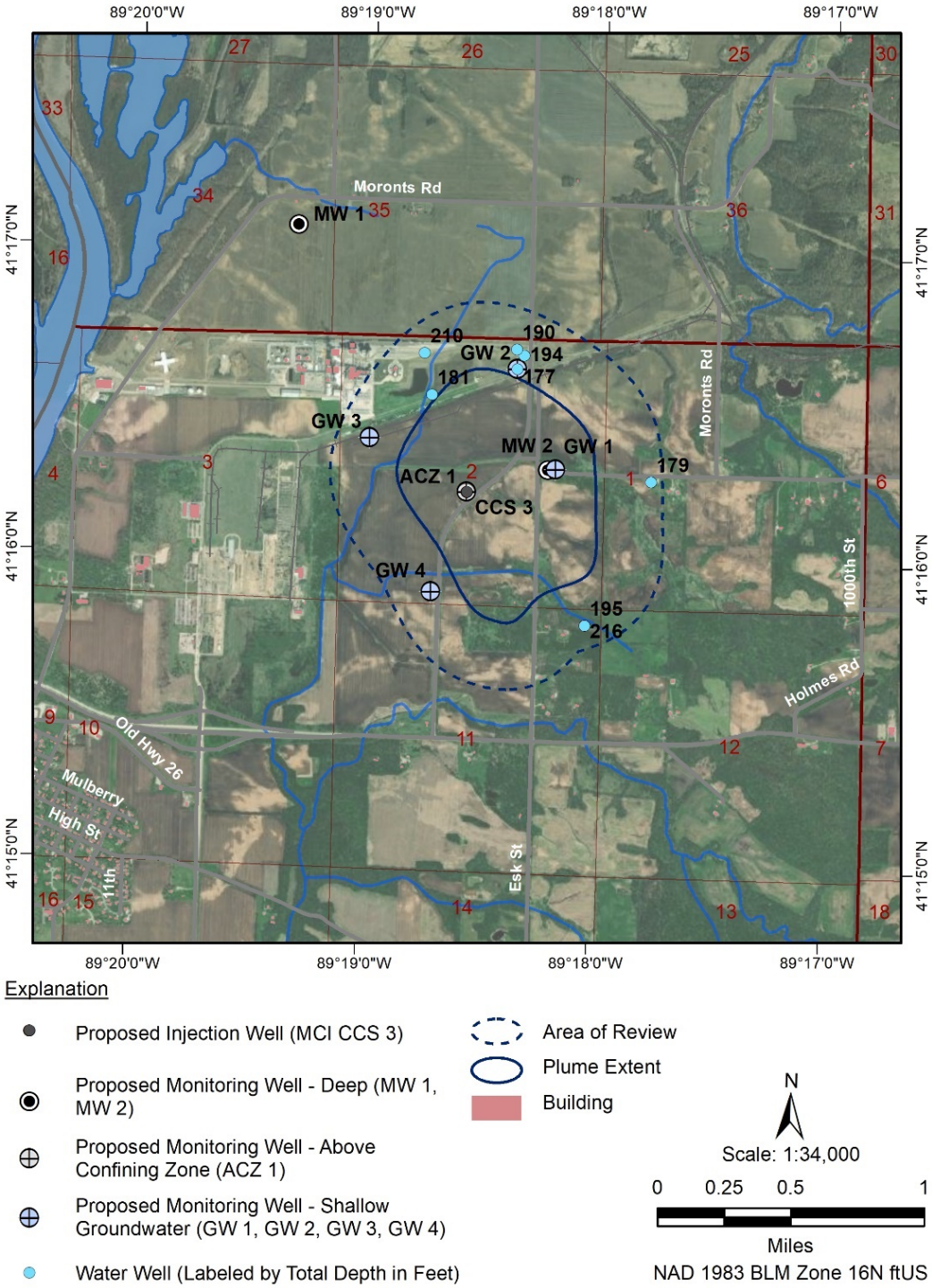


Figure 10-1: Map of the site resources and infrastructure.

10.3 Potential Risk Scenarios

The following events related to the Marquis BioCarbon Project could potentially result in an emergency response:

- MCI CCS 3 well or MCI MW 2 well integrity failure.
- MCI CCS 3 well monitoring equipment failure (e.g., shut-off valve or pressure gauge, etc.).
- A natural disaster (e.g., earthquake, tornado, lightning strike).
- Fluid (e.g., brine) leakage to a USDW.
- CO_2 leakage to USDW or land surface
- Induced seismic event.

Response actions will depend on the severity of the event(s) triggering an emergency response and are categorized below in Table 10-1.

In addition to the potential risk scenarios listed above a Feature, Event, and Process (FEP) risk assessment has been undertaken. A summary of this exercise is shown in Appendix A which describes the main FEPs identified for this project .

Emergency Condition	Definition
Major emergency	Event poses immediate substantial risk to human health, USDW's, other resources, or infrastructure. Emergency actions involving local authorities (evacuation or isolation of areas) should be initiated.
Serious emergency	Event poses potential serious (or significant) near-term risk to human health, resources, or infrastructure if conditions worsen, or no response actions taken.
Minor emergency	Event poses no immediate risk to human health, resources, or infrastructure.

Table 10-1: Degrees of risk for emergency events.

10.4 Emergency Identification and Response Actions

Steps to identify and characterize an emergency event will be dependent on the specific issue identified and the severity of the event. Each of the potential risk scenarios identified in the previous section are detailed below.

10.4.1 Well Integrity Failure

Integrity loss of the MCI CCS 3 well and/or MCI MW 2 well may endanger USDWs. Integrity loss may have resulted, and automatic shutdown devices will be activated if the following events occur:

- Wellhead (injection) pressure exceeds the shutdown pressure specified in the permit.
- Annulus pressure indicates a loss of external or internal well containment.
- Mechanical integrity test results identify a loss of mechanical integrity.

Response actions for the situations listed above are detailed below in Table 10-2.

Emergency Condition	Response Action and Notification Procedures
All	1. Notify the Marquis Carbon Injection, LLC Environmental Manager and CCS Operations Manager immediately. 2. Notify the UIC Director within 24 hours of the emergency event, per 40 CFR 146.91(c). 3. After an initial assessment, the Environmental Manager and/or the CCS Operations Manager will notify other Project Management and Operational Personnel. 4. Determine the severity of the event, based on the information available, within 24 hours of notification.
Major or Serious	5. Initiate shutdown plan a. Shut in well (close flow valve). Prior to closing the flow valve, notify plant personnel to direct CO_2 from the Scrubbers to the atmosphere. b. Check wind direction c. Mark an exclusion zone around the affected area/well to limit access to authorized personnel only. d. Notify plant safety personnel that well has been shut down. e. Vent excess CO_2 from surface lines and well, as necessary to reduce pressures and clear lines. f. Notify local authorities and plant personnel, as necessary. g. If evacuation plan must be implemented, notify all surrounding businesses and offices, and local authorities. h. Monitor the well conditions (i.e., pressures, temperatures, and annulus pressure) to determine potential causes and the extent of any failure, as well as any additional steps in the emergency procedure. 6. Evaluate whether any leaks to groundwater or surface water occurred. 7. If contamination of groundwater or surface water is detected, identify, and implement appropriate remedial actions (in consultation with the UIC Program Director).
Minor	1. Conduct assessment to determine whether there has been a loss of mechanical integrity. 2. If there has been a loss of mechanical integrity, initiate shutdown plan. 3. For shutdown plan, implement the following: a. Shut in well (close flow valve). Prior to closing the flow valve, notify plant personnel to direct CO_2 from the Scrubbers to the atmosphere. b. Vent excess CO_2 from surface lines and well, as necessary to reduce pressures and clear lines. c. Mark an exclusion zone around the affected well to limit access to well to authorized personnel only. d. Notify plant safety personnel that well has been shut down. e. Monitor the well conditions (i.e., pressures, temperatures, and annulus pressure) to determine potential causes and the extent of any failure. f. Identify and, if necessary, implement appropriate remedial actions in consultation with the UIC Program Director.

Table 10-2: Response actions to an emergency associated with well integrity failure.

10.4.2 Injection Well Monitoring Equipment Failure

The failure of monitoring equipment for wellhead pressure, temperature, and/or annulus pressure may indicate a problem with the MCI CCS 3 well that could endanger USDWs. Most equipment failures can be rapidly addressed by replacing the failed pieces of equipment and are likely minor emergencies. However, if the situation cannot be quickly addressed, system shutdown may be required.

The response actions to an emergency associated with well equipment failure is detailed below in Table 10-3.

Emergency Condition	Response Action and Notification Procedures
All	1. Notify the Marquis Carbon Injection, LLC Environmental Manager and CCS Operations Manager immediately. 2. Notify the UIC Director within 24 hours of the emergency event, per 40 CFR 146.91(c). 3. After an initial assessment, the Environmental Manager and/or the CCS Operations Manager will notify other Project Management and Operational Personnel. 4. Determine the severity of the event, based on the information available, within 24 hours of notification.
Major or Serious	5. Initiate shutdown plan a. Shut in well (close flow valve). Prior to closing the flow valve, notify plant personnel to direct CO_2 from the Scrubbers to the atmosphere. b. Vent excess CO_2 from surface lines and well, as necessary to reduce pressures and clear lines. c. Mark an exclusion zone around the affected well to limit access to well. d. Notify local authorities and plant personnel, as necessary. e. Monitor the well conditions (i.e., pressures, temperatures, and annulus pressure) to determine additional steps in the emergency procedure. 6. Identify and, if necessary, implement appropriate remedial actions (in consultation with the UIC Program Director).
Minor	1. Conduct assessment to determine whether there has been a loss of mechanical integrity. 2. If there has been a loss of mechanical integrity, initiate shutdown plan. 3. For shutdown plan, implement the following: a. Shut in well (close flow valve). Prior to closing the flow valve, notify plant personnel to direct CO_2 from the Scrubbers to the atmosphere. b. Vent excess CO_2 from surface lines and well, as necessary to reduce pressures and clear lines. c. Reset or repair automatic shutdown devices, if necessary. d. Monitor the well conditions (i.e., pressures, temperatures, and annulus pressure) to determine potential causes and the extent of any failure. 4. Repair or replace monitoring equipment that failed. 5. Identify and, if necessary, implement appropriate remedial actions in consultation with the UIC Program Director.

Table 10-3: Response actions to an emergency associated with well equipment failure.

10.4.3 Potential Brine or CO_2 Leakage to USDW

Elevated concentrations of indicator parameter(s) in groundwater sample(s) from the MCI ACZ 1 well or increased pressures in the MCI ACZ 1 well may indicate fluid (brine) or CO_2 leakage into a USDW.

The response actions to an emergency associated with potential Brine or CO_2 leakage to a USDW is detailed below in Table 10-4.

Emergency Condition	Response Action and Notification Procedures
All	1. Notify the Marquis Carbon Injection, LLC Environmental Manager and CCS Operations Manager immediately. 2. After an initial assessment, the Environmental Manager and/or the CCS Operations Manager will notify other Project Management and Operational Personnel. 3. Notify the UIC Director within 24 hours of the emergency event, per 40 CFR 146.91(c). 4. Determine the severity of the event, based on the information available, within 24 hours of notification. 5. For all cases of confirmed migration of non-native fluid or CO_2 above the confining zone: a. Initiate shutdown plan i. Shut in well (close flow valve). Prior to closing the flow valve, notify plant personnel to direct CO_2 from the Scrubbers to the atmosphere. ii. Vent excess CO_2 from surface lines and well, as necessary to reduce pressures and clear lines. iii. Mark an exclusion zone around the affected well to limit access to affected area. iv. Notify local authorities and plant personnel, as necessary. v. Monitor the well conditions (i.e., pressures, temperatures, geochemical parameter, temperature data, etc.) to determine additional steps in the emergency procedure. b. Collect confirmation sample(s) of groundwater and analyze for indicator parameters. See Table 7-6 of the Testing and Monitoring Plan. 6. If the leakage of non-native fluid or CO_2 is confirmed, develop (in consultation with the UIC Program Director) a case-specific plan with various methods to address any unacceptable impacts to the affected USDW while achieving certain goals. The goals and proposed methods are as follows: a. Install additional groundwater monitoring points near the affected groundwater well(s) to delineate the extent of impact. b. Remediate the affected USDW to mitigate any unsafe conditions through the installation of: i. A system to intercept and extract non-native fluid or CO_2; or ii. A pump-and-treat type system to aerate the water contaminated with CO_2 to purge the CO_2 from the water. c. Arrange for an alternate potable water supply if the USDW was being utilized as a drinking water source and has exceeded drinking water standards by CO_2 or brine infiltration. d. Continue groundwater remediation and monitoring on a frequent basis (frequency to be determined by Marquis Carbon Injection, LLC and the UIC Director) until unacceptable adverse USDW impact has been addressed.

Table 10-4: Response actions to an emergency associated with potential Brine or CO_2 leakage to a USDW.

10.4.4 Natural Disaster

Well problems (integrity loss, leakage, or malfunction) may arise because of a natural disaster affecting the normal operation of the MCI CCS 3 well. An earthquake may disturb surface and/or subsurface facilities; and weather-related disasters (e.g., tornado or lightning strike) may affect surface facilities. The Marquis Carbon Injection facility lies outside the Federal Emergency Management Agency Adverse Effects (FEMA AE) Zone for floodplains.

The response actions to an emergency associated with a natural disaster are detailed below in Table 10-5.

Emergency Condition	Response Action and Notification Procedures
All	1. Notify the Marquis Carbon Injection, LLC Environmental Manager and CCS Operations Manager immediately. 2. The Environmental Manager and/or the CCS Operations Manager or their designee will notify other Project Management and Operational Personnel. 3. Notify the UIC Director within 24 hours of the emergency event, per 40 CFR 146.91(c). 4. Determine the severity of the event, based on the information available, within 24 hours of notification.
Major or Serious	5. Initiate shutdown plan a. Confirm no leakage from the CO_2 injection system. b. Shut in well (close flow valve). Prior to closing the flow valve, notify plant personnel to direct CO_2 from the Scrubbers to the atmosphere. c. Vent excess CO_2 from surface lines and well, as necessary to reduce pressures and clear lines. d. Mark an exclusion zone around the affected well to limit access. e. Notify local authorities and plant personnel, as necessary. f. Determine if any leaks to groundwater or surface water occurred. g. Monitor the well conditions (i.e., pressures, temperatures, etc.) to determine additional steps in the emergency procedure. 5. If contamination or endangerment is detected, identify, and implement appropriate remedial actions (in consultation with the UIC Program Director).
Minor	4. Conduct assessment to determine whether there has been a loss of mechanical integrity. 5. If there has been a loss of mechanical integrity, initiate shutdown plan. For shutdown plan, implement the following: i. Shut in well (close flow valve). Prior to closing the flow valve, notify plant personnel to direct CO_2 from the Scrubbers to the atmosphere. ii. Vent excess CO_2 from surface lines and well, as necessary to reduce pressures and clear lines. iii. Monitor the well conditions (i.e., pressures, temperatures, and annulus pressure) to determine potential causes and the extent of any failure. 6. Identify and, if necessary, implement appropriate remedial actions in consultation with the UIC Program Director.

Table 10-5: Response actions to an emergency associated with a natural disaster.

10.4.5 Induced Seismic Event

The Marquis BioCarbon Project is in a seismically stable region. To monitor the AoR for any potential seismic activity, a network of surface seismological stations will be deployed to continuously record background seismic activity. The number of required stations will be determined based on a site-specific modeling exercise incorporating the AoR and the seismic event magnitudes to be monitored. Baseline microseismic data will be acquired for six months prior to the start of injection operations. Triggered seismic event data will be processed to provide seismic moment magnitude and precise location and depth information on a real-time basis and reported daily should any occur.

Based on the periodic analysis of the monitoring data, observed level of seismic activity, and local reporting of felt events, the site will be assigned an operating state based on the protocol described in Table 10-6. The operating state is determined using threshold criteria which correspond to the site's potential risk and level of seismic activity. The operating state provides operating personnel information about the potential risk of further seismic activity and guides them through a series of response actions.

Operating State	Threshold Condition	Response Action
Green	Seismic events less than or equal to M1.5	1. Continue normal operation within permitted levels.
Yellow	Five (5) or more seismic events within a 30-day period having a magnitude greater than M1.5 but less than or equal to M2.0	1. Continue normal operation within permitted levels. 2. Within 24 hours of the fifth event, notify the UIC Director of the operating status of the well.
Orange	Seismic event greater than M1.5 and local observation or felt report Seismic event greater than M2.0 and no felt report	4. Continue normal operation within permitted levels. 5. Within 24 hours of the incident, notify the UIC Director, of the operating status of the well. 6. Review seismic and operational data. 7. Report findings to the UIC Director and issue corrective actions.
Magenta	Seismic event greater than M2.0 and local observation or report	1. Initiate rate reduction plan (section 1 above). 2. Within 24 hours of the incident, notify the UIC Director, of the operating status of the well. 3. Communicate with facility personnel and local authorities to initiate evacuation plans, as necessary. 4. Monitor well pressure, temperature, and annulus pressure to verify well status and determine the cause and extent of any failure; identify and implement appropriate remedial actions (in consultation with the UIC Director). 5. Determine if leaks to ground water or surface water occurred. 6. If USDW contamination is detected: a. Notify the UIC Director within 24 hours of the determination. 7. Review seismic and operational data. 8. Report findings to the UIC Director and issue corrective actions.
Red	Seismic event greater than M2.0, and local observation or report, and local report and confirmation of damage Seismic event >M3.5	1. Initiate shutdown plan. 2. Within 24 hours of the incident, notify the UIC Director of the operating status of the well. 3. Communicate with facility personnel and local authorities to initiate evacuation plans, as necessary. 4. Monitor well pressure, temperature, and annulus pressure to verify well status and determine the cause and extent of any failure; identify and implement appropriate remedial actions (in consultation with the UIC Director). 5. Determine if leaks to ground water or surface water occurred. 6. If USDW contamination is detected, notify the UIC Director within 24 hours of the determination. 7. Review seismic and operational data. 8. Report findings to the UIC Director and issue corrective actions.

Table 10-6: Induced seismicity protocol for seismic events located with an epicenter within the AoR.

10.5 Response Personnel and Equipment

Site personnel, project personnel, and local authorities will be relied upon to implement this ERRP.

A site-specific emergency contact list is provided in Table 10-7 and will be maintained during the life of the project. Marquis Carbon Injection, LLC will provide the current site-specific emergency contact list to the UIC Program Director.

Position	Name	Phone Number
Project Officer	Jason Marquis	815-878-4307
Project Manager	Lester Smith	815-878-2134
CCS Operations Manager	Jared Walker	435-241-8214
Plant Safety Manager	Jeff Sonnenberg	815-252-3916
Safety Coordinator	Tyler Smith	815-878-7121
Safety Coordinator	Bob Boehm	815-760-0553
Environmental Director	Beth Steinhour	815-878-2321
Environmental Manager	Bridget Conlon	815-760-2637
Plant Technology Director	Trevor Davis	217-440-7401
Marquis Energy Control Room		815-925-7300
Marquis Marine Terminal		815-925-7065

Table 10-7: Site-specific emergency contact list.

Key local, state, and other authority's emergency contact list is provided in Table 10-8 and will also be maintained during the life of the project.

Agency	Phone Number
Local police (Hennepin Police)	815-925-7084
Illinois State police (LaSalle office, IL)	815-224-1171
Putnam County Sheriff	815-925-7015
Hennepin Fire Department	815-925-7225 or 911
Illinois Emergency Management Agency	800-782-7860
Environmental Services Contractor	Clean Harbors 1-800-645-8265
UIC Director US EPA Region V	312-353-7648

Table 10-8: Key local, state, and other authority's emergency contact list.

Equipment needed in the event of an emergency and remedial response will vary, depending on the triggering emergency event. Response actions (cessation of injection, well shut-in, and evacuation) will generally not require specialized equipment to implement. Where specialized equipment (such as a drilling rig or logging equipment) is required, Marquis Carbon Injection, LLC shall be responsible for its procurement.

10.6 Emergency Communications Plan

Marquis Carbon Injection, LLC will communicate to the public about any event that requires an emergency response to ensure that the public understands what happened and whether there are any environmental or safety implications, in consultation with the UIC Program Director. The amount of information, timing, and communications method(s) will be appropriate to the event, its severity, whether any impacts to drinking water or other environmental resources occurred, any impacts to the surrounding community, and their awareness of the event.

Marquis Carbon Injection, LLC will describe what happened, any impacts to the environment or other local resources, how the event was investigated, what responses were taken, and the status of the response. For responses that occur over the long-term (e.g., ongoing cleanups), Marquis Carbon Injection, LLC will provide periodic updates on the progress of the response action(s).

Marquis Carbon Injection, LLC will also communicate with entities who may need to be informed about or act in response to the event, including local water systems, CO_2 source(s) and pipeline operators, landowners, and Regional Response Teams (as part of the National Response Team).

Emergency situations related to the injection project and described in this EERP will be managed by Marquis Carbon Injection's communication team. All media communications with the public through either interviews, press releases, website postings, or other.

The individual to be designated by Marquis Carbon Injection will be the first contact during an emergency event.

This individual will contact the crisis communication team as appropriate. Emergency responses to the media from Marquis Carbon Injection will be dealt with by personnel designated by Marquis Carbon Injection.

Individuals assigned the emergency response communications duties should have availability 24-hours a day in the event of an emergency.

10.7 Plan Review

This ERRP shall be reviewed:

- At least once every five-years following its approval by the permitting agency.
- Within one-year of an AoR re-evaluation.
- Within six-months following any significant changes to the injection process or the injection facility, or an emergency event; or
- As required by the permitting agency.

If the review indicates that no amendments to the ERRP are necessary, Marquis Carbon Injection, LLC will provide the permitting agency with the documentation supporting the "no amendment necessary" determination.

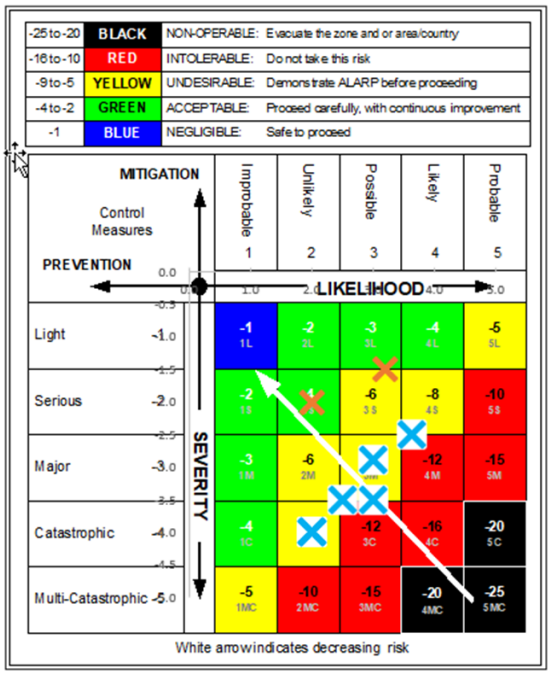
If the review indicates that amendments to the ERRP are necessary, amendments shall be made and submitted to the permitting agency within six-months following an event that initiates the ERRP review procedure.

10.8 Staff Training and Exercise Procedures

Marquis Carbon Injection, LLC will integrate this ERRP into the project-specific standard operating procedures and training program. Periodic training will be provided, not less than annually, to well operators, CO_2 scrubber operators, safety and environmental personnel, plant technology manager and corporate communications. The training plan will document that the above listed personnel have been trained and possess the required skills to perform their relevant emergency response activities described in the ERRP.

Appendix 10.A – FEP Risk Assessment

Feature, Event, or Process	Avg Severity	Avg Likelihood	Multiplier (sev*like)	Scenarios	RRA	Resulting Severity	Resulting Likelihood	Multiplier
Schedule and Planning (Financial)	-2.5	3.6	9.1	Increasing oilfield activity; long lead times for materials or services	Plan ahead as much as possible; drilling or well ops in off-peak times (spring, fall)	-1.5	3.2	4.8
Procurement Delays – Well Tubulars; Well Hardware	-2.9	3.0	8.6	Delays in obtaining specialized equipment/materials	Plan ahead as much as possible; reduce equipment exposure to injectate; develop relationships with vendors now	-2	2	4
Accidents and Unplanned Events: Project	-4	2	8.0	Large presure swings from errant compressor sensors				0
Hydrogeology	-4	2	8.0	CO2 leaking into groundwater				0
CO2 Injectate: Water Vapor	-4	2	8.0	Scrubber upset causes water to carry over				0
Interruptions of CO2 Source Plant	-4	2	8.0	Ethanol plant production slows				0
Legal/Regulatory: Permits: Construction, Discharge, and Other Operations	-3.5	3.0	10.5	Permit timelines change				0
Legal/Regulatory: Permits: Drilling, Injection/Storage	-3.5	2.5	8.8	Not many sites permitted in IL before				0



Class VI UIC Area of Review and Corrective Action

This submission is for:

Project ID: R05-IL-0006

Project Name: Marquis Carbon

Current Project Phase: Pre-Injection Prior to Construction

Overview

Simulator Used for AoR delineation modeling: GEM

Version Used: Version 2021

Simulator Description/Documentation: https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R05-IL-0006/Phase1-PreConstruction/AoRModeling-06-17-2022-1736/Overview_1_Model_and_Simulator_Description.pdf

Description of File Contents: The simulator version and properties are described in the document. In addition, a brief overview is provided of how reservoir properties are combined with geological parameters. Model dimensions and injection and monitoring duration are also described.

Total Simulation Time From Start of Injection: 20148 days

Additional AoR Delineation Information: https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R05-IL-0006/Phase1-PreConstruction/AoRModeling-06-17-2022-1736/State--primacy--statement.pdf

Description of Information Submitted: This explains how AoR was determined based on CO2 plume size

Model Domain

Coordinate System: Geographic (Lat-Long)

Horizontal Datum: NAD83

Vertical Datum: Mean Sea Level

Describe Vertical Datum: NAD 1983 BLM Zone 16N ftUS

Mesh Type: Other

Describe Mesh Type: Pillar Grid

Domain Size in Global Units Specified Above

Domain Coordinates File: https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R05-IL-0006/Phase1-PreConstruction/AoRModeling-06-17-2022-1736/ModelDomain_1_CoordinateFile.jpg

Grid Size

Number of Nodes in x: 74 y: 72 z: 201

Grid Spacing: Constant

Grid Spacing in x: 73 y: 71 z: 200

Grid File Format: Eclipse Keyword File

Grid File Description: https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R05-IL-0006/Phase1-PreConstruction/AoRModeling-06-17-2022-1736/ModelDomain_2_GridDescription.pdf

Eclipse Keyword File: https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R05-IL-0006/Phase1-PreConstruction/AoRModeling-06-17-2022-1736/ModelDomain_3_StaticEarthModel_ECLIPSE.ASCII

Faults Modeled: No

Caprock Modeled: Yes

Image File(s) for Model Domain Grid: https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R05-IL-0006/Phase1-PreConstruction/AoRModeling-06-17-2022-1736/ModelDomain_4_ModelZones.jpg

https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R05-IL-0006/Phase1-PreConstruction/AoRModeling-06-17-2022-1736/ModelDomain_4_ModelBoundary.jpg

Processes Modeled by Simulator

Reservoir Conditions:

Supercritical CO2 Conditions Subcritical CO2 Conditions

Phases Modeled:

Liquid-CO2 Supercritical CO2

Liquid-CO2 Phase:

Phase Compressibility: Compressible

Phase Composition: Compositional

Liquid-CO2 Phase Components:

CO2 Water

Supercritical CO2 Phase:

Phase Compressibility: Compressible

Phase Composition: Compositional

Supercritical CO2 Phase Components:

CO2 Water

Equation of State Description Including Reference: PEGN Robinson EOS equation of state was used to model the fluid properties of the injected CO2 in gaseous/supercritical phases (Peng and Robinson, 1976).

File with EOS Reference or Documentation: https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R05-IL-0006/Phase1-PreConstruction/AoRModeling-06-17-2022-1736/PEGN_RobinsonPaper.pdf

Multifluid Flow Processes:

Advection Diffusion

Non-wetting Fluid Trapping Pore Compressibility

Thermal Conditions: Non-Isothermal

File Describing Thermal Conductivity Function including Parameters: https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R05-IL-0006/Phase1-PreConstruction/AoRModeling-06-17-2022-1736/Heat--Conductivity--Equation--in--GEM.pdf

Heat Transport Processes:

Heat of Solution

Geochemistry Modeled: No

Geomechanical/Structural Deformations Modeled: No

Modeled Processes Comments: A keyword in the simulation data file was specified to allow for thermal effects between injected CO2 and reservoir. CO2 trapping is accomplished through relative permeability and hysteresis. Pore compressibility is specified from characterization well logs.

Rock Properties and Constitutive Relationships

Porosity/Permeability Model

Single Porosity

Porosity Distribution: Heterogeneous

Porosity included in Eclipse Keyword File: Yes

Porosity Variable Name in Eclipse Keyword File: PHI

File Describing how Porosity was Determined and Assigned to Numerical Model: https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R05-IL-0006/Phase1-PreConstruction/AoRModeling-06-17-2022-1736/RockProperties_1_PorosityModeling.pdf

Image Files for Porosity Distributions: https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R05-IL-0006/Phase1-PreConstruction/AoRModeling-06-17-2022-1736/RockProperties_2_PorosityDistributions.jpg

https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R05-IL-0006/Phase1-PreConstruction/AoRModeling-06-17-2022-1736/RockProperties_2_PorosityDistributions.jpg

https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R05-IL-0006/Phase1-PreConstruction/AoRModeling-06-17-2022-1736/RockProperties_2_PorosityProperty.jpg

Permeability Distribution: Heterogeneous

Permeability included in Eclipse Keyword File: Yes

Permeability Variable Name in Eclipse Keyword File: PERMX,PERMY,PERMZ

File Describing how Permeability was Determined and Assigned to Numerical Model: https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R05-IL-0006/Phase1-PreConstruction/AoRModeling-06-17-2022-1736/RockProperties_3_PermeabilityModeling.pdf

Image Files for Permeability Distributions: https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R05-IL-0006/Phase1-PreConstruction/AoRModeling-06-17-2022-1736/RockProperties_4_PermeabilityDistribution-w-Functions.jpg

Number of Rock Types Modeled: 1

Description of Rock Type Selection and Assignment: https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R05-IL-0006/Phase1-PreConstruction/AoRModeling-06-17-2022-1736/RockProperties_5_FaciesModeling.pdf

Rock Type Distribution Data File: https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R05-IL-0006/Phase1-PreConstruction/AoRModeling-06-17-2022-1736/RockProperties_6_Seal_PHI_Distribution

https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R05-IL-0006/Phase1-PreConstruction/AoRModeling-06-17-2022-1736/RockProperties_6_Shale_PHI_Distribution

https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R05-IL-0006/Phase1-PreConstruction/AoRModeling-06-17-2022-

1736/RockProperties_6_MS2-3_DirtySand_PHI_Distribution

https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R05-IL-0006/Phase1-PreConstruction/AoRModeling-06-17-2022-1736/RockProperties_6_MS2-3_CleanSand_PHI_Distribution

https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R05-IL-0006/Phase1-PreConstruction/AoRModeling-06-17-2022-1736/RockProperties_6_DirtySand_PHI_Distribution

https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R05-IL-0006/Phase1-PreConstruction/AoRModeling-06-17-2022-1736/RockProperties_6_CleanSand_PHI_Distribution

Image Files for Rock Type Distribution: https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R05-IL-0006/Phase1-PreConstruction/AoRModeling-06-17-2022-1736/RockProperties_7_Facies_Property.jpg

https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R05-IL-0006/Phase1-PreConstruction/AoRModeling-06-17-2022-1736/RockProperties_7_EOD_Property.jpg

Rock Type #1

Rock Compressibility: Pore

Rock Compressibility Distribution: Single Value

Compressibility Value: 0.000001 1/psi

Compressibility included in Eclipse Keyword File: Yes

Compressibility Variable Name in Eclipse Keyword File: CPOR

Constitutive Relationships

Porosity and Permeability Reduction Due to Salt Precipitation

Rock Properties Comments: Three rock types were used due to relative permeability differences, but compressibility was the same on all. Therefor only one rock type is listed above.

Boundary Conditions

Attach Boundary Conditions Description File: https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R05-IL-0006/Phase1-PreConstruction/AoRModeling-06-17-2022-1736/Boundary_Conditions.pdf

Initial Conditions

Initial Phases in Domain: Aqueous

Initial Aqueous Pressure: Varying with Depth, Temperature, and Salinity

Initial Aqueous Pressure: 1491 psi at Reference Elevation: -2839 ft

Initial Temperature: Varying with Depth

Initial Temperature: 91.5 F at Reference Elevation: -4168 ft Gradient: 0.02 deg F/ft

Initial Salinity: Spatially Constant

Initial Salinity: 45000 ppm

Operational Information

Number of Injection Wells: 1

Injection Well #1

Well Direction: Vertical

Location: X: -89.309393 Longitude (DD) Y: 41.270265 Latitude (DD)

Wellbore Diameter: Constant

Wellbore Diameter: 9.625 in

Well Screen Interval Provided as: Single Interval

Elevation of Top of Screened Interval: -3226 Elevation of Bottom of Screened Interval: -4781 ft

Mass Rate of Injection: 1.5 MMT/yr

Total Mass of Injection: 7.5 MMT

Actual Injection Temperature: 93 F

Fracture Gradient: 0.76 psi/ft

Maximum Injection Pressure: 2207 psi Elevation Corresponding to Pressure: 2694 ft

Description of How Fracture Gradient and Maximum Injection Pressure were Determined: DIrect measurement through minifrac in MCI MW1 well

Description of How Fracture Gradient and Maximum Injection Pressure were Determined File: https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R05-IL-0006/Phase1-PreConstruction/AoRModeling-06-17-2022-1736/Fracture--gradient--calculation.pdf

Composition of Injectate: Pure CO2

Injection Schedule Provided as: Single Injection Period

Injection Start Date: 09/01/2023 Stop Date: 08/31/2028

Number of Production/Withdrawal Wells: 0

Model Output/Results

Provide file name and corresponding spatial location for each file: CO2 Mass Injected.csv: Total Mass CO2 Injected in tonnes vs Time Bottom Hole Pressure.csv: Injection Pressure time plot CO2 Saturation.csv: gaseous gas saturation plt

Time-Series File: https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R05-IL-0006/Phase1-PreConstruction/AoRModeling-06-17-2022-1736/Time--Series--Data.zip

Provide file name and corresponding variable and time stamp for each file: Global Mole Fraction co2 spacial.txt: represents CO2 in moles (fraction) at end of injection) Pressure differential Spacial.txt: Pressure differential at end of injection Gas Mole Fraction co2 spacial.txt: represents gas CO2 in moles at end of injection Gas Saturation Spacial.txt: CO2 Saturation

Snapshot File: https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R05-IL-0006/Phase1-PreConstruction/AoRModeling-06-17-2022-1736/Snapshot--Data.zip

Provide file name and corresponding description of surface for each file: Flux files.zip Sensitivitiy Analysis.PDF

Surface Flux File: https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R05-IL-0006/Phase1-PreConstruction/AoRModeling-06-17-2022-1736/Flux--Files.zip

Sensitivity Analysis Description/Results: https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R05-IL-0006/Phase1-PreConstruction/AoRModeling-06-17-2022-1736/Sensitivity--Analysis.pdf

AoR Pressure Front Delineation

Lowermost USDW:

Name of Lowermost USDW: Gunter Sandstone

Water Density: 997.95 kg/m^3 at Elevation: -1593 ft

Location of Measurement for Density: MCI MW 1 well

Temperature: 70 F at Elevation: -1593 ft

Location of Measurement: MCI MW 1 well

Pressure: 941.6 psi at Elevation: -1593 ft

Location of Measurement: MCI MW 1 well

Salinity: 665 ppm at Elevation: -1593 ft

Location of Measurement: MCI MW 1 well

Elevation of bottom of USDW: -1600 m

Injection Zone:

Name of Injection Zone: MT Simon Sandstone

Water Density: 1029.99 kg/m^3 at Elevation: -3200 ft

Location of Measurement: MCI MW 1 well

Temperature: 91.5 F at Elevation: -4168 ft

Location of Measurement: MCI MW 1 well

Pressure: 1760 psi at Elevation: -4000 ft

Location of Measurement: MCI MW 1 well

Salinity: 26215 mg/L at Elevation: -3200 ft

Location of Measurement: MCI MW 1 well

Elevation of top of Injection Zone: 3226 ft

Method of Estimating Critical Pressure: Other

File Describing Critical Pressure Estimation: https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R05-IL-0006/Phase1-PreConstruction/AoRModeling-06-17-2022-1736/Critical--Pressure.pdf

Estimated Critical Pressure: 477 psi

Delineated AoR:

Shapefile or KML File Showing Delineated AoR: https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R05-IL-0006/Phase1-PreConstruction/AoRModeling-06-17-2022-1736/AoRPressureFrontDelineation_2_AoR.cpg

https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R05-IL-0006/Phase1-PreConstruction/AoRModeling-06-17-2022-1736/AoRPressureFrontDelineation_2_AoR.shx

https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R05-IL-0006/Phase1-PreConstruction/AoRModeling-06-17-2022-1736/AoRPressureFrontDelineation_2_AoR.sbx

https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R05-IL-0006/Phase1-PreConstruction/AoRModeling-06-17-2022-1736/AoRPressureFrontDelineation_2_AoR.sbn

https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R05-IL-0006/Phase1-PreConstruction/AoRModeling-06-17-2022-1736/AoRPressureFrontDelineation_2_AoR.dbf

https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R05-IL-0006/Phase1-PreConstruction/AoRModeling-06-17-2022-1736/AoRPressureFrontDelineation_2_AoR.prj

https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R05-IL-0006/Phase1-PreConstruction/AoRModeling-06-17-2022-1736/AoRPressureFrontDelineation_2_AoR.shp.xml

https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R05-IL-0006/Phase1-PreConstruction/AoRModeling-06-17-2022-1736/AoRPressureFrontDelineation_2_AoR.shp

AoR Pressure Front Delineation Comments: Critical pressure calculated by hydrostatic difference.

Corrective Action

File with Location of All Penetrations within AoR: https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R05-IL-0006/Phase1-PreConstruction/AoRModeling-06-17-2022-1736/CorrectiveAction_1_PenetrationsWithinAoR.csv

Corrective Action Comments: No wells identified in AOR

Area of Review and Corrective Action Plan [40 CFR 146.82(a)(13) and 146.84(b) or applicable state requirements]

Are you making an Area of Review and Corrective Action Plan submission at this time?: Yes

Reason for Project Plan Submission: Permit application submission

Project Plan Upload

Attach the Area of Review and Corrective Action Plan: https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R05-IL-0006/Phase1-PreConstruction/AoRModeling-06-17-2022-1736/2.--AoR--and--Corrective--Action--Plan.pdf

https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R05-IL-0006/Phase1-PreConstruction/AoRModeling-06-17-2022-1736/2.--AoR--and--Corrective--Action--Plan--REV--1.pdf

Appendices and Supporting Materials Upload

Attach Any Supporting Documentation for the AoR and Corrective Action Plan: https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R05-IL-0006/Phase1-PreConstruction/AoRModeling-06-17-2022-1736/2.2.--Computational--Modeling.pdf

Area of Review Reevaluation [40 CFR 146.84(e) or applicable state requirements]

Minimum fixed frequency of AoR reevaluation: 5 Years

Are you making an Area of Review reevaluation submission at this time?: No

Reevaluation Background

Reevaluation Materials

Please upload your amended AoR and Corrective Action Plan on the previous tab.

Complete Submission

Authorized submission made by: Jared Lee Walker

Comments regarding this submission: Updated AOR and corrective action plan

For confirmation a read-only copy of your submission will be emailed to: bethsteinhour@marquisenergy.com

COMPUTATIONAL MODELING DETAILS
40 CFR 146.84(b)

MARQUIS BIOCARBON PROJECT

Facility Information

Facility name: MARQUIS BIOCARBON PROJECT

Facility contact: ELIZABETH STEINHOUR
DIRECTOR OF ENVIRONMENTAL AFFAIRS
10000 MARQUIS DRIVE, HENNEPIN, IL 61327
815.925.7300 / BETHSTEINHOUR@MARQUISENERGY.COM

Well name: MCI CCS 3
Well location: PUTNAM COUNTY, ILLINOIS
S2 T32N R2W
Latitude: 41.27026520 N, Longitude: 89.30939322 W

Table of Contents

COMPUTATIONAL MODELING DETAILS 1
1.0 Static Earth Model (SEM) 4
1.1 Overview 4
1.2 Model Framework 4
1.3 Property Modeling 5
1.4 SEM Summary 8
2.0 Dynamic Reservoir Model (DRM) 9
2.1 Overview 9
2.2 Reservoir Initialization 9
2.2 Rock Fluid Properties 10
2.2 Injection Strategy 11
2.3 Main Model Results 13
2.4 Alternative Scenarios for Uncertainty Analysis 19

List of Tables

Table 1: Model domain information. 4
Table 2: Summary of Marquis model formation depths, layering method, and depositional environment at MCI CCS 3. 5
Table 3: Proportions of lithofacies modeled within each depositional environment represented in the Mt. Simon formation. 5
Table 4: Flow-based facies proportions used for each sand type from the lithofacies property. Shales in the lithofacies property remained shales in the flow-based facies property. 6
Table 5: Summary of petrophysical model statistics by model zone for the Marquis site. All averages are based on the arithmetic mean method. Thickness is based on the structure as modeled at the MWI CCS 3 well. 8
Table 6: Initial Conditions 9
Table 7: Model operations details. 11
Table 8: Summary of alternative subsurface scenarios for the Marquis BioCarbon Project. 19

List of Figures

Figure 1: Porosity-permeability transform equations and model result shown by flow-based facies type. 7

Figure 2: Relative Permeability Curves imported into dynamic reservoir model. The plot on the left was assigned to high flow sands, the plot in the middle was assigned to midflow sands and the plot on the right was assigned to low flow sands. 10

Figure 3: Map view of computational model with zoomed well grid (top) and cross section of the model (below). 12

Figure 4: Cross section view of model showing perforation location (green dots) versus permeability. 12

Figure 5: Cumulative CO_2 injected mass and the average model reservoir pressure profile for the 5-year injection period. The red line represents cumulative injection while the blue line represents average reservoir pressure. 13

Figure 6: : Development of CO_2 plume after 1 year (top), 3 years (middle), and 5 years (lower) of injection. 14

Figure 7: CO_2 plume 3, 5, 10 and 50 years after cessation of injection. 16

Figure 8: Development of CO_2 plume after 1 year, 3 years, and 5 years of injection at layer 153 representing AoR. 16

Figure 9: CO_2 plume mapping 3 year, 5 years, 10 years, 30 years, and 50 years after injection stopped at layer 153 (representing AoR). 17

Figure 10: Predicted pressure plume response front at the end of the injection phase and 1 year after injection stops. The pressure build-up cut-off is 150 psi. 18

Figure 11: Plot of porosity and permeability relationships for high side case (orange line) and low side case (blue line). The numbers on the orange are permeability values, number on the blue line are porosity values. 20

Figure 12: CO_2 plume at wellbore cross section after 3 years of injection. The left plume diagram represents the base case, middle represents the high side case and the right plume diagram represents the low side case. 21

Figure 13: CO_2 plume at layer 153 (used to delineate AoR) at the end of injection and after, 1, 5 and 10 years after cessation of injection for the high side case (top row) and low side case (bottom row). 21

1.0 Static Earth Model (SEM)

This section provides a tabular summary describing the static earth modeling for the Marquis BioCarbon Project.

1.1 Overview

A SEM was prepared by Battelle using Schlumberger's Petrel® modeling software. This software enabled the integration of data representing well trajectories, well tops, well logs, and regional contour maps to form the SEM. By integrating multiple data types, the model represents the spatial distribution of available pore space and flow potential (permeability), enabling a data-driven estimation of carbon dioxide (CO_2) storage capacity. The SEM serves as the framework (in terms of delineating zones, surfaces, porosity, and permeability) for dynamic simulation of CO_2 injection.

Computational modeling to simulate CO_2 injection into the saline aquifer was completed by Battelle using the three-dimensional (3D) multiphase flow simulator CMG-GEM version 2016 (CMG-GEM, 2016). In addition to the geological framework and associated properties imported from the SEM, parameters such as relative permeability, initial conditions, phase behavior, and well completion were added to the dynamic model for simulation. CMG-GEM is an equation-of-state based compositional simulator that models the phase behavior of brine and CO_2 plumes during the injection and post-injection phases of a project.

Coordinate System	NAD 1983 BLM Zone 16N ftUS		
Horizontal Datum	NAD83		
Coordinate System Units	Field = feet		
Zone	UTC -06:00 Central Time (US & Canada)		
FIPSZONE	1202		
Coordinate of X min	987293.52	**Coordinate of Y min**	14979542.23
Elevation of bottom of domain	-4473.32	**Elevation of top of domain**	-2117.49

Table 1: Model domain information.

1.2 Model Framework

The model framework for the Marquis BioCarbon Project includes 10 model zones from the top of the Eau Claire Shale to the Precambrian Basement. Each of the 10 model zones were divided into proportional layers, resulting in an average layer thickness of 12 feet (ft) in the confining units and 10 ft in the injection interval. Zone divisions and layering methods are listed in Table 2.

Zone	Formation	Depth (ft, MD)	Layer Method	Layers	Lithology
Confining	Eau Claire Shale	2,722	Proportional	16	Shallow Marine
	Eau Claire Sand 1	2,913	Proportional	7	Shallow Marine
	Upper Elmhurst	2,998	Proportional	6	Shallow Marine
Injection	Lower Elmhurst	3,074	Proportional	4	Shallow Marine
	Mt. Simon 1	3,125	Proportional	43	Shallow Marine / Peritidal
	Mt. Simon 2	3,561	Proportional	21	Fluvial
	Mt. Simon 3	3,784	Proportional	20	Distal Braid Plain
	Mt. Simon 4	3,970	Proportional	35	Eolian Sand Sheet
	Mt. Simon 5	4,364	Proportional	23	Eolian
	Mt. Simon 6	4,607	Proportional	10	Eolian
	Mt. Simon 7	4,716	Proportional	15	Fluvial
	Precambrian Basement	4,880	Proportional		

Table 2: Summary of Marquis model formation depths, layering method, and depositional environment at MCI CCS 3.

1.3 Property Modeling

To populate reservoir properties, sequential indicator simulation was used for distributing lithofacies within object-based environments of deposition (EODs), which controlled the lateral distribution of sands and shales. Proportions of lithofacies assigned to each EOD are shown in Table 3. Porosity was modeled by lithofacies using Sequential Gaussian Simulation, and a locally varying azimuth which was derived from the object-based depositional bodies. The porosity variogram type was spherical, with an anisotropic range of 2500 x 1,000 ft, and nugget of zero.

Facies	Tidal	Dune	Flood Plain	Braided Channel	Overbank	Channel
Clean Sand	70	95	60	75	65	80
Dirty Sand	25	5	30	20	30	15
Shale	5	0	10	5	5	5

Table 3: Proportions of lithofacies modeled within each depositional environment represented in the Mt. Simon formation.

The permeability model utilized flow-based facies derived from the flow zone indicator (FZI) log. The flow-based facies groups were high-flow sand, mid-flow sand, low-flow sand, and shale, and subsequently modeled as targeted proportions within each of the lithofacies (Table 4). Proportions were derived from well-log-assessed abundance of flow-based facies types within each lithofacies for a given zone at the MCI MW 1 well. A higher trend was applied for the mid-flow and high-flow sand facies, and a lower trend was applied for the low-flow and shale facies (Figure 1). The flow-based facies property was ultimately used to calculate permeability assigning a higher porosity-permeability transform to the mid-flow and high-flow sand facies and a lower transform to the low-flow sand and shale facies. A multiplier was applied to the property to introduce scatter in poro-perm space consistent with scatter seen in the log data.

Formation	Sand Type	Low Flow	Mid Flow	High Flow
Elmhurst	Sand	60	40	
	Dirty Sand	100		
Mt. Simon 1	Sand	40	40	20
	Dirty Sand	60	40	
Mt. Simon 2	Sand	100		
	Dirty Sand	100		
Mt. Simon 3	Sand	85	15	
	Dirty Sand	100		
Mt. Simon 4	Sand		40	60
	Dirty Sand		100	
Mt. Simon 5	Sand		40	60
	Dirty Sand	20	40	40
Mt. Simon 6	Sand	85	15	
	Dirty Sand	100		
Mt. Simon 7	Sand	60	30	10
	Dirty Sand	100		

Table 4: Flow-based facies proportions used for each sand type from the lithofacies property. Shales in the lithofacies property remained shales in the flow-based facies property.

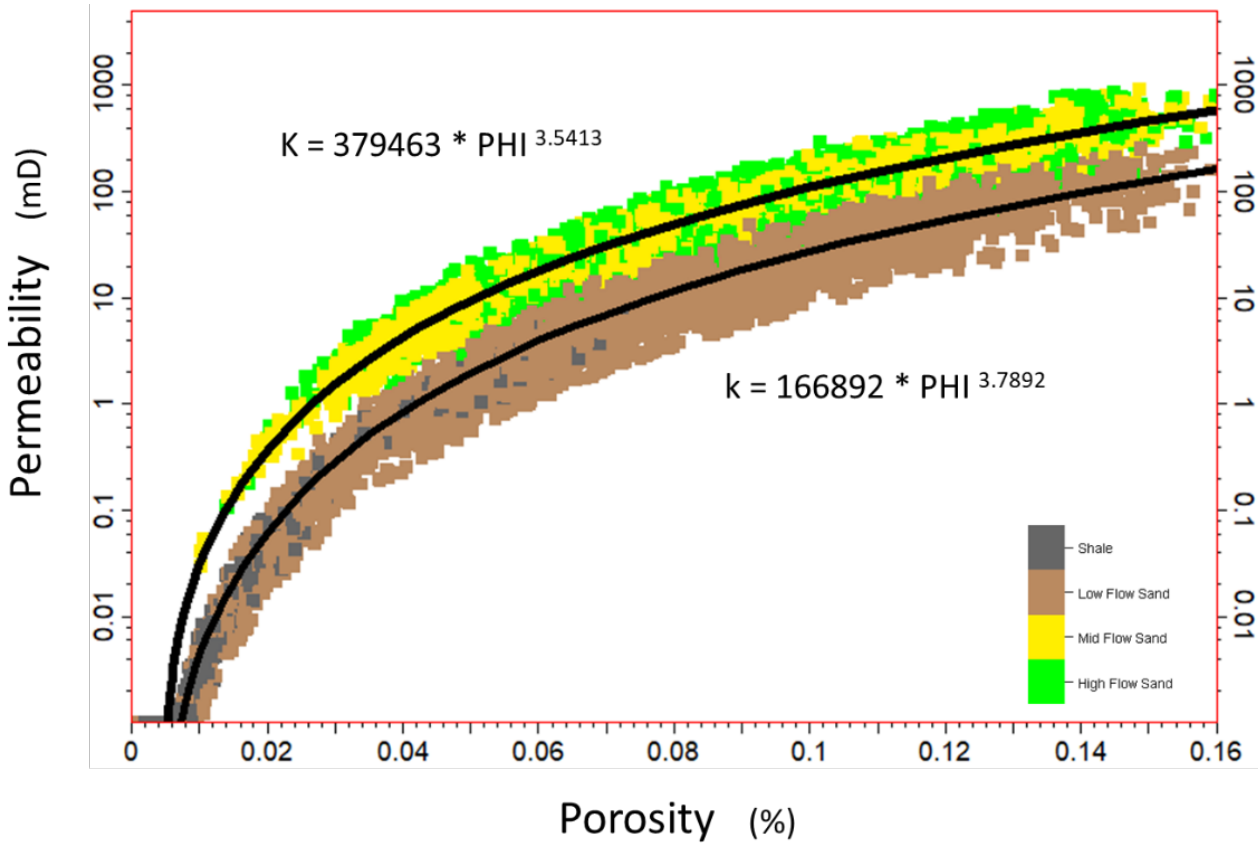


Figure 1: Porosity-permeability transform equations and model result shown by flow-based facies type.

Petrophysical statistics for each model zone are summarized in Table 5. The confining unit, comprised of the Eau Claire Shale, Eau Claire Sand I, and Upper Elmhurst units are reflective of lower-quality, shale-abundant lithologies. Statistics for the injection zone, which is dominated by clean sands, show markedly higher values, less the Mt. Simon 2 and Mt. Simon 3, which are regionally recognized as lower-quality intra-Mt. Simon units.

Zone	Formation	Thickness	Ave. Por. (%)	Ave. Perm. (mD)
Confining	Eau Claire Shale	191	5.60	10.03
	Eau Claire Sand 1	85	2.70	5.23
	Upper Elmhurst	76	7.10	9.88
	Total Seal	**352**	**5.20**	**8.84**
Injection	Lower Elmhurst	51	7.60	18.63
	Mt. Simon 1	436	8.00	61.12
	Mt. Simon 2	223	5.20	5.08
	Mt. Simon 3	186	6.20	9.20
	Mt. Simon 4	394	8.20	97.63
	Mt. Simon 5	243	9.00	129.96
	Mt. Simon 6	109	10.50	41.03
	Mt. Simon 7	164	9.50	78.15
	Total Reservoir	**1806**	**7.90**	**64.22**

Table 5: Summary of petrophysical model statistics by model zone for the Marquis Biocarbon Project site. All averages are based on the arithmetic mean method. Thickness is based on the structure as modeled at the MWI CCS 3 well.

1.4 SEM Summary

The Marquis Static Earth Model is 2,158 ft thick by 49 square miles (mi^2) at the surface and includes the Eau Claire Formation (confining layer) and the Mt. Simon Sandstone (injection interval). The model is comprised of 1.02 million cells and is centered on the MCI CCS 3 well. Data representing these formations were collected at the MCI MW1 well, located about one mile (mi) away, and used to populate the model with petrophysical properties.

For the MCI CCS 3 well, the top of the Eau Claire Formation confining layer is estimated at 2,722 ft measured depth (MD) and has intervals with permeability less than 0.01 millidarcies (mD). The injection interval, comprised of the lower Elmhurst Sandstone and Mt. Simon Sandstone is estimated at 3,074 ft MD and has an estimated thickness of 1,806 ft, with an average moveable porosity of 8% and arithmetic average permeability of 64 mD. Based on logs and core data from the MCI MW1 well, the Mt. Simon 1, Mt. Simon 4, and Mt. Simon 5 have the highest reservoir quality of the injection interval, with the Mt. Simon 2 and Mt. Simon 3 containing low reservoir quality in the mid-section of the Mt. Simon formation.

2.0 Dynamic Reservoir Model (DRM)

2.1 Overview

CMG Builder was used to build the dynamic model of the Marquis Biocarbon Project site. Following the model creation, the model run was performed on CMG-GEM compositional simulator. Dynamic modeling involved importing the SEM from Petrel into the simulator and providing additional data such as perforation depths, tubing properties, hydrogeologic properties, rock-fluid interactions, fluid saturations, and injection rate data. These data were used to simulate the CO_2 injection via a single well. The model's lateral size is approximately 7 mi × 7 mi to cover an extensive area around the injection well and provide reasonable computational performance. The model was used to simulate a maximum injection rate of 1.5 MT per year for 5 years which resulted in negligible field-wide pressure increase. This is reflective of reservoir geology conducive to CO_2 injection in the target interval. A period of 50 years following the injection period has also been simulated in the model.

2.2 Reservoir Initialization

Initial conditions for the model are given in Table 6. The reservoir was initialized at a pore pressure gradient of 0.44 pounds per square inch (psi)/ft (hydrostatic). Formation pressure is then calculated in the model to vary with depth as a function of the pore pressure gradient. The value of 0.44 psi/ft was based on drill stem testing (DST) measurements in the MCI MW 1 characterization well. A temperature gradient of approximately 0.02 degrees Fahrenheit (F°)/ft was specified in the dynamic model to match the gradient in the MCI MW 1 characterization well's temperature log. A salinity of 45000 parts per million (ppm) was specified in the model following geochemical analysis performed on a composite fluid sample collected during pumping the MCI MW 1 characterization well. Fluid density was calculated as a function of pressure, temperature, and salinity in the simulator.

Parameter	Value or Range	Units	Corresponding Elevation (ft MSL)	Data Source
Temperature	0.02	°F/ft	3,147.00 – 5,297.00	Temperature Log
Pore pressure gradient	0.44	psi/ft	2,117.49 – 4,473.32	Drill Stem Testing
Fluid density	0.029	tonne/ft^3	2,117.49 – 4,473.32	CMG Reservoir Simulator Calculation
Salinity	45000	ppm	2,985.00 – 4,870.00	Drill Stem Testing

Table 6: Initial Conditions

2.2 Rock Fluid Properties

Relative permeability relationships served as the main constitutive relationships in the dynamic model. Relative permeability is an important input for describing dynamic behavior in reservoir simulators and it is a required property in the saturation equation describing multiphase flow in porous media. This flow property is represented as a saturation function and will significantly influence the simulated injection profiles. The curves incorporated in the model were from the CO_2-brine drainage relative permeability experiments performed by Core Laboratories on cores from the MCI MW 1 characterization well. The steady-state method of measuring relative permeability was performed on three core samples taken at depths of 3,384.9, 3709.75 and 4,105 ft MD in the Mt. Simon Sandstone, producing three relative permeability drainage plots (Figure 2). Relative permeability vs saturation curves were assigned to facies in the dynamic model based on permeability and flow characteristics. Facies in the Mt. Simon Sandstone were categorized as "low-flow sand", "mid-flow sand" and "high-flow sand". The model assumed a compressibility of 1×10^{-6} 1/psi, which is the average of the MCI MW 1 well pore volume compressibility log in the Mt. Simon. The log values were computed by Baker Hughes from geomechanics core tests and logs.

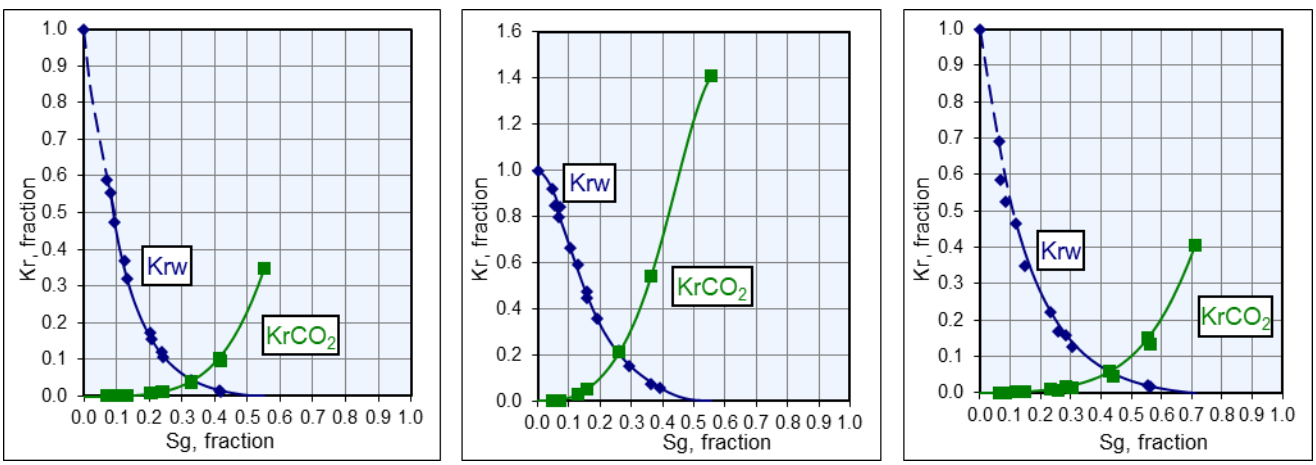


Figure 2: Relative Permeability Curves imported into dynamic reservoir model. The plot on the left was assigned to high flow sands, the plot in the middle was assigned to midflow sands and the plot on the right was assigned to low flow sands.

2.2 Injection Strategy

The model well location and perforation information are specified in Table 7. A cross-section of the model at the wellbore location as well as map view of the model is shown in Figure 3.

The injection well was defined in the model as a 3,150 ft wellbore with 4.5-inch tubing (4-inch internal diameter) and perforations are concentrated in the low and moderate permeability zones (Figure 4). A wellhead temperature of 93°F and tubing bottomhole temperature were also specified in the simulator to model CO_2 injection thermal effects in the reservoir.

The model investigates an injection period of 5 years and a 50-year post-injection period. The CO_2 injection rate was constrained to 1.5 MT/year, a fracture gradient of 0.76 psi/ft (measured from minifrac testing) was used to constrain the wellbore bottom-hole pressure at a reference depth of 3226 ft, located at the top of the perforation interval. The assigned maximum well pressure was 90% of the fracture pressure at 3226 ft (90% × 0.76 psi/ft × 3226 ft = 2207 psi) following EPA's guidelines.

	Operating Information	**MCI CCS 3**
Location (global coordinates)	X Y	41.27026520° -89.30939322°
Model coordinates (ft) (SW Corner)	X Y	987293.52° 14979542.23°
Perforated interval (MSL)	Top Bottom	-3,226.14 ft -4,781.53 ft
	Wellbore diameter (in.)	9 5/8 inch
Planned injection period	Start End	01/01/2024 03/01/2029
	Injection duration	5 years
	Maximum injection rate	1.5 million tonnes (MT)/year

Table 7: Model operations details.

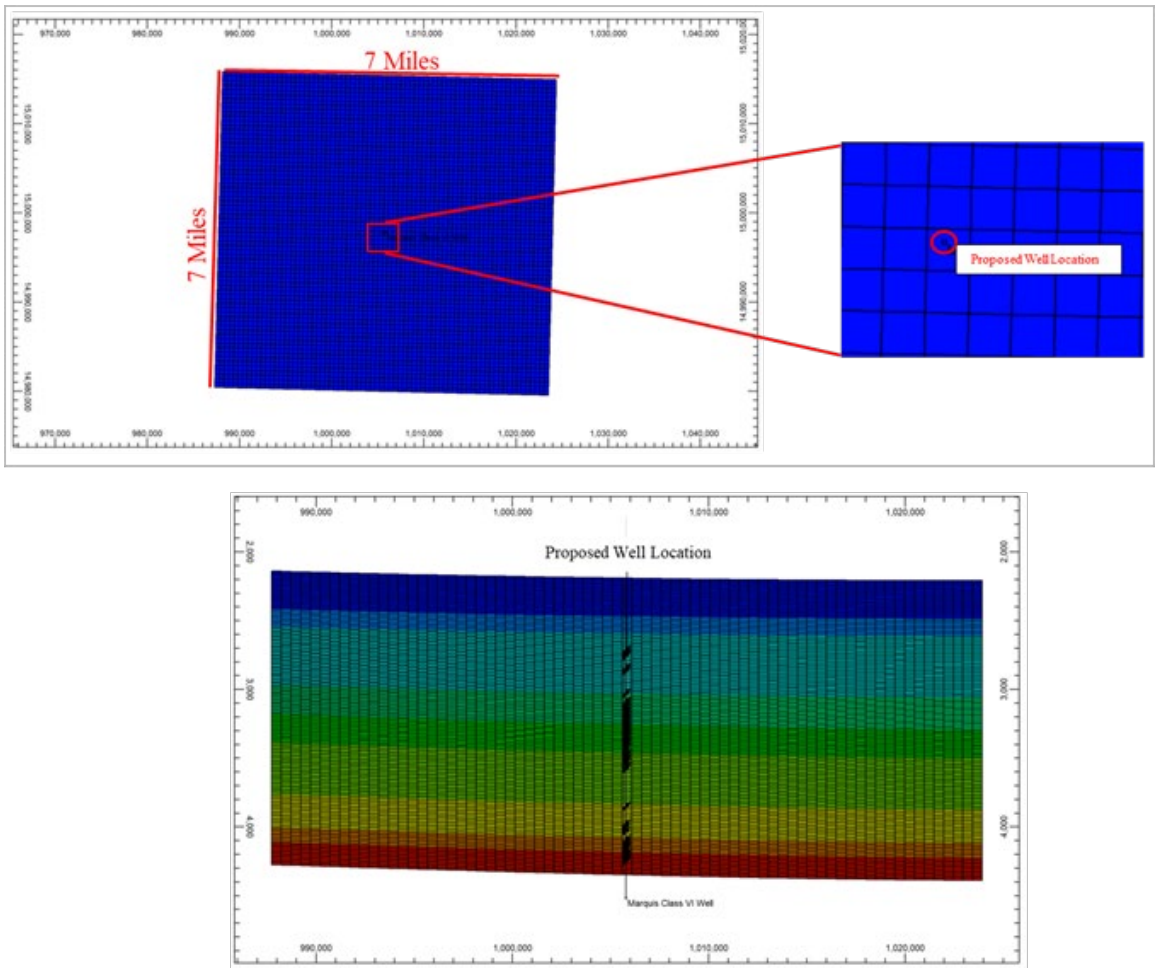


Figure 3: Map view of computational model with zoomed well grid (top) and cross section of the model (below).

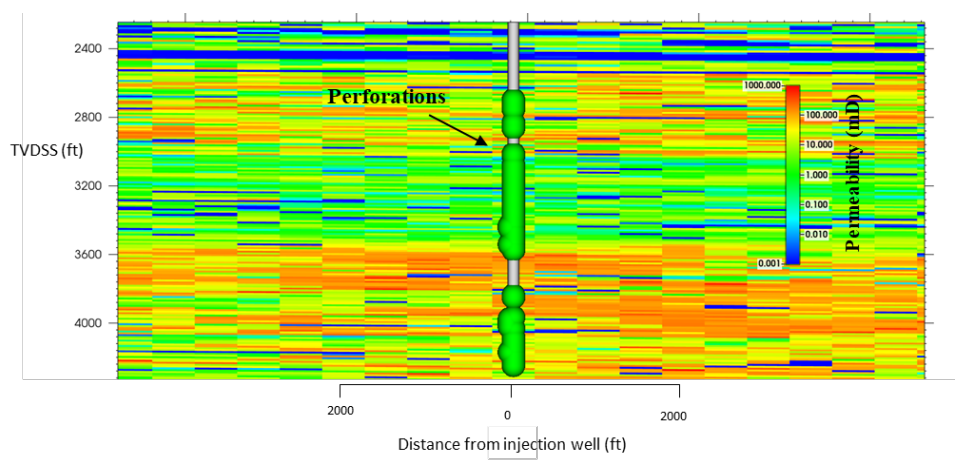


Figure 4: Cross section view of model showing perforation location (green dots) versus permeability.

2.3 Main Model Results

Using the constraints specified in the previous section, the model results show that the reservoir sustained injection at an average of 1.5 MT per year for 5 years (7.5 MT total), with negligible average pressure increase across the extent of the 7 mile x 7 mile model. This is reflective of good reservoir geological and fluid flow quality in the target interval.

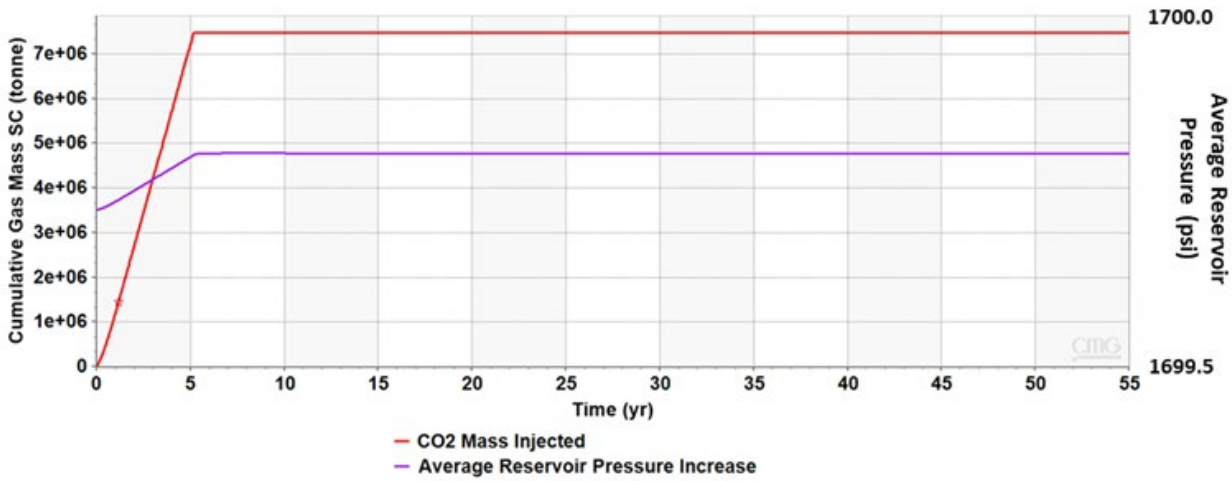


Figure 5: Cumulative CO_2 injected mass and the average model reservoir pressure profile for the 5-year injection period. The red line represents cumulative injection while the blue line represents average reservoir pressure.

CO_2 phase saturation was used as a defining parameter for the CO_2 plume extent. Figure 6 shows a side view of the CO_2 plume at the wellbore at 1, 3, and 5 years of injection. The CO_2 plume expands during the 5 years of injection. Variation across the Mt. Simon Sandstone permeability causes changes in the vertical extent of the CO_2 plume. Figure 6 also shows that the CO_2 does not penetrate the confining zone due to the low permeability of the Eau Claire Shale. The CO_2 plume at the wellbore cross-sections 3, 5, 10, and 50 years after injection stopped are illustrated in Figure 7. It can be seen that the CO_2 plume does not expand in diameter and is stable during the post-injection period.

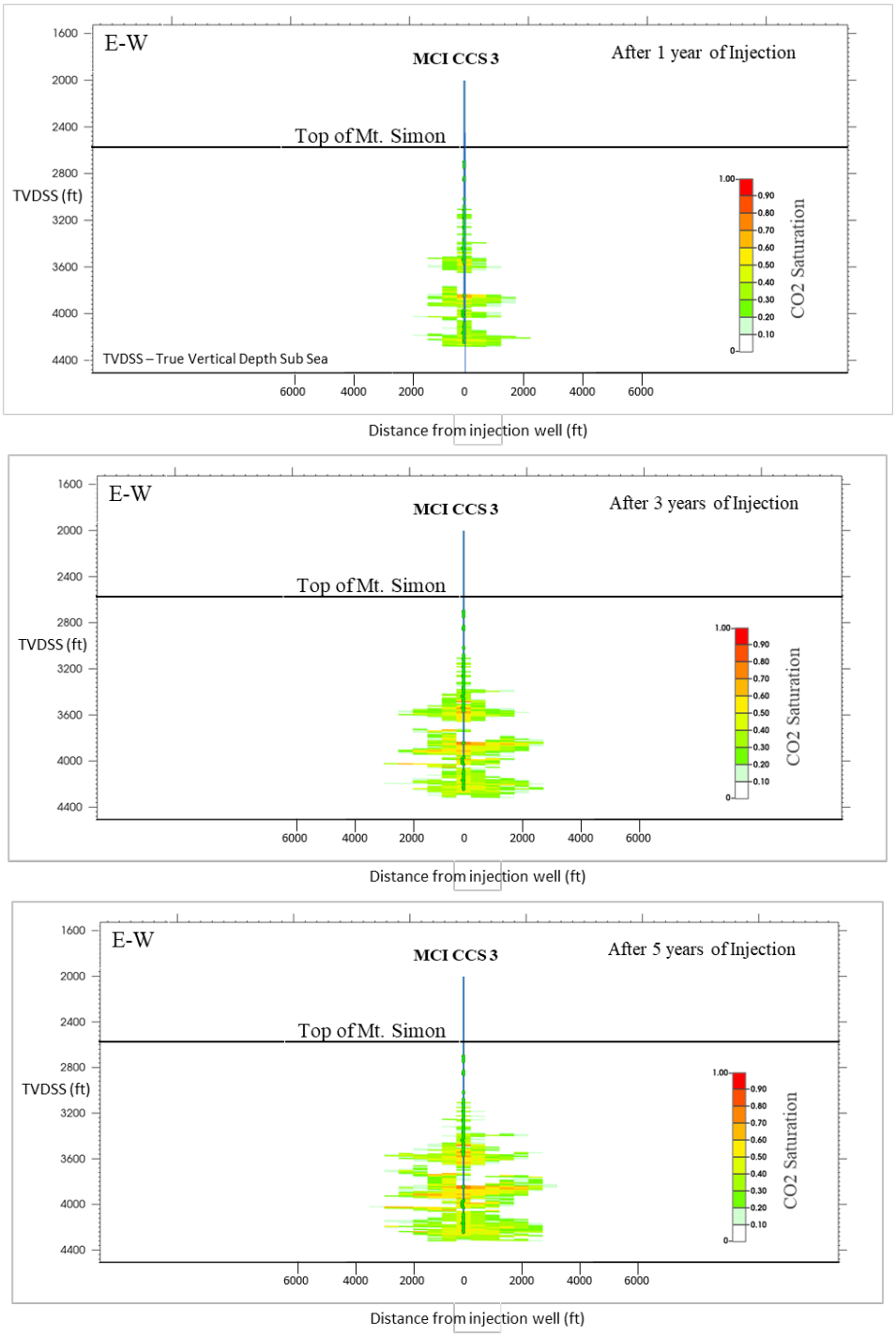
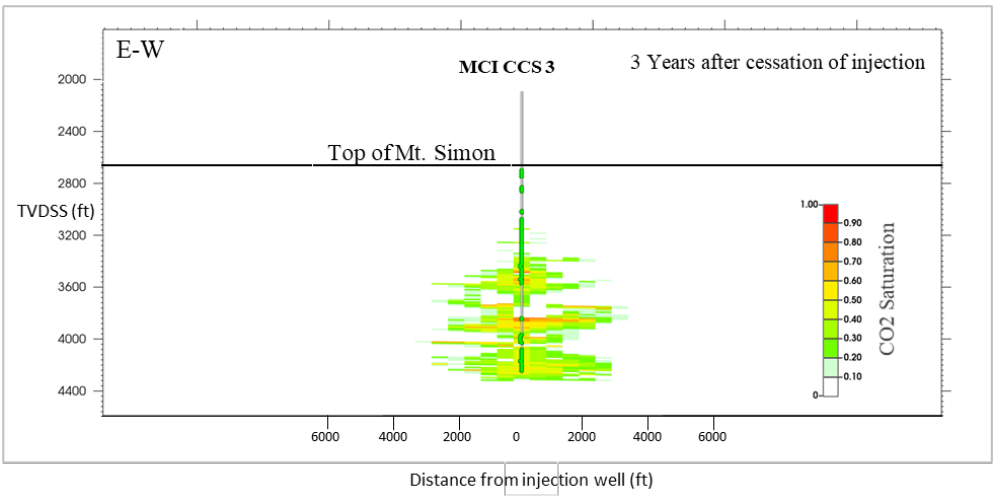
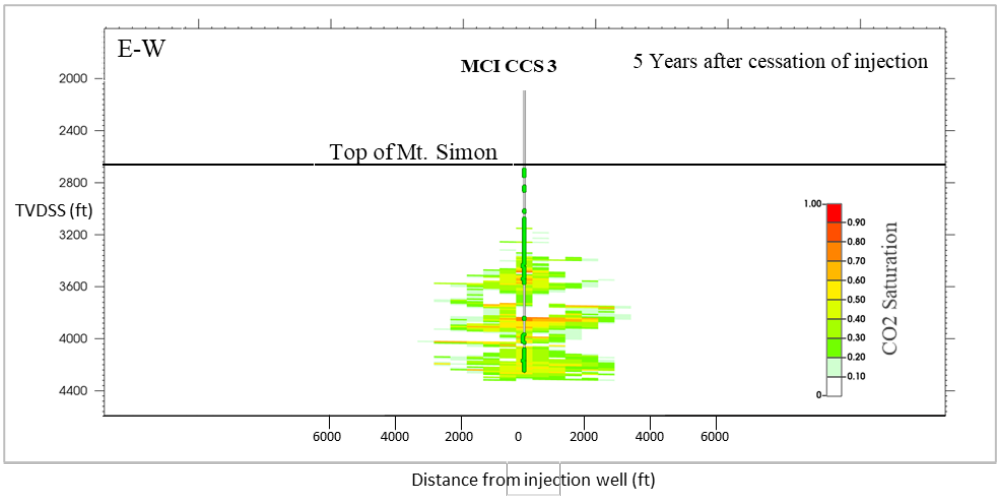
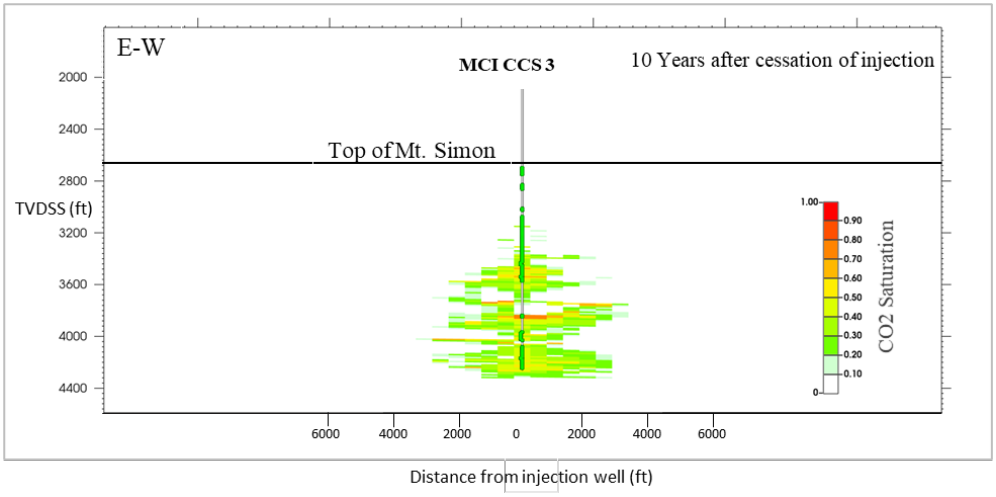


Figure 6: Development of CO_2 plume after 1 year (top), 3 years (middle), and 5 years (lower) of injection.


E-W
MCI CCS 3
3 Years after cessation of injection
Top of Mt. Simon
TVDSS (ft)
2000
2400
2800
3200
3600
4000
4400
6000
4000
2000
0
2000
4000
6000
Distance from injection well (ft)
CO2 Saturation
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0


E-W
MCI CCS 3
5 Years after cessation of injection
Top of Mt. Simon
TVDSS (ft)
2000
2400
2800
3200
3600
4000
4400
6000
4000
2000
0
2000
4000
6000
Distance from injection well (ft)
CO2 Saturation
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0


E-W
MCI CCS 3
10 Years after cessation of injection
Top of Mt. Simon
TVDSS (ft)
2000
2400
2800
3200
3600
4000
4400
6000
4000
2000
0
2000
4000
6000
Distance from injection well (ft)
CO2 Saturation
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0

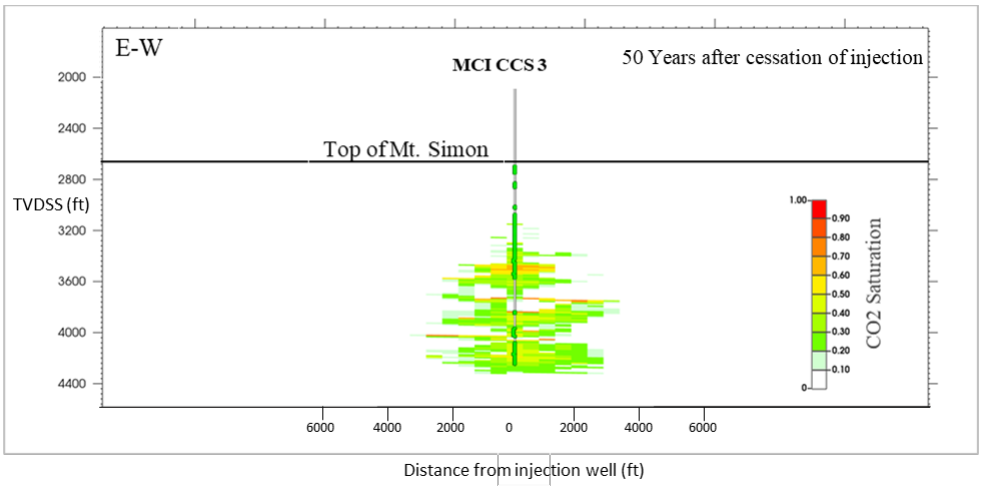


Figure 7: CO_2 plume 3, 5, 10 and 50 years after cessation of injection.

The area of review (AoR) is determined by using the average plume sizes for all layers in the model at the end of the 5-year injection period which corresponds to layer 153. The CO_2 saturation in that layer at the end of injection period was therefore selected to define AoR. Figure 8 shows the expansion of the plume size after 1 year, 3 years, and 5 years of injection at layer 153. Figure 9 shows the post injection CO_2 plume from layer 153 mapped 3 years, 5 years, 10 years, 30 years, and 50 years after the cessation of injection.

Refer to the AoR and Corrective Action Plan (Permit Section 2) for more information on delineation of the AoR.

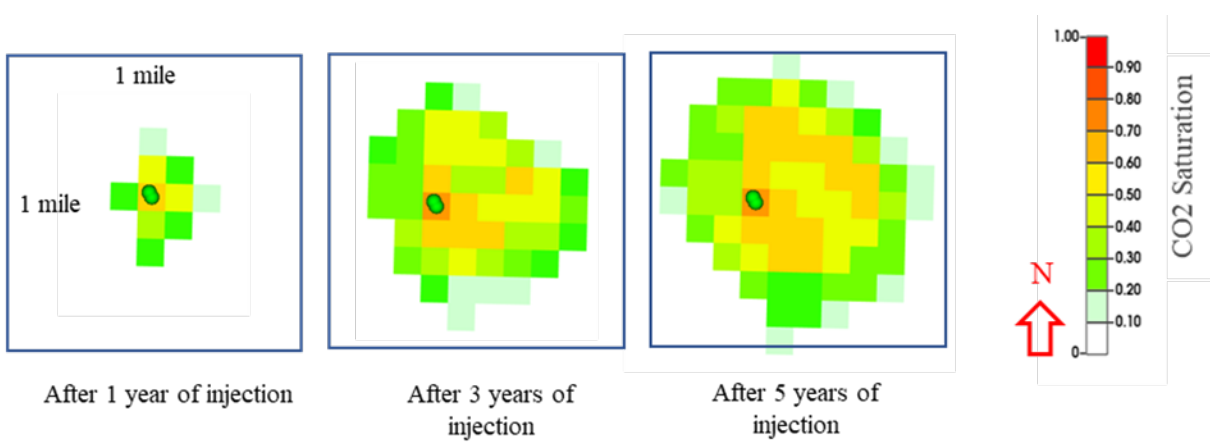


Figure 8: Development of CO_2 plume after 1 year, 3 years, and 5 years of injection at layer 153 representing AoR.

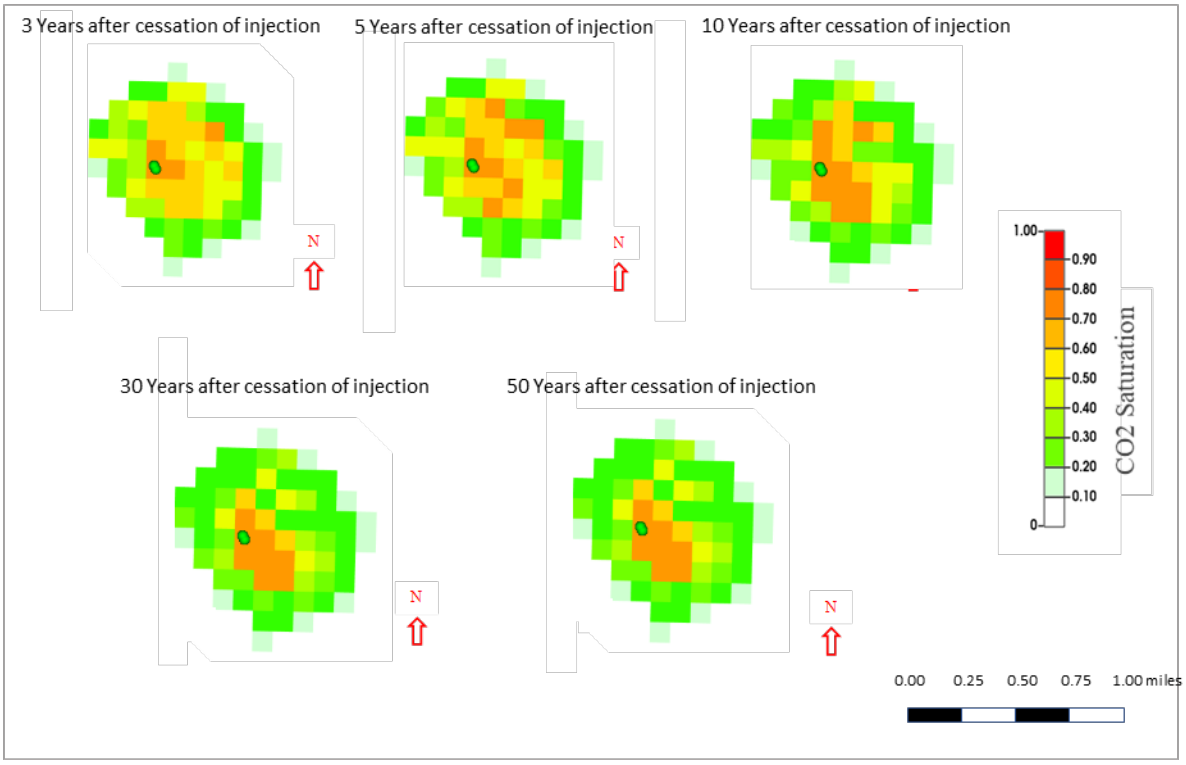
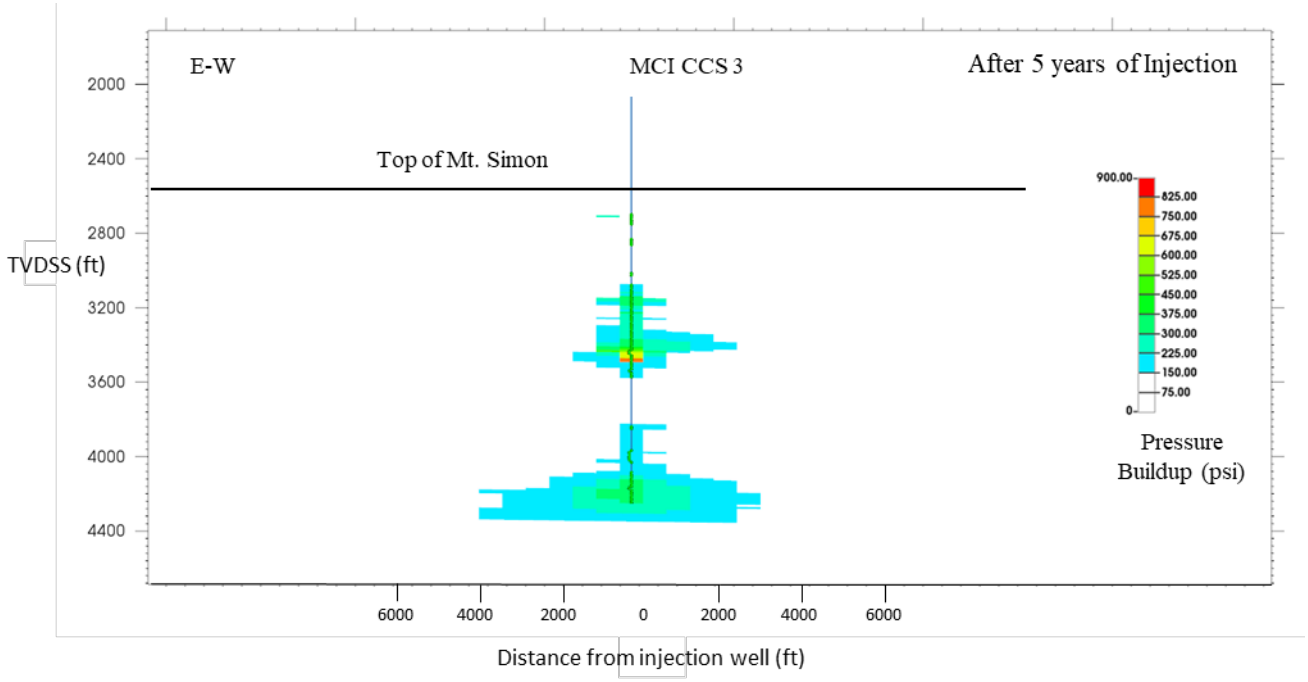


Figure 9: CO_2 plume mapping 3 year, 5 years, 10 years, 30 years, and 50 years after injection stopped at layer 153 (representing AoR).

AoR mapping also requires analyzing reservoir pressure buildup [40 CFR 146.84 (c)(1)]. Determining the furthest extent of the pressurization from injection involves calculating a minimum threshold (of pressure increase) that accounts for the depth from the shallowest fresh waterbody to the target injection interval also known as critical pressure. The critical pressure corresponds to the pressure needed to move fluids from the storage formation into an underground source of drinking water (USDW) through a hypothetical open conduit such as an uncemented well. A simple hydrostatic head calculation (density of injection zone brine × depth distance between lowest USDW and top of injection zone × gravity constant) was used to estimate such required pressure. The calculated value using this equation is 477 psi.

Figure 10 shows the pressure front in the Mt. Simon formation after 5 years of injection and 1 year after injection is stopped. A pressure cut-off of 150 psi was used in the plot to delineate pressure front expansion as a function of injection time. The pressure buildup is localized around the wellbore during injection and dissipates quickly after injection stops.



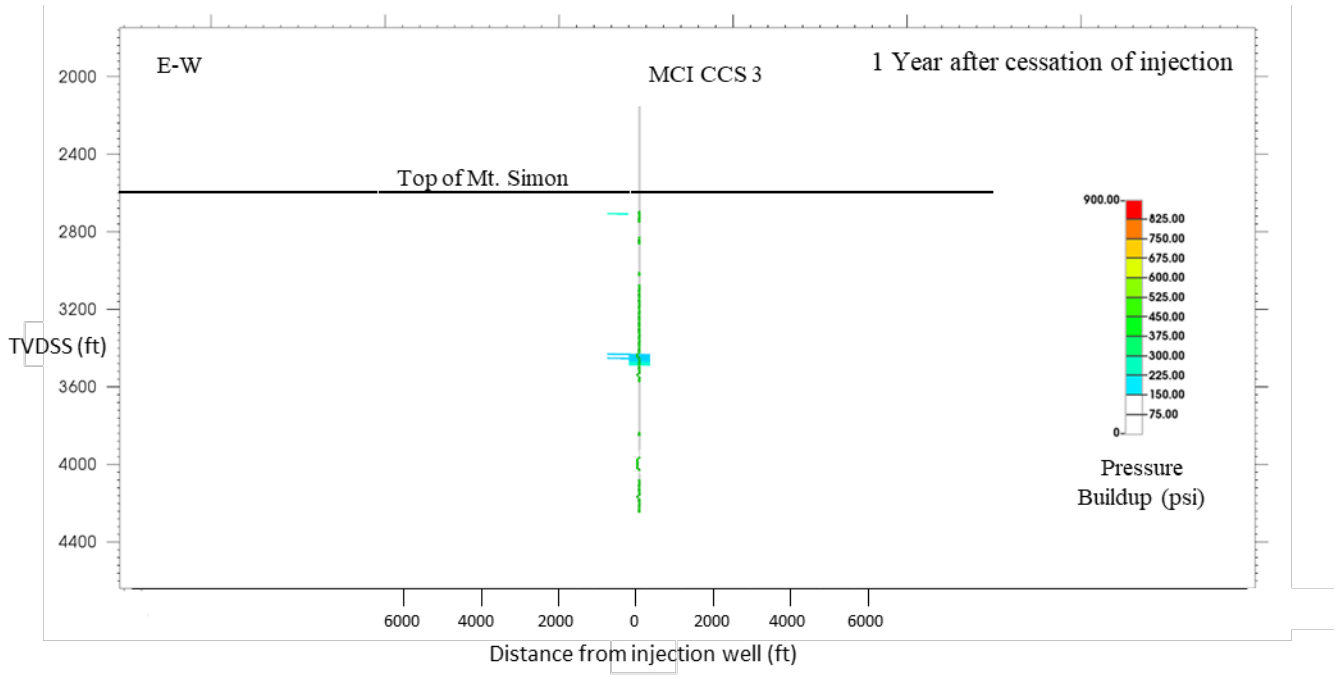


Figure 10: Predicted pressure plume response front at the end of the injection phase and 1 year after injection stops. The pressure build-up cut-off is 150 psi.

2.4 Alternative Scenarios for Uncertainty Analysis

Subsurface uncertainty is addressed through the creation and simulation of alternative scenarios. These scenarios are utilized to ensure that the range of uncertainty in the subsurface is considered and covered within the scope of the injection and monitoring plan. The scenarios explored for the Marquis BioCarbon Project are shown in Table 8. Each scenario resulted in its own Petrel SEM realization, which was imported into the CMG dynamic model.

Scenario	Scenario Objective	Plume Implication	Summary of Property Adjustments
High side	Highest injectable volume while maintaining AoR constraints	Largest volume, smallest plume	Higher porosity, decreased permeability
Base case	Base case volumes	Base case plume	Base case properties
Low side	Lowest injectable volume to maintain AoR constraints	Lowest volume, largest plume	Lower porosity, increased permeability

Table 8: Summary of alternative subsurface scenarios for the Marquis BioCarbon Project.

As summarized in Table 8, the high and low side case runs were performed in addition to the base case to access the effects of varying porosity/permeability relationships on CO_2 plume and AoR. The permeability versus porosity plot for each case in the Mt. Simon is shown in Figure 13. Every parameter in the model was the same as the base case except for porosity and permeability. From the plot, it can be seen that there is an inverse relationship between porosity and permeability, where in the high side case there is high porosity versus low permeability and vice versa for the low side case.

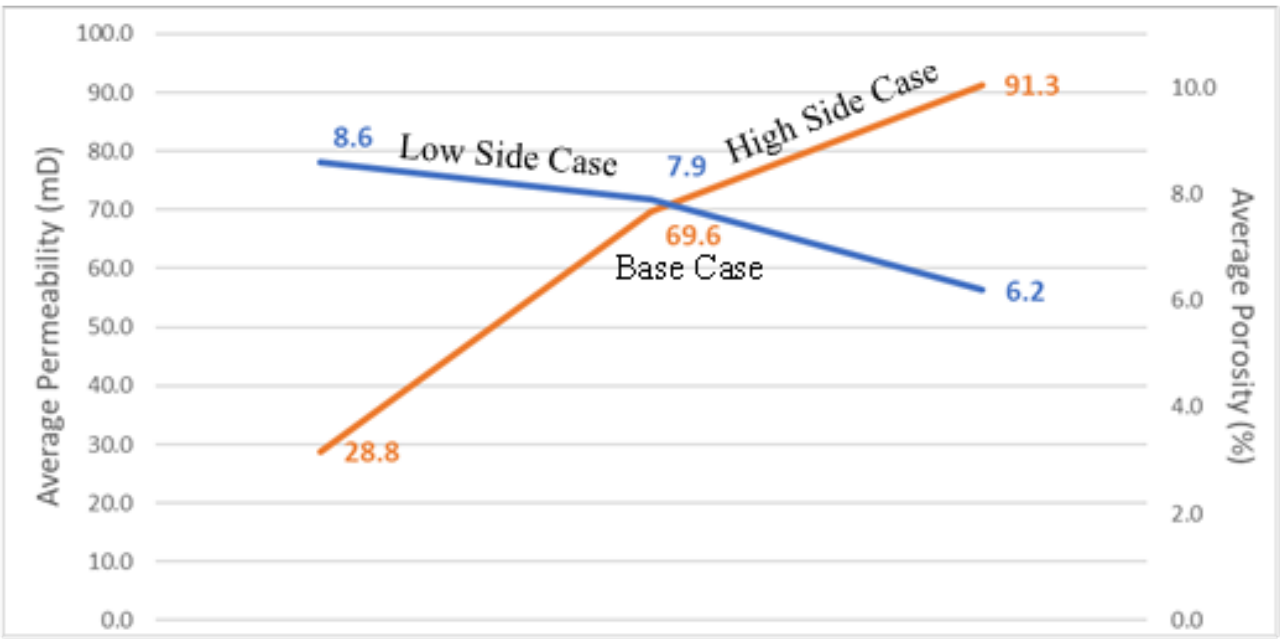


Figure 11: Plot of porosity and permeability relationships for high side case (orange line) and low side case (blue line). The numbers on the orange are permeability values, number on the blue line are porosity values.

The plume side views for the base, high side and low side cases after three years of injection are compared in Figure 12. The low side case scenario results in a larger overall plume diameter compared to other two cases, especially near the lower Mt. Simon. Results of the sensitivity analysis (high side case and low side case) shown in Figure 13 for CO_2 plume at layer 153 show that the AoR is smaller compared to base case scenario at the end of injection and post injection. These results indicate that there is low uncertainty around the AoR extent for varying geological parameters.

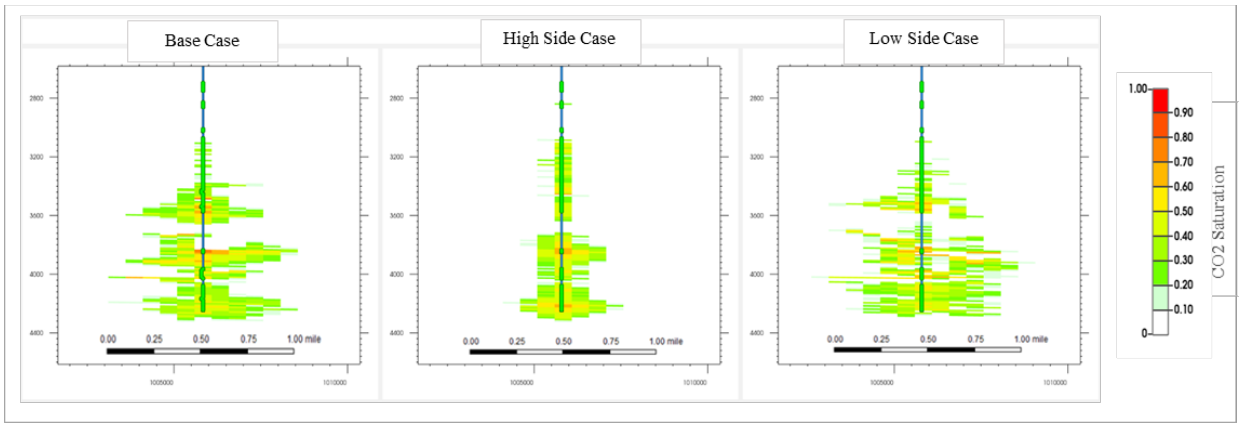


Figure 12: CO_2 plume at wellbore cross section after 3 years of injection. The left plume diagram represents the base case, middle represents the high side case, and the right plume diagram represents the low side case.

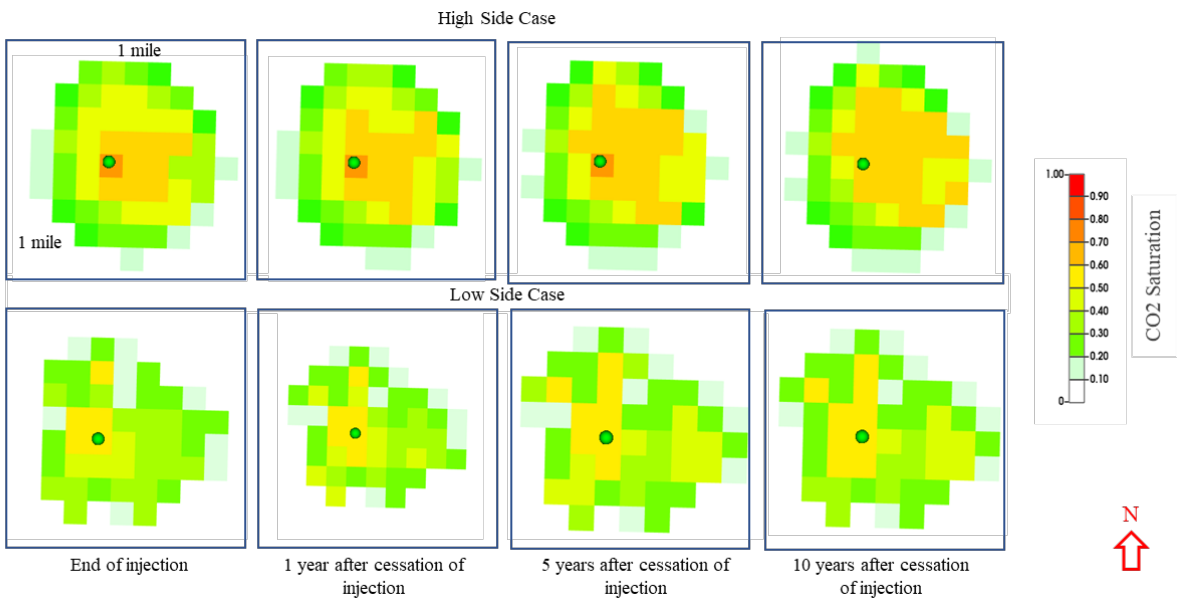


Figure 13: CO_2 plume at layer 153 (used to delineate AoR) at the end of injection and after, 1, 5 and 10 years after cessation of injection for the high side case (top row) and low side case (bottom row).

2.0 AREA OF REVIEW AND CORRECTIVE ACTION PLAN 40 CFR 146.84(b)

MARQUIS BIOCARBON PROJECT

Facility Information

Facility name:	MARQUIS BIOCARBON PROJECT
Facility contact:	ELIZABETH STEINHOUR DIRECTOR OF ENVIRONMENTAL AFFAIRS 10000 MARQUIS DRIVE, HENNEPIN, IL 61327 815.925.7300 / BETHSTEINHOUR@MARQUISENERGY.COM
Well name:	MCI CCS 3
Well location:	PUTNAM COUNTY, ILLINOIS S2 T32N R2W Latitude: 41.27026520 N, Longitude: 89.30939322 W

Table of Contents

2.0 AoR and Corrective Action Plan 6
2.1 Computational Modeling Approach 6
2.1.1 Model Background 6
2.1.2 Site Geology and Hydrology 7
2.1.3 Model Domain 20
2.1.4 Porosity and Permeability 22
2.1.5 Constitutive Relationships and Other Rock Properties 26
2.1.6 Boundary Conditions 27
2.1.7 Initial Conditions 27
2.1.8 Operational Information 28
2.1.9 Fracture Pressure and Fracture Gradient 28
2.2 Computational Modeling Results 29
2.2.1 Predictions of System Behavior 29
2.2.2 Model Calibration and Validation 38
2.3 AoR Delineation 40
2.3.1 Critical Pressure Calculations 40
2.3.2 AoR Delineation 41
2.4 Corrective Action 41
2.4.1 Tabulation of Wells within the AoR 41
2.4.2 Wells Penetrating the Confining Zone 44
2.4.3 Plan for Site Access 44
2.4.4 Corrective Action Schedule 44
2.5 Re-evaluation Schedule and Criteria 44
2.5.1 AoR Re-evaluation Cycle 44
2.5.2 Triggers for AoR Reevaluations Prior to the Next Scheduled Reevaluation 46
2.6 References 48

List of Tables

Table 2-1: Model domain information. 21
Table 2-2: Initial conditions. 28
Table 2-3: Operating details. 28
Table 2-4: Injection pressure details. 29
Table 2-5: Input data used for critical pressure calculation. 41
Table 2-6: Tabulation of wells within the AoR 42
Table 2-7: Changes in operations and site characterization that may trigger AoR re-evaluation. 47
Table 2-8: Observed changes in monitoring data that may trigger an AoR re-evaluation. 47

List of Figures

Figure 2-1: Stratigraphic column with lithology and hydrostratigraphy for the Marquis BioCarbon Project site based on data from the characterization well, MCI MW 1. 8
Figure 2-2: Precambrian basement elevation map. Modified from Willman et al. (1975). 9
Figure 2-3: Mt. Simon Sandstone elevation map over the west-central portion of the Illinois Basin. Modified from FutureGen Alliance (2013). 10
Figure 2-4: Mt. Simon Sandstone thickness map over the west-central portion of the Illinois Basin. Modified from FutureGen Alliance (2013). 11
Figure 2-5: Eau Claire elevation map over the west-central portion of the Illinois Basin. Modified from FutureGen Alliance (2013). 12
Figure 2-6: Eau Claire Eau Claire thickness map. Modified from Willman et al. (1975). 13
Figure 2-7: Map showing the analog well locations used in depositional environment interpretations to the north and south of the Marquis BioCarbon Project site. 14
Figure 2-8: Regional depositional model for the Mt. Simon Sandstone. Broad fluvial braid systems feed into a shallow inland sea. Sediments on inactive braid plaids are reworked by eolian processes. Sediment source is primarily from the north. Modified from Fischietto (2009). 15
Figure 2-9: Interpreted Mt. Simon depositional environments and corresponding intraformational zones. 16
Figure 2-10: Example conceptual schematic drawing of the Mt. Simon Zone 5 representing the eolian depositional environment and interpreted orientations at the Marquis site (not to scale), as well as representative bedding features in whole acquired from Mt. Simon Zone 5. Modified from Freiburg et al. (2020). 17
Figure 2-11: Principle geologic structures of Illinois. Modified from Willman et al. (1975). 18

Figure 2-12: Geologic cross sections near Putnam County featuring the structural configuration of Cambrian strata that contains the target injection zone and caprock. The locations of these cross-section lines are shown in Figure 2-11. Modified from Willman et al. (1975). 20

Figure 2-13: Static Earth Model 7-mile by 7-mile boundary centered around the MCI CCS 3 well. 21

Figure 2-14: Model Zones and corresponding gamma ray, resistivity, and porosity logs. Lower part of the Elmhurst and the entire Mt. Simon are considered reservoir, while the upper Elmhurst and Eau Claire shale act as the seal. 22

Figure 2-15: Histograms of porosity ranges by facies type showing correlative distributions for the clean sand, dirty sand, and shale facies. Distinctly different distributions for clean sand and dirty sand in Mt. Simons 2 and 3, where normal distribution means are lower. 23

Figure 2-16: Final (a) porosity and (b) permeability properties showing the effect of depositional constraints on spatial property distribution within the 3D geocellular model. 24

Figure 2-17: Logs at the MCI MW-1 well showing (left to right) gamma ray, stratigraphic zone, confining unit or injection interval, whole core, sidewall core, porosity, flow-based facies, and permeability. There is a match between the model (blocky colors) and the log (black line) for porosity and permeability, and core-measured permeability points plotted on the permeability track in magenta show strong correlation to NMR-based log values. 25

Figure 2-18: Porosity-Permeability cross-plot colored by flow facies showing the utilization of two different transforms, applied by flow-based rock classifications. 26

Figure 2-19: Relative Permeability Curves imported into dynamic reservoir model. The plot on the left was assigned to high-flow sands, the plot in the middle was assigned to mid-flow sands and the plot on the right was assigned to low-flow sands. 27

Figure 2-20: Map view of computational model with zoomed well grid (top) and cross section of the model (below). 30

Figure 2-21: Development of CO_2 plume after 1 year (top), 3 years (middle), and 5 years (lower) of injection. 31

Figure 2-22: CO_2 plume 3, 5, 10 and 50 years after cessation of injection. 33

Figure 2-23: CO_2 plume after 5 years of injection in plan view for layers 111, 129, 153 and 186. 33

Figure 2-24: Development of CO_2 plume after 1 year, 3 years, and 5 years of injection at layer 153 representing the AoR. 34

Figure 2-25: CO_2 plume mapping 3 year, 5 years, 10 years, 30 years, and 50 years after cessation of at layer 153 (representing the AoR). 34

Figure 2-26: Pressure front after 1, 3 and 5 years of injection using 150 psi pressure cut-off. 36

Figure 2-27: Pressure time-series data during injection and 50 years of post-injection period at depth of middle perforation (model layer 153, 3,833 TVDSS, ft.) 36

Figure 2-28: Pressure time-series data during injection and post injection period for monitoring (MCI MW 2) and injection well (MCI CCS 3) location at layer 153, 3,833 TVDSS, ft. 37

Figure 2-29: CO_2 saturation time-series data during injection and post injection period for monitoring and injection well location at layer 153 with MSL of 3,833 ft 37

Figure 2-30: Porosity and permeability relationships for high side case (orange line) and low side case (blue line) showing an inverse relationship between the two scenarios. The numbers on the orange are permeability values, number on the blue line are porosity values. 38

Figure 2-31: CO_2 plume at wellbore cross section after 3 years of injection. The left plume diagram represents the base case, middle represents the high side case, and the right plume diagram represents the low side case. 39

Figure 2-32: CO_2 plume at layer 153 (used to delineate AoR) for the base case at the end of injection, 5 years after injection stopped, and 10 years after injection stopped. 39

Figure 2-33: CO_2 plume at layer 153 (used to delineate AoR) at the end of injection and after, 1, 5 and 10 years after cessation of injection for the high side case (top row) and low side case (bottom row). 40

Figure 2-34: Map showing the modeled CO_2 plume footprint, AoR, and existing and proposed project wells within the AoR. Well data is summarized in 2-6. 43

Figure 2-35: Workflow used to update the SEM and computational modeling. 45

2.0 AoR and Corrective Action Plan

2.1 Computational Modeling Approach

2.1.1 Model Background

Computational modeling at the Marquis BioCarbon Project site was completed to delineate the plume size and shape, area of pressure buildup, and Area of Review (AoR) for injected carbon dioxide (CO_2). A static earth model (SEM) named Marquis_SEM_1 was prepared by Battelle using the Schlumberger Petrel® modeling software. The SEM is a three-dimensional (3D) geocellular model that represents petrophysical properties within the stratigraphic formation intended for CO_2 storage, as well as the overlying confining layer. This type of model offers the best options for quantifying, visualizing, and simulating dynamic behavior through the subsurface geology at the site. By integrating multiple data types, the model represents the spatial distribution of available pore space and flow potential (permeability), enabling a data-driven estimation of CO_2 storage capacity. The SEM serves as the framework (in terms of delineating zones, surfaces, porosity, and permeability) for dynamic simulation of CO_2 injection.

Computational modeling to simulate CO_2 injection into the saline aquifer was completed by Battelle using the 3D multiphase flow simulator CMG-GEM version 2016 (CMG-GEM, 2016). In addition to the geological framework and associated properties imported from the SEM, parameters such as relative permeability, initial reservoir conditions, phase behavior, and well completion were added to the dynamic model for simulation. CMG-GEM is an equation-of-state based compositional simulator that models the phase behavior of brine and CO_2 plumes during the injection and post-injection stages of a project.

Aqueous, gaseous, and supercritical phases of CO_2 were accounted for in the computational model. Component transport equations, which describe the thermodynamic equilibrium between gaseous or supercritical with aqueous phases, were used in the compositional simulator to model CO_2 injection into the saline aquifer (Nghiem et al., 2004). The Peng-Robinson equation of state was used to model the fluid properties of the injected CO_2 in gaseous/supercritical phases (Peng and Robinson, 1976). The solubility of the injected CO_2 in brine is modeled as a phase equilibrium process, which is computed using Henry's law to estimate the fugacity of the gaseous and aqueous phases as functions of pressure and temperature (Li and Nghiem, 1986; Enick and Klara, 1990; Nghiem et al., 2009a). Additionally, the viscosity and density of the aqueous phase were calculated as functions of pressure, temperature, and salinity. Rowe and Chow (1970) equation was used to estimate aqueous phase density, and the Kestin et al. (1981) correlation was used to estimate the viscosity of the aqueous fluids.

2.1.2 Site Geology and Hydrology

The subsurface geologic and hydrologic data analyzed in this study were acquired from the nearby characterization well, MCI MW 1, drilled in 2021. The characterization data types, and depth coverages are detailed in the Pre-Operational Testing Program (Permit Section 5). Publicly available geologic and hydrologic data in the region, as well as well data, were compiled from well databases held by the Illinois State Geological Survey (ISGS).

The Marquis BioCarbon Project site is structurally located on the northern edge of the elliptically shaped, northwest-southeast trending Illinois Basin in Hennepin, Putnam County, Illinois. This basin contains dominantly marine sedimentary sequences which range in thickness from 1500 feet (ft) to 15,000 ft from north to south. Figure 2-1 shows the stratigraphic succession at the Marquis BioCarbon Project site MCI MW 1 well, along with the proposed injection zone and confining zones and hydrostratigraphy. Except for the Permian, most of the Paleozoic is present. The target injection zone is the regionally extensive Cambrian-age Mt. Simon Sandstone, which is locally more than 1700 ft thick. The lower confining unit is the impermeable Precambrian basement rock, which acted as a structural control during the deposition of the basal sedimentary units. Overlying the Mt. Simon Sandstone are regionally extensive shale units of the primary confining zone, the Cambrian-age Eau Claire Shale. The Mt. Simon Sandstone and the Eau Claire Shale are both laterally extensive and do not pinch-out in the region. Overlying the Eau Claire are thin sandstone units of the Ironton and Galesville Formations and the approximately 950-foot-thick Knox Supergroup.

At the Marquis BioCarbon Project site, the Mt. Simon Sandstone is not considered an underground source of drinking water (USDW) based on salinity samples acquired from the MCI MW 1 well, with total dissolved solids (TDS) concentrations greater than 10,000 milligrams per liter (mg/L) or 10,000 parts per million (ppm). The lowermost USDW is defined locally as the Gunter Sandstone of the Prairie du Chien Group (Knox Supergroup). At the MCI MW 1 well, the base of the Gunter Sandstone is 963 ft above the top of the Mt. Simon. USDWs in the project site range in depth from the Gunter Sandstone (deepest USDW) to shallow, near-surface glacial till aquifers.

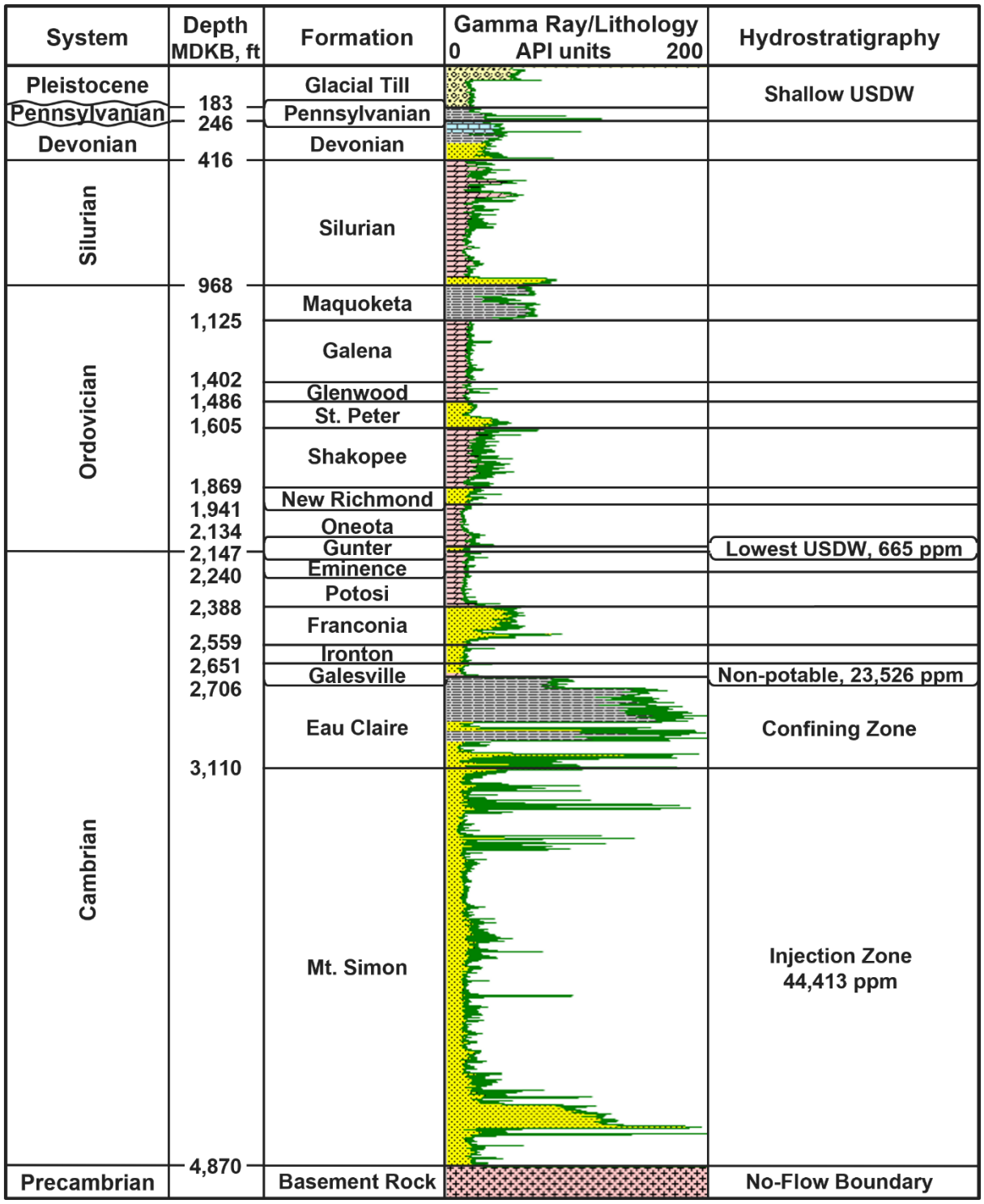


Figure 2-1: Stratigraphic column with lithology and hydrostratigraphy for the Marquis BioCarbon Project site based on data from the characterization well, MCI MW 1.

The Precambrian Granite forms a non-conformable base upon which all the sedimentary strata were deposited and is the oldest rock in the stratigraphic sequence. The structure of the top of the Precambrian basement is illustrated in Figure 2-2. In west-central Illinois the Precambrian basement dips gently to the east-southeast. Substantial local relief is present on the Precambrian surface and is evident as a controlling topography in the subsequent depositional of the Mt. Simon Sandstone (Atherton, 1971). At the MCI MW 1 well, the basement rock is at 4,869 ft measured depth (MD).

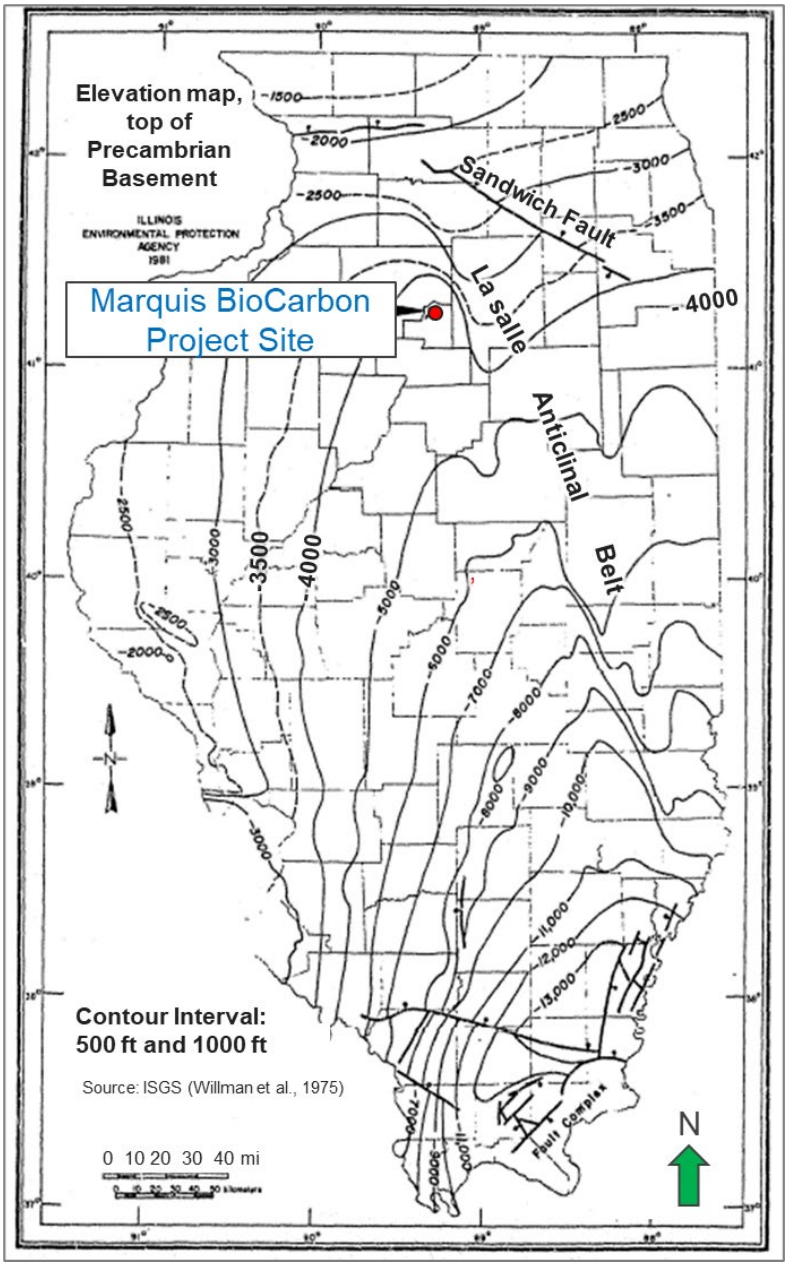


Figure 2-2: Precambrian basement elevation map. Modified from Willman et al. (1975).

The Mt. Simon Sandstone covers an extensive area and is not locally bound by faulting or folding that could pose a constraint to CO_2 injection operations at the Marquis BioCarbon Project site. It consists of porous and permeable, fine to coarse grain, partially pebbly and friable sandstone with minor siltstone and conglomerate. The depositional thickness of the Mt. Simon is not concentric with its structural top (Figure 2-3 and Figure 2-4). A post-Cambrian shift in basin subsidence gradually caused the center of the basin to migrate southeast. While the Mt. Simon deepens to the southeast, it thins from over 2000 ft thick in the northeastern portion of the state to less than 500 ft thick in the southwest. Locally, the Mt. Simon Sandstone is 3,110 ft MD and 1,760 ft thick in the MCI MW 1 well and has a shallow dip of 28 ft per mile (mi) to the southeast. This equates to a shallow grade of 0.53%, which limits the effect that formation dip has on CO_2 migration distance.

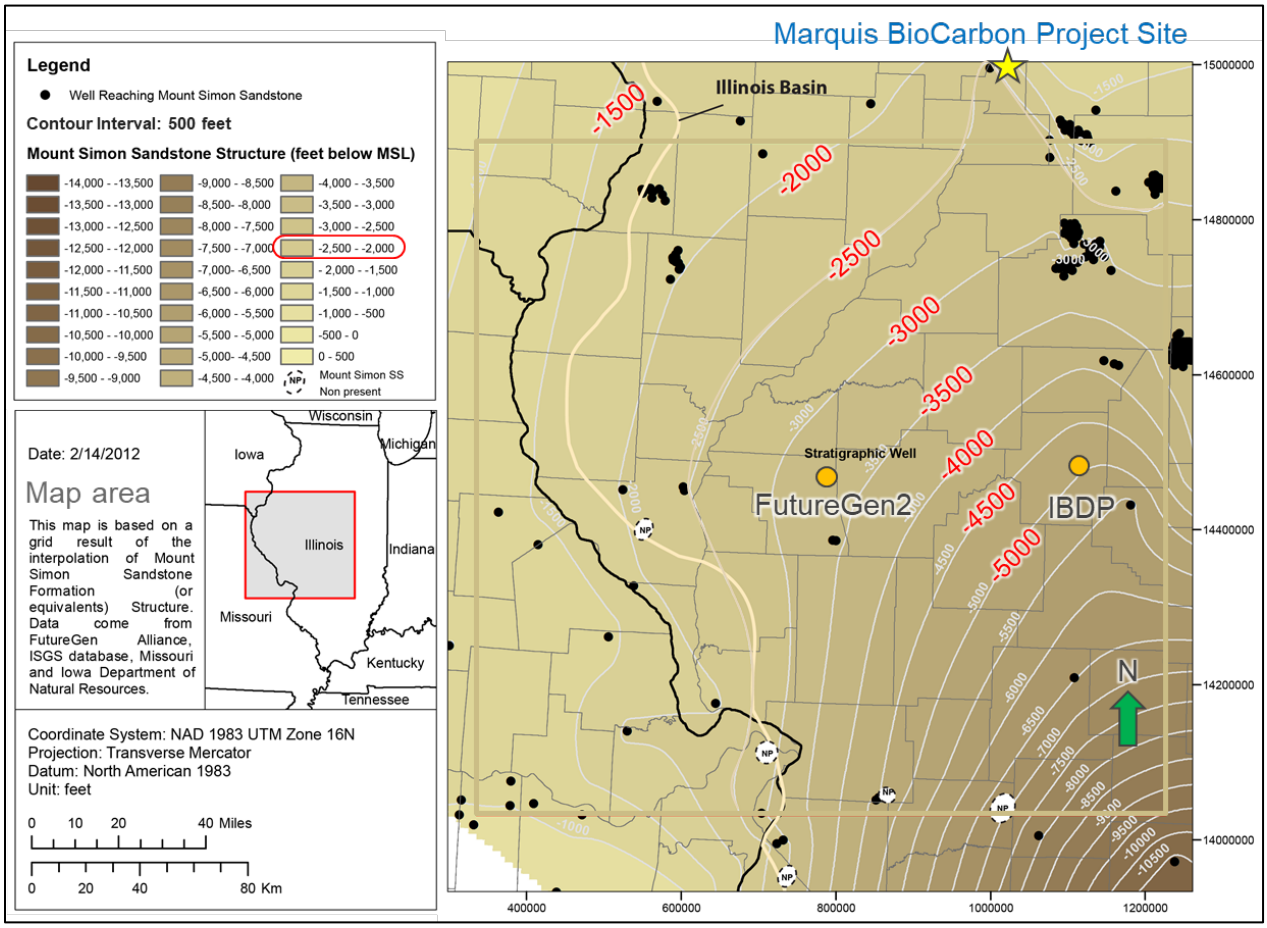


Figure 2-3: Mt. Simon Sandstone elevation map over the west-central portion of the Illinois Basin. Modified from FutureGen Alliance (2013).

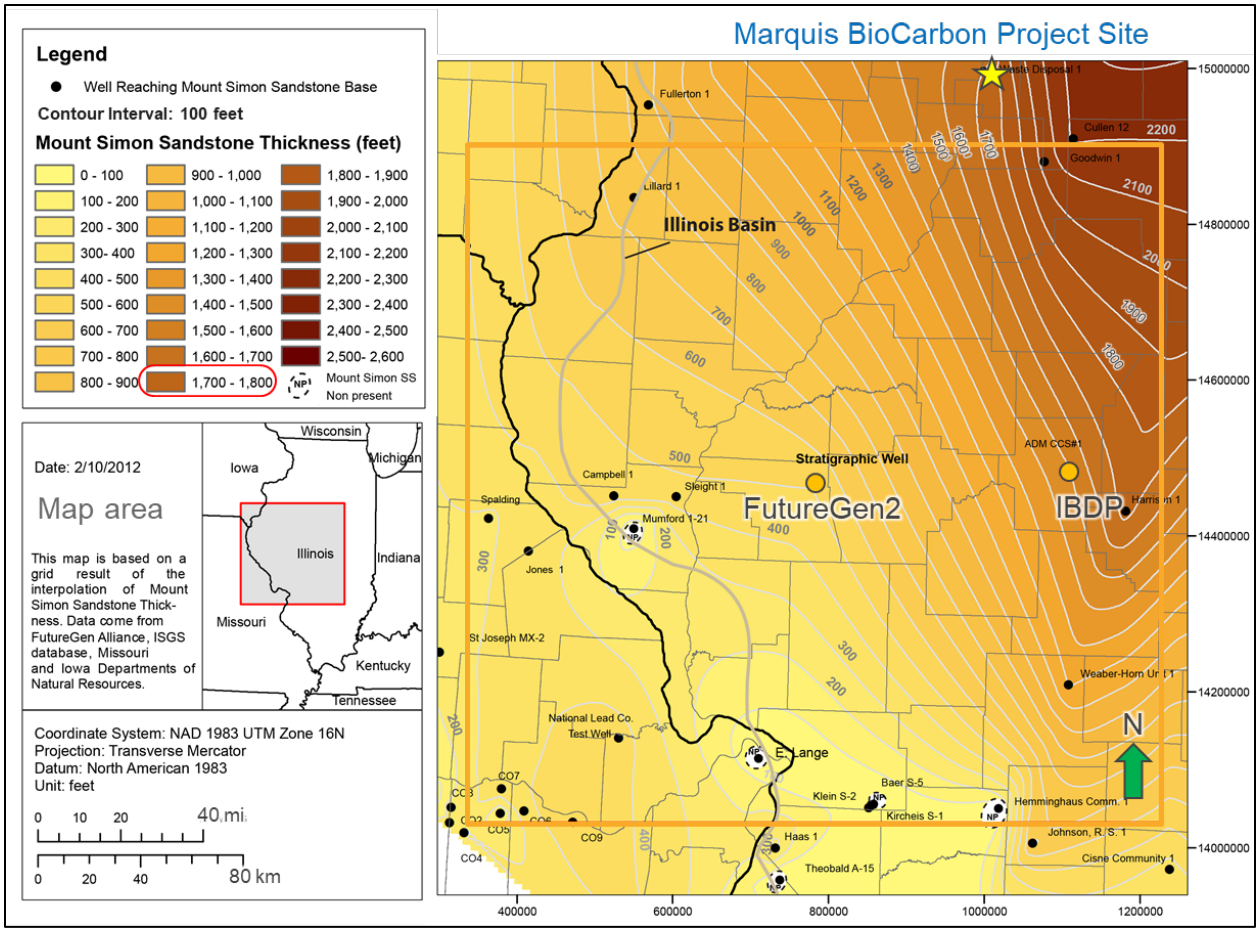


Figure 2-4: Mt. Simon Sandstone thickness map over the west-central portion of the Illinois Basin. Modified from FutureGen Alliance (2013).

The Eau Claire formation consists of interbedded shales, siltstones, sandstones, and minor dolomites. A basal Eau Claire sandstone member, the Elmhurst Sandstone, sits at 2983 ft MD and is comprised of 127 ft of fine to medium grained sandstone with interbedded siltstones and gray shales. The thickness of the Eau Claire formation varies regionally from less than 300 ft in western Illinois to more than 1,000 ft in southeastern Illinois (Figure 2-6). Locally, the Eau Claire is 404 ft thick at the MCI MW 1 well, with 350 ft of the formation characterized as confining zone for the Marquis BioCarbon Project site. The confining zone is defined by the top of the Eau Claire (2706 ft MD at MCI MW 1) through an 11-foot-thick shale in the upper Elmhurst (3043–3054 ft MD) as shown in Figure 2-14. Confining zone properties were confirmed based on core analysis from MCI MW 1 well. Like the Mt. Simon, the depth of the Eau Claire increases to the southeast (Figure 2-5).

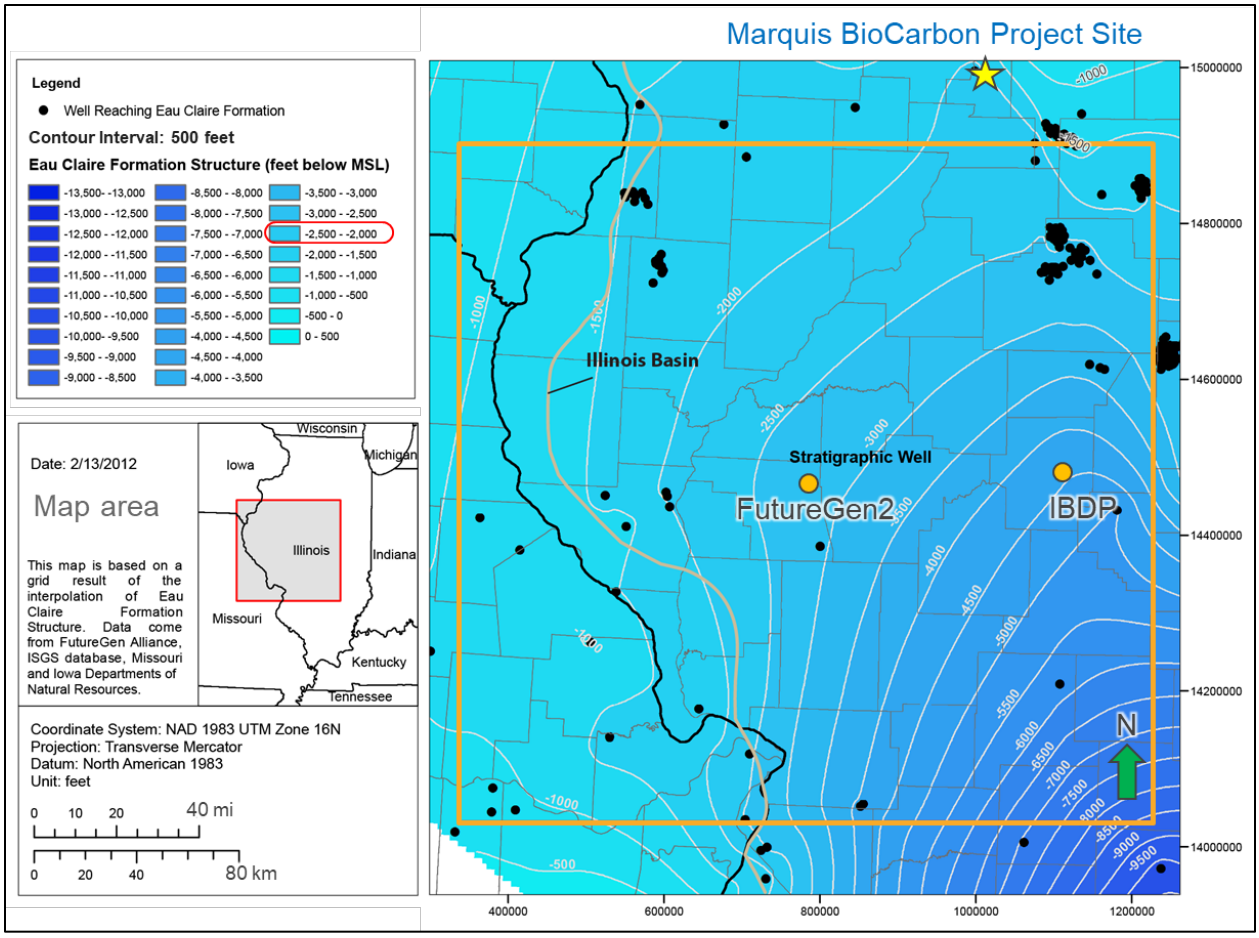


Figure 2-5: Eau Claire elevation map over the west-central portion of the Illinois Basin. Modified from FutureGen Alliance (2013).

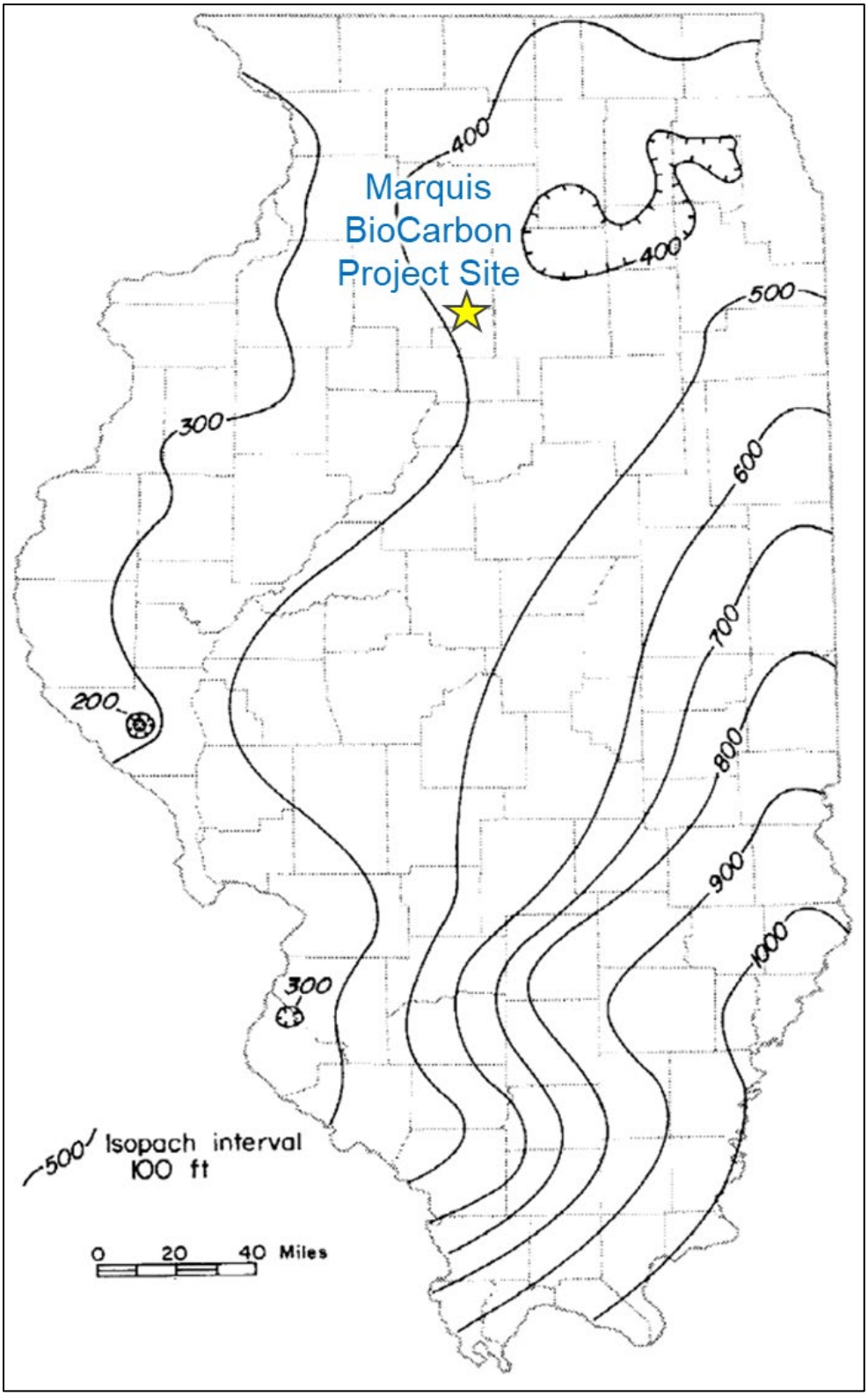


Figure 2-6: Eau Claire Eau Claire thickness map. Modified from Willman et al. (1975).

For the Marquis BioCarbon Project site, interpretations of the Mt. Simon's depositional setting were derived from work associated with the Illinois Basin Decatur Project site in Decatur, Illinois (Palkovic, 2015; Freiburg, 2020; Reesink, 2020), as well previous research on the UPH-3 well in Stephenson County, Illinois (Fischietto, 2009; Lovell, 2017). Previous research on these analog wells have detailed depositional environments, paleogeography, and Precambrian basement structure in the Illinois Basin. The proposed site location falls between these two data points (Figure 2-7), enabling on-site data to be correlated with regional interpretations.

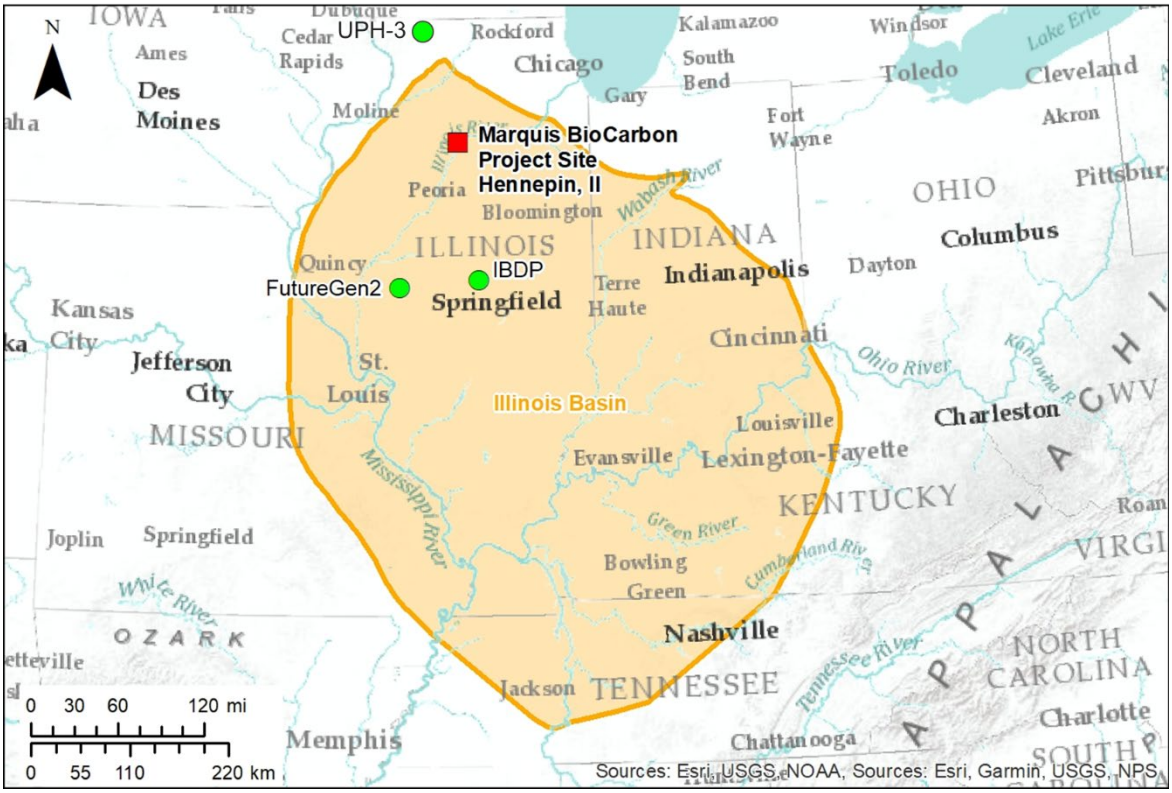


Figure 2-7: Map showing the analog well locations used in depositional environment interpretations to the north and south of the Marquis BioCarbon Project site.

Studying the composition of these core samples enabled an interpretation of lithofacies and depositional environments for the Mount Simon Sandstone in northern Illinois. During the Cambrian Period, a terrestrial fluvial environment of deposition transported sediments from topographically higher regions, such as mountains to the north (Wisconsin region), to a shallower region in Illinois. During transport, these sediments formed the Cambrian-aged depositional environments of the fluvial braid plains and eolian sand dunes (Figure 2-8).

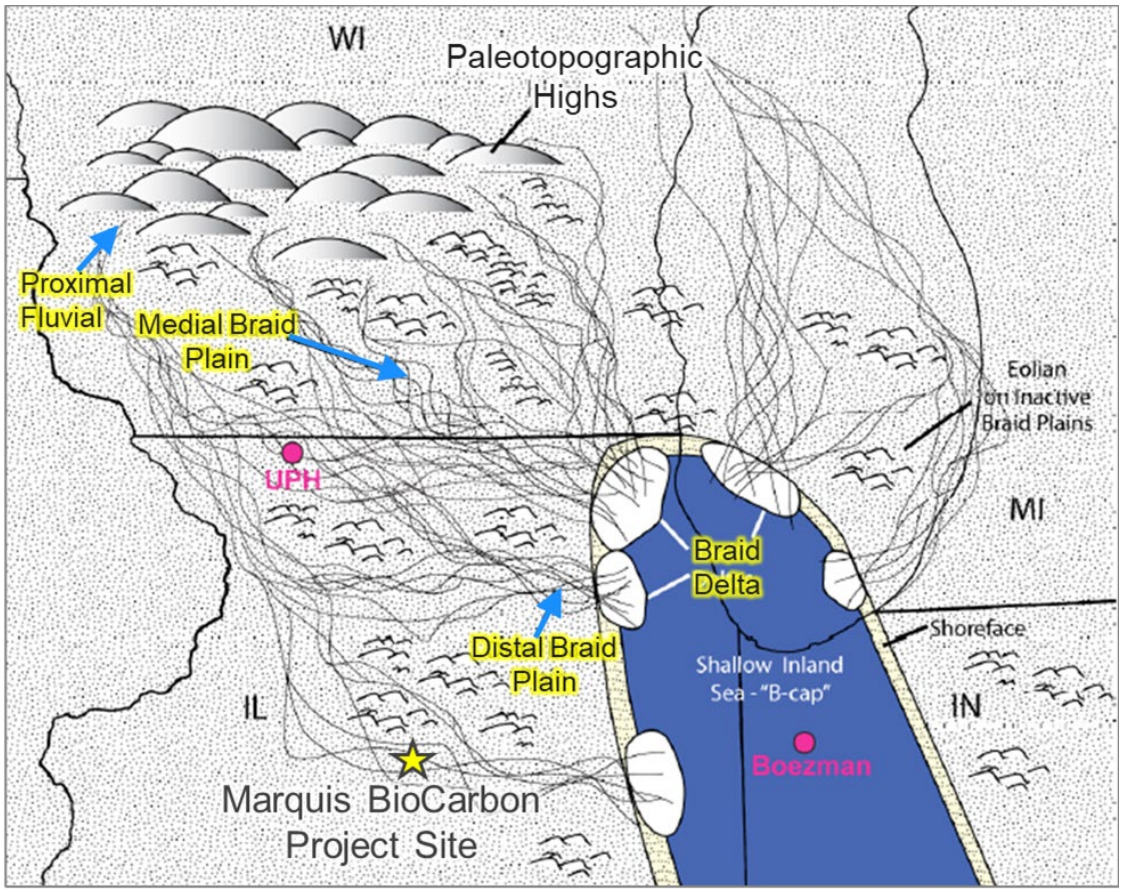


Figure 2-8: Regional depositional model for the Mt. Simon Sandstone. Broad fluvial braid systems feed into a shallow inland sea. Sediments on inactive braid plaids are reworked by eolian processes. Sediment source is primarily from the north. Modified from Fischietto (2009).

The Mt. Simon Sandstone can be divided into stratigraphic intervals associated with the timing and development of the basin that affects depositional settings. Core samples from the project site were integrated with regional studies, resulting in seven distinct depositional packages in the Mt. Simon (Figure 2-9). These environments include eolian sand dunes, fluvial braid plains, and braid deltas that transitioned into shallow marine depositional environments as sea level rose during deposition of the upper Mt. Simon and Eau Claire. Within the regional fluvial braid plain, there are playa (flat "ponding" areas) and eolian (dunal) sedimentary areas (Figure 2-10).

The Mt. Simon consists of sandstones that are generally clean, well-sorted, and porous. Variations in sediment grain size depend on how far sediments were transported from their source and whether they were reworked by wind (eolian sandstone), rivers and streams (fluvial systems), or water (shallow marine sandstones modified and sorted by wave action). At the Marquis BioCarbon Project site, the lower Mt. Simon consists of conglomerate and very coarse to fine-grained sandstone deposited by braided fluvial channels and eolian systems, as well as arkosic sandstones yielding high gamma ray values in Mt. Simon zones 5 and 6. In the Upper

Mt. Simon fluvial, tidal, and shallow marine depositional systems resulted in finer grained sandstone and increased clay content. During the deposition of the Eau Claire, shallow marine systems on the continental shelf deposited shales, siltstones, and fine to very-fine grained sandstones with dolomitic and arkosic compositions.

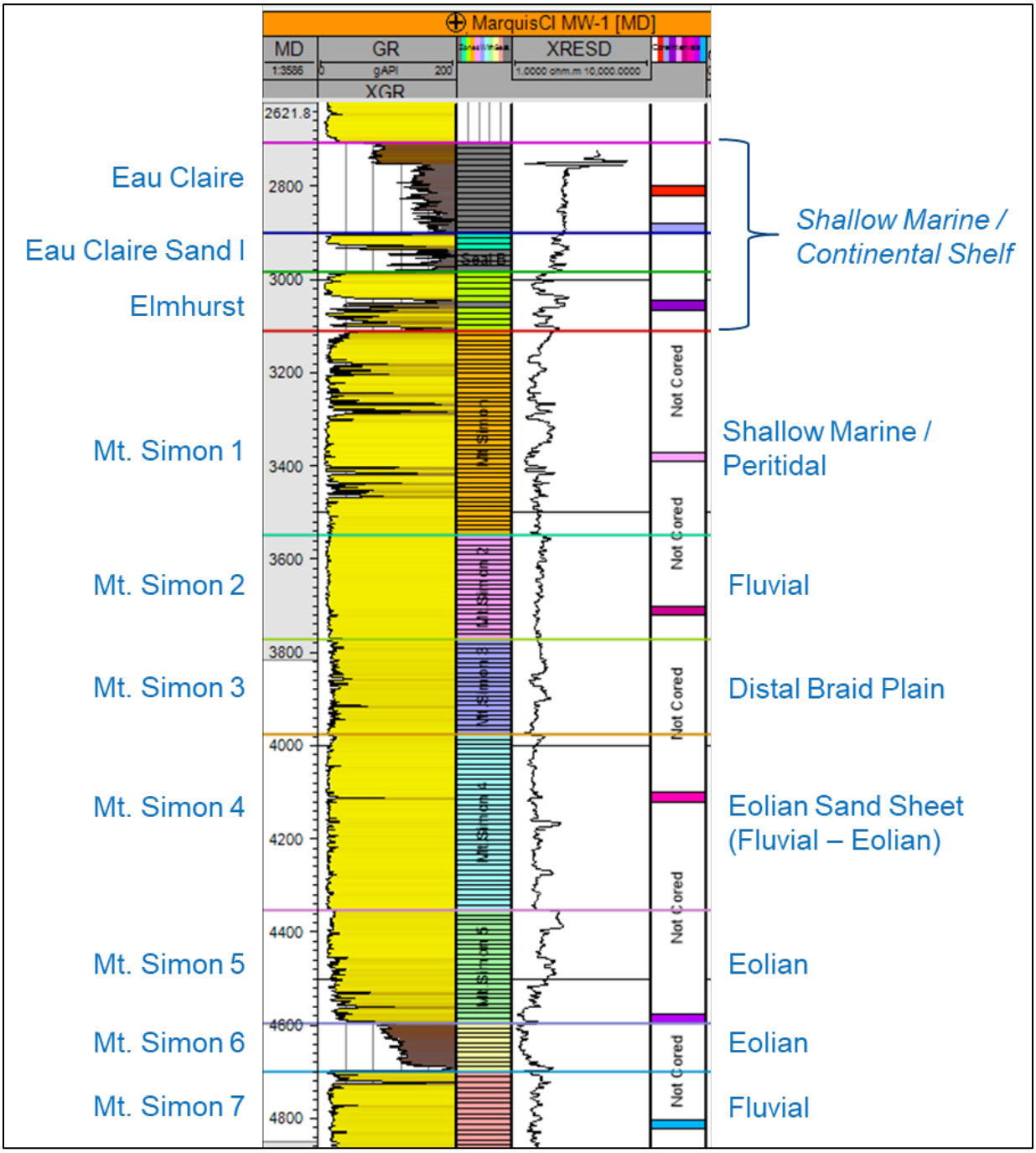


Figure 2-9: Interpreted Mt. Simon depositional environments and corresponding intraformational zones.

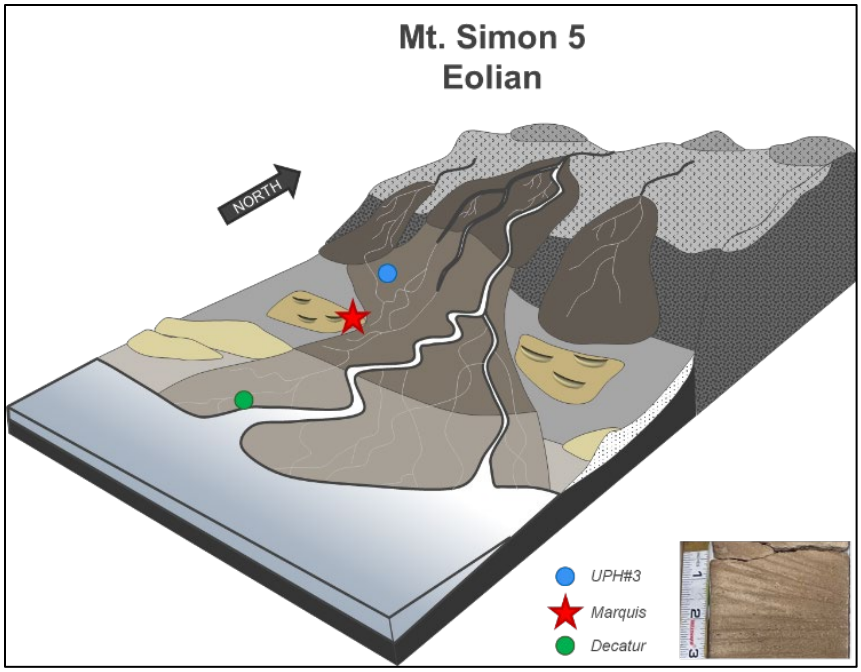


Figure 2-10: Example conceptual schematic drawing of the Mt. Simon Zone 5 representing the eolian depositional environment and interpreted orientations at the Marquis site (not to scale), as well as representative bedding features in whole core acquired from Mt. Simon Zone 5 (insert). Modified from Freiburg et al. (2020).

There are several geologic structures northeast of Putnam County (Figure 2-11). Within the Marquis BioCarbon Project AoR and Putnam County, these structures do not appear to have a significant impact on the confining zone and the target saline storage reservoir. The La Salle Anticlinorium is the dominant regional structure within the basin and has associated faults which cause varied relief of strata along its trend. This structure extends from La Salle County in north central Illinois to the southeast towards Lawrence County near Vincennes, Indiana. This feature is believed to be a drape fold or fault-propagation fold similar in structural style to monoclines that developed during the Laramide Orogeny in the western Unites States (Nelson, 1995). More than half of the La Salle Anticlinorium's uplift is believed to occur during Late Mississippian time, with the remaining uplift and nearby structural features occurring during the Pennsylvanian. There are small faults, anticlines, and domes near the La Salle Anticlinorium and along its trend. The Marquis BioCarbon Project site resides in an area fully removed from the anticline. Other structural features to the northeast of Putman County include the Ashton, Kankakee, and Wisconsin Arches, the Sandwich Fault Zone, and several minor synclines, anticlines, and domes (Golden StrataServices, 1984).

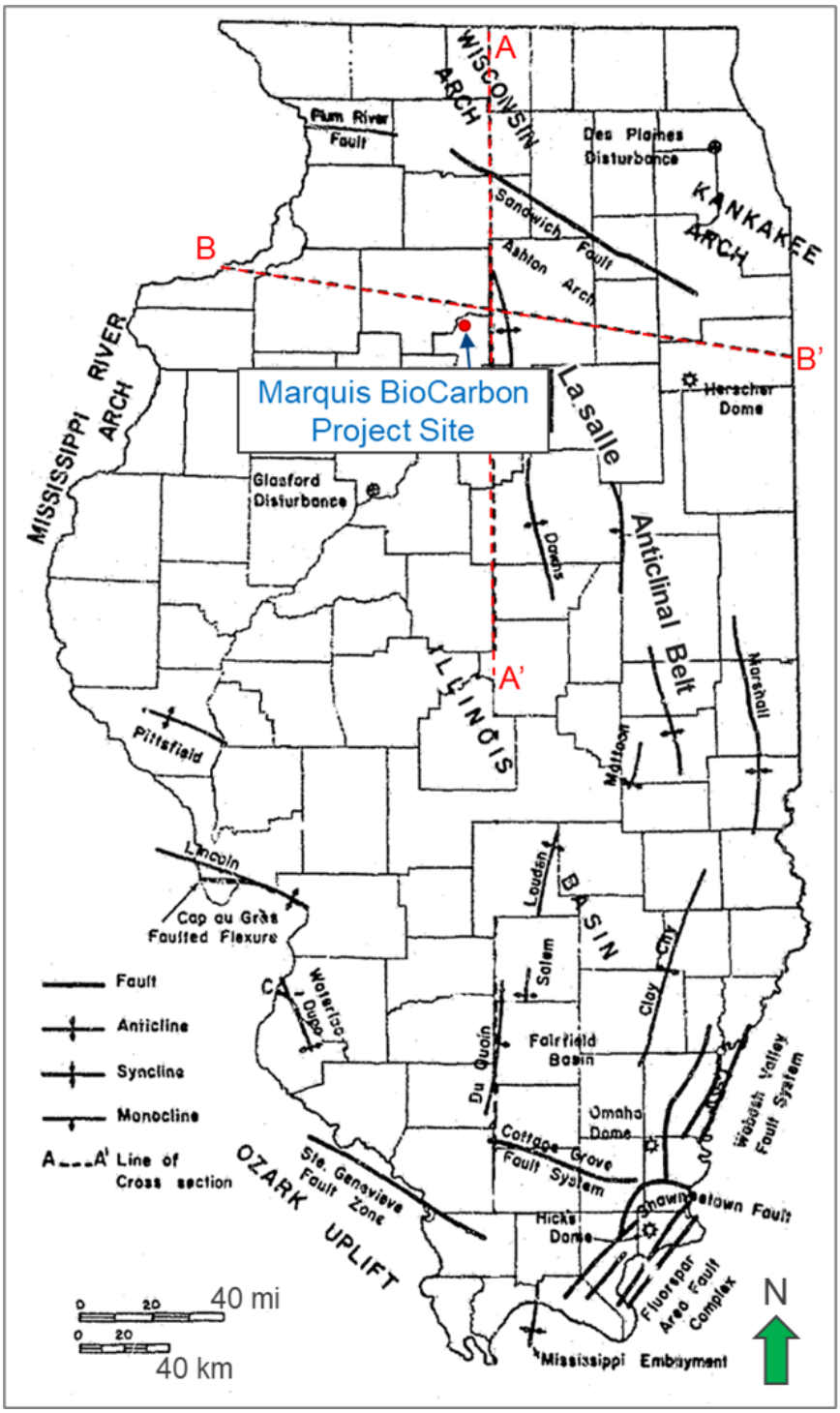


Figure 2-11: Principle geologic structures of Illinois. Modified from Willman et al. (1975) with N-S and E-W cross section marked in red. (See Figure 2-12 for cross sections)

Major geologic units and their stratigraphic relationships are depicted in regional cross sections shown in Figure 2-12. These two cross sections show the northward shallowing of Cambrian strata as well as the regional effect of the La Salle Anticline on the structural configuration of the Cambrian strata. At the Marquis BioCarbon Project site, the injection zone is deep enough for supercritical CO_2 storage, and there is no evidence of faulting, folding, and fracturing structures. This is based on observations from the two-dimensional (2D) seismic data, an example of which is shown in Figure 1-6 of the Project Narrative (Permit Section 1). These observations include the lateral continuity of the subsurface formations and a relatively flat dip angle. The seismic program confirmed the absence of large-scale faulting in the vicinity of the Marquis BioCarbon Project site.

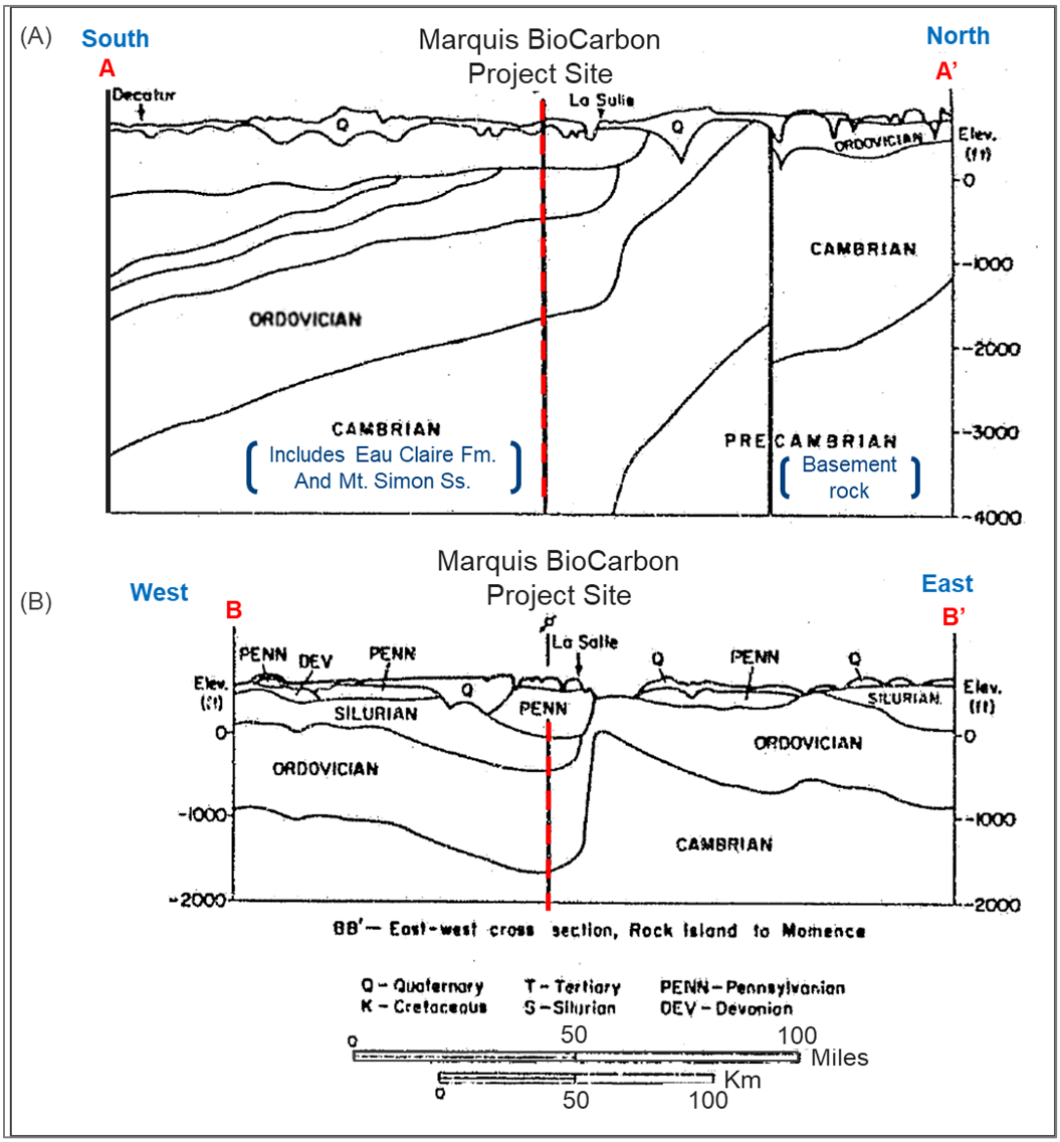


Figure 2-12: Geologic cross sections near Putnam County featuring the structural configuration of Cambrian strata that contains the target injection zone and caprock. The locations of these cross-section lines are shown in Figure 2-11. Modified from Willman et al. (1975).

2.1.3 Model Domain

A 49 mi^2 SEM centered on the Marquis BioCarbon Project site was used to assess potential CO_2 storage and estimate the extent of the CO_2 plume. To mitigate potential edge-effects in simulation, the 7-mi by 7-mi model grid was designed to encase the entirety of the plume and pressure front for the intended injection period. The grid size is set at 500 ft by 500 ft with an average of 10 ft layers in the injection zone and 12 ft layers in the confining unit. The model grid is centered around the MCI CCS 3 well, extending approximately 3.4 mi away from it in the X and Y directions. The proposed well location at the Marquis BioCarbon Project site is provided in Figure 2-13 and model domain information is summarized in Table 2-1.

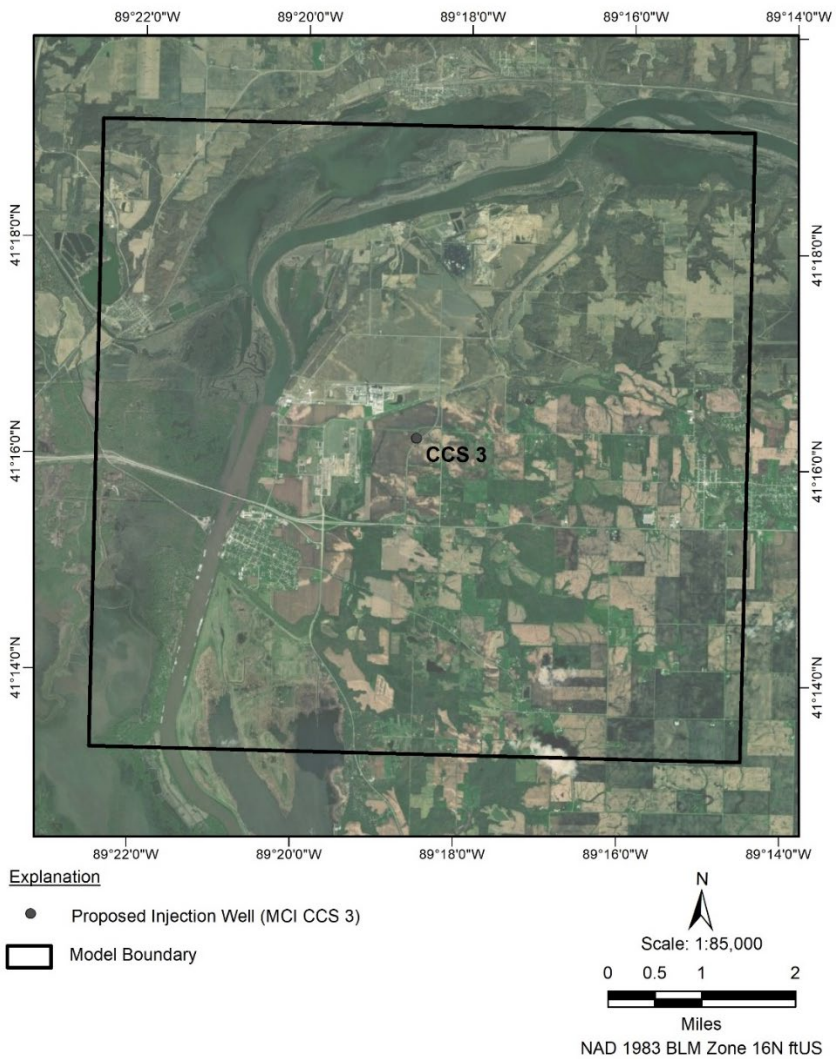


Figure 2-13: Static Earth Model 7-mile by 7-mile boundary centered around the MCI CCS 3 well.

Coordinate System	NAD 1983 BLM Zone 16N ft US		
Horizontal Datum	NAD83		
Coordinate System Units	Field = feet		
Zone	UTC -06:00 Central Time (US & Canada)		
FIPSZONE	1202		
Coordinate of X min	987293.52	**Coordinate of Y min**	14979542.23
Elevation of bottom of domain	-4473.32	**Elevation of top of domain**	-2117.49

Table 2-1: Model domain information.

The Mt. Simon sandstone is subdivided into seven internal zones based on observed responses seen in gamma ray and resistivity logs. These zones are numbered top down, as shown in Figure 2-14. While differently named, these zones are roughly equivalent to Mt. Simon subdivisions used in other studies and at other sites (Fischietto, 2009; FutureGen Alliance, 2013; Freiburg et al., 2014). Generalized reservoir quality of the zones indicates highest quality sands in the lower half of the formation, a middle section of lower-quality sands, and an upper section of higher quality, which is also a trend seen at the regional scale.

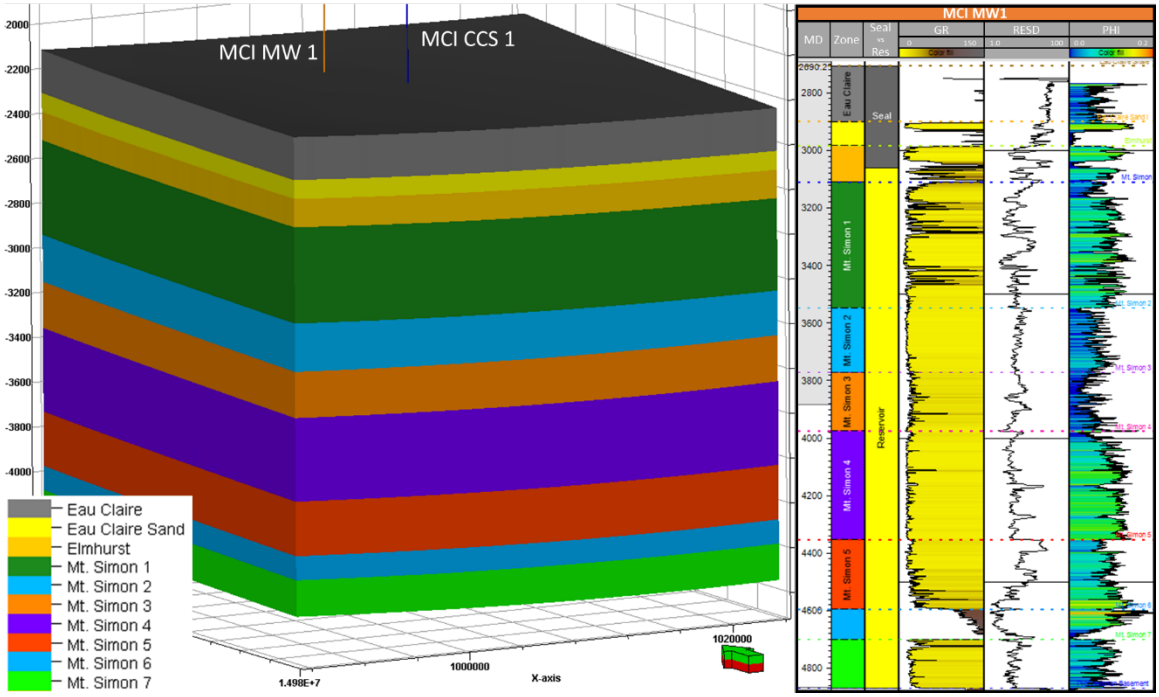


Figure 2-14: Model Zones and corresponding gamma ray, resistivity, and porosity logs. Lower part of the Elmhurst and the entire Mt. Simon are considered reservoir, while the upper Elmhurst and Eau Claire shale act as the seal.

2.1.4 Porosity and Permeability

The geology of the injection interval was characterized based on depositional environments and subsequent controls on sand-quality distribution and implied flow geometries. Environments of deposition (EODs) were determined using paleogeographic information, results of well analyses of the Mt. Simon in analog studies (Fischietto, 2009; Freiburg et al., 2014), and rock observations in the whole core samples from the MCI MW 1 well.

EODs were defined on a zone-by-zone basis and incorporated into the model as objects representing channels and eolian sand deposits. These objects provided a way to constrain facies distribution throughout the model, where environmental controls on the deposition of clean sand and shale components could be represented. Facies used were defined with a clay fraction (vClay) log to separate the rock into three main types: clean sand, dirty sand, and shale. Each facies had a unique distribution of porosity values (Figure 2-15), which were utilized during the porosity property modeling process. Clean sand and dirty sand histograms had a distinctly different distribution in the Mt. Simon 2 and Mt. Simon 3 intervals, where normal distributions were centered around means which were shifted several porosity percentage points to the left (lower).

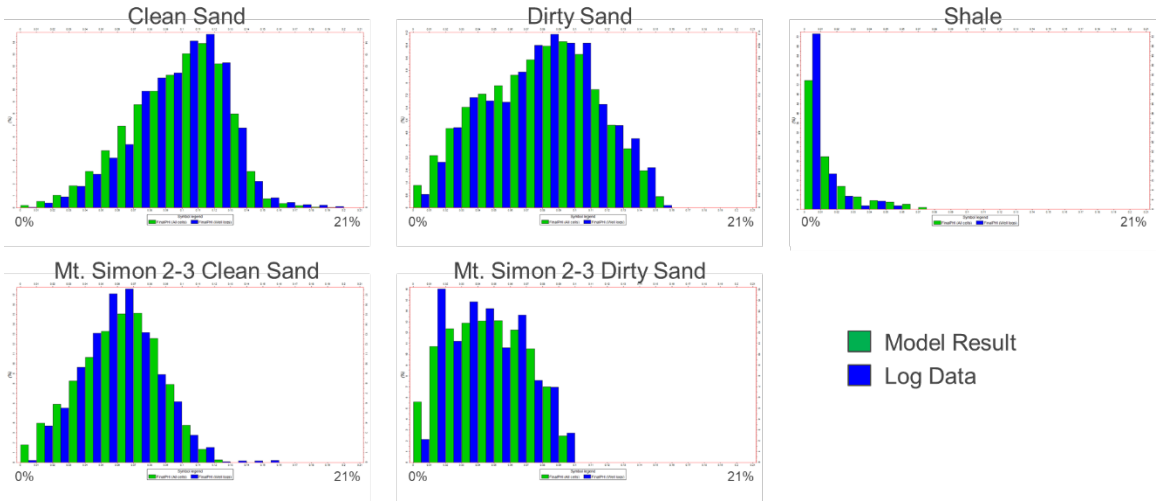


Figure 2-15: Histograms of porosity ranges by facies type showing correlative distributions for the clean sand, dirty sand, and shale facies. Distinctly different distributions for clean sand and dirty sand in Mt. Simons 2 and 3, where normal distribution means are lower.

The resulting porosity property (Figure 2-16a) was used as a direct input into the permeability property (Figure 2-16b), which was calculated in millidarcies (mD) using porosity-permeability transform functions derived from the nuclear magnetic resonance (NMR)-based permeability log. The NMR-based permeability values were cross-checked with core-measured permeability, and a strong correlation was shown (Figure 2-17). This provides confidence in the use of the NMR-based permeability log. The porosity-permeability function was applied based on flow-based facies, which were defined using a flow zone indicator (FZI) log.

The FZI data resulted in four additional "flow-based" facies types: high-flow sand, mid-flow sand, low-flow sand, and shale. Each lithofacies contained a component of each FZI and were subsequently divided into the corresponding amount of flow facies, which represented variabilities in pore-throat size and directly correlates to flow-potential. Two transforms were defined from this data: an upper transform for the high- and mid-flow sands, and a lower transform for the shale and low-flow sands (Figure 2-18). The final permeability property was cross-checked with well test results to ensure permeability height achieved in the model matched dynamic observations at the MCI MW 1 well.

Results of the property models reflect the degraded quality of the Mt. Simon 2 and Mt. Simon 3 relative to other zones. Conversely, the Mt. Simon 1, Mt. Simon 4, and Mt. Simon 5 were the highest quality zones. These relationships were considered when determining the well completions strategy, which is described in more detail in Section 2.2.

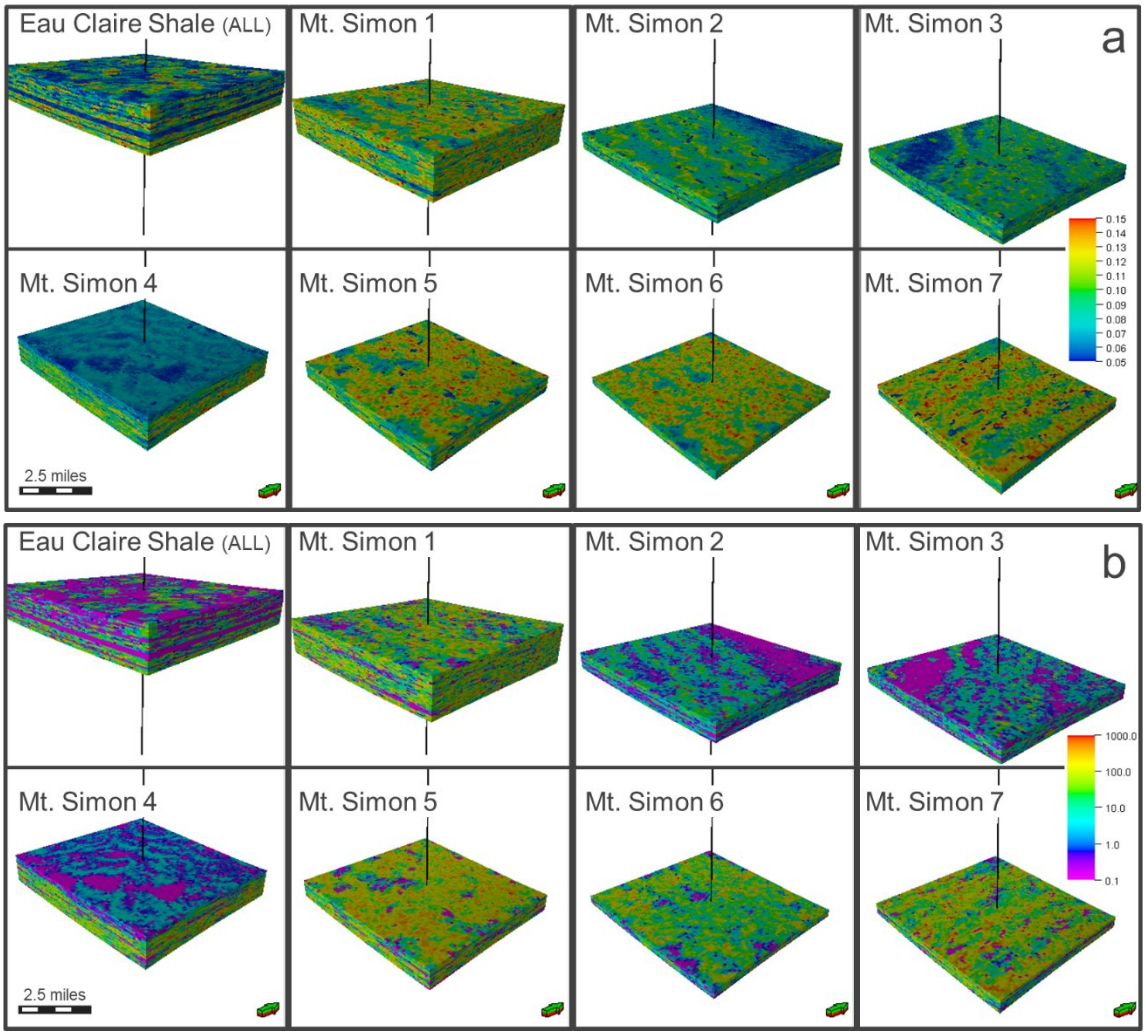


Figure 2-16: Final (a) porosity and (b) permeability properties showing the effect of depositional constraints on spatial property distribution within the 3D geocellular model.

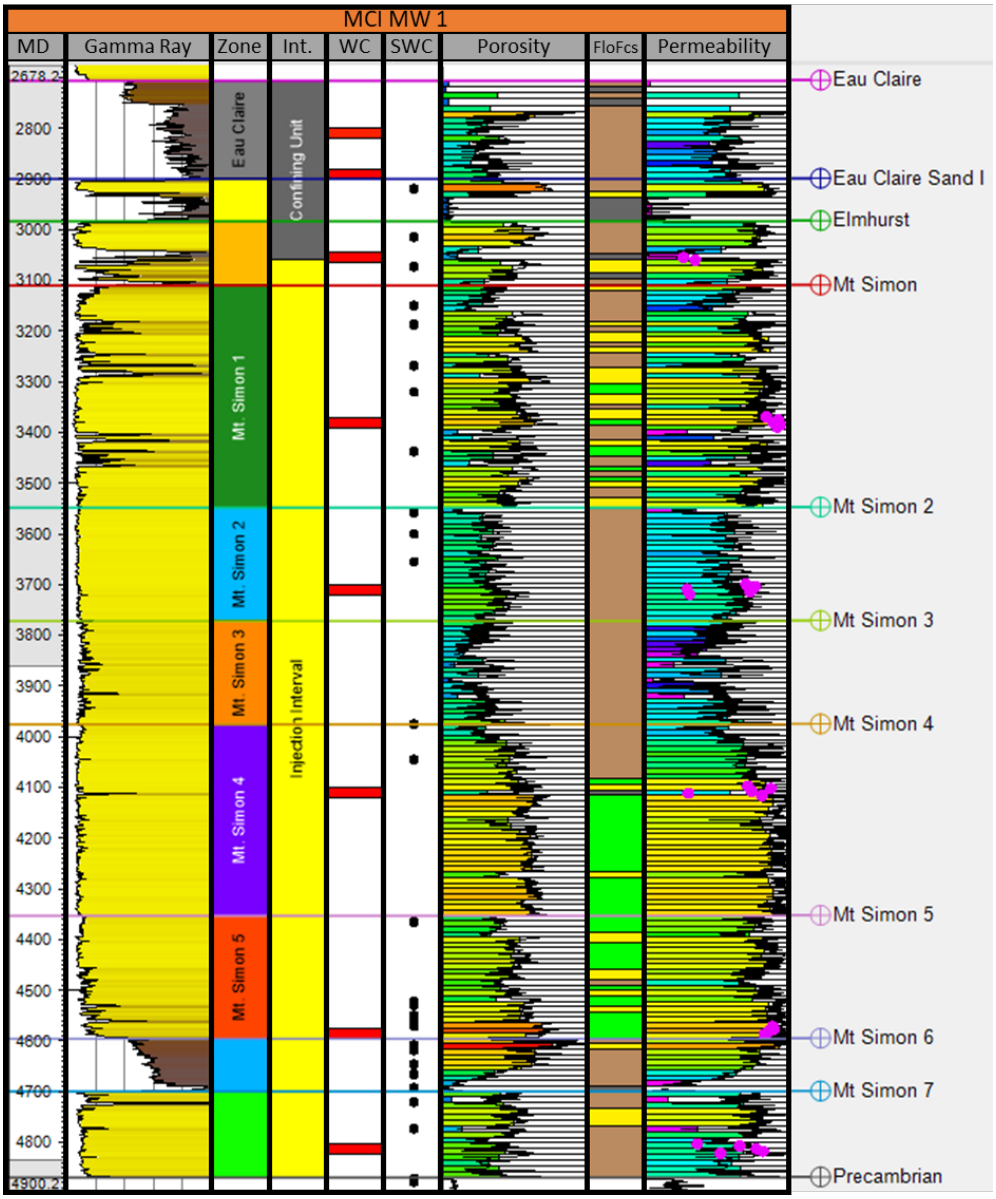


Figure 2-17: Logs at the MCI MW-1 well showing (left to right) gamma ray, stratigraphic zone, confining unit or injection interval, whole core, sidewall core, porosity, flow-based facies, and permeability. There is a match between the model (blocky colors) and the log (black line) for porosity and permeability, and core-measured permeability points plotted on the permeability track in magenta show strong correlation to NMR-based log values.

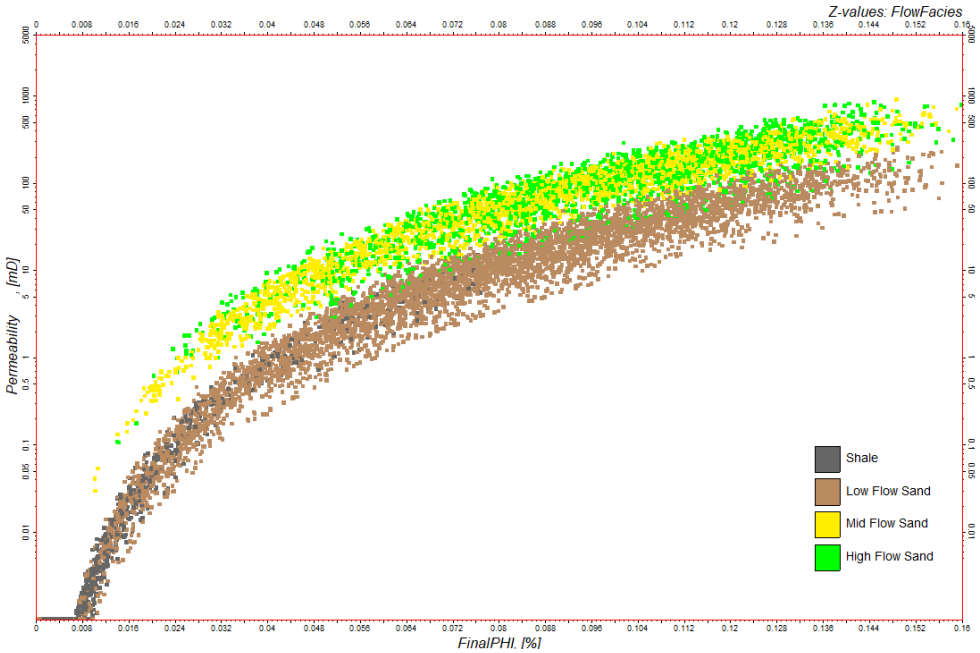


Figure 2-18: Porosity-Permeability cross-plot colored by flow facies showing the utilization of two different transforms, applied by flow-based rock classifications.

2.1.5 Constitutive Relationships and Other Rock Properties

Relative permeability relationships served as the main constitutive relationships in the dynamic model. Relative permeability is an important input for describing dynamic behavior in reservoir simulators and it is a required property in the saturation equation describing multiphase flow in porous media. This flow property is represented as a saturation function and will significantly influence the simulated injection profiles. The curves incorporated in the model were from the CO_2-brine drainage relative permeability experiments performed by Core Laboratories on cores from the MCI MW 1 well. The steady-state method of measuring relative permeability was performed on three core samples taken at depths of 3,384.9, 3709.75, and 4,105 ft MD in the Mt. Simon Sandstone, producing three relative permeability drainage plots (Figure 2-19). Relative permeability versus saturation curves were assigned to facies in the dynamic model based on permeability and flow characteristics. Facies in the Mt. Simon Sandstone were categorized as "low-flow sand", "mid-flow sand" and "high-flow sand". The model assumed a compressibility of 1×10^{-6} 1/pound per square inch (psi), which is the average of the MCI MW 1 well pore volume compressibility log in the Mt. Simon. The log values were computed by Baker Hughes from geomechanics core tests and logs.

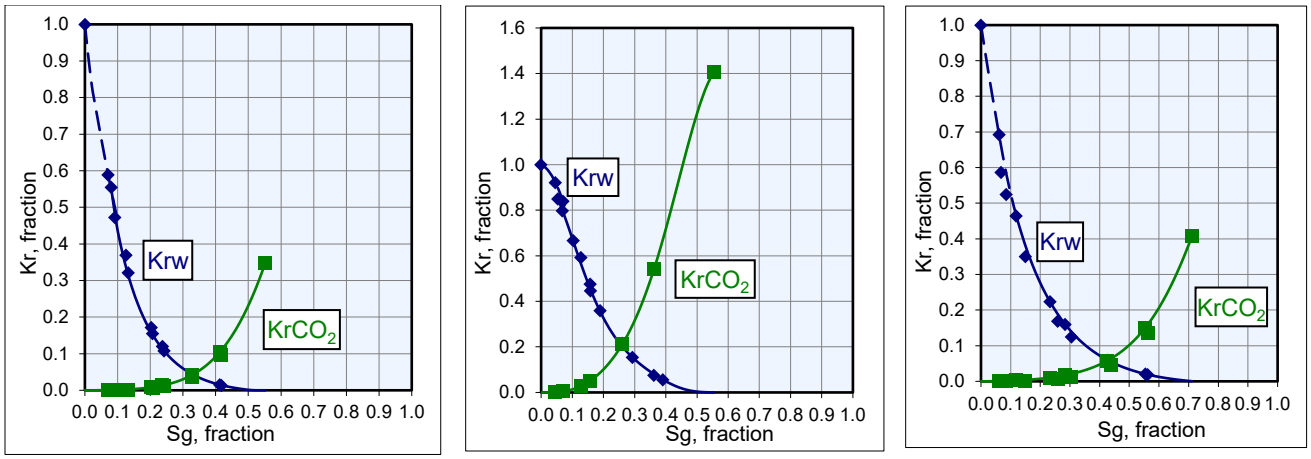


Figure 2-19: Relative Permeability Curves imported into dynamic reservoir model. The plot on the left was assigned to high-flow sands, the plot in the middle was assigned to mid-flow sands and the plot on the right was assigned to low-flow sands.

2.1.6 Boundary Conditions

The model's lower boundary was the top of the Precambrian basement rock. While this surface is expected to have some topographical features, in general, it is assumed to dip to the southeast in the Putnam County area. The size of the static earth model was 7 mi × 7 mi. A single injection well was used at the center of the model so that the CO_2 plume and pressure buildup would be far from the computational model boundary (7 mi × 7 mi) and the model would be able to capture the multiphase flow phenomena. The model lateral boundary is assumed to be an infinite or open boundary reservoir. To model an open boundary reservoir, a volume modifier was used for the grids at the model boundary as recommended by CMG-GEM (CMG-GEM, 2016; Nghiem et al., 2009b).

2.1.7 Initial Conditions

Initial conditions for the model are given in Table 2-2. The pressure gradient profile for the MCI MW 1 was measured during drill stem testing. Based on the measured data, pore pressure gradient in the Mt. Simon was measured to be 0.44 psi/ft, which is close to normal pressure gradient. This pressure gradient is consistent with the regional data. The measured pore pressure gradient of 0.44 psi/ft was used to estimate the initial conditions at the corresponding depth of the modeled well. Formation pressure varies in the model as a function of the pore pressure gradient. A temperature gradient of approximately 0.02 degrees Fahrenheit (°F)/ft was specified in the dynamic model to match the gradient in the MCI MW 1 well's temperature log. Furthermore, geochemical analysis was performed on a composite fluid sample that was collected from the Mt. Simon while pumping the well. These, tests indicated a chloride concentration of 26,215 mg/L (TDS/salinity in the range of ~45,000 ppm), which was used as

input in the simulator. Fluid density was calculated as a function of pressure, temperature, and salinity in the simulator.

Parameter	Value or Range	Units	Corresponding Elevation (ft MSL)	Data Source
Temperature	0.02	F°/ft	3,147.00 – 5,297.00	Temperature Log
Pore pressure gradient	0.44	psi/ft	2,117.49 – 4,473.32	Drill Stem Testing
Fluid density	0.029	tonne/ft^3	2,117.49 – 4,473.32	CMG Reservoir Simulator Calculation
Salinity	45000	ppm	2,985.00 – 4,870.00	Drill Stem Testing

Table 2-2: Initial conditions.

2.1.8 Operational Information

Details on the injection operation are presented in Table 2-3.

	Operating Information	MCI CCS 3
Location (global coordinates)	X Y	41.27026520° -89.30939322°
Model coordinates (ft)	X Y	987293.52° 14979542.23°
Perforated interval (MSL)	Top Bottom	-3,226.14 ft -4,781.53 ft
	Wellbore diameter (in.)	9 5/8 inch
Planned injection period	Start End	01/01/2024 03/01/2029
	Injection duration	5 years
	Maximum injection rate	1.5 million tonnes (MT) /year

Table 2-3: Operating details.

2.1.9 Fracture Pressure and Fracture Gradient

The average fracture propagation pressure gradient measured at the MCI MW 1 well in the Mt. Simon, estimated during the analysis of the minifrac tests was 0.76 psi/ft. This value is consistent

with literature and results from the hydraulic fracture tests performed in the FutureGen 2.0 site located in Morgan County, Illinois discussed in (Cornet, 2014).

This fracture gradient was used to constrain the wellbore pressure at the top of the perforation interval in CMG-GEM. The assigned well pressure in this case is 2,207 psi (3,226 ft MD × 0.76 psi/ft × 90%) following EPA guidelines.

The measured average fracture gradient for the Eau Claire Caprock is 0.95 psi/ft. A higher fracture gradient in the caprock compared to the Mt. Simon implies that even if a fracture were to be created in the Mt. Simon reservoir (e.g., due to inadvertent injection pressures), it would not extend or penetrate the overlying Eau Claire caprock layer.

Injection Pressure Details	**MCI MW 1**
Fracture gradient	0.76 psi/ ft
Maximum injection pressure (90% of fracture pressure)	2207 psi
Elevation corresponding to maximum injection pressure (MSL)	-2694 ft (3226 ft MD)

Table 2-4: Injection pressure details.

2.2 Computational Modeling Results

2.2.1 Predictions of System Behavior

A 3D multi-phase flow simulator (CMG–GEM, 2021) was used to model CO_2 injection, determine the CO_2 plume position, and pressure front at the end of the injection period and during the post-injection period. The model includes target storage formations and confining zone formations. The geological model (SEM) that includes the permeability, porosity, and gridding of the model was imported from Petrel. The gas-water relative permeability relationship assigned to the model is described in Section 2.1.5.

The injection well (MCI CCS 3) was defined in the model as a 3,150 ft wellbore with 4.5-inch tubing (4-inch internal diameter) and perforations as shown in Table 2-3. A wellhead temperature of 93°F was specified. A cross-section view of the model at the wellbore location as well as map view of the model is shown in Figure 2-20.

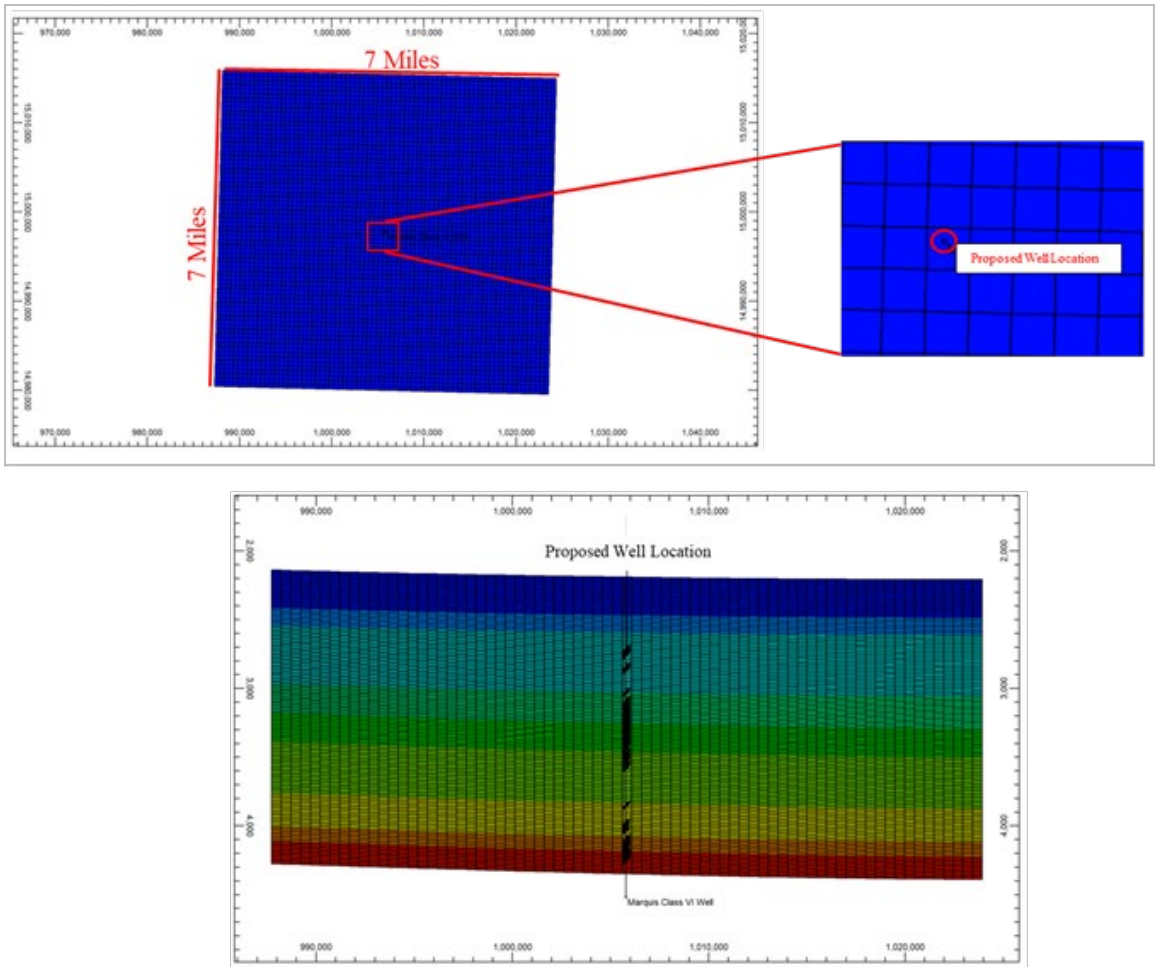


Figure 2-20: Map view of computational model with zoomed well grid (top) and cross section of the model (below).

The model demonstrates a 5-year injection period and 50-year post-injection period. The CO_2 injection rate was constrained to 1.5 MT/year.

CO_2 phase saturation is used as a defining parameter for the CO_2 plume extent. Figure 2-21 shows a side view of the CO_2 plume at the wellbore after 1, 3, and 5 years of injection. Figure 2-22 shows the same side view of the CO_2 plume at the wellbore at 3, 5, 10 and 50 years after the cessation of injection.

The CO_2 plume expands during the injection period and local permeability variations within the Mt. Simon Sandstone causes changes in the distribution of the CO_2 plume. At no time either during or after injection does the CO_2 migrate toward the top of the Mt. Simon.

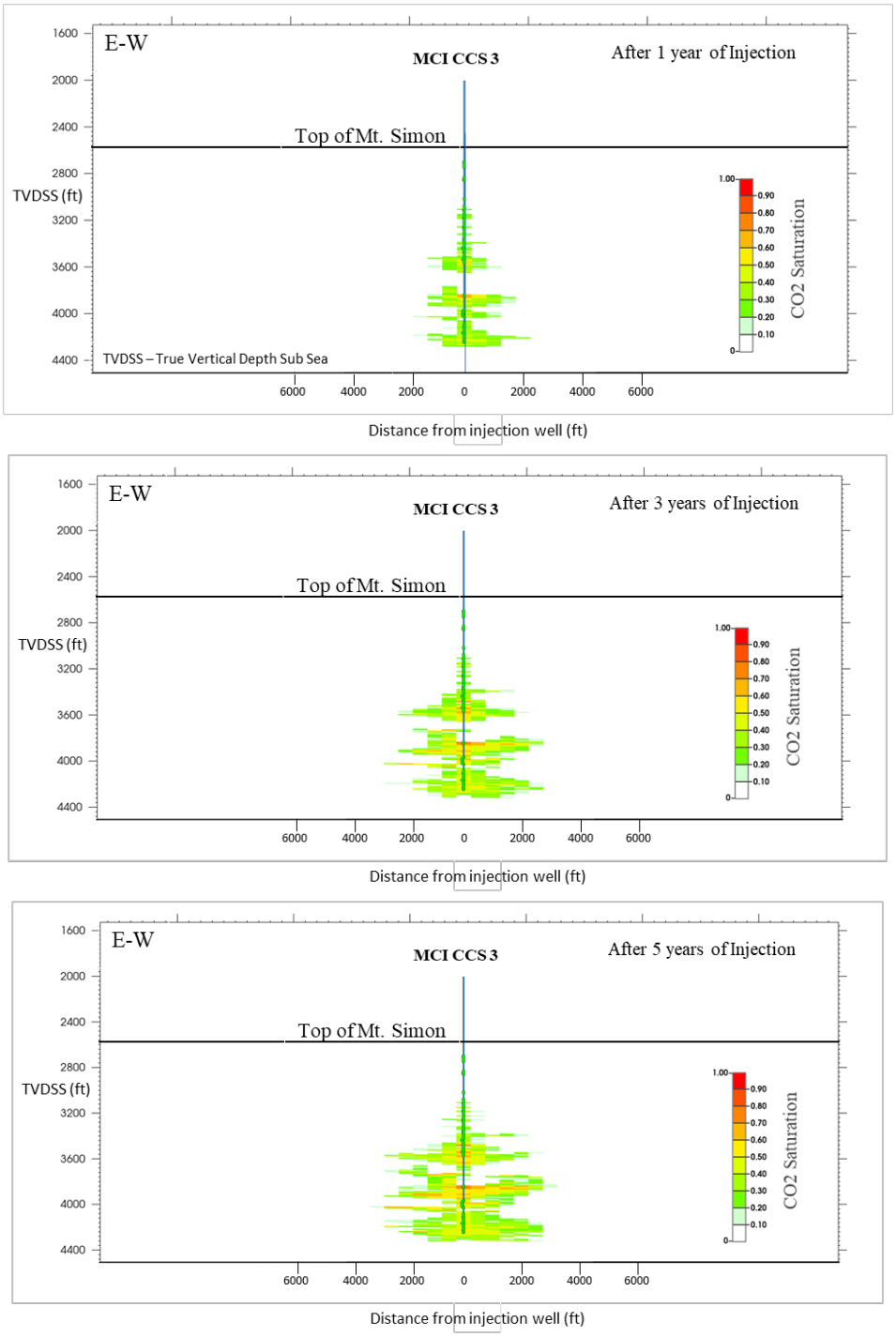
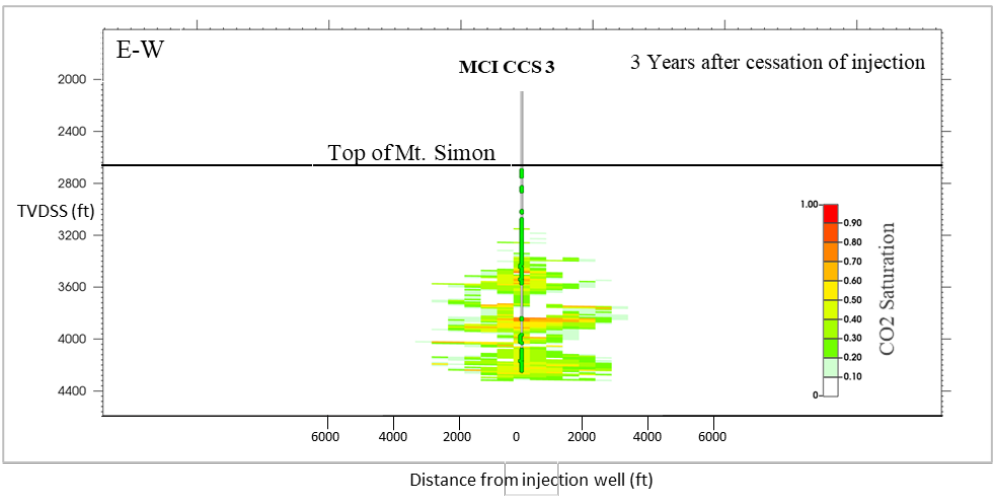
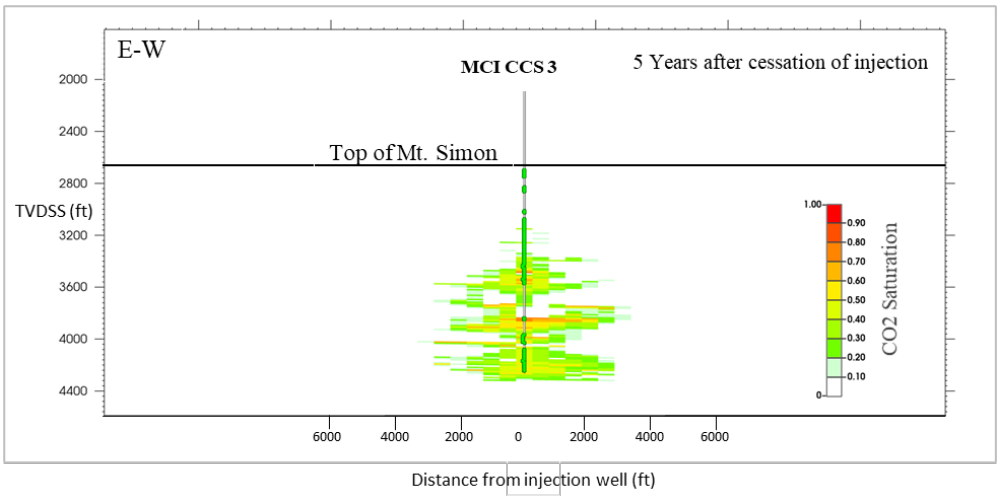
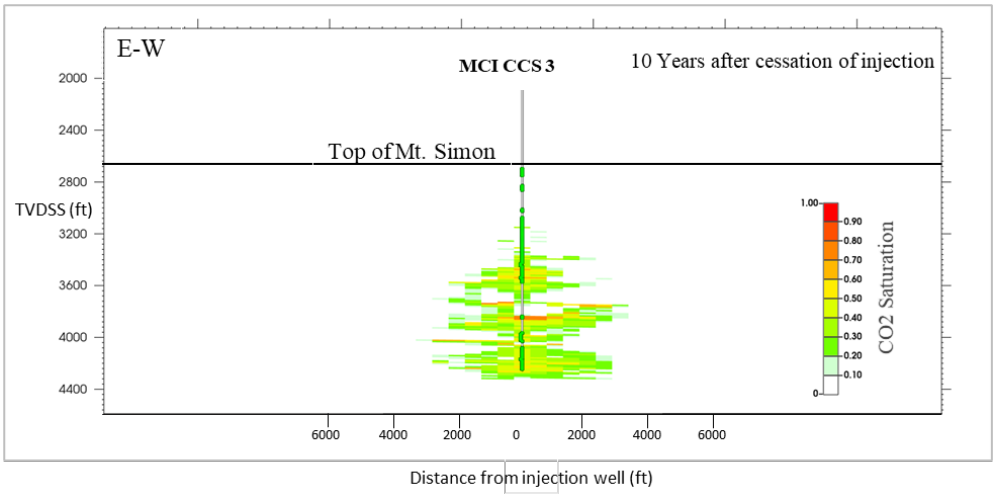


Figure 2-21: Development of CO_2 plume after 1 year (top), 3 years (middle), and 5 years (lower) of injection.


E-W
MCI CCS 3
3 Years after cessation of injection
Top of Mt. Simon
TVDSS (ft)
2000
2400
2800
3200
3600
4000
4400
6000
4000
2000
0
2000
4000
6000
Distance from injection well (ft)
CO2 Saturation
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0


E-W
MCI CCS 3
5 Years after cessation of injection
Top of Mt. Simon
TVDSS (ft)
2000
2400
2800
3200
3600
4000
4400
6000
4000
2000
0
2000
4000
6000
Distance from injection well (ft)
CO2 Saturation
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0


E-W
MCI CCS 3
10 Years after cessation of injection
Top of Mt. Simon
TVDSS (ft)
2000
2400
2800
3200
3600
4000
4400
6000
4000
2000
0
2000
4000
6000
Distance from injection well (ft)
CO2 Saturation
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0

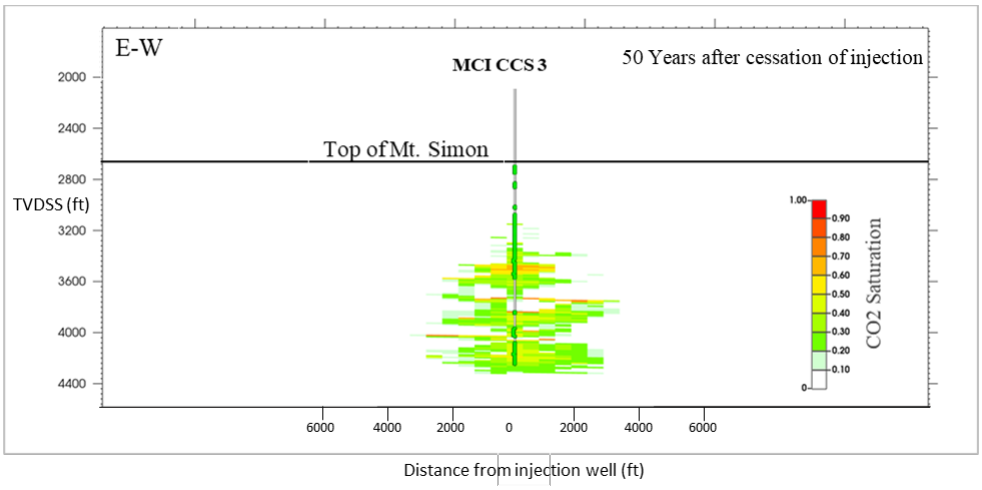


Figure 2-22: CO_2 plume 3, 5, 10 and 50 years after cessation of injection.

The CO_2 plume size after 5 years of injection for four different layers is shown in map view in Figure 2-23.

The AoR is determined by using the average plume sizes for all layers in the model at the end of the 5-year injection period which corresponds to layer 153. The CO_2 saturation in that layer at the end of injection period was selected to define AoR.

Figure 2-24 shows the development of the CO_2 plume size after 1, 3, and 5 years of injection for layer 153. Figure 2-25 shows the CO_2 plume size in the post injection time frame and clearly indicates stabilization of the plume after the cessation of injection.

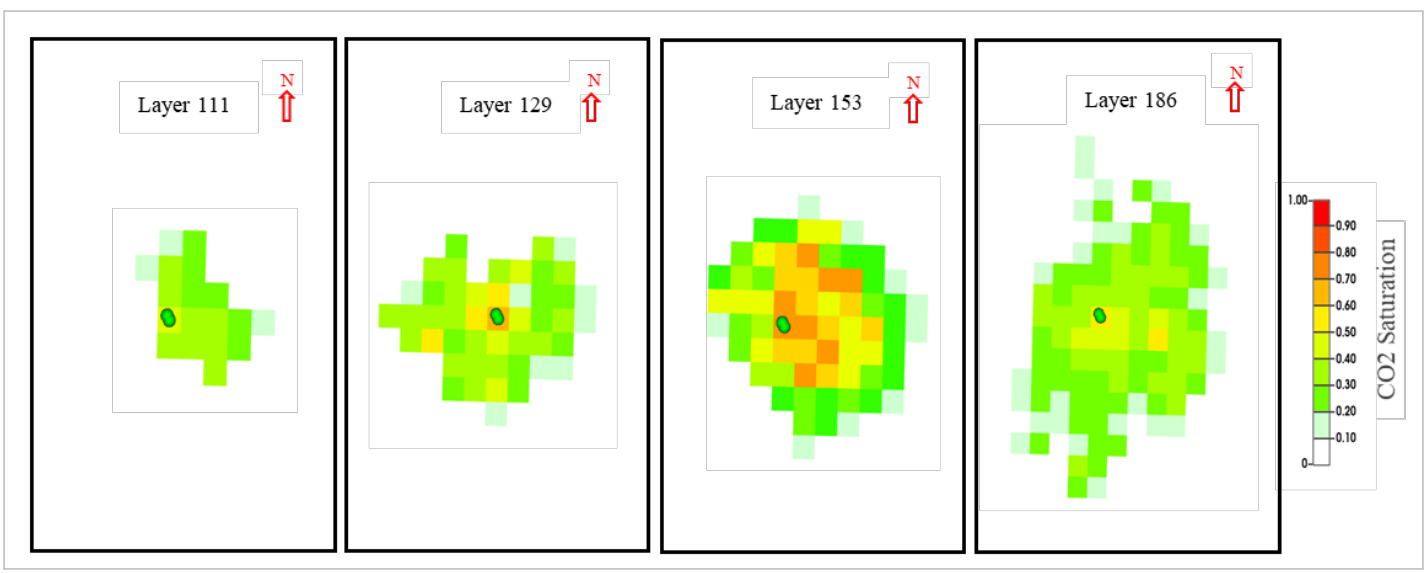


Figure 2-23: CO_2 plume after 5 years of injection in plan view for layers 111, 129, 153 and 186.

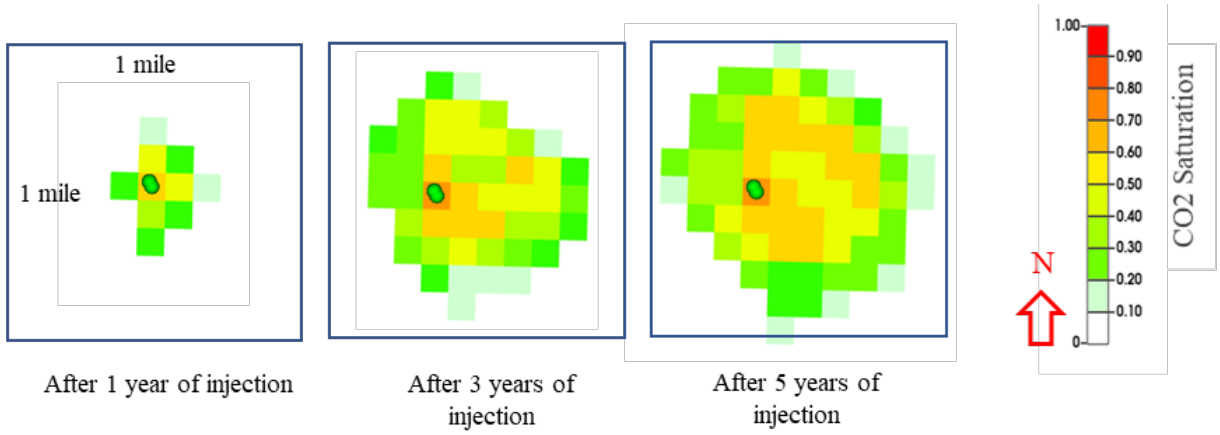


Figure 2-24: Development of CO_2 plume after 1 year, 3 years, and 5 years of injection at layer 153 representing the AoR.

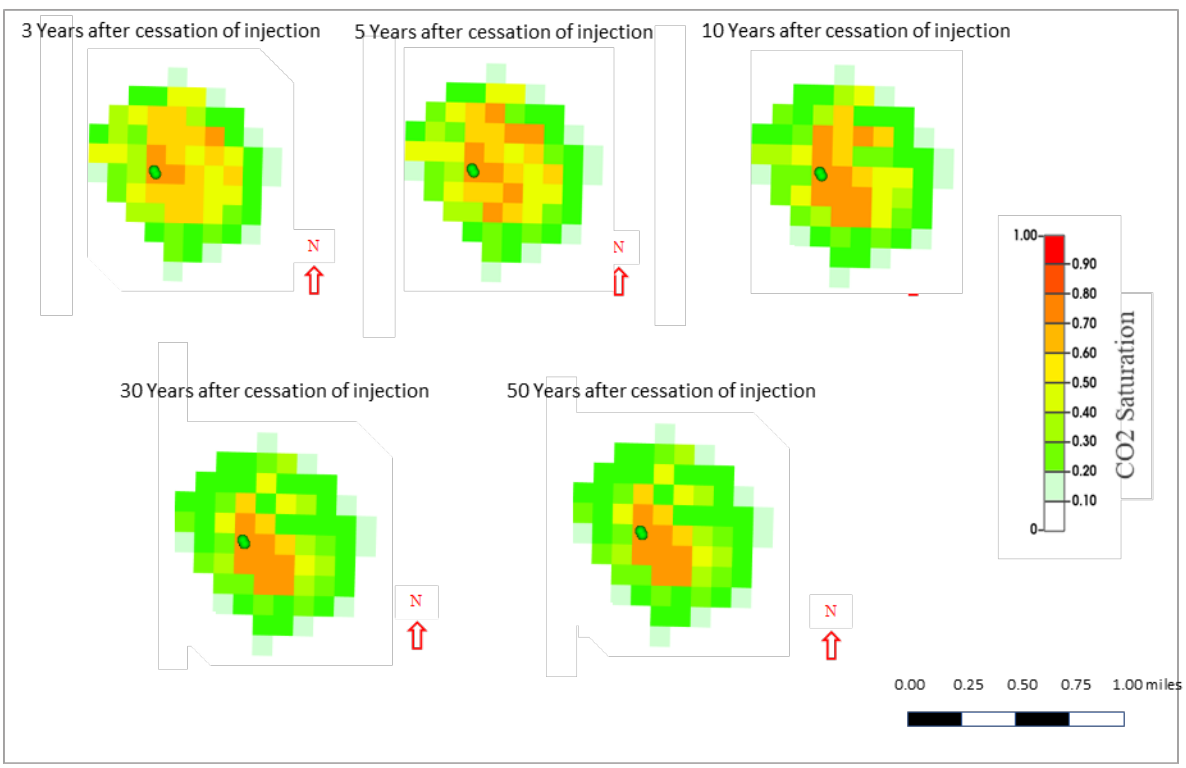
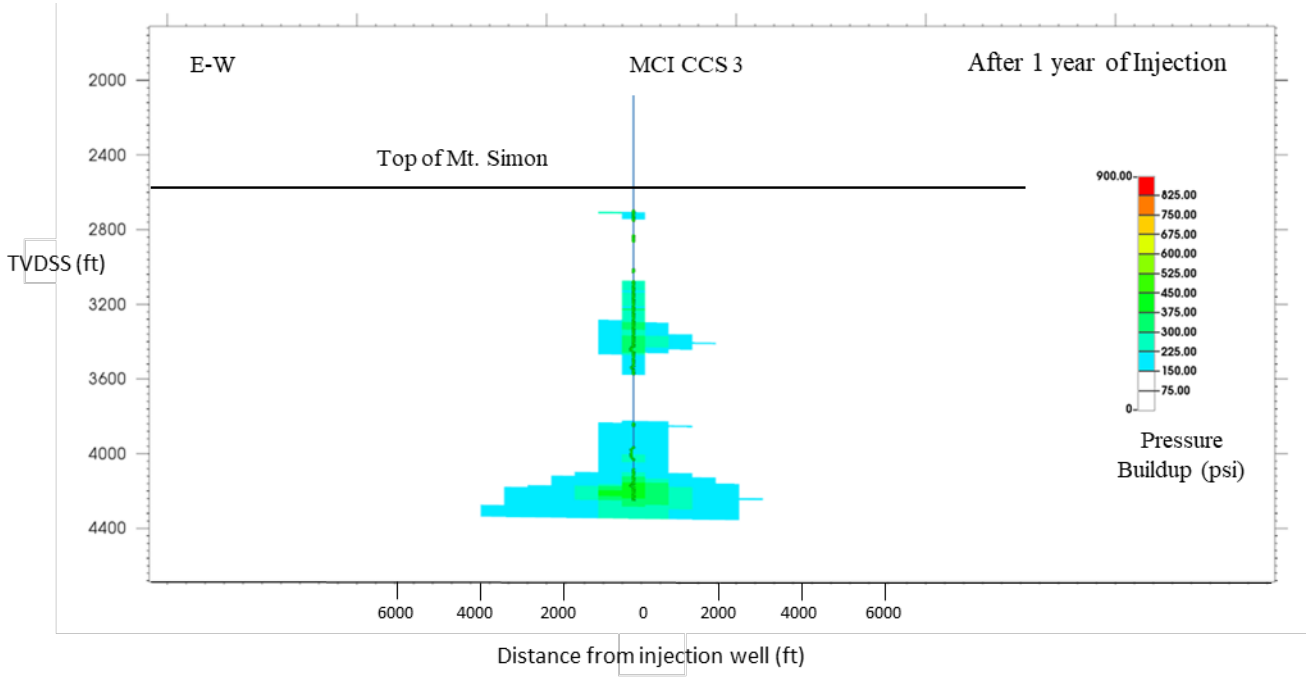
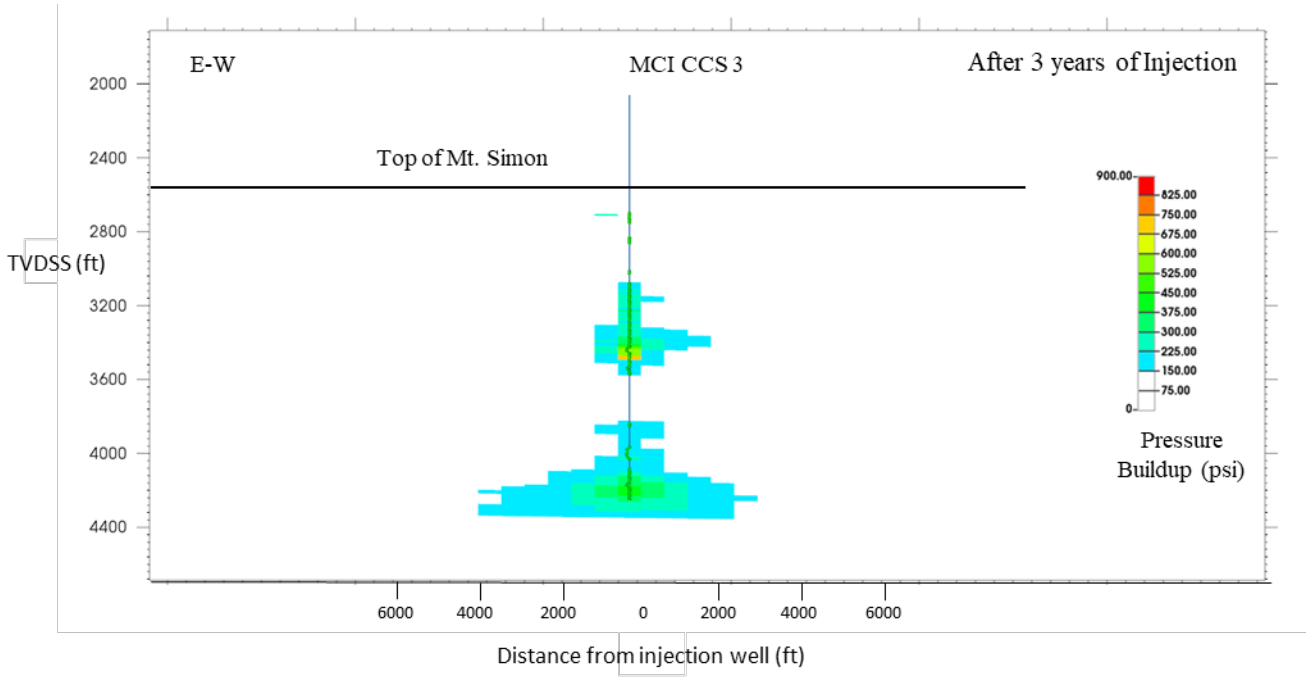


Figure 2-25: CO_2 plume mapping 3 year, 5 years, 10 years, 30 years, and 50 years after cessation of at layer 153 (representing the AoR).

Figure 2-26 shows the pressure build-up (increase from initial pressure) in the Mt. Simon formation after 1, 3, and 5 years of injection. A pressure cut-off of 150 psi was used in the plot to delineate pressure front expansion as a function of injection time as detailed in section 2.3.

Figure 2-27 shows the pressure time-series at the depth of the middle perforation. The pressure remains lower than the maximum injection pressure and declines rapidly after injection ceases.





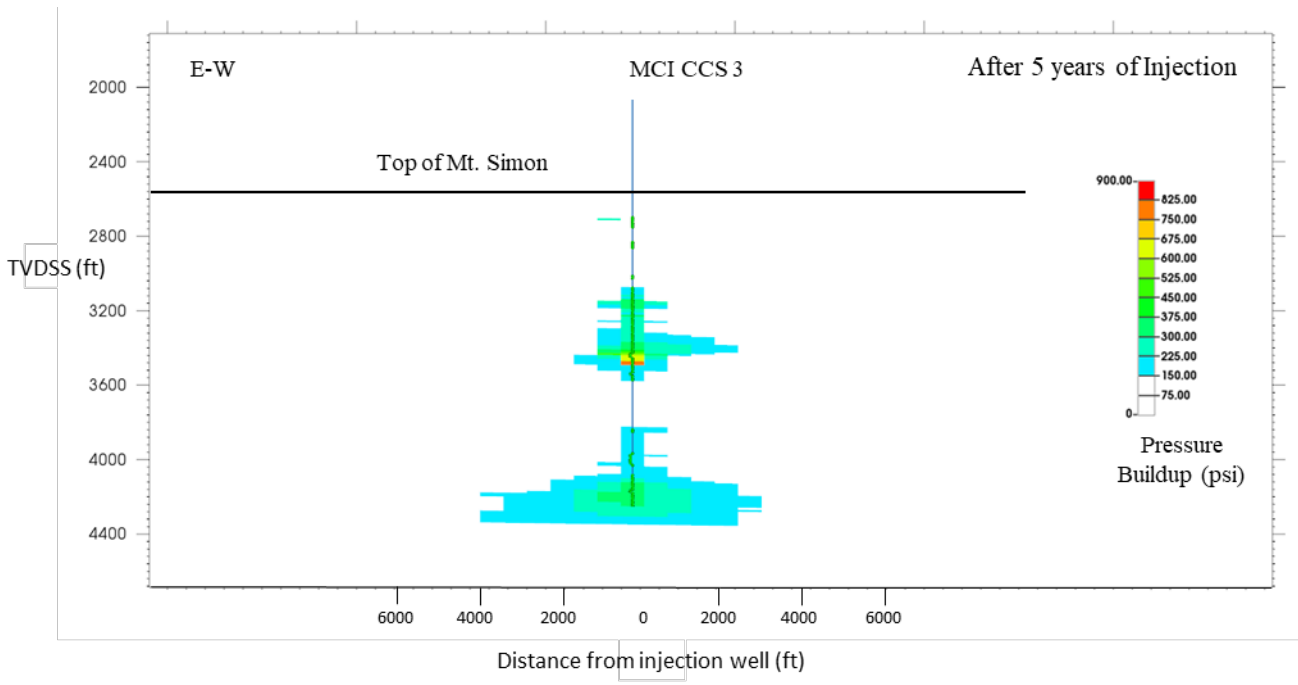


Figure 2-26: Pressure front after 1, 3 and 5 years of injection using 150 psi pressure cut-off.

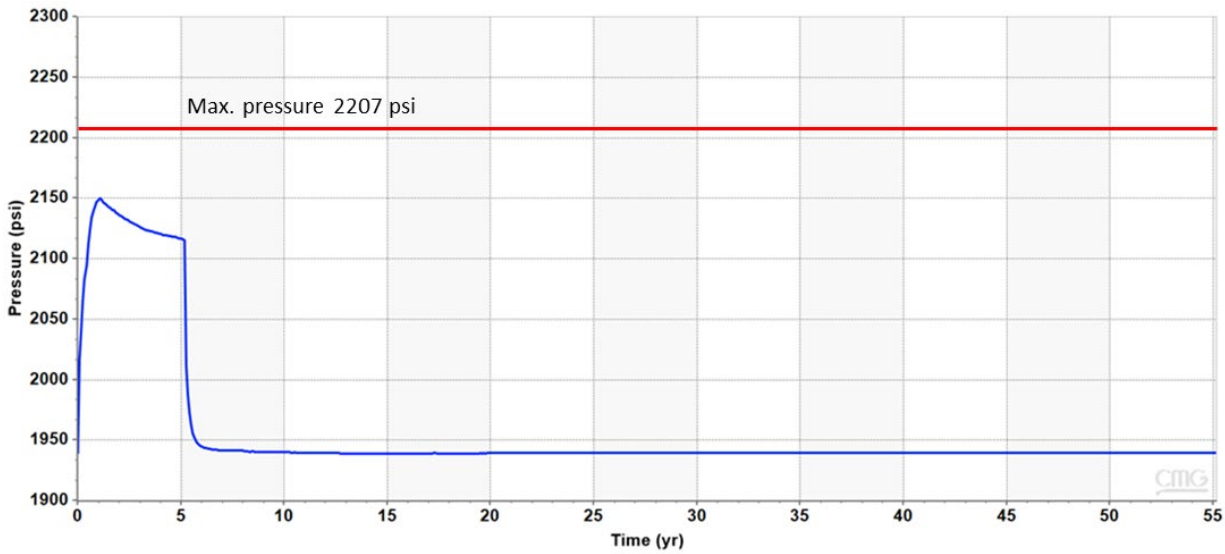


Figure 2-27: Pressure time-series data during injection and 50 years of post-injection period at depth of middle perforation (model layer 109, 3,898 TVDSS, ft.)

CO_2 saturation and pressure build-up were also modeled at the monitoring well location (MCI MW 2). The pressure at layer 153 (3,833 ft Subsea true vertical depth [TVDSS]) for the MCI CCS 3 and MCI MW 2 wells is plotted in Figure 2-27. As expected, the pressure build-up at the MCI MW 2 well is lower than the MCI CCS 3 well, and pressures quickly decline after injection stops.

Figure 2-29 shows the development of the CO_2 plume in layer 153 at the MCI CCS 3 and MCI MW 2 well. The CO_2 saturation immediately increases at the MCI CCS 3 well location compared to the MCI MW 2 well location.

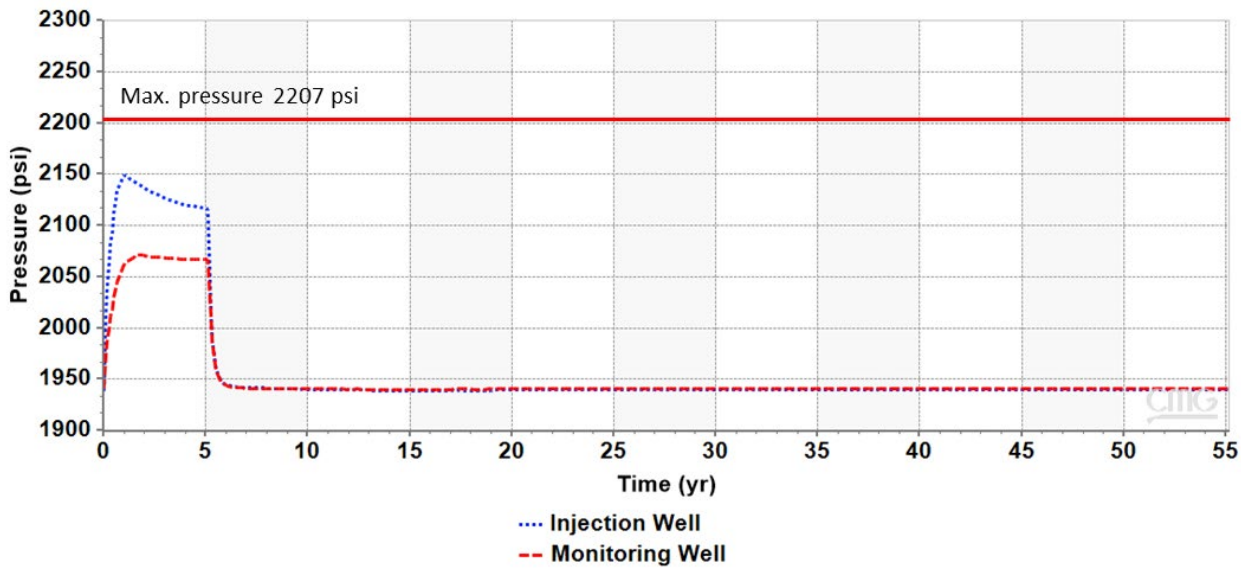


Figure 2-28: Pressure time-series data during injection and post injection period for monitoring (MCI MW 2) and injection well (MCI CCS 3) location at layer 153, 3,833 TVDSS, ft

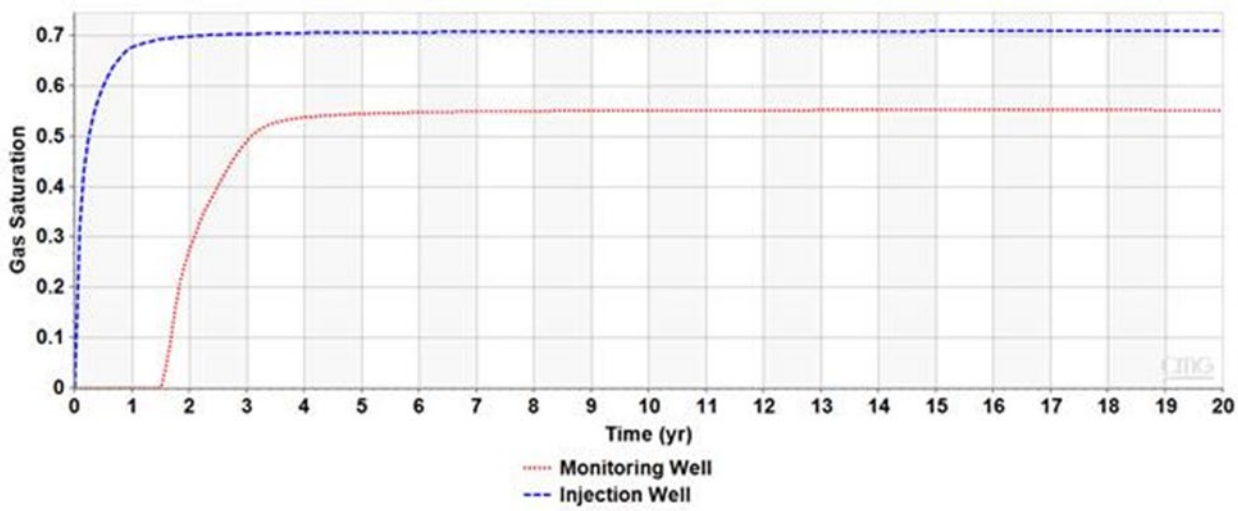


Figure 2-29: CO_2 saturation time-series data during injection and post injection period for monitoring (MCI MW 2) and injection (MCI CCS 3) well locations at layer 153 with MSL of 3,833 ft

2.2.2 Model Calibration and Validation

A robust earth model has been built and calibrated using data acquired in the MCI MW 1 well. Geological parameters (e.g., porosity, permeability), fluid flow data (e.g., relative permeability), and initial reservoir data (e.g., temperature, initial pressure gradient, fracture pressure gradient) used to build the computational model, were derived from data collected from the well. A wide variety of data was acquired from logs, core tests and other field measurements such as minifracs and drill stem tests (DSTs). The data acquired greatly enhances the geologic knowledge of the area confirming the characteristics of the site as a viable storage site.

Planned wellbore parameters such as tubing size and tubing temperature profile were also incorporated in the model for additional accuracy. Once the injection phase of the project begins, the monitoring data such as pressure and injected rates will be used to calibrate, and history match the model as the project proceeds. Moreover, as described in section 2.4 (below), the AoR will be assessed during the lifetime of the project.

Subsurface uncertainty is also addressed through the creation and simulation of alternative geological scenarios. Sensitivity runs were performed for different porosity and permeability relationships as shown in Figure 2-30. All model parameters were the same as the base case apart from the porosity and permeability.

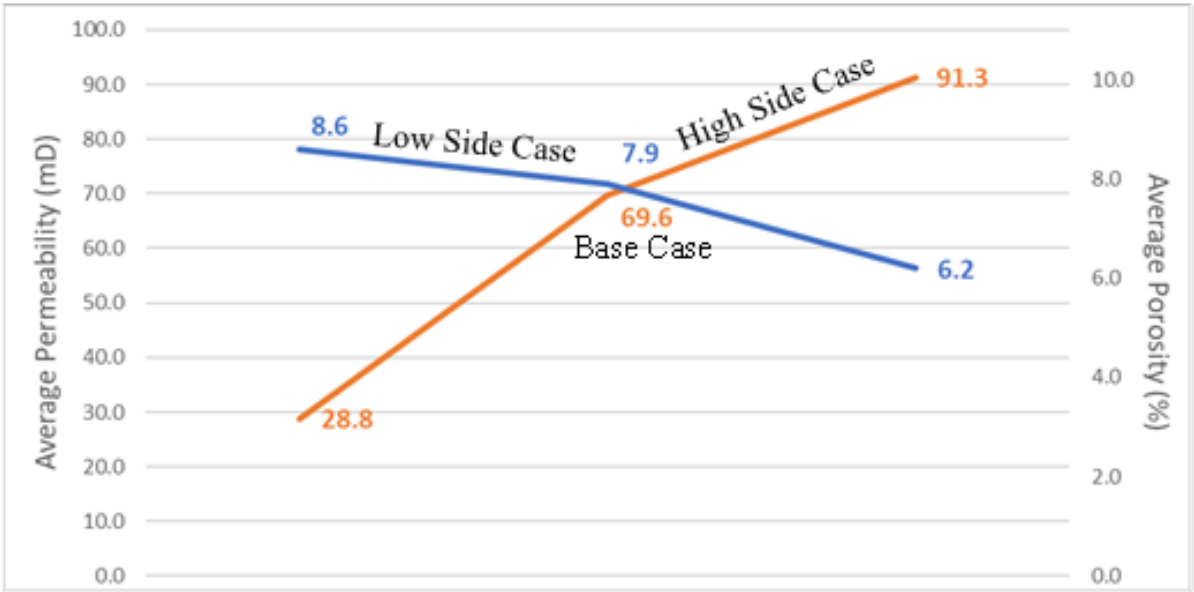


Figure 2-30: Porosity and permeability relationships for high side case (orange line) and low side case (blue line) showing an inverse relationship between the two scenarios. The numbers on the orange are permeability values, number on the blue line are porosity values.

The plume side views for the base, high side and low side cases after 3 years of injection are compared in Figure 2-31. The low side case scenario results in a larger overall plume diameter compared to the other two cases. Figure 2-32 shows the CO_2 plume in map view at layer 153, at the end of injection period and 5 and 10 years after the injection stops for the base case scenario. Results of the sensitivity analysis (high side case and low side case) shown in Figure 2-33 for CO_2 plume at layer 153 show that the AoR is smaller compared to base case scenario at the end of injection and post injection. It is also shown in Figure 2-33 that the plume size in the high and low side scenarios remains unchanged after 1 year post injection.

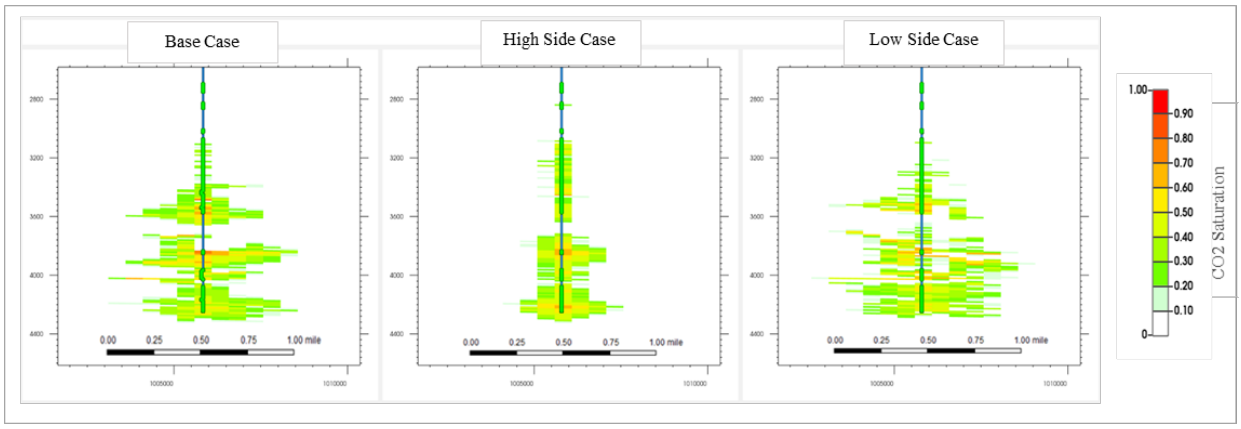


Figure 2-31: CO_2 plume at wellbore cross section after 3 years of injection. The left plume diagram represents the base case, middle represents the high side case, and the right plume diagram represents the low side case.

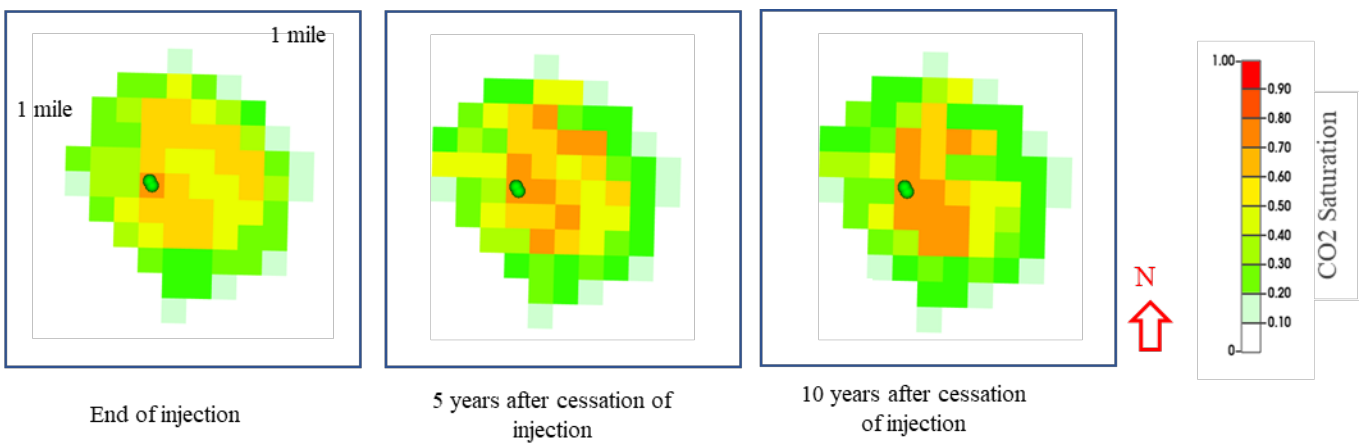


Figure 2-32: CO_2 plume at layer 153 (used to delineate AoR) for the base case at the end of injection, 5 years after injection stopped, and 10 years after injection stopped.

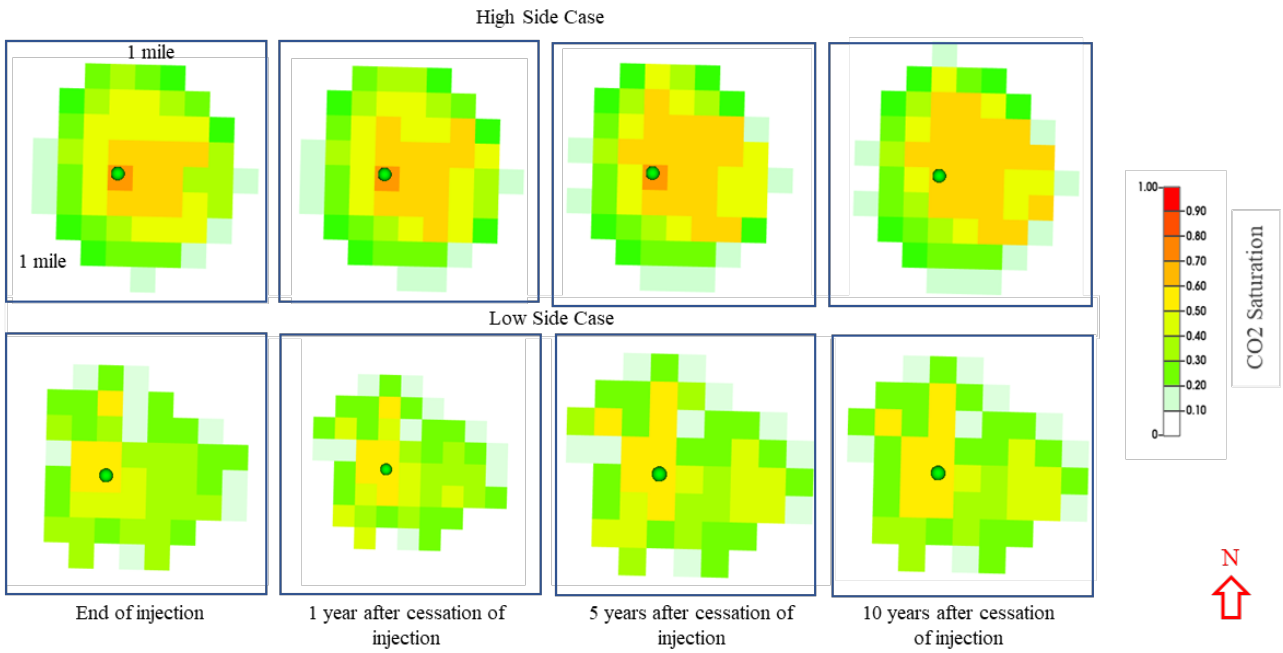


Figure 2-33: CO_2 plume at layer 153 (used to delineate AoR) at the end of injection and after, 1, 5 and 10 years after cessation of injection for the high side case (top row) and low side case (bottom row).

2.3 AoR Delineation

2.3.1 Critical Pressure Calculations

The critical pressure corresponds to the pressure needed to move fluids from the storage formation into a USDW through a hypothetical open conduit such as an uncemented well. Different methods can be used to calculate the required pressure to move fluid from the reservoir into a USDW. A simple hydrostatic head calculation (density of injection zone brine × depth distance between lowest USDW and top of injection zone × gravity constant) was used to estimate such required pressure. Using parameters listed in Table 2-5, the hydrostatic pressure required to move fluid was calculated to be 477 psi for the site. This pressure was calculated based on depth and pressure gradient and is the difference in hydrostatic pressure between the first perforation depth and lowest USDW. The storage formation overpressure would need to increase to values equal to or above 477 psi to move storage formation fluids into the USDW. This method was chosen for critical pressure calculation, since it is expected that pressure will dissipate early after shut-in due to the high permeability in the storage formation.

Input Data (Available)		
Attribute	**Zone**	**Value**
Depth	Deepest known USDW (Gunter)	2,140 ft, MD
	Top of the first injection zone (Mt. Simon Sandstone)	3,226 ft, MD
Pore pressure gradient (to estimate pressure)	All zones	0.44 psi/ft
Input Data (Calculated)		
Attribute	**Zone**	**Value**
Pressure	USDW	956.3 psi
	Topmost injection zone (Mt. Simon Sandstone)	3226 ft, MD

Table 2-5: Input data used for critical pressure calculation.

2.3.2 AoR Delineation

For the purposes of AoR determination, the extent of the CO_2 plume has been assessed at each vertical layer of the storage reservoir in the computational model. As discussed above, the plume size at layer 153 represents the average plume size of all the layers during injection and post-injection. The AoR is established by expanding the plume by 0.25 mi in all directions. Figure 2-34 shows the CO_2 plume extent and AoR delineation predicted by the computational modeling during the project lifetime.

2.4 Corrective Action

2.4.1 Tabulation of Wells within the AoR

Wells within the AoR were identified using well databases held by the ISGS. Available well information indicates that wells inside the AoR are all shallow groundwater wells less than 220 ft MD. A total of seven water wells are present within the AoR. Table 2-6 details these wells and includes the locations, dates drilled, total depths and aquifer depths, and compositions of the aquifers. One of the wells was deepened after being drilled and is represented twice in the table (API 121552046800 and API 121552052200). The wells correlate with the map provided in Figure 2-36, where existing wells are labeled by the corresponding total depth. No wells currently penetrate either the confining or injection zones within the AoR. The only wells in the AoR that will penetrate the confining zone will be wells related to the project. It is not believed that there are any deep historical wells in the area that have not been captured by these data sources.

API Number	Latitude	Longitude	Date Drilled	Total Depth (ft)	Total Depth Lithology	Bedrock top depth (ft)	Aquifer Top Depth (ft)	Aquifer Bottom Depth (ft)	Aquifer Description	Static Water Level (ft)
121552046800	41.263135	-89.30066	3/25/1996	216	SH/CL	216	206	216	S	169
121552052200	41.263135	-89.30066	10/31/1999	195	SH/CL		166	204	S	164
121552076400	41.277758	-89.31269	9/8/2006	210	SH	188	133	187	S	99
121552082100	41.278067	-89.30605	11/18/2007	190	SH	166	138	165	S	80
121552084100	41.27699	-89.30599	2/13/2011	177	SH	175	141	175	SG	86
121552084200	41.277739	-89.3055	4/19/2011	194	SH	192	136	193	SG	78
121552084300	41.27549	-89.3121	5/4/2011	181	SH	180	150	179	SG	74
121552085800	41.271028	-89.29614	7/24/2014	179	S		150	179	S	130

Lithology Key: SH = shale, CL = clay, S = sand, SG = sand & gravel.

Table 2-6: Tabulation of wells within the AoR

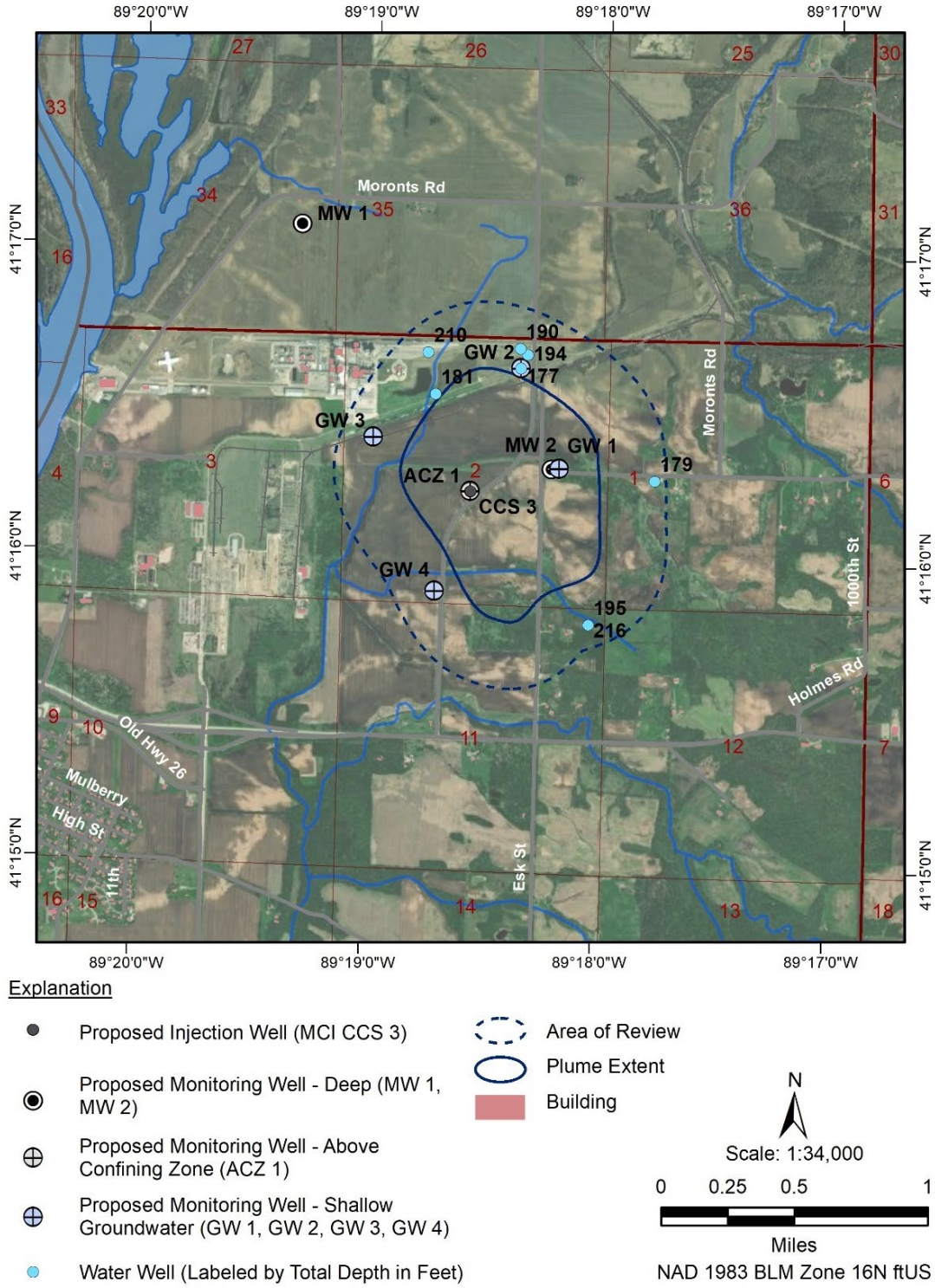


Figure 2-34: Map showing the modeled CO_2 plume footprint, AoR, and existing and proposed project wells within the AoR. Well data is summarized in 2-6.

2.4.2 Wells Penetrating the Confining Zone

The total depths of wells within the AoR were determined using the ISGS well databases. These well databases indicate that no wells within the AoR penetrate the confining zone. The deepest wells within the AoR are shallow groundwater wells less than 220 ft MD. Therefore, no corrective action will be needed.

2.4.3 Plan for Site Access

There are seven shallow groundwater wells (less than 220 ft MD) within the AoR. Five of the wells are located on property owned by Marquis. The other two wells are located within the AoR but outside of the CO_2 plume. However, of the existing seven wells, only one of the wells has been designated for purposes of shallow groundwater monitoring. Three additional shallow groundwater wells will be drilled within the AoR on land owned by Marquis. Because the wells are located on flat farmland owned by Marquis in a location that is free of obstructions and away from residential areas, the shallow groundwater monitoring wells are easily accessible.

Additionally, since none of the existing or future groundwater wells within the AoR have total depths deeper than 220 ft MD, there are no wells within the AoR that penetrate the Eau Claire Shale. Therefore, no corrective action activities have been proposed as part of the Marquis BioCarbon Project.

2.4.4 Corrective Action Schedule

It is not expected that any of the groundwater wells in the AoR will require corrective action. No corrective action schedule has been developed due to the absence of wells penetrating the confining zone within the AoR. The AoR will be re-evaluated every five years during the injection and post-injection phases unless an event occurs that triggers an AoR re-evaluation sooner. If the results of testing and monitoring and/or AoR re-evaluation throughout the project lifecycle indicate potential interference with any wells penetrating the confining zone, an amended corrective action plan will be implemented and submitted to the EPA (40 CFR 146.84 (e)(4)).

2.5 Re-evaluation Schedule and Criteria

2.5.1 AoR Re-evaluation Cycle

Marquis BioCarbon Project will re-evaluate the above described AoR every five years during the injection and post-injection phases pursuant to 146.84 (e).

The workflow (procedures) for incorporating the new data into the models as the project progresses is detailed in Figure 2-35.

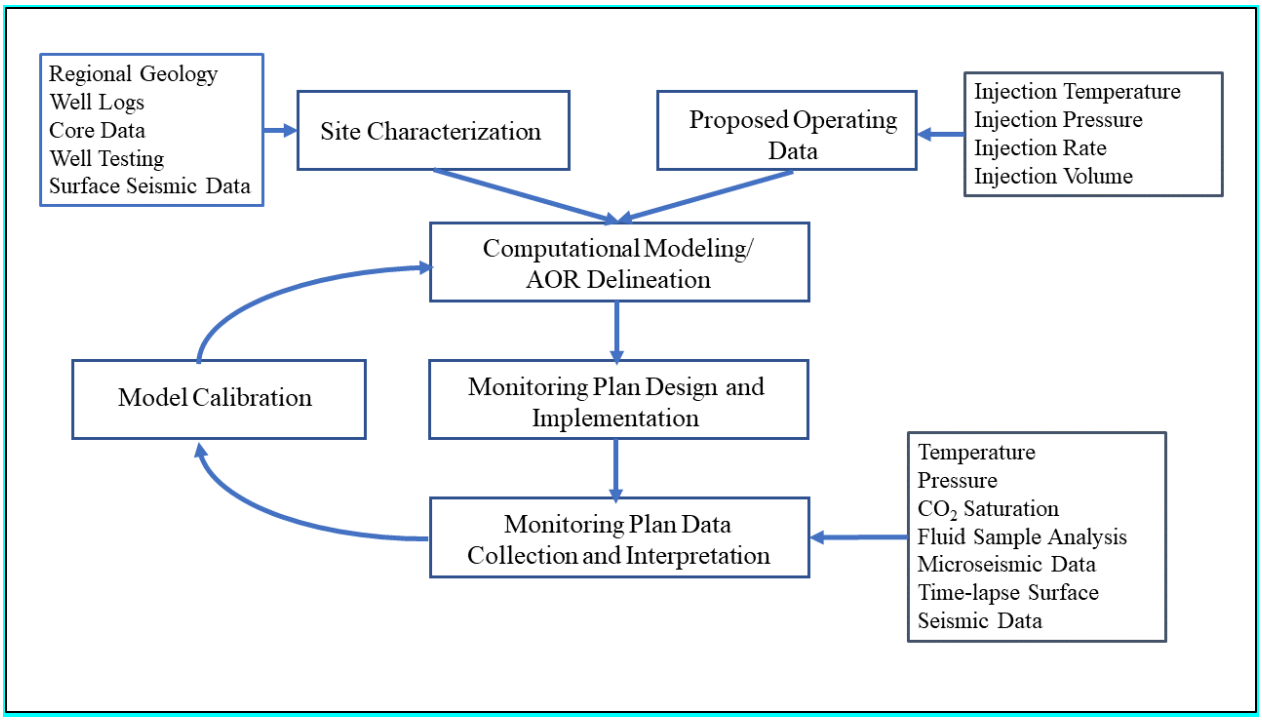


Figure 2-35: Workflow used to update the SEM and computational modeling.

With new data, model refinement is anticipated. The comparison of the original modeling with the updated modeling can take the form of several key evaluation metrics. This includes a comparison of:

- Changes to the static CO_2 resource estimate
- Differences in CO_2 plume geometry and volume
- Changes in pressure response

Any updates to the AOR will include an assessment of any additional wells that might be in the re-evaluated AoR that may need corrective action as well as an amended AoR and corrective action plan (40 CFR 146.84 (e)).

Once the injection phase of the project commences, both operational and verification monitoring data will be used to calibrate and update the computational model. Figure 2-35 illustrates the workflow and data inputs used to inform and calibrate the computational modeling. Operational monitoring data will be recorded on a continuous basis through the injection phase of the project. Pressure sensors located in the Mt. Simon Sandstone in the MCI MW 2 well will be retrieved on a quarterly basis for data download. In addition, pulsed neutron logs will be acquired in the MCI MW 2 well on a yearly basis to monitor CO_2 saturations along the well bores. The pressure and CO_2 saturation data from the MCI MW 2 well will be particularly useful in calibrating the computational model, as it will provide data on how the pressure plume is propagating through the Mt. Simon Sandstone away from the injection well. Computational model updates are also

expected to occur when the time-lapse surface seismic data are acquired on a four-year schedule. For more details on the Testing and Monitoring Plan and schedule refer to Permit Section 7.

The computational modeling will be updated with the downhole pressure and operational monitoring data on a quarterly basis for the first year of injection. If the system stabilizes, model updates will be scaled back to semi-annual updates to coincide with EPA reporting requirements (40 CFR 146.01). Any significant divergence of the monitoring data from the model predictions will be identified during the regular model updates and investigated. Model calibration with early monitoring data is expected to improve model predictions over the course of injection. It should be noted that model history-matching and calibration are not expected to trigger AoR reevaluations on a regular basis.

2.5.2 Triggers for AoR Reevaluations Prior to the Next Scheduled Reevaluation

The AoR will be updated on a 5-year schedule. However, Marquis Carbon Injection LLC will discuss any events that could impact the AoR with the UIC Director to determine if an AoR re-evaluation is required. If an unscheduled re-evaluation is triggered, Marquis Carbon Injection LLC will perform the steps described at the beginning of this section of this Plan. A report will be submitted to the UIC Director within 90 days of the AoR re-evaluation.
Monitoring and operational conditions that may warrant a re-evaluation of the AoR include (EPA, 2013):

- Changes in site operations that might alter the model predictions or the AoR delineation
- Site characterization data that may significantly change the computational model predictions and delineated AoR
- Monitoring results that indicate that the areal extent of the CO_2 plume or pressure front differ significantly from the model predictions
- Monitoring results indicate that the CO_2 has migrated beyond the confining zone

Table 2-7 details the operational changes and site characterization data that may warrant a reevaluation of the AoR. Table 2-8 specifies the observed changes and monitoring technologies that may trigger a re-evaluation of the AoR. Refer to the Testing and Monitoring Plan for more details on the proposed monitoring technologies for the project (Permit Section 7).

Area of Change	Variable
Operational Changes	• Increase in number of Class VI injection wells injecting in the Mt. Simon Sandstone in the immediate project area • Increase in CO_2 injection rates or volumes • Injection pressures more than the maximum allowable injection pressure for the project
Site Characterization Data	• Identification of a potential conduit for CO_2 or brine migration through the confining zone • Further characterization of storage formation heterogeneity that significantly effects CO_2 and pressure plume development

Table 2-7: Changes in operations and site characterization that may trigger AoR re-evaluation.

Observed Change	Monitoring Technology
Significantly larger pressure increases in the Mt. Simon Sandstone in the monitor well than were predicted by the model	Pressure sensors
Early breakthrough of CO_2 at the monitor well	Fluid sampling Pulsed neutron logging
CO_2 plume expands much faster than predicted by model	Time-lapse surface seismic data
Sustained pressure increases observed in above confining zone (ACZ) monitoring intervals	Pressure sensors
Geochemical changes in the ACZ monitoring intervals indicate potential CO_2 or brine migrations above the confining layer	Fluid sampling
CO_2 accumulations identified in the ACZ intervals	Pulsed neutron logging Time-lapse surface seismic data

Table 2-8: Observed changes in monitoring data that may trigger an AoR re-evaluation.

If the re-evaluated AoR is substantially different from the previous AoR, the project will identify all active and abandoned wells that penetrate the confining zone in the re-evaluated AoR and will perform corrective actions on those wells (40 CFR 146.84 (e)). As needed, all other plans, such as the Emergency and Remedial Response Plan, will be revised to account for the re-evaluated AoR and will submit those plans to the UIC Director for review and approval (40 CFR 146.84 (f)).

Note that seismic events are covered under the Emergency and Remedial Response Plan. A tiered approach to responding to seismic events will be based on magnitude and location. A notification procedure is provided in that plan.

2.6 References

Atherton, E., 1971, Tectonic development of the Eastern Interior Region of the United States: Illinois State Geological Survey Illinois Petroleum 96, p. 29-43.

Birkholzer JT, Nicot JP, Oldenburg CM, Zhou Q, Kraemer S, Bandilla K. Brine flow up a well caused by pressure perturbation from geologic carbon sequestration: Static and dynamic evaluations. International journal of greenhouse gas control 2011;5(4):850-61.

Burger C, Wortman D, Brown C, Hassan S, Humphreys K, Willford M. FutureGen 2.0 Pipeline and Regional Carbon Capture Storage Project-Final Report. Futuregen Industrial Alliance, Inc., Washington, DC (United States); 2016.

CMG-GEM. Advance compositional and GHG reservoir simulator user's guide. Calgary, Alberta 2016.

Cornet F. Results from the In-Situ Stress Characterization Program, Phase 1: Geomechanical Tests Conducted in the FutureGen Stratigraphic Well (FGA#1). The FutureGen Industrial Alliance, Inc. 2014.

DOE/EIS-0460. Final Environmental Impact Statement for the FutureGen 2.0 Project, Morgan County, Illinois. 2013.

Engelder T. Stress regimes in the lithosphere: Princeton University Press, 1992.
Enick RM, Klara SM. CO_2 solubility in water and brine under reservoir conditions. Chemical Engineering Communications 1990;90(1):23-33.

Fischietto NE. Lithofacies and Depositional Environments of the Cambrian Mount Simon Sandstone in the Northern Illinois Basin: Implications for CO_2 Sequestration (M.S. thesis, Purdue University); 2009.

Freiburg JT, Holland ME, Malone DH, Malone SJ. Detrital zircon geochronology of basal Cambrian strata in the deep Illinois Basin, USA: evidence for the Paleoproterozoic-Cambrian tectonic and sedimentary evolution of central Laurentia. The Journal of Geology. 2020 May 1;128(3):303-17.

Freiburg JT, Morse DG, Leetaru HE, Hoss RP, Yan Q. A Depositional and Diagenetic Characterization of the Mt. Simon Sandstone at the Illinois Basin - Decatur Project Carbon Capture and Storage Site, Decatur, Illinois, USA. Illinois State Geological Survey Circular 583. 2014

FutureGen Alliance, 2013, Underground Injection Control Permit Applications for FutureGen 2.0 Morgan County Class VI UIC Wells 1, 2, 3, and 4, FG-RPT-017.

Hall HN. Compressibility of reservoir rocks. Journal of Petroleum Technology 1953;5(01):17-9.

Jahediesfanjani H, Warwick PD, Anderson ST. 3D Pressure-limited approach to model and estimate CO_2 injection and storage capacity: saline Mount Simon Formation. Greenhouse Gases: Science and Technology 2017;7(6):1080-96.

Kestin J, Khalifa HE, Correia RJ. Tables of the dynamic and kinematic viscosity of aqueous NaCl solutions in the temperature range 20–150 C and the pressure range 0.1–35 MPa. Journal of physical and chemical reference data 1981;10(1):71-88.

Krevor SC, Pini R, Zuo L, Benson SM. Relative permeability and trapping of CO_2 and water in sandstone rocks at reservoir conditions. Water resources research 2012;48(2).

Kumar A, Noh M, Pope G, Sepehrnoori K, Bryant S, Lake L. Reservoir simulation of CO_2 storage in deep saline aquifers. SPE/DOE Symposium on Improved Oil Recovery: Society of Petroleum Engineers; 2004.

Land CS. Calculation of imbibition relative permeability for two-and three-phase flow from rock properties. Society of Petroleum Engineers Journal 1968;8(02):149-56.

Li YK, Nghiem LX. Phase equilibria of oil, gas and water/brine mixtures from a cubic equation of state and Henry's law. The Canadian Journal of Chemical Engineering 1986;64(3):486-96.

Lovell TR. An Intracratonic Record of North American Tectonics (Doctoral dissertation, Purdue University); 2017.

McCutcheon SC, Martin J, Barnwell T, Maidment D. Handbook of hydrology. Handbook of hydrology New York: McGraw-Hill 1993.

Mehnert E, Weberling PH. Groundwater Salinity within the Mt. Simon Sandstone in Illinois and Indiana. Illinois State Geological Survey, Prairie Research Institute.; 2014.

Nelson WJ. Structural features in Illinois. Illinois State Geological Survey, Bulletin no. 100. 1995.

Nghiem L, Sammon P, Grabenstetter J, Ohkuma H. Modeling CO_2 storage in aquifers with a fully-coupled geochemical EOS compositional simulator. SPE/DOE symposium on improved oil recovery: Society of Petroleum Engineers; 2004.

Nghiem L, Shrivastava V, Tran D, Kohse B, Hassam M, Yang C. Simulation of CO_2 storage in saline aquifers. SPE/EAGE Reservoir Characterization & Simulation Conference: European Association of Geoscientists & Engineers; 2009a. p. cp-170-00063.

Nghiem L, Shrivastava V, Tran D, Kohse B, Hassam M, Yang C. Simulation of CO_2 storage in saline aquifers. SPE/EAGE Reservoir Characterization & Simulation Conference2009b.

Nicot J-P, Oldenburg CM, Bryant SL, Hovorka SD. Pressure perturbations from geologic carbon sequestration: Area-of-review boundaries and borehole leakage driving forces. Energy Procedia 2009;1(1):47-54.

Palkovic MJ. Depositional characterization of the Eau Claire Formation at the Illinois Basin-Decatur Project: facies, mineralogy and geochemistry (M.S. thesis, University of Illinois at Urbana-Champaign); 2015.

Peng D-Y, Robinson DB. A new two-constant equation of state. Industrial & Engineering Chemistry Fundamentals 1976;15(1):59-64.

Raziperchikolaee S, Alvarado V, Yin S. Effect of hydraulic fracturing on long-term storage of CO_2 in stimulated saline aquifers. Applied energy 2013;102:1091-104.

Reesink AJ, Best J, Freiburg JT, Webb ND, Monson CC, Ritzi RW. Interpreting pre-vegetation landscape dynamics: The Cambrian Lower Mount Simon Sandstone, Illinois, USA. Journal of Sedimentary Research. 2020 Nov;90(11):1614-41.

Rowe Jr AM, Chou JC. Pressure-volume-temperature-concentration relation of aqueous sodium chloride solutions. Journal of Chemical and Engineering Data 1970;15(1):61-6.

Roy P, Morris JP, Walsh SD, Iyer J, Carroll S. Effect of thermal stress on wellbore integrity during CO_2 injection. International Journal of Greenhouse Gas Control 2018;77:14-26.

United States Environmental Protection Agency. Geologic Sequestration of Carbon Dioxide: Underground Injection Control (UIC) Program Class VI Well Area of Review Evaluation and Corrective Action Guidance. 2013: 96 p.

Willman, H.B., Atherton, E., Buschbach, T.C., Collinson, C., Frye, J.C., Hopkins, M.E. Lineback, J.A. and Simon, J.A. 1975. Handbook of Illinois Stratigraphy. Champaign, Illinois: Illinois State Geological Survey, Bulletin 95.

2.0 AREA OF REVIEW AND CORRECTIVE ACTION PLAN 40 CFR 146.84(b)

MARQUIS BIOCARBON PROJECT

Facility Information

Facility name:	MARQUIS BIOCARBON PROJECT
Facility contact:	ELIZABETH STEINHOUR DIRECTOR OF ENVIRONMENTAL AFFAIRS 10000 MARQUIS DRIVE, HENNEPIN, IL 61327 815.925.7300 / BETHSTEINHOUR@MARQUISENERGY.COM
Well name:	MCI CCS 3
Well location:	PUTNAM COUNTY, ILLINOIS S2 T32N R2W Latitude: 41.27026520 N, Longitude: 89.30939322 W

Table of Contents

2.0 AoR and Corrective Action Plan 6
2.1 Computational Modeling Approach 6
2.1.1 Model Background 6
2.1.2 Site Geology and Hydrology 7
2.1.3 Model Domain 20
2.1.4 Porosity and Permeability 22
2.1.5 Constitutive Relationships and Other Rock Properties 26
2.1.6 Boundary Conditions 27
2.1.7 Initial Conditions 27
2.1.8 Operational Information 28
2.1.9 Fracture Pressure and Fracture Gradient 29
2.2 Computational Modeling Results 29
2.2.1 Predictions of System Behavior 29
2.2.2 Model Calibration and Validation 38
2.3 AoR Delineation 40
2.3.1 Critical Pressure Calculations 40
2.3.2 AoR Delineation 41
2.4 Corrective Action 41
2.4.1 Tabulation of Wells within the AoR 41
2.4.2 Wells Penetrating the Confining Zone 44
2.4.3 Plan for Site Access 44
2.4.4 Corrective Action Schedule 44
2.5 Re-evaluation Schedule and Criteria 44
2.5.1 AoR Re-evaluation Cycle 44
2.5.2 Triggers for AoR Reevaluations Prior to the Next Scheduled Reevaluation 46
2.6 References 48

List of Tables

Table 2-1: Model domain information. 21
Table 2-2: Initial conditions. 28
Table 2-3: Operating details. 28
Table 2-4: Injection pressure details. 29
Table 2-5: Input data used for critical pressure calculation. 41
Table 2-6: Tabulation of wells within the AoR 42
Table 2-7: Changes in operations and site characterization that may trigger AoR re-evaluation. 47
Table 2-8: Observed changes in monitoring data that may trigger an AoR re-evaluation. 47

List of Figures

Figure 2-1: Stratigraphic column with lithology and hydrostratigraphy for the Marquis BioCarbon Project site based on data from the characterization well, MCI MW 1. 8
Figure 2-2: Precambrian basement elevation map. Modified from Willman et al. (1975). 9
Figure 2-3: Mt. Simon Sandstone elevation map over the west-central portion of the Illinois Basin. Modified from FutureGen Alliance (2013). 10
Figure 2-4: Mt. Simon Sandstone thickness map over the west-central portion of the Illinois Basin. Modified from FutureGen Alliance (2013). 11
Figure 2-5: Eau Claire elevation map over the west-central portion of the Illinois Basin. Modified from FutureGen Alliance (2013). 12
Figure 2-6: Eau Claire Eau Claire thickness map. Modified from Willman et al. (1975). 13
Figure 2-7: Map showing the analog well locations used in depositional environment interpretations to the north and south of the Marquis BioCarbon Project site. 14
Figure 2-8: Regional depositional model for the Mt. Simon Sandstone. Broad fluvial braid systems feed into a shallow inland sea. Sediments on inactive braid plaids are reworked by eolian processes. Sediment source is primarily from the north. Modified from Fischietto (2009). 15
Figure 2-9: Interpreted Mt. Simon depositional environments and corresponding intraformational zones. 16
Figure 2-10: Example conceptual schematic drawing of the Mt. Simon Zone 5 representing the eolian depositional environment and interpreted orientations at the Marquis site (not to scale), as well as representative bedding features in whole acquired from Mt. Simon Zone 5. Modified from Freiburg et al. (2020). 17
Figure 2-11: Principle geologic structures of Illinois. Modified from Willman et al. (1975). 18

Figure 2-12: Geologic cross sections near Putnam County featuring the structural configuration of Cambrian strata that contains the target injection zone and caprock. The locations of these cross-section lines are shown in Figure 2-11. Modified from Willman et al. (1975). 20

Figure 2-13: Static Earth Model 7-mile by 7-mile boundary centered around the MCI CCS 3 well. 21

Figure 2-14: Model Zones and corresponding gamma ray, resistivity, and porosity logs. Lower part of the Elmhurst and the entire Mt. Simon are considered reservoir, while the upper Elmhurst and Eau Claire shale act as the seal. 22

Figure 2-15: Histograms of porosity ranges by facies type showing correlative distributions for the clean sand, dirty sand, and shale facies. Distinctly different distributions for clean sand and dirty sand in Mt. Simons 2 and 3, where normal distribution means are lower. 23

Figure 2-16: Final (a) porosity and (b) permeability properties showing the effect of depositional constraints on spatial property distribution within the 3D geocellular model. 24

Figure 2-17: Logs at the MCI MW-1 well showing (left to right) gamma ray, stratigraphic zone, confining unit or injection interval, whole core, sidewall core, porosity, flow-based facies, and permeability. There is a match between the model (blocky colors) and the log (black line) for porosity and permeability, and core-measured permeability points plotted on the permeability track in magenta show strong correlation to NMR-based log values. 25

Figure 2-18: Porosity-Permeability cross-plot colored by flow facies showing the utilization of two different transforms, applied by flow-based rock classifications. 26

Figure 2-19: Relative Permeability Curves imported into dynamic reservoir model. The plot on the left was assigned to high-flow sands, the plot in the middle was assigned to mid-flow sands and the plot on the right was assigned to low-flow sands. 27

Figure 2-20: Map view of computational model with zoomed well grid (top) and cross section of the model (below). 30

Figure 2-21: Development of CO_2 plume after 1 year (top), 3 years (middle), and 5 years (lower) of injection. 31

Figure 2-22: CO_2 plume 3, 5, 10 and 50 years after cessation of injection. 33

Figure 2-23: CO_2 plume after 5 years of injection in plan view for layers 111, 129, 153 and 186. 33

Figure 2-24: Development of CO_2 plume after 1 year, 3 years, and 5 years of injection at layer 153 representing the AoR. 34

Figure 2-25: CO_2 plume mapping 3 year, 5 years, 10 years, 30 years, and 50 years after cessation of at layer 153 (representing the AoR). 34

Figure 2-26: Pressure front after 1, 3 and 5 years of injection using 150 psi pressure cut-off. 36

Figure 2-27: Pressure time-series data during injection and 50 years of post-injection period at depth of middle perforation (model layer 153, 3,833 TVDSS, ft.) 36

Figure 2-28: Pressure time-series data during injection and post injection period for monitoring (MCI MW 2) and injection well (MCI CCS 3) location at layer 153, 3,833 TVDSS, ft. 37

Figure 2-29: CO_2 saturation time-series data during injection and post injection period for monitoring and injection well location at layer 153 with MSL of 3,833 ft 37

Figure 2-30: Porosity and permeability relationships for high side case (orange line) and low side case (blue line) showing an inverse relationship between the two scenarios. The numbers on the orange are permeability values, number on the blue line are porosity values. 38

Figure 2-31: CO_2 plume at wellbore cross section after 3 years of injection. The left plume diagram represents the base case, middle represents the high side case, and the right plume diagram represents the low side case. 39

Figure 2-32: CO_2 plume at layer 153 (used to delineate AoR) for the base case at the end of injection, 5 years after injection stopped, and 10 years after injection stopped. 39

Figure 2-33: CO_2 plume at layer 153 (used to delineate AoR) at the end of injection and after, 1, 5 and 10 years after cessation of injection for the high side case (top row) and low side case (bottom row). 40

Figure 2-34: Map showing the modeled CO_2 plume footprint, AoR, and existing and proposed project wells within the AoR. Well data is summarized in 2-6. 43

Figure 2-35: Workflow used to update the SEM and computational modeling. 45

2.0 AoR and Corrective Action Plan

2.1 Computational Modeling Approach

2.1.1 Model Background

Computational modeling at the Marquis BioCarbon Project site was completed to delineate the plume size and shape, area of pressure buildup, and Area of Review (AoR) for injected carbon dioxide (CO_2). A static earth model (SEM) named Marquis_SEM_1 was prepared by Battelle using the Schlumberger Petrel® modeling software. The SEM is a three-dimensional (3D) geocellular model that represents petrophysical properties within the stratigraphic formation intended for CO_2 storage, as well as the overlying confining layer. This type of model offers the best options for quantifying, visualizing, and simulating dynamic behavior through the subsurface geology at the site. By integrating multiple data types, the model represents the spatial distribution of available pore space and flow potential (permeability), enabling a data-driven estimation of CO_2 storage capacity. The SEM serves as the framework (in terms of delineating zones, surfaces, porosity, and permeability) for dynamic simulation of CO_2 injection.

Computational modeling to simulate CO_2 injection into the saline aquifer was completed by Battelle using the 3D multiphase flow simulator CMG-GEM version 2016 (CMG-GEM, 2016). In addition to the geological framework and associated properties imported from the SEM, parameters such as relative permeability, initial reservoir conditions, phase behavior, and well completion were added to the dynamic model for simulation. CMG-GEM is an equation-of-state based compositional simulator that models the phase behavior of brine and CO_2 plumes during the injection and post-injection stages of a project.

Aqueous, gaseous, and supercritical phases of CO_2 were accounted for in the computational model. Component transport equations, which describe the thermodynamic equilibrium between gaseous or supercritical with aqueous phases, were used in the compositional simulator to model CO_2 injection into the saline aquifer (Nghiem et al., 2004). The Peng-Robinson equation of state was used to model the fluid properties of the injected CO_2 in gaseous/supercritical phases (Peng and Robinson, 1976). The solubility of the injected CO_2 in brine is modeled as a phase equilibrium process, which is computed using Henry's law to estimate the fugacity of the gaseous and aqueous phases as functions of pressure and temperature (Li and Nghiem, 1986; Enick and Klara, 1990; Nghiem et al., 2009a). Additionally, the viscosity and density of the aqueous phase were calculated as functions of pressure, temperature, and salinity. Rowe and Chow (1970) equation was used to estimate aqueous phase density, and the Kestin et al. (1981) correlation was used to estimate the viscosity of the aqueous fluids.

2.1.2 Site Geology and Hydrology

The subsurface geologic and hydrologic data analyzed in this study were acquired from the nearby characterization well, MCI MW 1, drilled in 2021. The characterization data types, and depth coverages are detailed in the Pre-Operational Testing Program (Permit Section 5). Publicly available geologic and hydrologic data in the region, as well as well data, were compiled from well databases held by the Illinois State Geological Survey (ISGS).

The Marquis BioCarbon Project site is structurally located on the northern edge of the elliptically shaped, northwest-southeast trending Illinois Basin in Hennepin, Putnam County, Illinois. This basin contains dominantly marine sedimentary sequences which range in thickness from 1500 feet (ft) to 15,000 ft from north to south. Figure 2-1 shows the stratigraphic succession at the Marquis BioCarbon Project site MCI MW 1 well, along with the proposed injection zone and confining zones and hydrostratigraphy. Except for the Permian, most of the Paleozoic is present. The target injection zone is the regionally extensive Cambrian-age Mt. Simon Sandstone, which is locally more than 1700 ft thick. The lower confining unit is the impermeable Precambrian basement rock, which acted as a structural control during the deposition of the basal sedimentary units. Overlying the Mt. Simon Sandstone are regionally extensive shale units of the primary confining zone, the Cambrian-age Eau Claire Shale. The Mt. Simon Sandstone and the Eau Claire Shale are both laterally extensive and do not pinch-out in the region. Overlying the Eau Claire are thin sandstone units of the Ironton and Galesville Formations and the approximately 950-foot-thick Knox Supergroup.

At the Marquis BioCarbon Project site, the Mt. Simon Sandstone is not considered an underground source of drinking water (USDW) based on salinity samples acquired from the MCI MW 1 well, with total dissolved solids (TDS) concentrations greater than 10,000 milligrams per liter (mg/L) or 10,000 parts per million (ppm). The lowermost USDW is defined locally as the Gunter Sandstone of the Prairie du Chien Group (Knox Supergroup). At the MCI MW 1 well, the base of the Gunter Sandstone is 963 ft above the top of the Mt. Simon. USDWs in the project site range in depth from the Gunter Sandstone (deepest USDW) to shallow, near-surface glacial till aquifers.

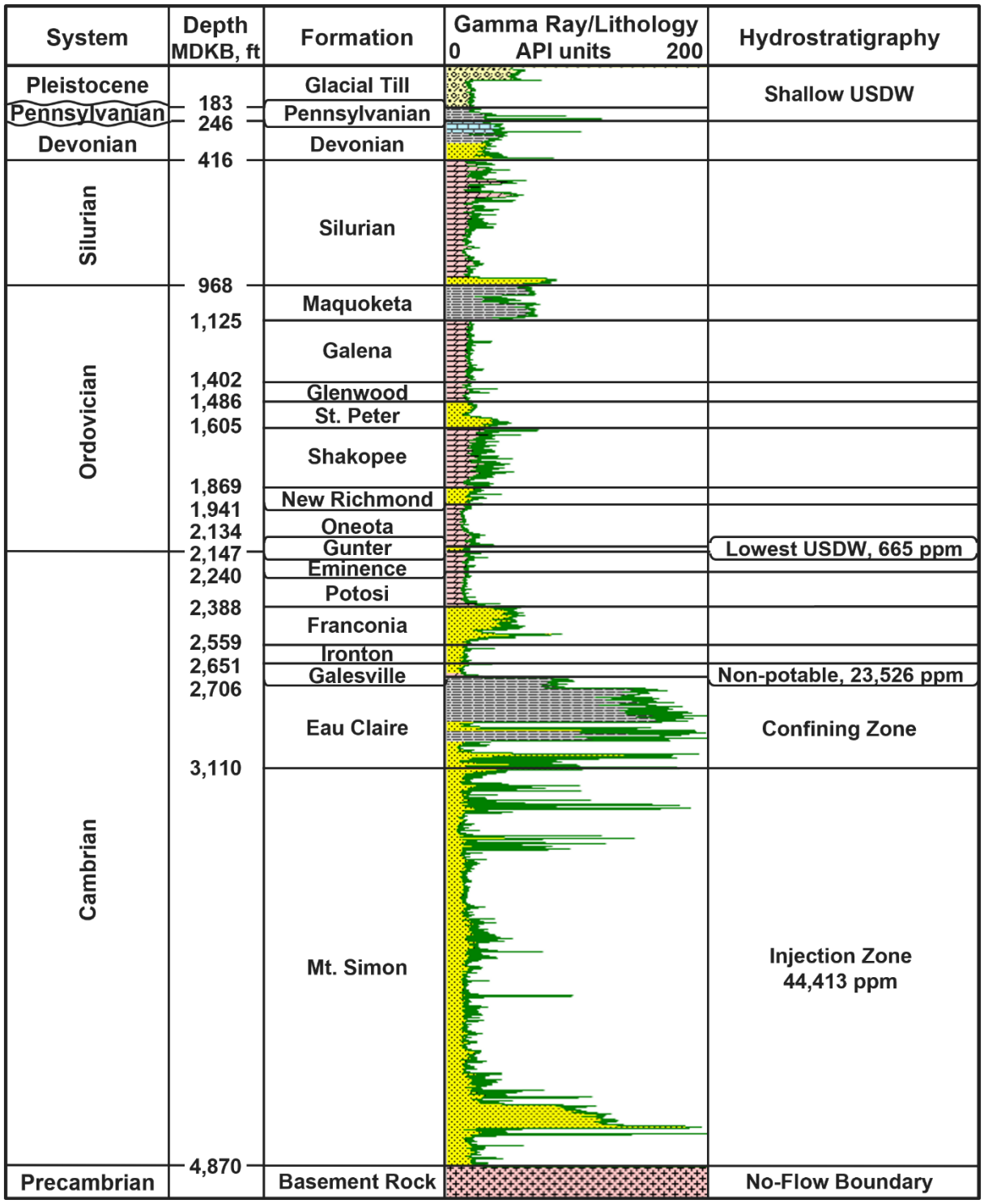


Figure 2-1: Stratigraphic column with lithology and hydrostratigraphy for the Marquis BioCarbon Project site based on data from the characterization well, MCI MW 1.

The Precambrian Granite forms a non-conformable base upon which all the sedimentary strata were deposited and is the oldest rock in the stratigraphic sequence. The structure of the top of the Precambrian basement is illustrated in Figure 2-2. In west-central Illinois the Precambrian basement dips gently to the east-southeast. Substantial local relief is present on the Precambrian surface and is evident as a controlling topography in the subsequent depositional of the Mt. Simon Sandstone (Atherton, 1971). At the MCI MW 1 well, the basement rock is at 4,869 ft measured depth (MD).

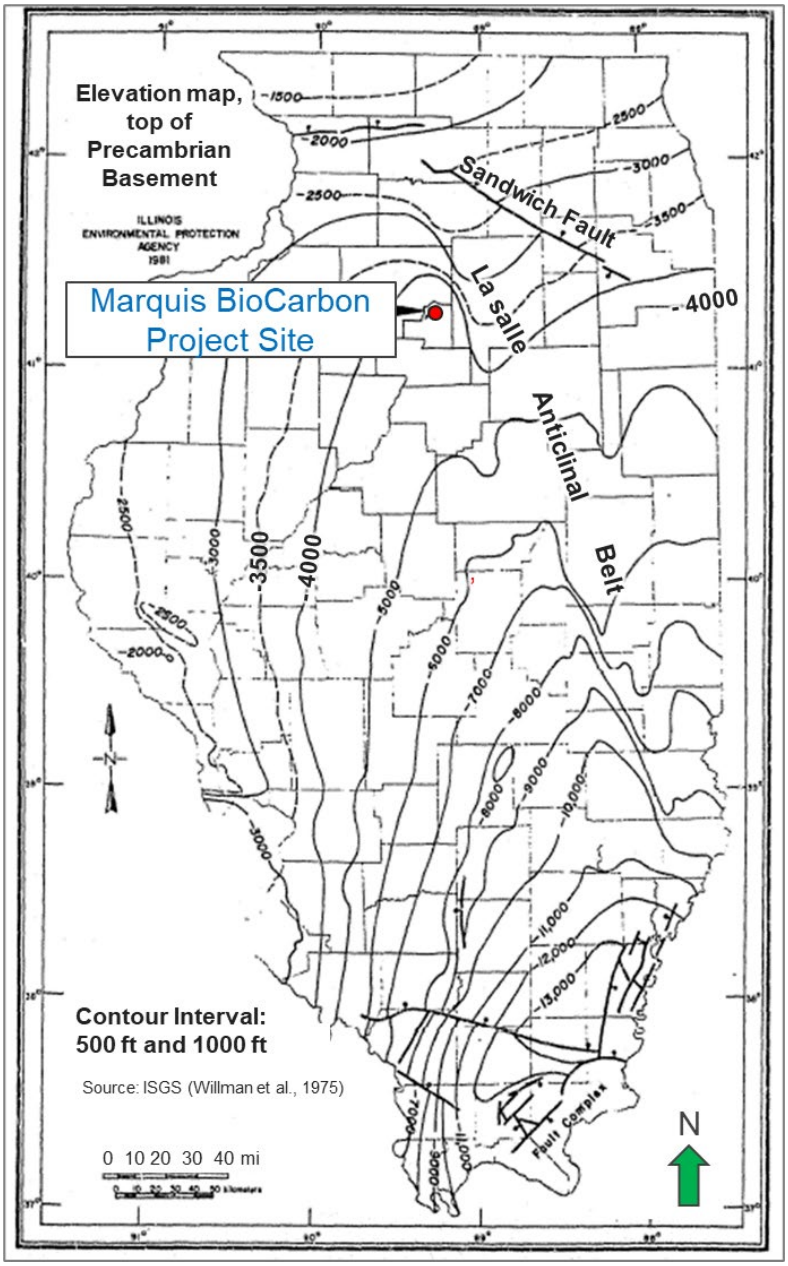


Figure 2-2: Precambrian basement elevation map. Modified from Willman et al. (1975).

The Mt. Simon Sandstone covers an extensive area and is not locally bound by faulting or folding that could pose a constraint to CO_2 injection operations at the Marquis BioCarbon Project site. It consists of porous and permeable, fine to coarse grain, partially pebbly and friable sandstone with minor siltstone and conglomerate. The depositional thickness of the Mt. Simon is not concentric with its structural top (Figure 2-3 and Figure 2-4). A post-Cambrian shift in basin subsidence gradually caused the center of the basin to migrate southeast. While the Mt. Simon deepens to the southeast, it thins from over 2000 ft thick in the northeastern portion of the state to less than 500 ft thick in the southwest. Locally, the Mt. Simon Sandstone is 3,110 ft MD and 1,760 ft thick in the MCI MW 1 well and has a shallow dip of 28 ft per mile (mi) to the southeast. This equates to a shallow grade of 0.53%, which limits the effect that formation dip has on CO_2 migration distance.

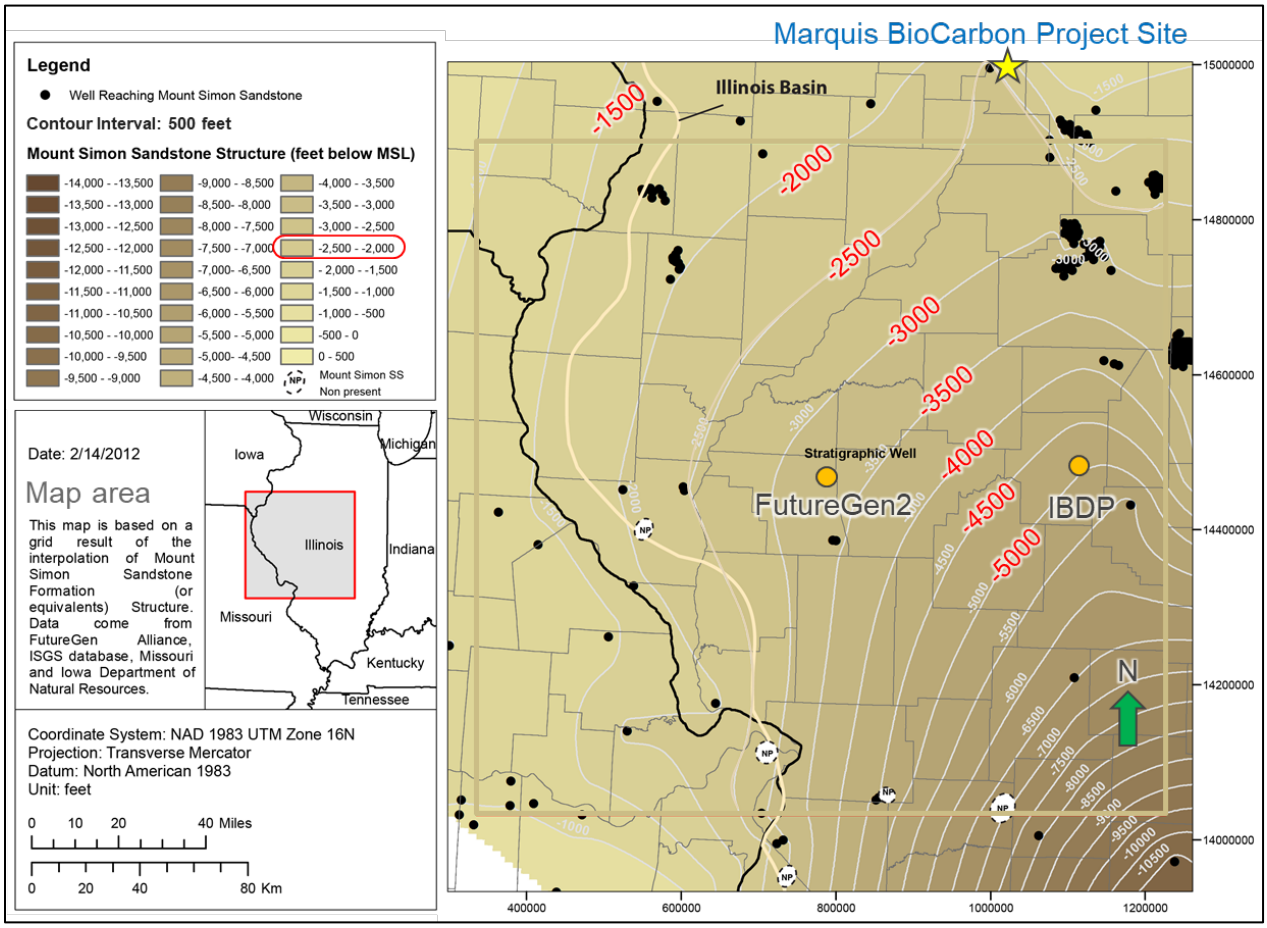


Figure 2-3: Mt. Simon Sandstone elevation map over the west-central portion of the Illinois Basin. Modified from FutureGen Alliance (2013).

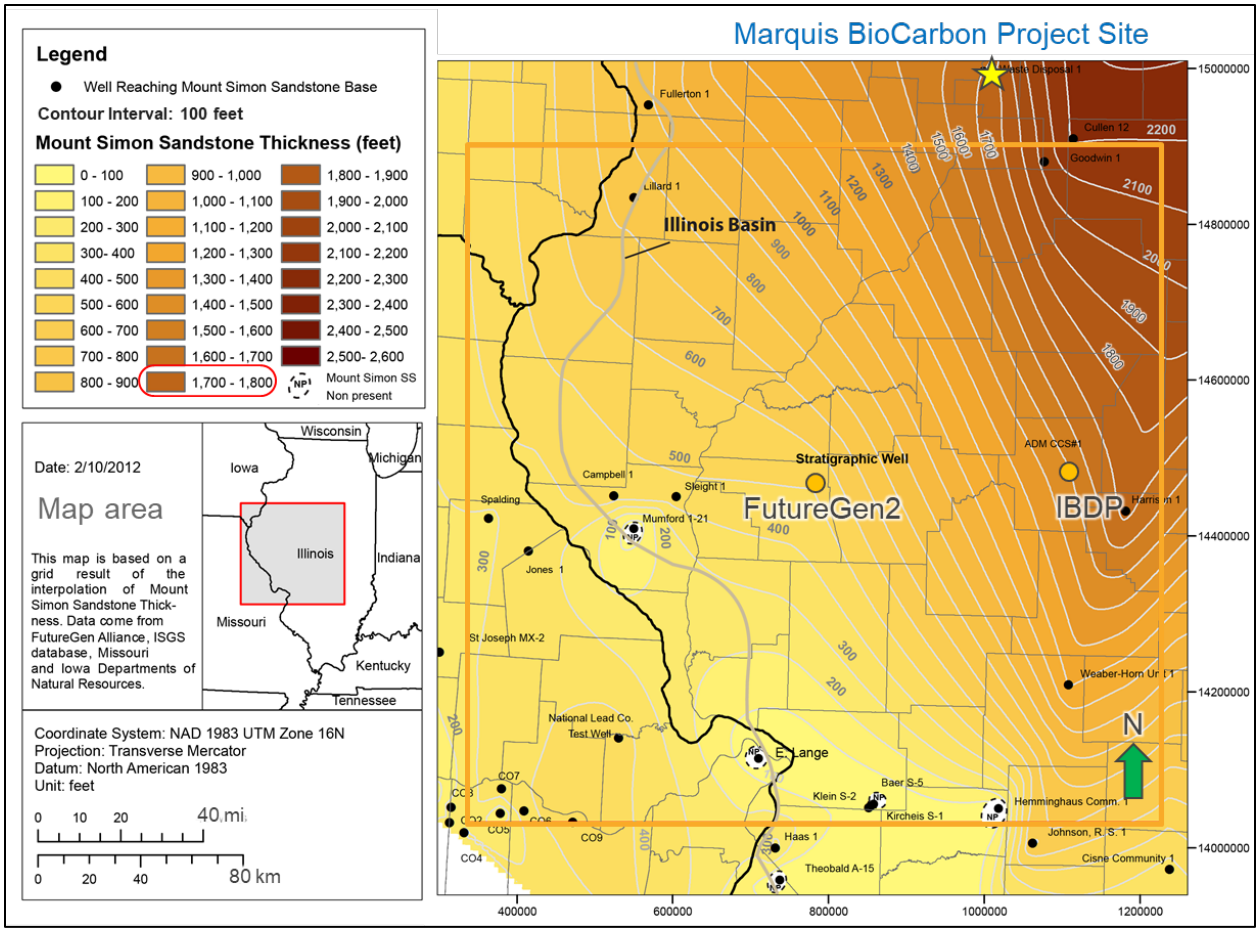


Figure 2-4: Mt. Simon Sandstone thickness map over the west-central portion of the Illinois Basin. Modified from FutureGen Alliance (2013).

The Eau Claire formation consists of interbedded shales, siltstones, sandstones, and minor dolomites. A basal Eau Claire sandstone member, the Elmhurst Sandstone, sits at 2983 ft MD and is comprised of 127 ft of fine to medium grained sandstone with interbedded siltstones and gray shales. The thickness of the Eau Claire formation varies regionally from less than 300 ft in western Illinois to more than 1,000 ft in southeastern Illinois (Figure 2-6). Locally, the Eau Claire is 404 ft thick at the MCI MW 1 well, with 350 ft of the formation characterized as confining zone for the Marquis BioCarbon Project site. The confining zone is defined by the top of the Eau Claire (2706 ft MD at MCI MW 1) through an 11-foot-thick shale in the upper Elmhurst (3043–3054 ft MD) as shown in Figure 2-14. Confining zone properties were confirmed based on core analysis from MCI MW 1 well. Like the Mt. Simon, the depth of the Eau Claire increases to the southeast (Figure 2-5).

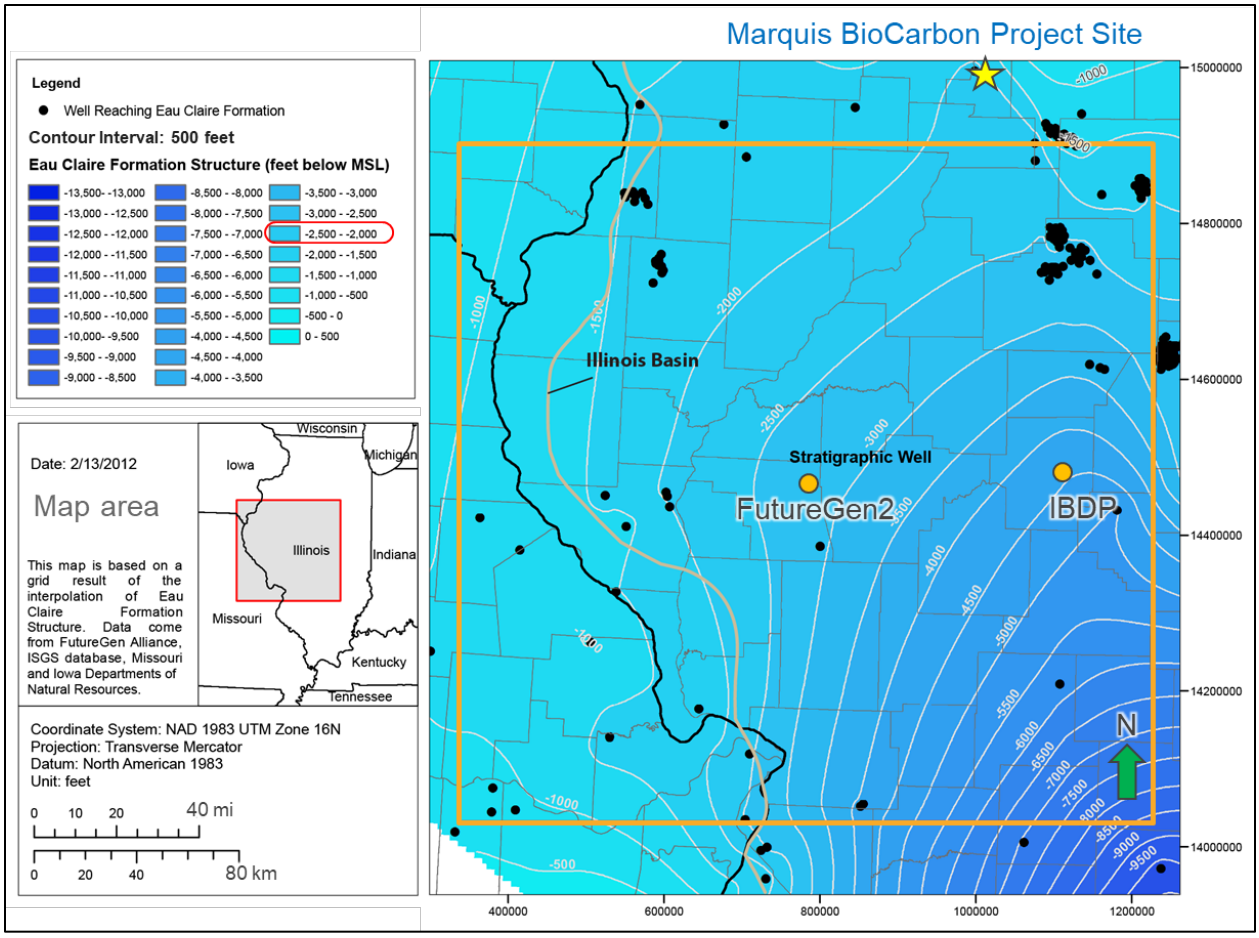


Figure 2-5: Eau Claire elevation map over the west-central portion of the Illinois Basin. Modified from FutureGen Alliance (2013).

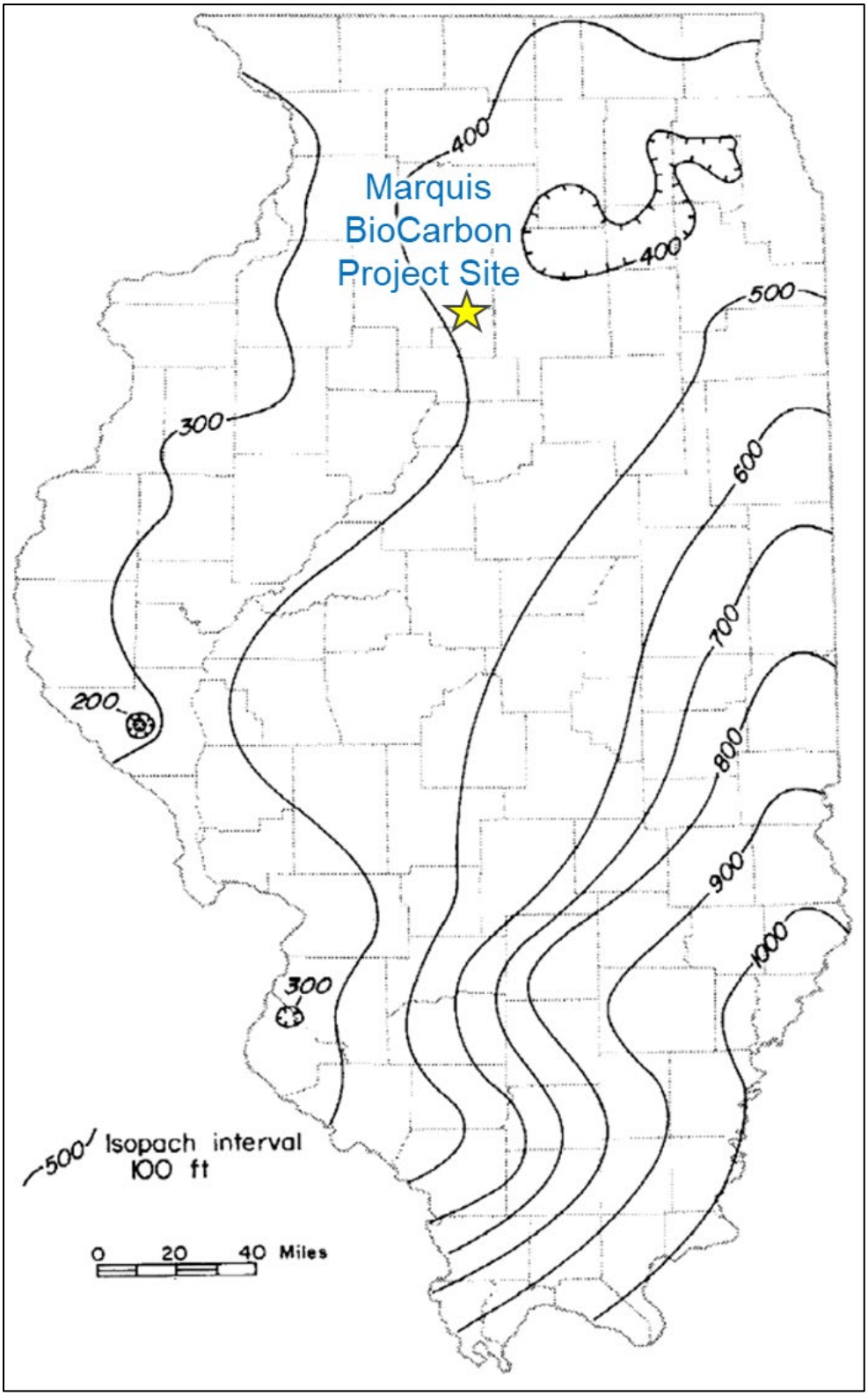


Figure 2-6: Eau Claire Eau Claire thickness map. Modified from Willman et al. (1975).

For the Marquis BioCarbon Project site, interpretations of the Mt. Simon's depositional setting were derived from work associated with the Illinois Basin Decatur Project site in Decatur, Illinois (Palkovic, 2015; Freiburg, 2020; Reesink, 2020), as well previous research on the UPH-3 well in Stephenson County, Illinois (Fischietto, 2009; Lovell, 2017). Previous research on these analog wells have detailed depositional environments, paleogeography, and Precambrian basement structure in the Illinois Basin. The proposed site location falls between these two data points (Figure 2-7), enabling on-site data to be correlated with regional interpretations.

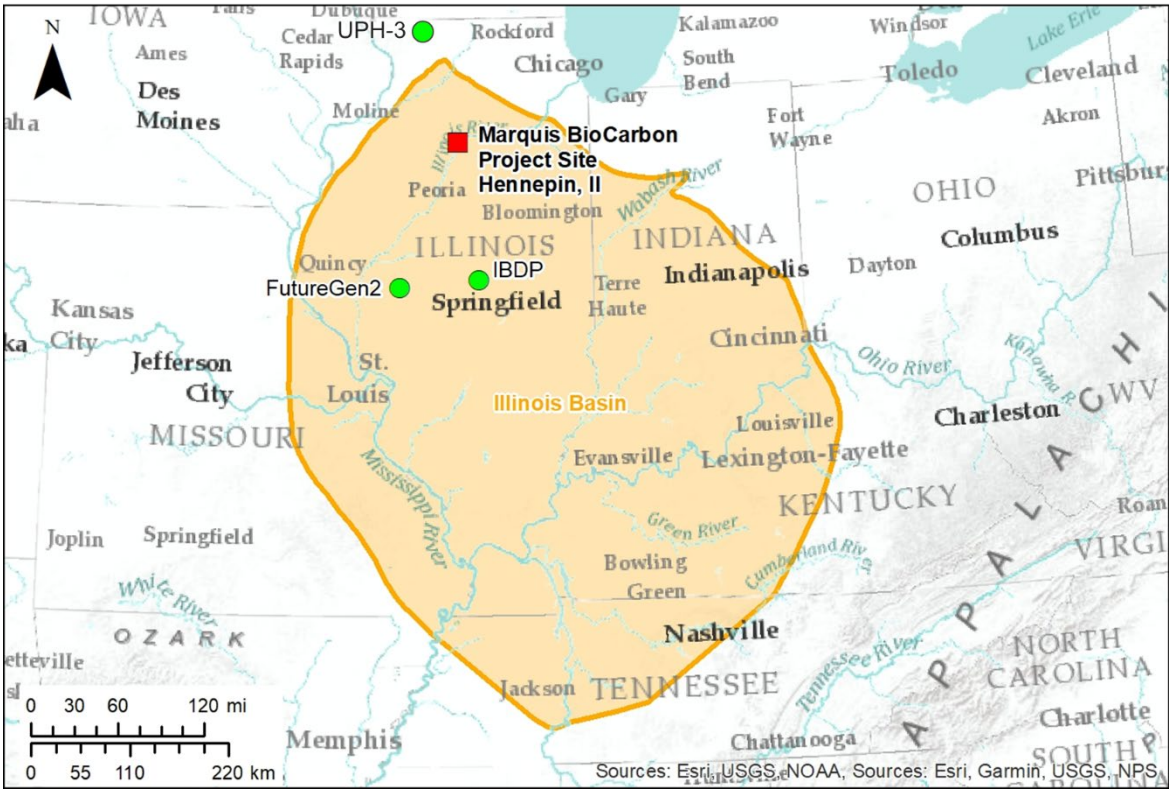


Figure 2-7: Map showing the analog well locations used in depositional environment interpretations to the north and south of the Marquis BioCarbon Project site.

Studying the composition of these core samples enabled an interpretation of lithofacies and depositional environments for the Mount Simon Sandstone in northern Illinois. During the Cambrian Period, a terrestrial fluvial environment of deposition transported sediments from topographically higher regions, such as mountains to the north (Wisconsin region), to a shallower region in Illinois. During transport, these sediments formed the Cambrian-aged depositional environments of the fluvial braid plains and eolian sand dunes (Figure 2-8).

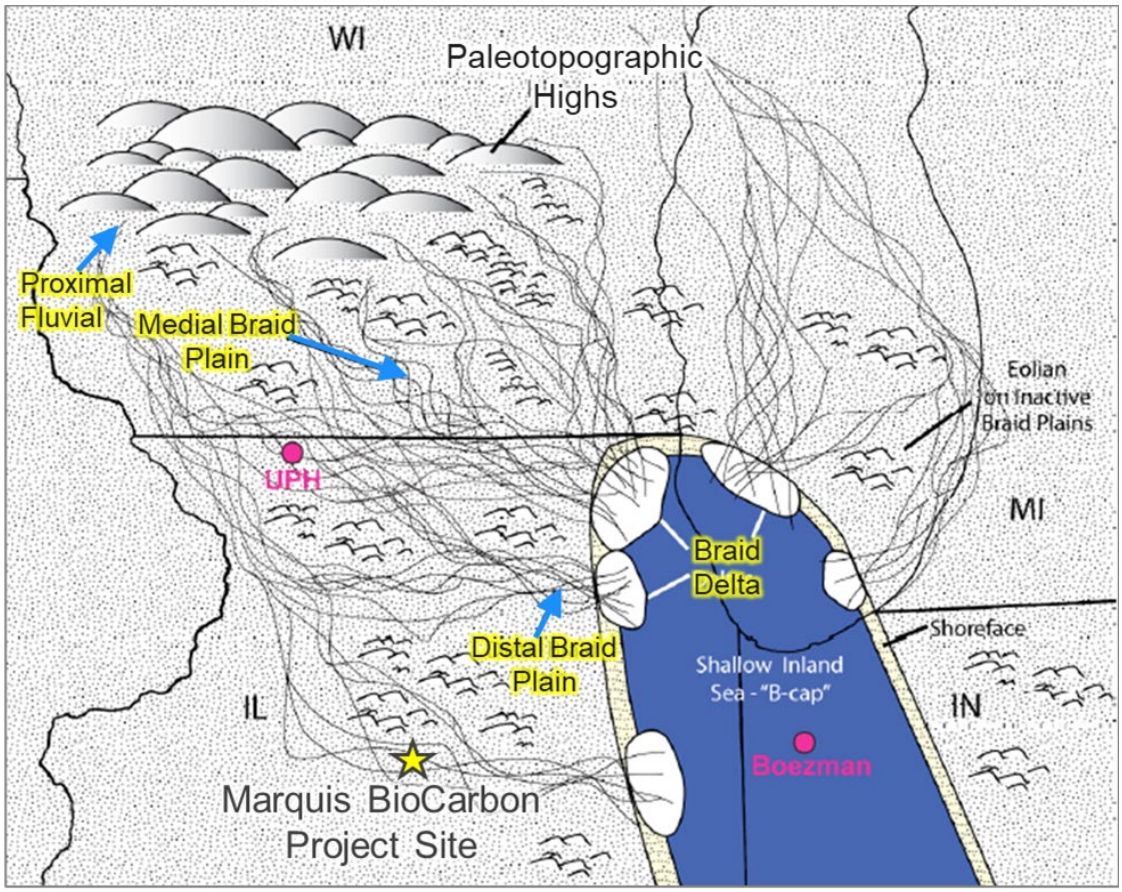


Figure 2-8: Regional depositional model for the Mt. Simon Sandstone. Broad fluvial braid systems feed into a shallow inland sea. Sediments on inactive braid plaids are reworked by eolian processes. Sediment source is primarily from the north. Modified from Fischietto (2009).

The Mt. Simon Sandstone can be divided into stratigraphic intervals associated with the timing and development of the basin that affects depositional settings. Core samples from the project site were integrated with regional studies, resulting in seven distinct depositional packages in the Mt. Simon (Figure 2-9). These environments include eolian sand dunes, fluvial braid plains, and braid deltas that transitioned into shallow marine depositional environments as sea level rose during deposition of the upper Mt. Simon and Eau Claire. Within the regional fluvial braid plain, there are playa (flat "ponding" areas) and eolian (dunal) sedimentary areas (Figure 2-10).

The Mt. Simon consists of sandstones that are generally clean, well-sorted, and porous. Variations in sediment grain size depend on how far sediments were transported from their source and whether they were reworked by wind (eolian sandstone), rivers and streams (fluvial systems), or water (shallow marine sandstones modified and sorted by wave action). At the Marquis BioCarbon Project site, the lower Mt. Simon consists of conglomerate and very coarse to fine-grained sandstone deposited by braided fluvial channels and eolian systems, as well as arkosic sandstones yielding high gamma ray values in Mt. Simon zones 5 and 6. In the Upper

Mt. Simon fluvial, tidal, and shallow marine depositional systems resulted in finer grained sandstone and increased clay content. During the deposition of the Eau Claire, shallow marine systems on the continental shelf deposited shales, siltstones, and fine to very-fine grained sandstones with dolomitic and arkosic compositions.

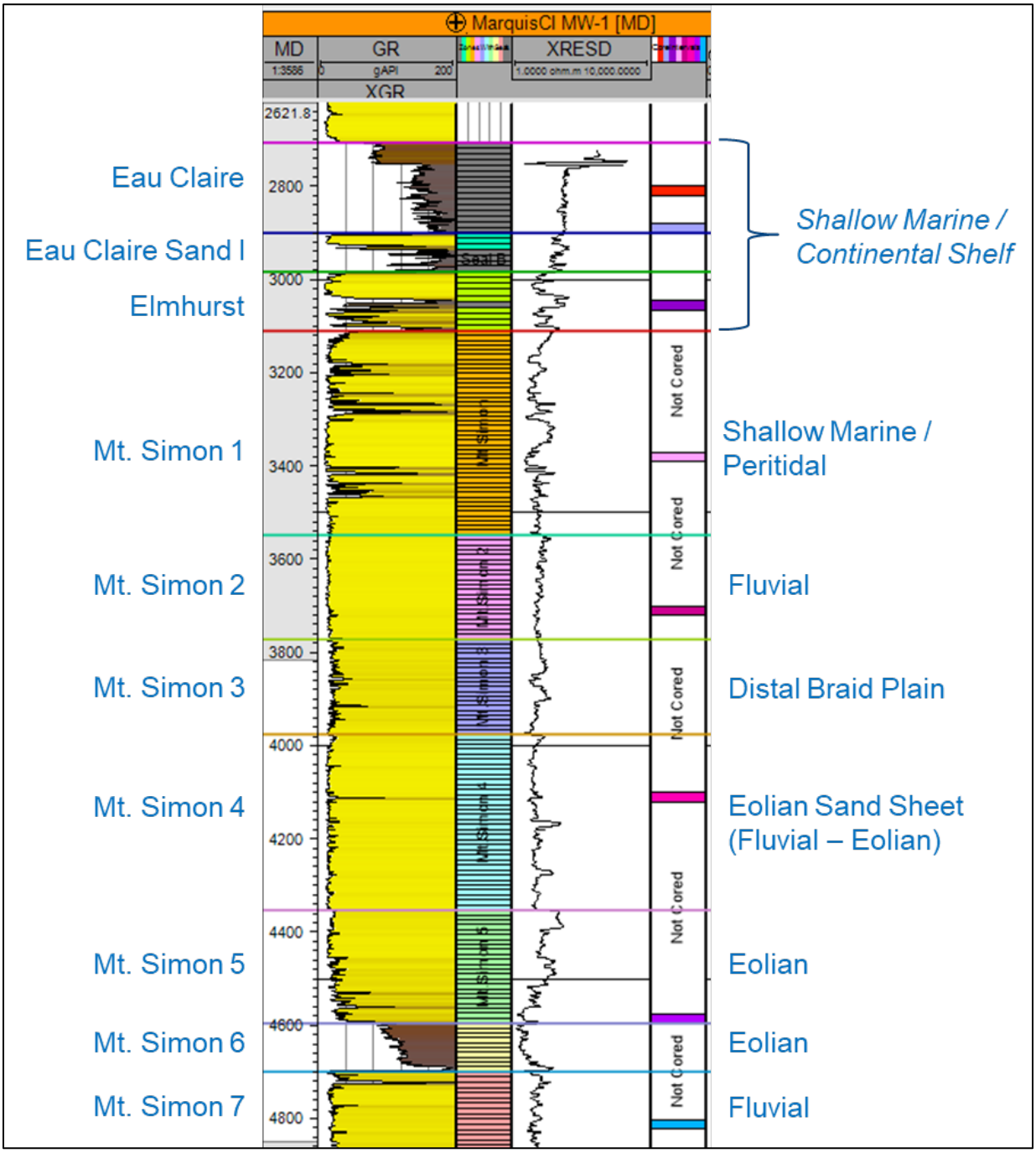


Figure 2-9: Interpreted Mt. Simon depositional environments and corresponding intraformational zones.

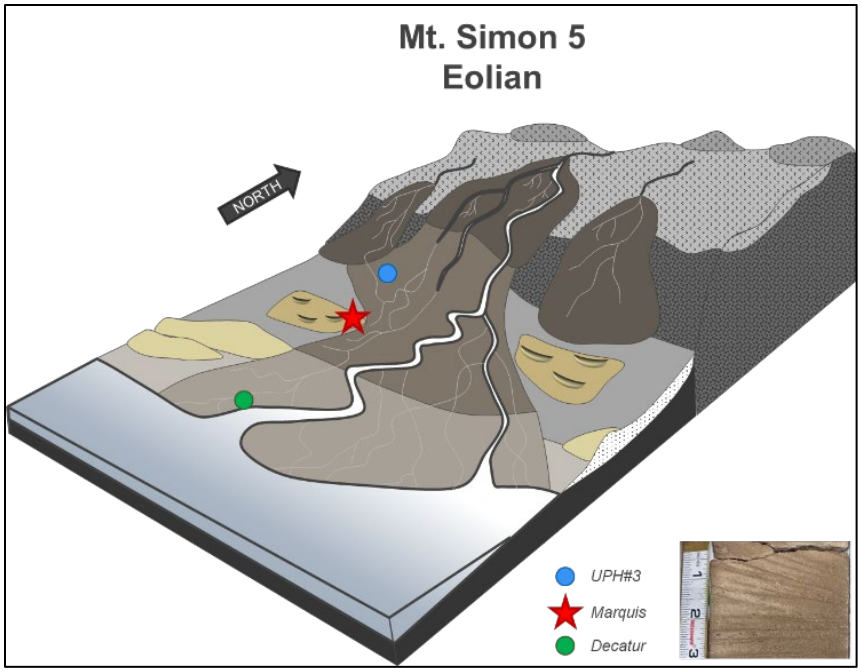


Figure 2-10: Example conceptual schematic drawing of the Mt. Simon Zone 5 representing the eolian depositional environment and interpreted orientations at the Marquis site (not to scale), as well as representative bedding features in whole core acquired from Mt. Simon Zone 5 (insert). Modified from Freiburg et al. (2020).

There are several geologic structures northeast of Putnam County (Figure 2-11). Within the Marquis BioCarbon Project AoR and Putnam County, these structures do not appear to have a significant impact on the confining zone and the target saline storage reservoir. The La Salle Anticlinorium is the dominant regional structure within the basin and has associated faults which cause varied relief of strata along its trend. This structure extends from La Salle County in north central Illinois to the southeast towards Lawrence County near Vincennes, Indiana. This feature is believed to be a drape fold or fault-propagation fold similar in structural style to monoclines that developed during the Laramide Orogeny in the western Unites States (Nelson, 1995). More than half of the La Salle Anticlinorium's uplift is believed to occur during Late Mississippian time, with the remaining uplift and nearby structural features occurring during the Pennsylvanian. There are small faults, anticlines, and domes near the La Salle Anticlinorium and along its trend. The Marquis BioCarbon Project site resides in an area fully removed from the anticline. Other structural features to the northeast of Putman County include the Ashton, Kankakee, and Wisconsin Arches, the Sandwich Fault Zone, and several minor synclines, anticlines, and domes (Golden StrataServices, 1984).

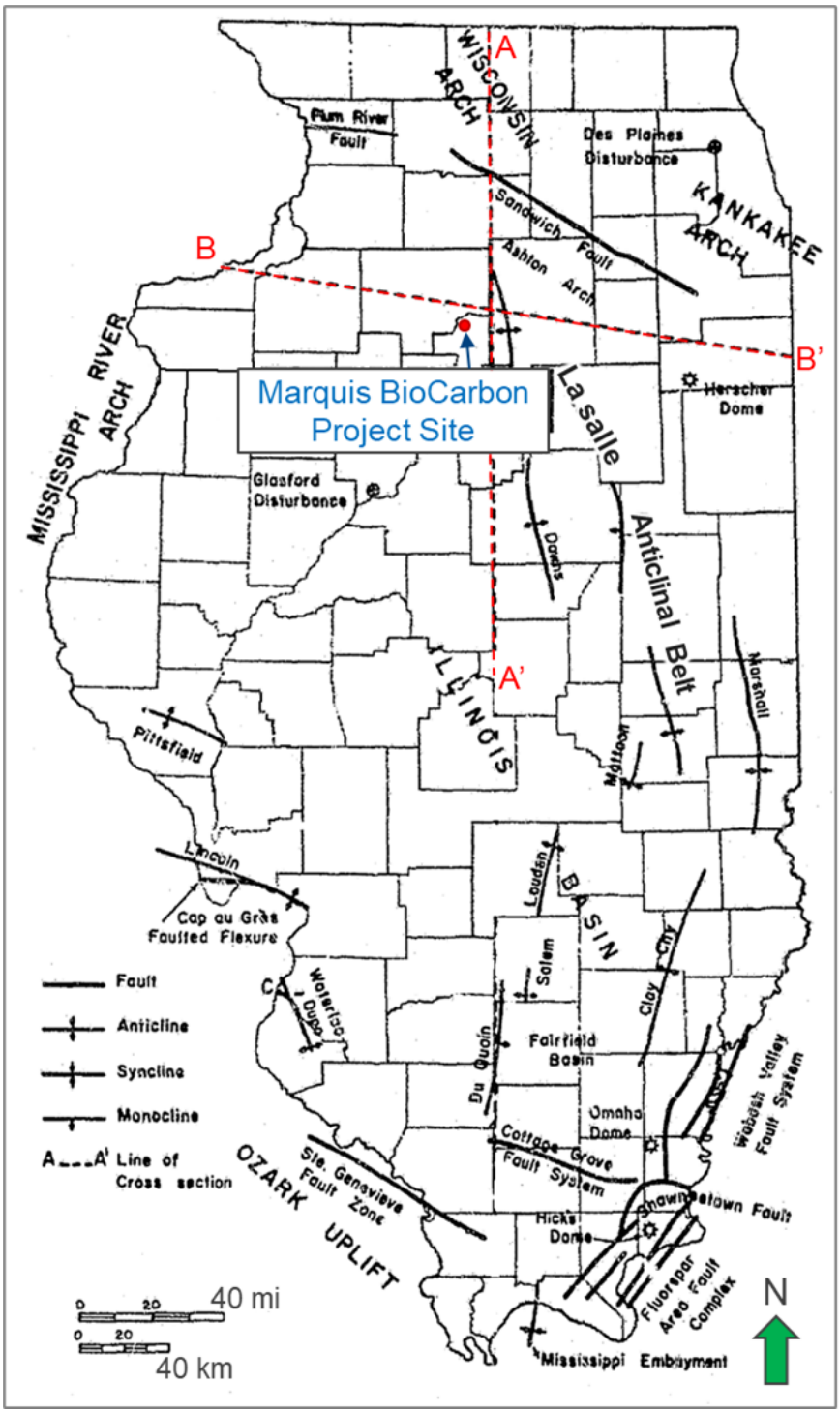


Figure 2-11: Principle geologic structures of Illinois. Modified from Willman et al. (1975) with N-S and E-W cross section marked in red. (See Figure 2-12 for cross sections)

Major geologic units and their stratigraphic relationships are depicted in regional cross sections shown in Figure 2-12. These two cross sections show the northward shallowing of Cambrian strata as well as the regional effect of the La Salle Anticline on the structural configuration of the Cambrian strata. At the Marquis BioCarbon Project site, the injection zone is deep enough for supercritical CO_2 storage, and there is no evidence of faulting, folding, and fracturing structures. This is based on observations from the two-dimensional (2D) seismic data, an example of which is shown in Figure 1-6 of the Project Narrative (Permit Section 1). These observations include the lateral continuity of the subsurface formations and a relatively flat dip angle. The seismic program confirmed the absence of large-scale faulting in the vicinity of the Marquis BioCarbon Project site.

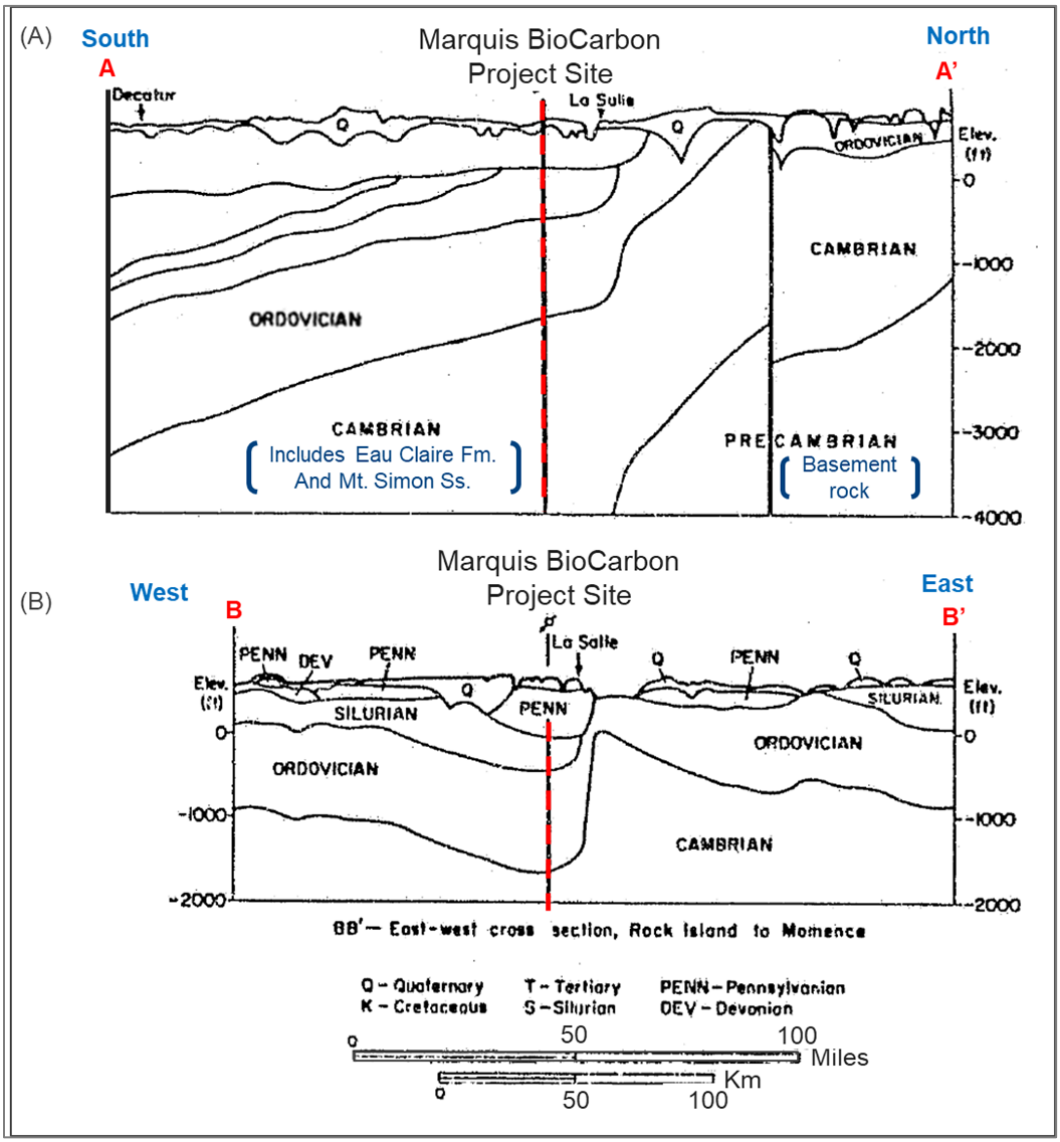


Figure 2-12: Geologic cross sections near Putnam County featuring the structural configuration of Cambrian strata that contains the target injection zone and caprock. The locations of these cross-section lines are shown in Figure 2-11. Modified from Willman et al. (1975).

2.1.3 Model Domain

A 49 mi^2 SEM centered on the Marquis BioCarbon Project site was used to assess potential CO_2 storage and estimate the extent of the CO_2 plume. To mitigate potential edge-effects in simulation, the 7-mi by 7-mi model grid was designed to encase the entirety of the plume and pressure front for the intended injection period. The grid size is set at 500 ft by 500 ft with an average of 10 ft layers in the injection zone and 12 ft layers in the confining unit. The model grid is centered around the MCI CCS 3 well, extending approximately 3.4 mi away from it in the X and Y directions. The proposed well location at the Marquis BioCarbon Project site is provided in Figure 2-13 and model domain information is summarized in Table 2-1.

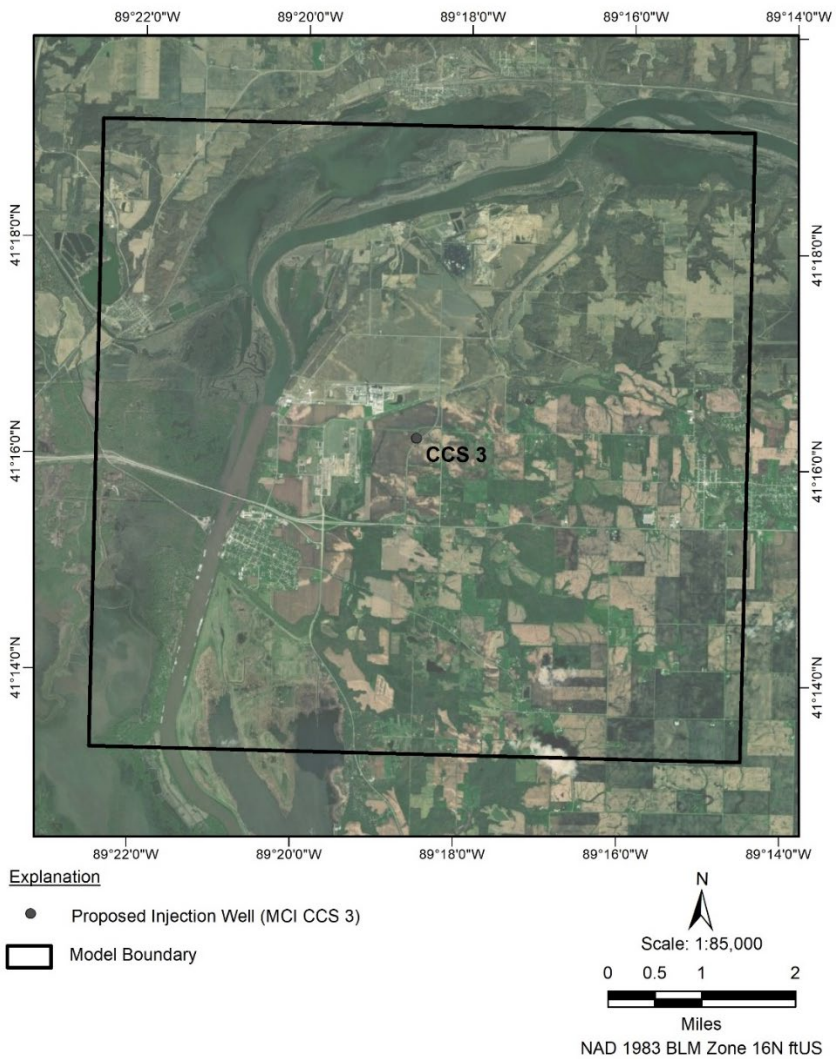


Figure 2-13: Static Earth Model 7-mile by 7-mile boundary centered around the MCI CCS 3 well.

Coordinate System	NAD 1983 BLM Zone 16N ft US		
Horizontal Datum	NAD83		
Coordinate System Units	Field = feet		
Zone	UTC -06:00 Central Time (US & Canada)		
FIPSZONE	1202		
Coordinate of X min	987293.52	**Coordinate of Y min**	14979542.23
Elevation of bottom of domain	-4473.32	**Elevation of top of domain**	-2117.49

Table 2-1: Model domain information.

The Mt. Simon sandstone is subdivided into seven internal zones based on observed responses seen in gamma ray and resistivity logs. These zones are numbered top down, as shown in Figure 2-14. While differently named, these zones are roughly equivalent to Mt. Simon subdivisions used in other studies and at other sites (Fischietto, 2009; FutureGen Alliance, 2013; Freiburg et al., 2014). Generalized reservoir quality of the zones indicates highest quality sands in the lower half of the formation, a middle section of lower-quality sands, and an upper section of higher quality, which is also a trend seen at the regional scale.

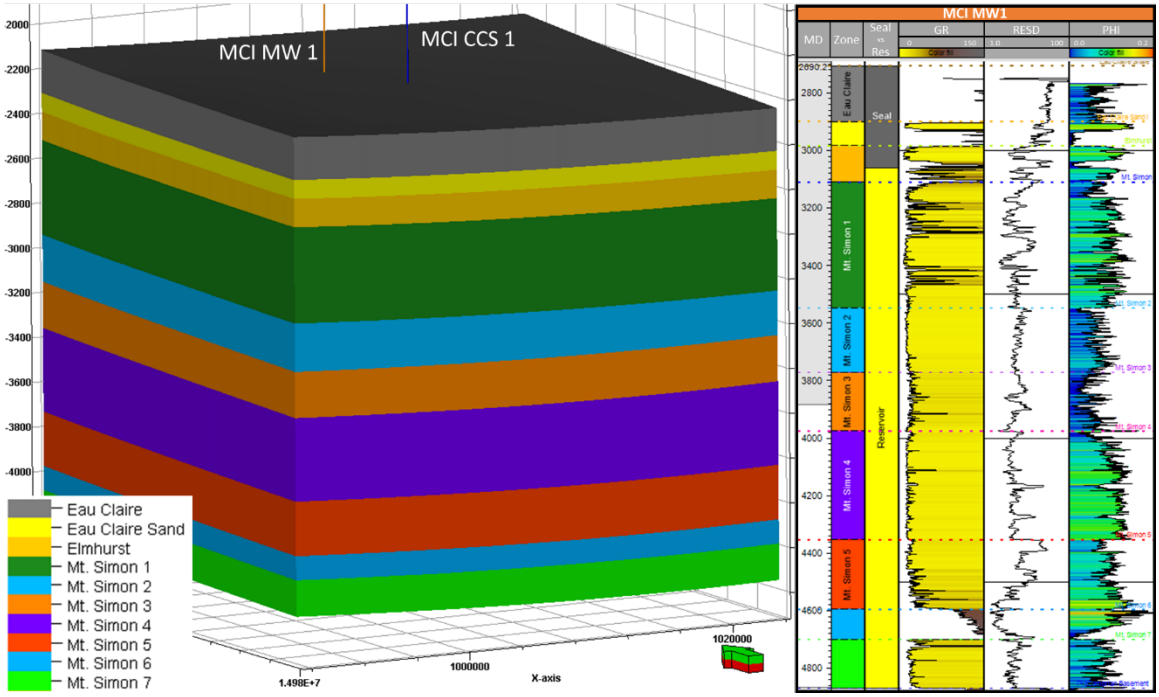


Figure 2-14: Model Zones and corresponding gamma ray, resistivity, and porosity logs. Lower part of the Elmhurst and the entire Mt. Simon are considered reservoir, while the upper Elmhurst and Eau Claire shale act as the seal.

2.1.4 Porosity and Permeability

The geology of the injection interval was characterized based on depositional environments and subsequent controls on sand-quality distribution and implied flow geometries. Environments of deposition (EODs) were determined using paleogeographic information, results of well analyses of the Mt. Simon in analog studies (Fischietto, 2009; Freiburg et al., 2014), and rock observations in the whole core samples from the MCI MW 1 well.

EODs were defined on a zone-by-zone basis and incorporated into the model as objects representing channels and eolian sand deposits. These objects provided a way to constrain facies distribution throughout the model, where environmental controls on the deposition of clean sand and shale components could be represented. Facies used were defined with a clay fraction (vClay) log to separate the rock into three main types: clean sand, dirty sand, and shale. Each facies had a unique distribution of porosity values (Figure 2-15), which were utilized during the porosity property modeling process. Clean sand and dirty sand histograms had a distinctly different distribution in the Mt. Simon 2 and Mt. Simon 3 intervals, where normal distributions were centered around means which were shifted several porosity percentage points to the left (lower).

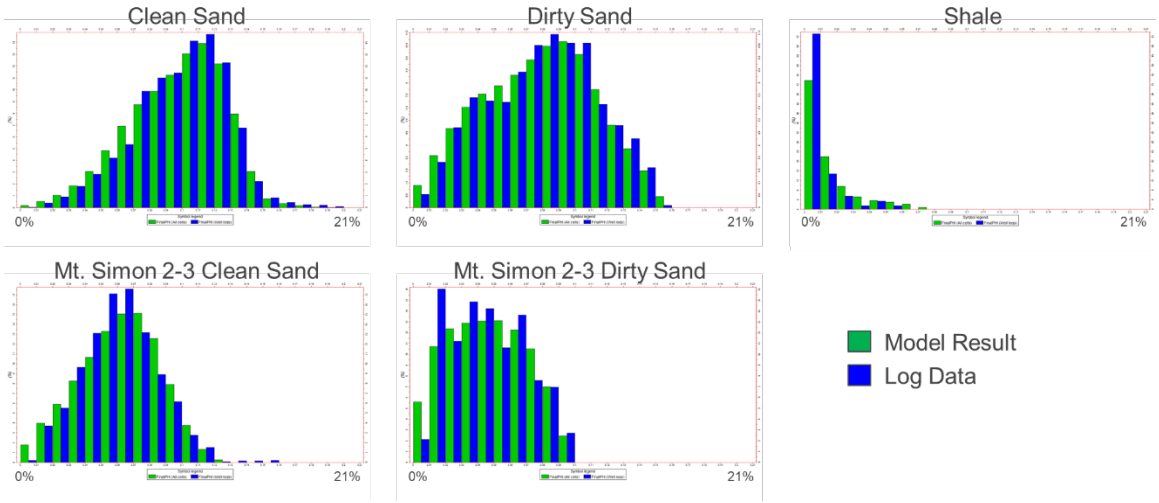


Figure 2-15: Histograms of porosity ranges by facies type showing correlative distributions for the clean sand, dirty sand, and shale facies. Distinctly different distributions for clean sand and dirty sand in Mt. Simons 2 and 3, where normal distribution means are lower.

The resulting porosity property (Figure 2-16a) was used as a direct input into the permeability property (Figure 2-16b), which was calculated in millidarcies (mD) using porosity-permeability transform functions derived from the nuclear magnetic resonance (NMR)-based permeability log. The NMR-based permeability values were cross-checked with core-measured permeability, and a strong correlation was shown (Figure 2-17). This provides confidence in the use of the NMR-based permeability log. The porosity-permeability function was applied based on flow-based facies, which were defined using a flow zone indicator (FZI) log.

The FZI data resulted in four additional "flow-based" facies types: high-flow sand, mid-flow sand, low-flow sand, and shale. Each lithofacies contained a component of each FZI and were subsequently divided into the corresponding amount of flow facies, which represented variabilities in pore-throat size and directly correlates to flow-potential. Two transforms were defined from this data: an upper transform for the high- and mid-flow sands, and a lower transform for the shale and low-flow sands (Figure 2-18). The final permeability property was cross-checked with well test results to ensure permeability height achieved in the model matched dynamic observations at the MCI MW 1 well.

Results of the property models reflect the degraded quality of the Mt. Simon 2 and Mt. Simon 3 relative to other zones. Conversely, the Mt. Simon 1, Mt. Simon 4, and Mt. Simon 5 were the highest quality zones. These relationships were considered when determining the well completions strategy, which is described in more detail in Section 2.2.

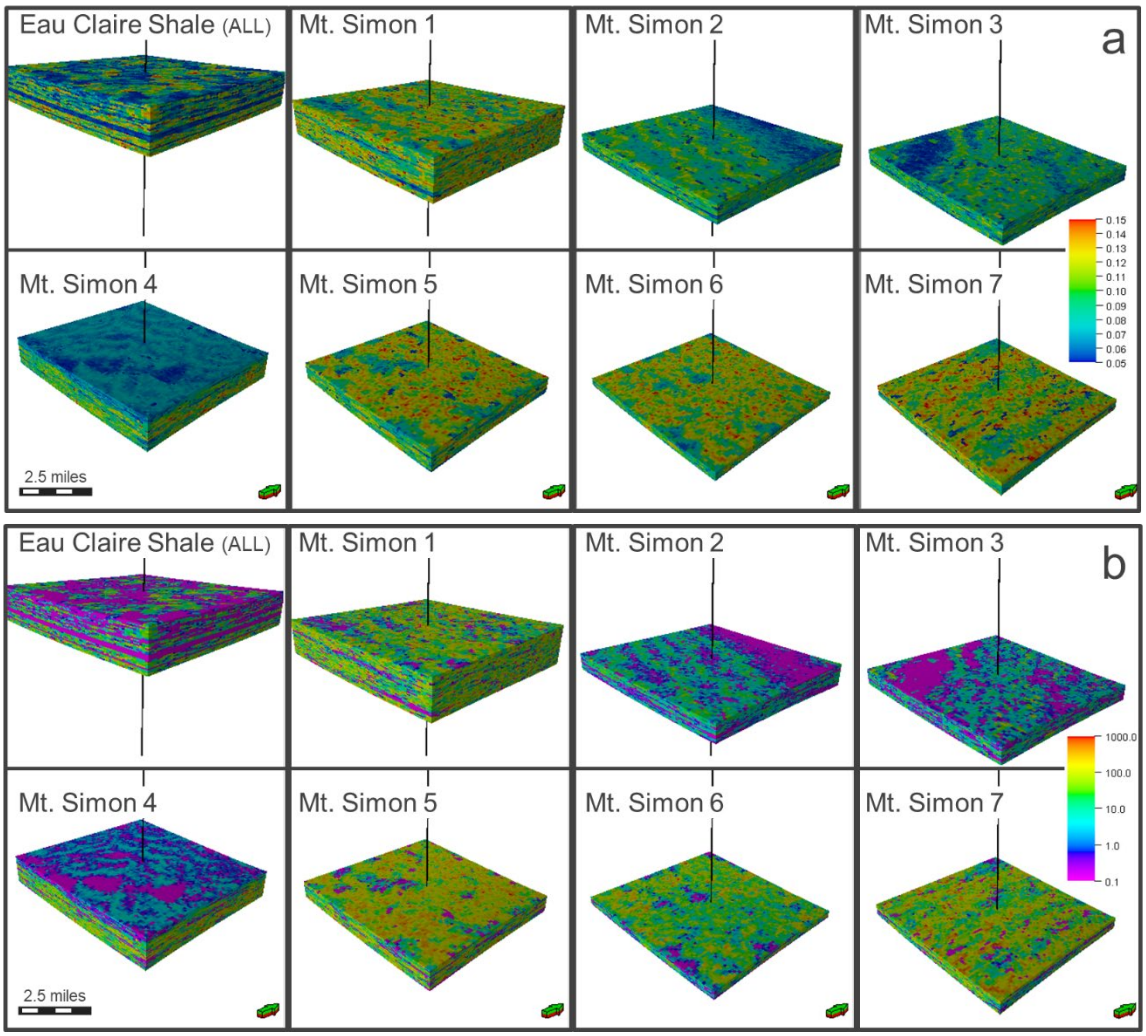


Figure 2-16: Final (a) porosity and (b) permeability properties showing the effect of depositional constraints on spatial property distribution within the 3D geocellular model.

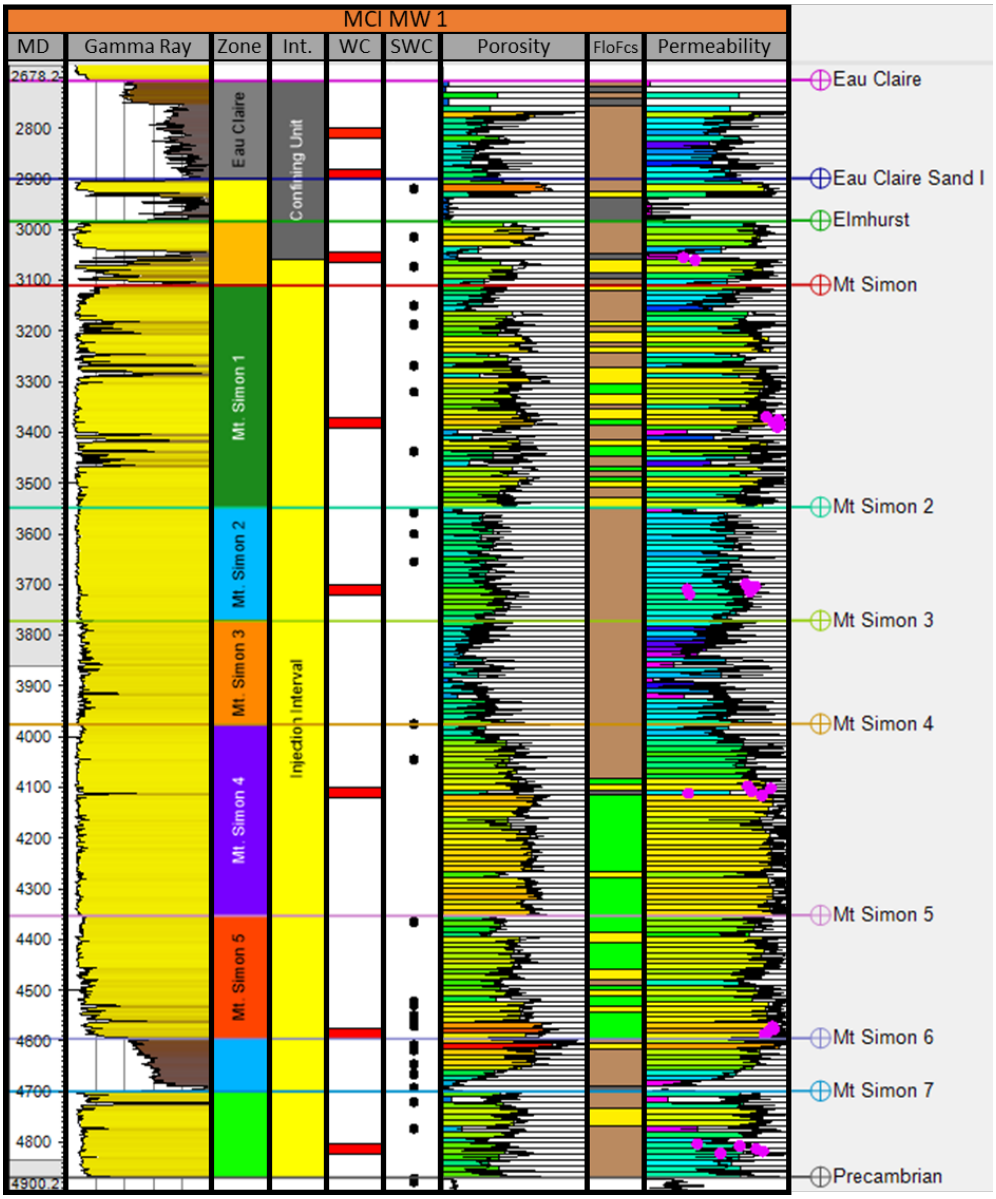


Figure 2-17: Logs at the MCI MW-1 well showing (left to right) gamma ray, stratigraphic zone, confining unit or injection interval, whole core, sidewall core, porosity, flow-based facies, and permeability. There is a match between the model (blocky colors) and the log (black line) for porosity and permeability, and core-measured permeability points plotted on the permeability track in magenta show strong correlation to NMR-based log values.

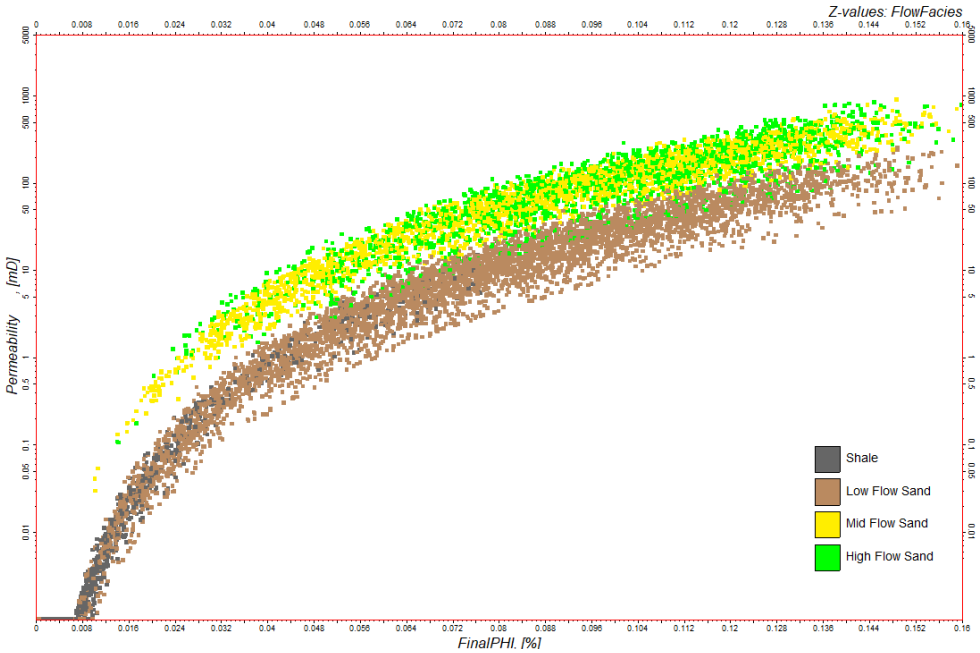


Figure 2-18: Porosity-Permeability cross-plot colored by flow facies showing the utilization of two different transforms, applied by flow-based rock classifications.

2.1.5 Constitutive Relationships and Other Rock Properties

Relative permeability relationships served as the main constitutive relationships in the dynamic model. Relative permeability is an important input for describing dynamic behavior in reservoir simulators and it is a required property in the saturation equation describing multiphase flow in porous media. This flow property is represented as a saturation function and will significantly influence the simulated injection profiles. The curves incorporated in the model were from the CO_2-brine drainage relative permeability experiments performed by Core Laboratories on cores from the MCI MW 1 well. The steady-state method of measuring relative permeability was performed on three core samples taken at depths of 3,384.9, 3709.75, and 4,105 ft MD in the Mt. Simon Sandstone, producing three relative permeability drainage plots (Figure 2-19). Relative permeability versus saturation curves were assigned to facies in the dynamic model based on permeability and flow characteristics. Facies in the Mt. Simon Sandstone were categorized as "low-flow sand", "mid-flow sand" and "high-flow sand". The model assumed a compressibility of 1×10^{-6} 1/pound per square inch (psi), which is the average of the MCI MW 1 well pore volume compressibility log in the Mt. Simon. The log values were computed by Baker Hughes from geomechanics core tests and logs.

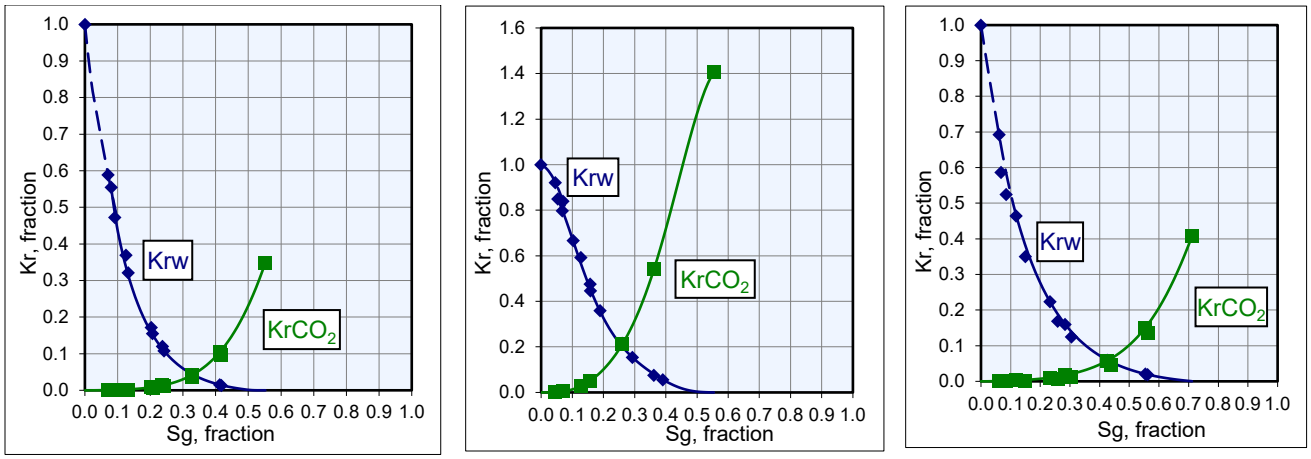


Figure 2-19: Relative Permeability Curves imported into dynamic reservoir model. The plot on the left was assigned to high-flow sands, the plot in the middle was assigned to mid-flow sands and the plot on the right was assigned to low-flow sands.

2.1.6 Boundary Conditions

The model's lower boundary was the top of the Precambrian basement rock. While this surface is expected to have some topographical features, in general, it is assumed to dip to the southeast in the Putnam County area. The size of the static earth model was 7 mi × 7 mi. A single injection well was used at the center of the model so that the CO_2 plume and pressure buildup would be far from the computational model boundary (7 mi × 7 mi) and the model would be able to capture the multiphase flow phenomena. The model lateral boundary is assumed to be an infinite or open boundary reservoir. To model an open boundary reservoir, a volume modifier was used for the grids at the model boundary as recommended by CMG-GEM (CMG-GEM, 2016; Nghiem et al., 2009b).

2.1.7 Initial Conditions

Initial conditions for the model are given in Table 2-2. The pressure gradient profile for the MCI MW 1 was measured during drill stem testing. Based on the measured data, pore pressure gradient in the Mt. Simon was measured to be 0.44 psi/ft, which is close to normal pressure gradient. This pressure gradient is consistent with the regional data. The measured pore pressure gradient of 0.44 psi/ft was used to estimate the initial conditions at the corresponding depth of the modeled well. Formation pressure varies in the model as a function of the pore pressure gradient. A temperature profile was specified in the dynamic model to match the measured temperatures in the MCI MW 1 characterization well. Furthermore, geochemical analysis was performed on a composite fluid sample that was collected from the Mt. Simon while pumping the well. These, tests indicated a chloride concentration of 26,215 mg/L (TDS/salinity in the range of ~45,000 ppm), which was used as input in the simulator. Fluid density was calculated as a function of pressure, temperature, and salinity in the simulator.

Parameter	Value or Range	Units	Corresponding Elevation (ft MSL)	Data Source
Temperature	81.5 83.6 93.0	°F	Top Eau Claire 2,158 Top Mt. Simon 2,562 Base Mt. Simon 4,321	Temperature Log
Pore pressure gradient	0.44	psi/ft	2,117.49 – 4,473.32	Drill Stem Testing
Fluid density	0.029	tonne/ft^3	2,117.49 – 4,473.32	CMG Reservoir Simulator Calculation
Salinity	45000	ppm	2,985.00 – 4,870.00	Drill Stem Testing

Table 2-2: Initial conditions.

2.1.8 Operational Information

Details on the injection operation are presented in Table 2-3.

	Operating Information	MCI CCS 3
Location (global coordinates)	X Y	41.27026520° -89.30939322°
Model coordinates (ft)	X Y	987293.52° 14979542.23°
Perforated interval (MSL)	Top Bottom	-3,226.14 ft -4,781.53 ft
	Wellbore diameter (in.)	9 5/8 inch
Planned injection period	Start End	01/01/2024 03/01/2029
	Injection duration	5 years
	Maximum injection rate	1.5 million tonnes (MT) /year

Table 2-3: Operating details.

2.1.9 Fracture Pressure and Fracture Gradient

The average fracture propagation pressure gradient measured at the MCI MW 1 well in the Mt. Simon, estimated during the analysis of the minifrac tests was 0.76 psi/ft. This value is consistent with literature and results from the hydraulic fracture tests performed in the FutureGen 2.0 site located in Morgan County, Illinois discussed in (Cornet, 2014).

This fracture gradient was used to constrain the wellbore pressure at the top of the perforation interval in CMG-GEM. The assigned well pressure in this case is 2,207 psi (3,226 ft MD × 0.76 psi/ft × 90%) following EPA guidelines.

The measured average fracture gradient for the Eau Claire Caprock is 0.95 psi/ft. A higher fracture gradient in the caprock compared to the Mt. Simon implies that even if a fracture were to be created in the Mt. Simon reservoir (e.g., due to inadvertent injection pressures), it would not extend or penetrate the overlying Eau Claire caprock layer.

Injection Pressure Details	**MCI MW 1**
Fracture gradient	0.76 psi/ ft
Maximum injection pressure (90% of fracture pressure)	2207 psi
Elevation corresponding to maximum injection pressure (MSL)	-2694 ft (3226 ft MD)

Table 2-4: Injection pressure details.

2.2 Computational Modeling Results

2.2.1 Predictions of System Behavior

A 3D multi-phase flow simulator (CMG–GEM, 2021) was used to model CO_2 injection, determine the CO_2 plume position, and pressure front at the end of the injection period and during the post-injection period. The model includes target storage formations and confining zone formations. The geological model (SEM) that includes the permeability, porosity, and gridding of the model was imported from Petrel. The gas-water relative permeability relationship assigned to the model is described in Section 2.1.5.

The injection well (MCI CCS 3) was defined in the model as a 3,150 ft wellbore with 4.5-inch tubing (4-inch internal diameter) and perforations as shown in Table 2-3. A wellhead temperature of 93°F was specified. A cross-section view of the model at the wellbore location as well as map view of the model is shown in Figure 2-20.

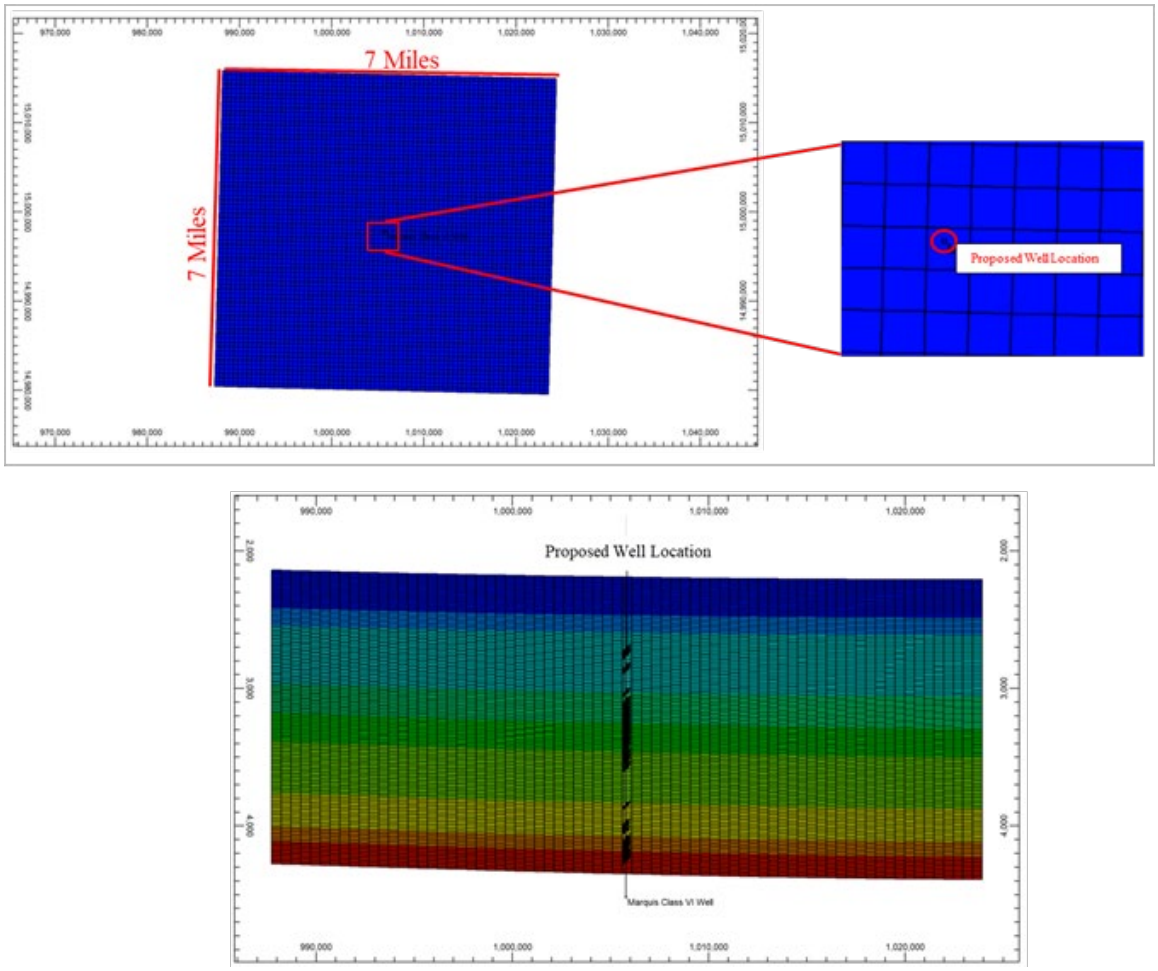


Figure 2-20: Map view of computational model with zoomed well grid (top) and cross section of the model (below).

The model demonstrates a 5-year injection period and 50-year post-injection period. The CO_2 injection rate was constrained to 1.5 MT/year.

CO_2 phase saturation is used as a defining parameter for the CO_2 plume extent. Figure 2-21 shows a side view of the CO_2 plume at the wellbore after 1, 3, and 5 years of injection. Figure 2-22 shows the same side view of the CO_2 plume at the wellbore at 3, 5, 10 and 50 years after the cessation of injection.

The CO_2 plume expands during the injection period and local permeability variations within the Mt. Simon Sandstone causes changes in the distribution of the CO_2 plume. At no time either during or after injection does the CO_2 migrate toward the top of the Mt. Simon.

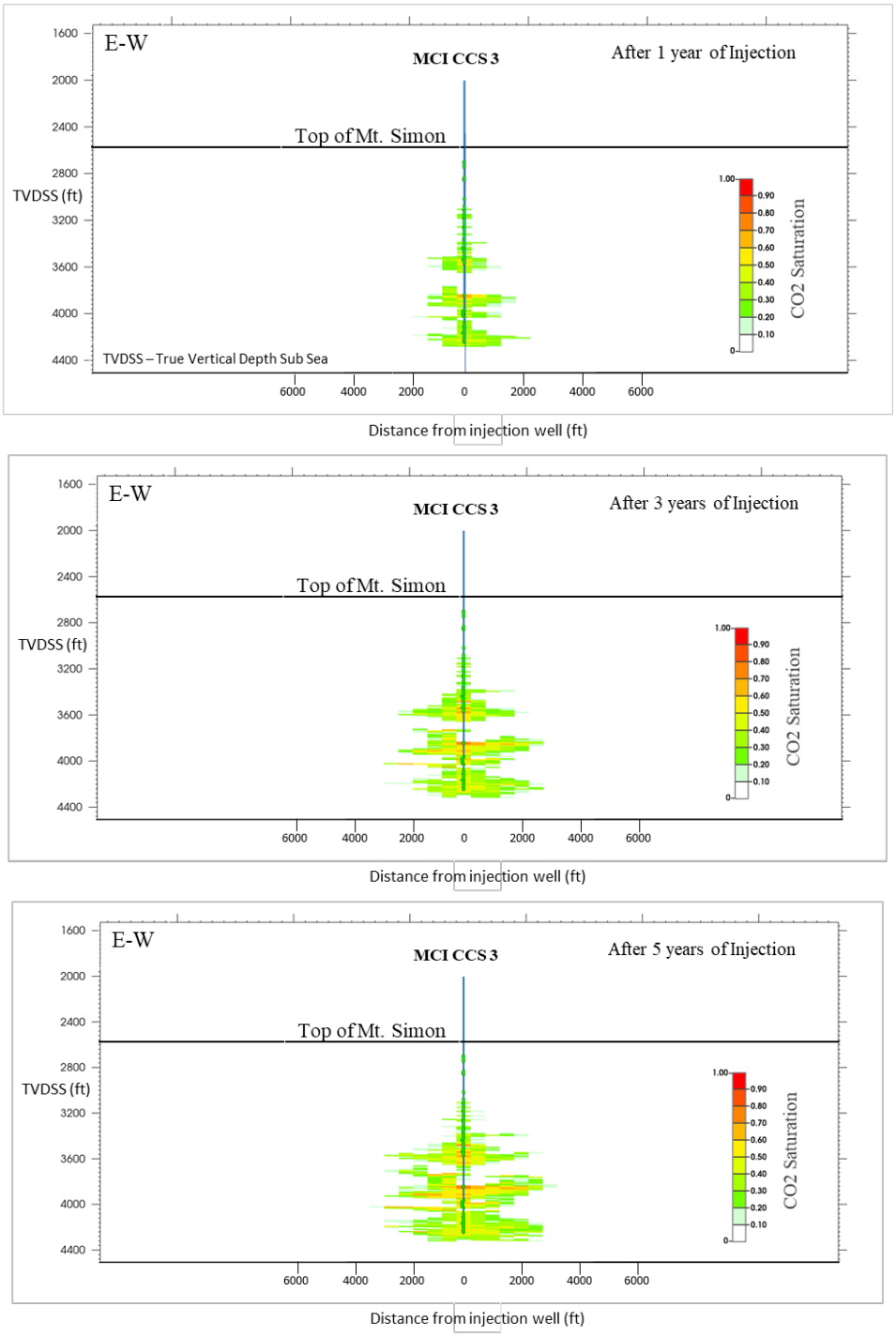
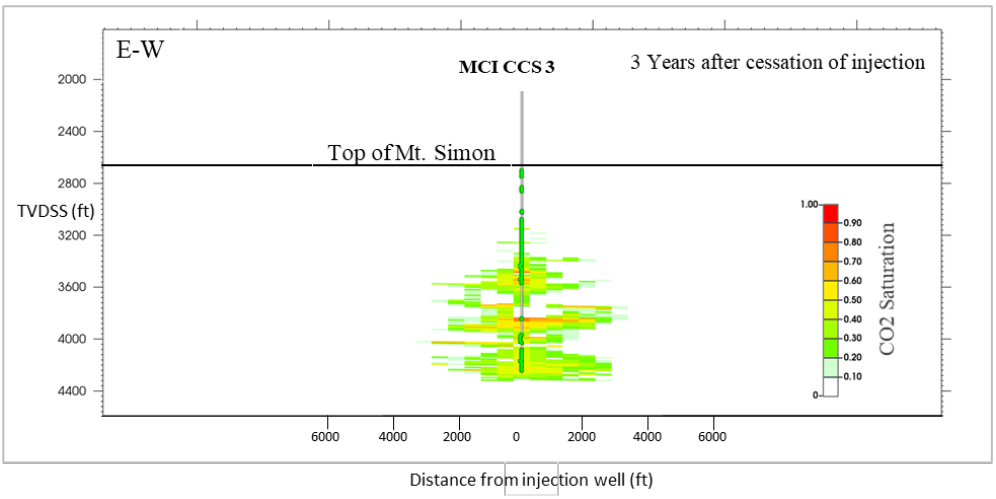
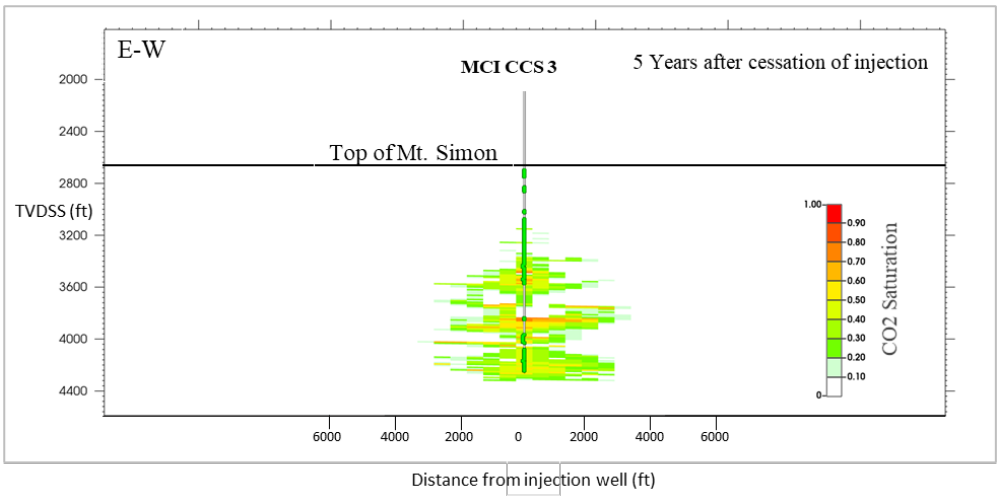
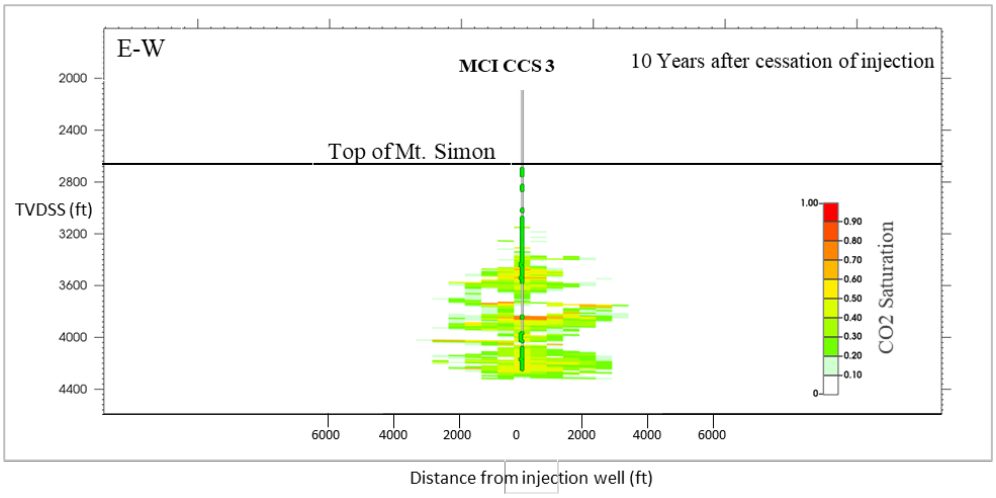


Figure 2-21: Development of CO_2 plume after 1 year (top), 3 years (middle), and 5 years (lower) of injection.


E-W
MCI CCS 3
3 Years after cessation of injection
Top of Mt. Simon
TVDSS (ft)
2000
2400
2800
3200
3600
4000
4400
6000
4000
2000
0
2000
4000
6000
Distance from injection well (ft)
CO2 Saturation
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0


E-W
MCI CCS 3
5 Years after cessation of injection
Top of Mt. Simon
TVDSS (ft)
2000
2400
2800
3200
3600
4000
4400
6000
4000
2000
0
2000
4000
6000
Distance from injection well (ft)
CO2 Saturation
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0


E-W
MCI CCS 3
10 Years after cessation of injection
Top of Mt. Simon
TVDSS (ft)
2000
2400
2800
3200
3600
4000
4400
6000
4000
2000
0
2000
4000
6000
Distance from injection well (ft)
CO2 Saturation
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0

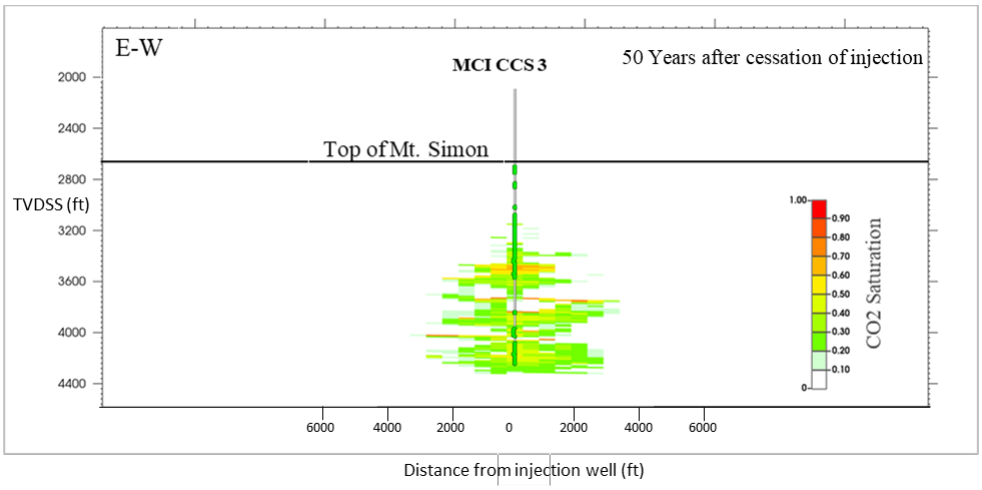


Figure 2-22: CO_2 plume 3, 5, 10 and 50 years after cessation of injection.

The CO_2 plume size after 5 years of injection for four different layers is shown in map view in Figure 2-23.

The AoR is determined by using the average plume sizes for all layers in the model at the end of the 5-year injection period which corresponds to layer 153. The CO_2 saturation in that layer at the end of injection period was selected to define AoR.

Figure 2-24 shows the development of the CO_2 plume size after 1, 3, and 5 years of injection for layer 153. Figure 2-25 shows the CO_2 plume size in the post injection time frame and clearly indicates stabilization of the plume after the cessation of injection.

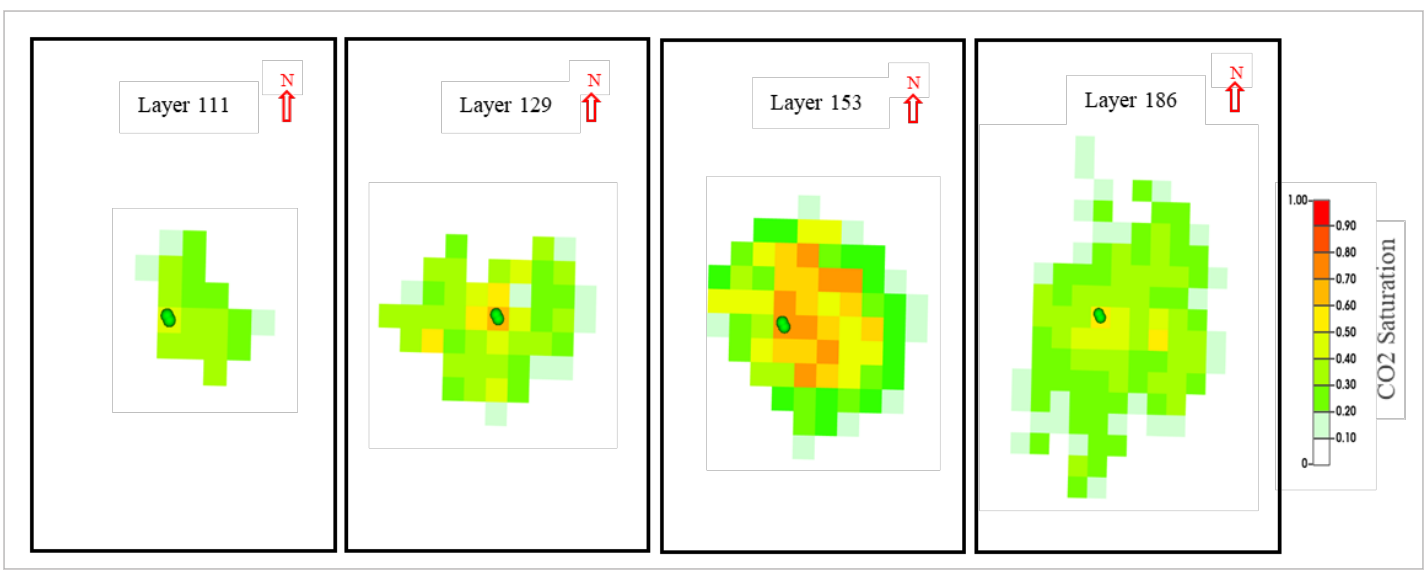


Figure 2-23: CO_2 plume after 5 years of injection in plan view for layers 111, 129, 153 and 186.

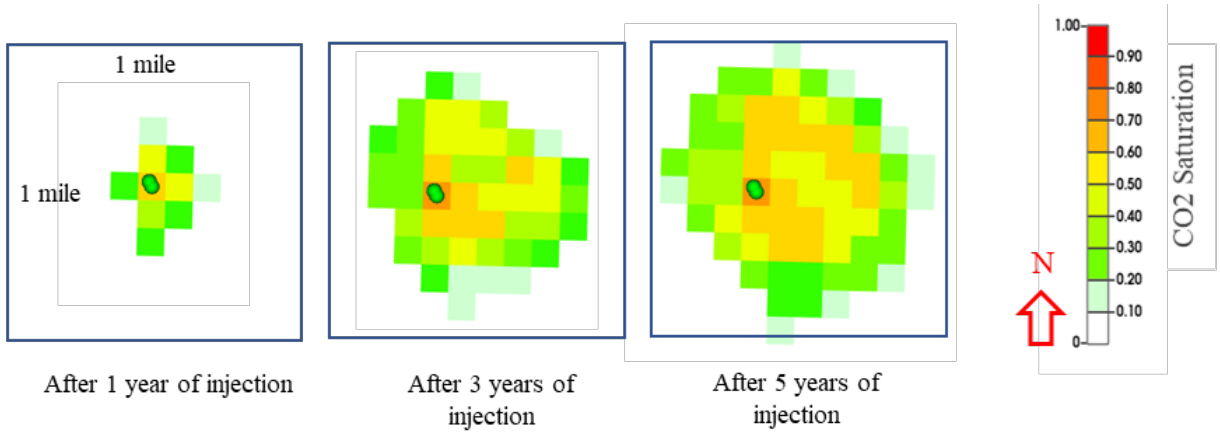


Figure 2-24: Development of CO_2 plume after 1 year, 3 years, and 5 years of injection at layer 153 representing the AoR.

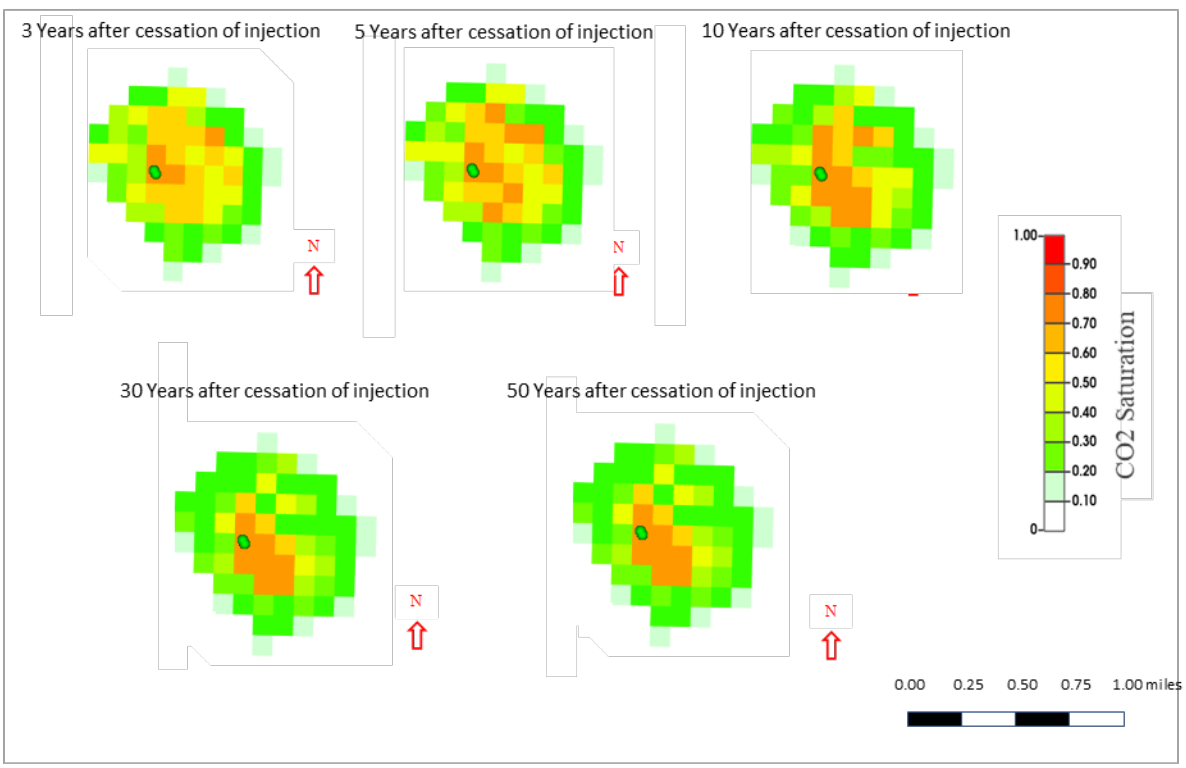
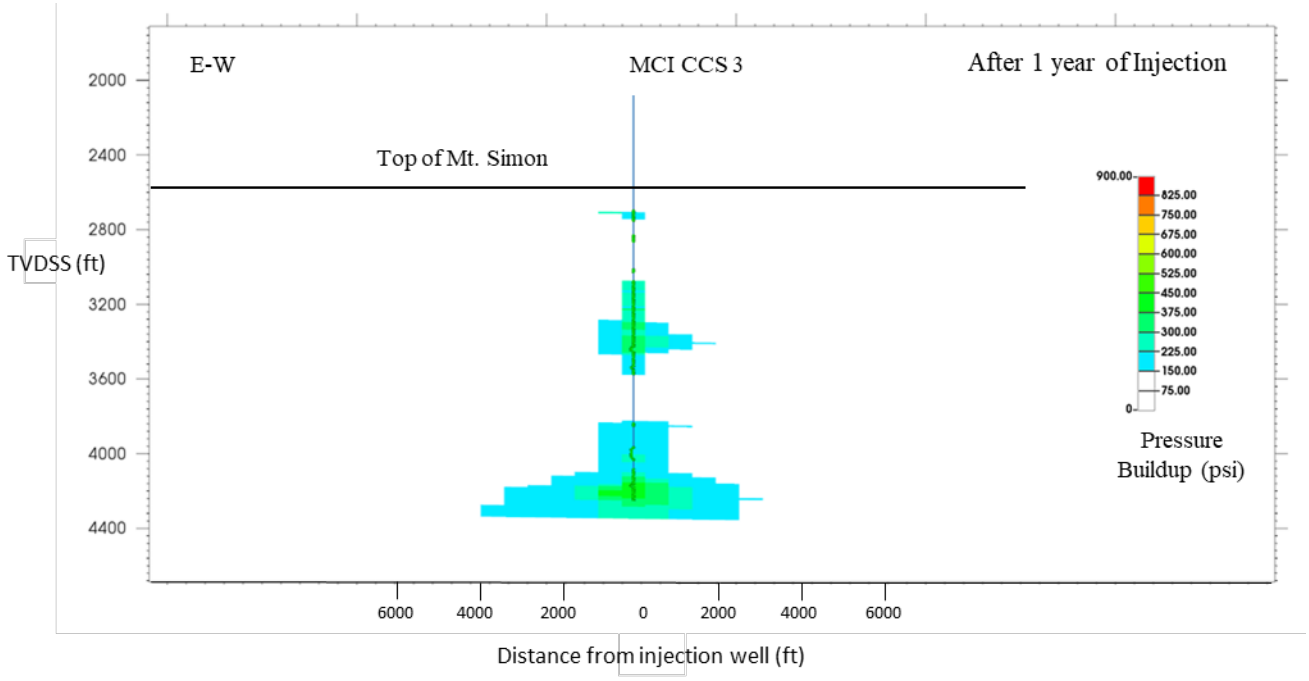
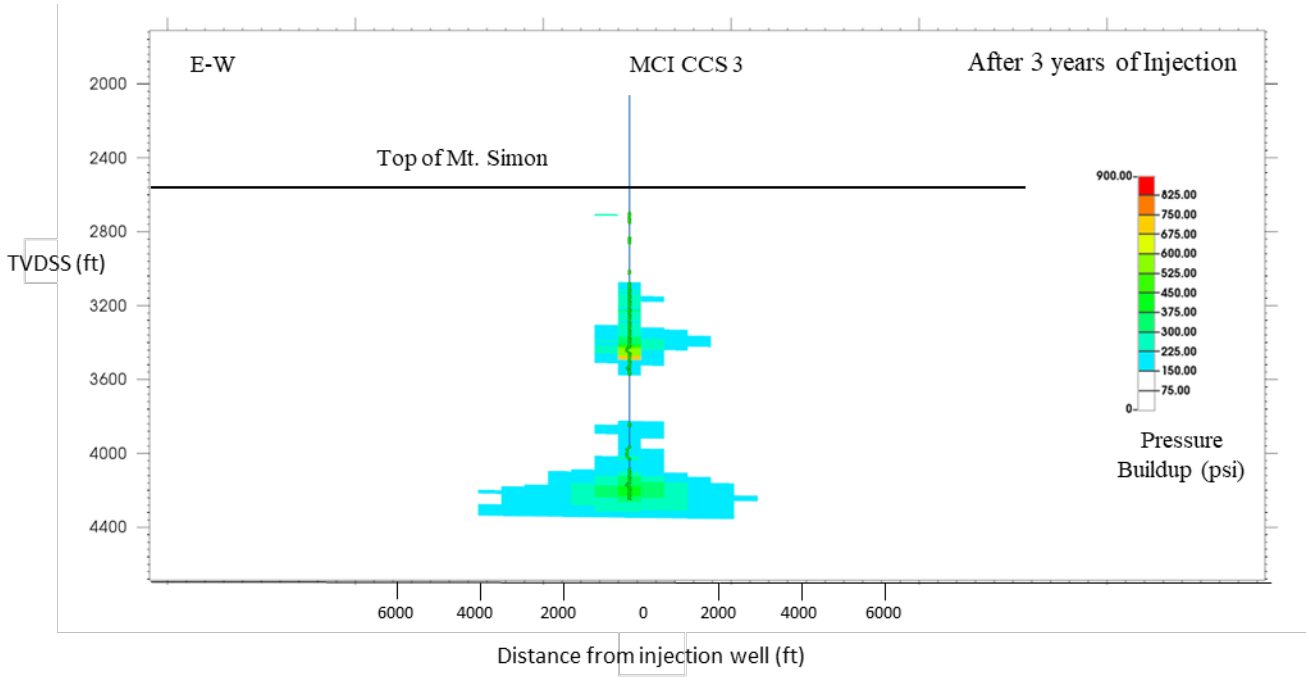


Figure 2-25: CO_2 plume mapping 3 year, 5 years, 10 years, 30 years, and 50 years after cessation of at layer 153 (representing the AoR).

Figure 2-26 shows the pressure build-up (increase from initial pressure) in the Mt. Simon formation after 1, 3, and 5 years of injection. A pressure cut-off of 150 psi was used in the plot to delineate pressure front expansion as a function of injection time as detailed in section 2.3.

Figure 2-27 shows the pressure time-series at the depth of the middle perforation. The pressure remains lower than the maximum injection pressure and declines rapidly after injection ceases.





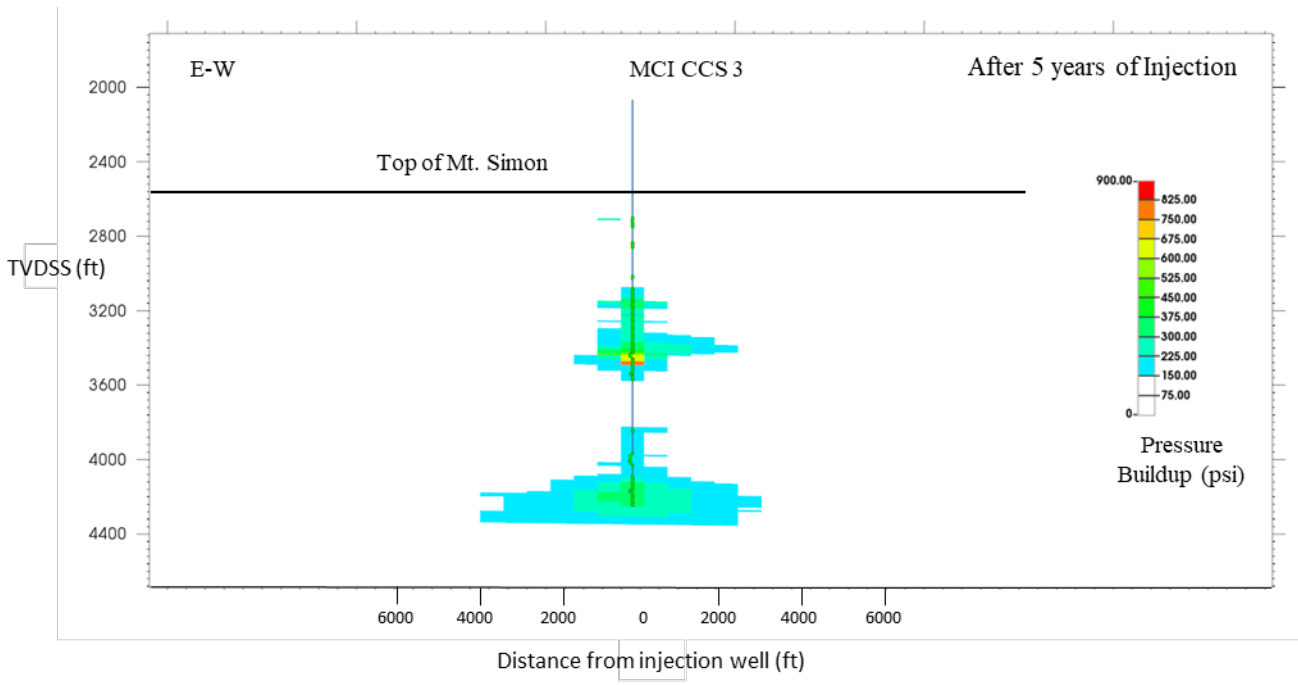


Figure 2-26: Pressure front after 1, 3 and 5 years of injection using 150 psi pressure cut-off.

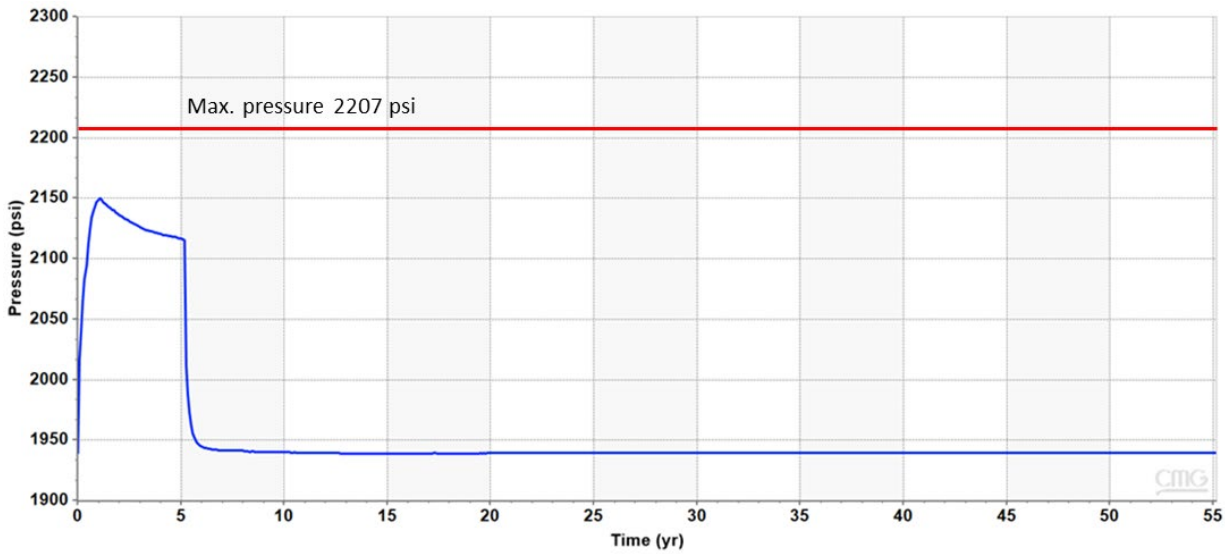


Figure 2-27: Pressure time-series data during injection and 50 years of post-injection period at depth of middle perforation (model layer 109, 3,898 TVDSS, ft.)

CO_2 saturation and pressure build-up were also modeled at the monitoring well location (MCI MW 2). The pressure at layer 153 (3,833 ft Subsea true vertical depth [TVDSS]) for the MCI CCS 3 and MCI MW 2 wells is plotted in Figure 2-27. As expected, the pressure build-up at the MCI MW 2 well is lower than the MCI CCS 3 well, and pressures quickly decline after injection stops.

Figure 2-29 shows the development of the CO_2 plume in layer 153 at the MCI CCS 3 and MCI MW 2 well. The CO_2 saturation immediately increases at the MCI CCS 3 well location compared to the MCI MW 2 well location.

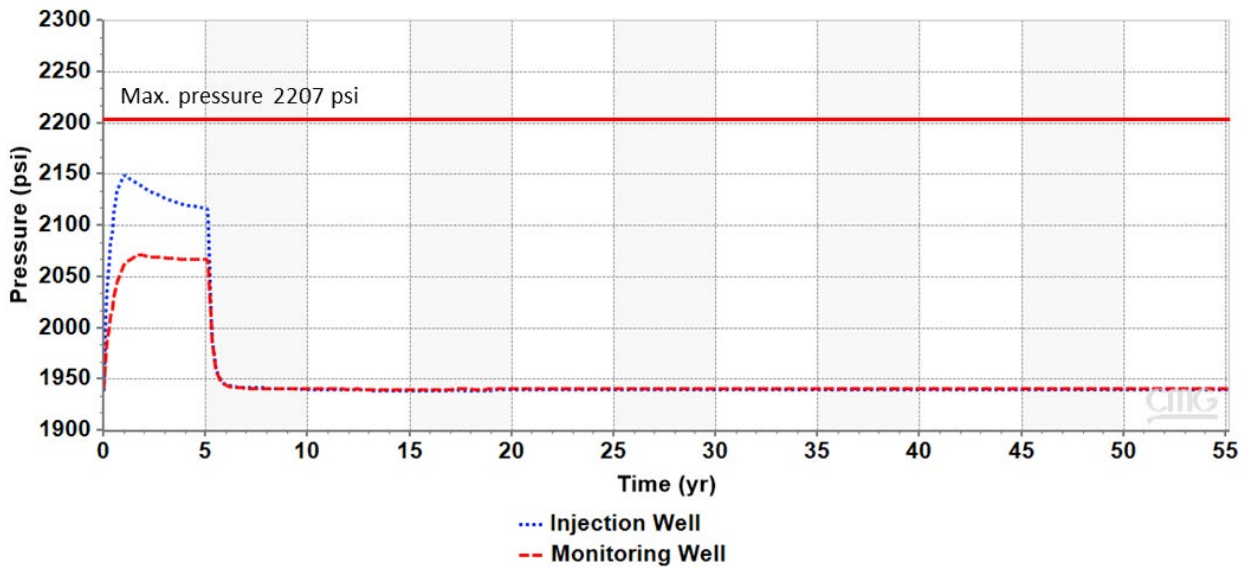


Figure 2-28: Pressure time-series data during injection and post injection period for monitoring (MCI MW 2) and injection well (MCI CCS 3) location at layer 153, 3,833 TVDSS, ft

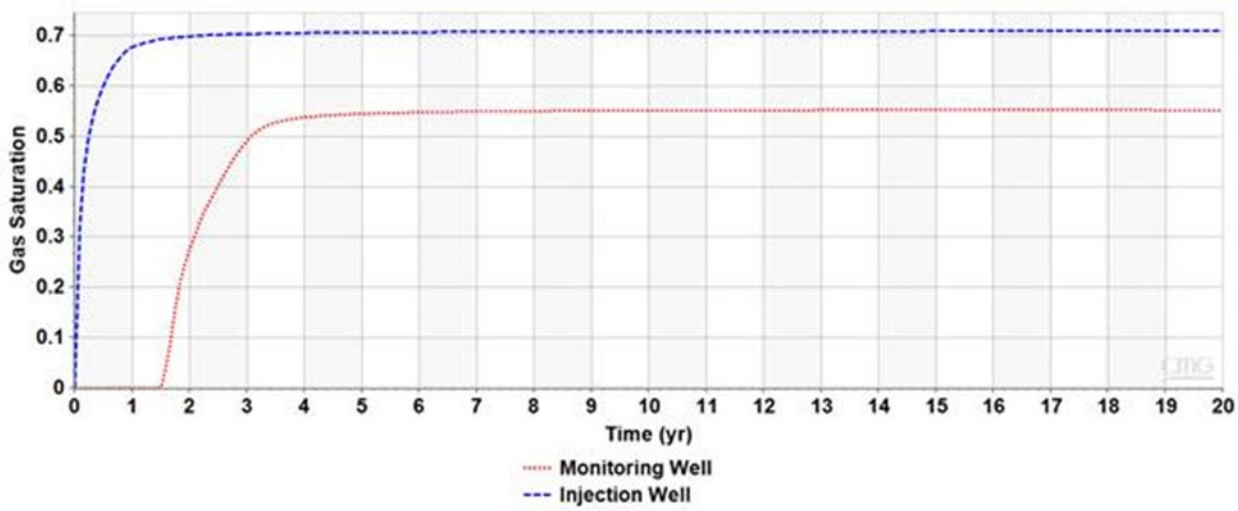


Figure 2-29: CO_2 saturation time-series data during injection and post injection period for monitoring (MCI MW 2) and injection (MCI CCS 3) well locations at layer 153 with MSL of 3,833 ft

2.2.2 Model Calibration and Validation

A robust earth model has been built and calibrated using data acquired in the MCI MW 1 well. Geological parameters (e.g., porosity, permeability), fluid flow data (e.g., relative permeability), and initial reservoir data (e.g., temperature, initial pressure gradient, fracture pressure gradient) used to build the computational model, were derived from data collected from the well. A wide variety of data was acquired from logs, core tests and other field measurements such as minifracs and drill stem tests (DSTs). The data acquired greatly enhances the geologic knowledge of the area confirming the characteristics of the site as a viable storage site.

Planned wellbore parameters such as tubing size and tubing temperature profile were also incorporated in the model for additional accuracy. Once the injection phase of the project begins, the monitoring data such as pressure and injected rates will be used to calibrate, and history match the model as the project proceeds. Moreover, as described in section 2.4 (below), the AoR will be assessed during the lifetime of the project.

Subsurface uncertainty is also addressed through the creation and simulation of alternative geological scenarios. Sensitivity runs were performed for different porosity and permeability relationships as shown in Figure 2-30. All model parameters were the same as the base case apart from the porosity and permeability.

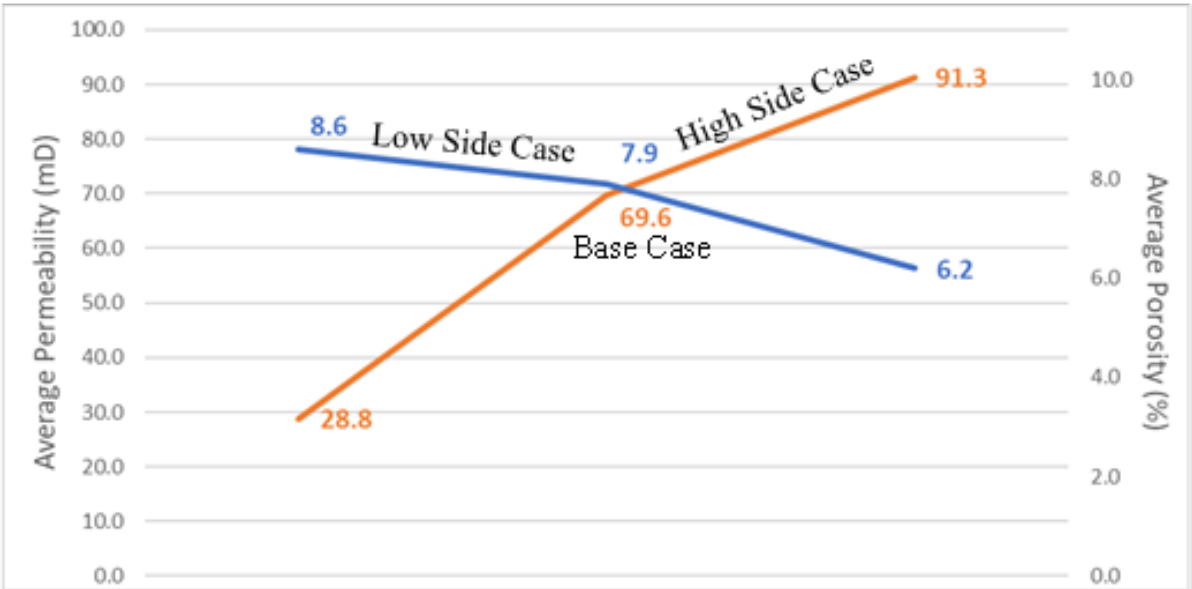


Figure 2-30: Porosity and permeability relationships for high side case (orange line) and low side case (blue line) showing an inverse relationship between the two scenarios. The numbers on the orange are permeability values, number on the blue line are porosity values.

The plume side views for the base, high side and low side cases after 3 years of injection are compared in Figure 2-31. The low side case scenario results in a larger overall plume diameter compared to the other two cases. Figure 2-32 shows the CO_2 plume in map view at layer 153, at the end of injection period and 5 and 10 years after the injection stops for the base case scenario. Results of the sensitivity analysis (high side case and low side case) shown in Figure 2-33 for CO_2 plume at layer 153 show that the AoR is smaller compared to base case scenario at the end of injection and post injection. It is also shown in Figure 2-33 that the plume size in the high and low side scenarios remains unchanged after 1 year post injection.

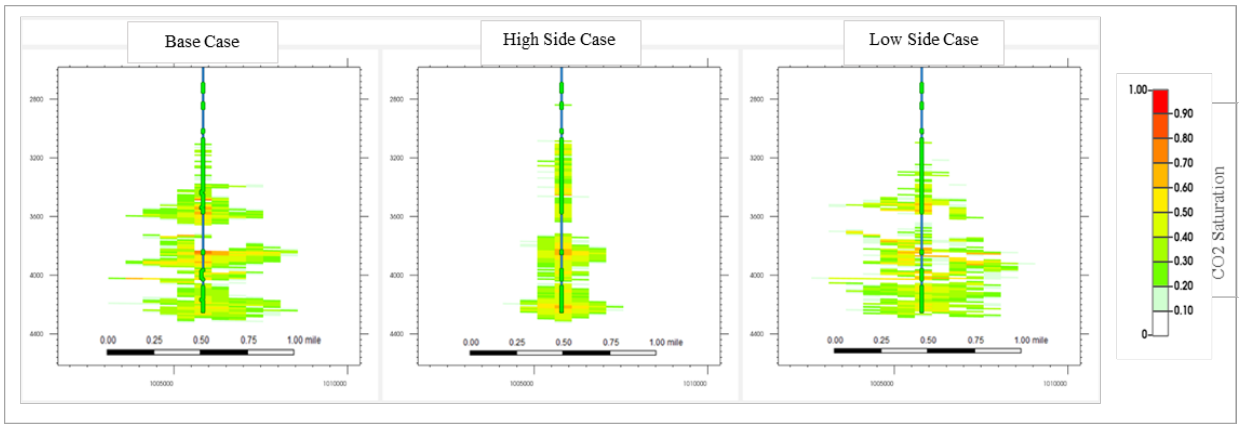


Figure 2-31: CO_2 plume at wellbore cross section after 3 years of injection. The left plume diagram represents the base case, middle represents the high side case, and the right plume diagram represents the low side case.

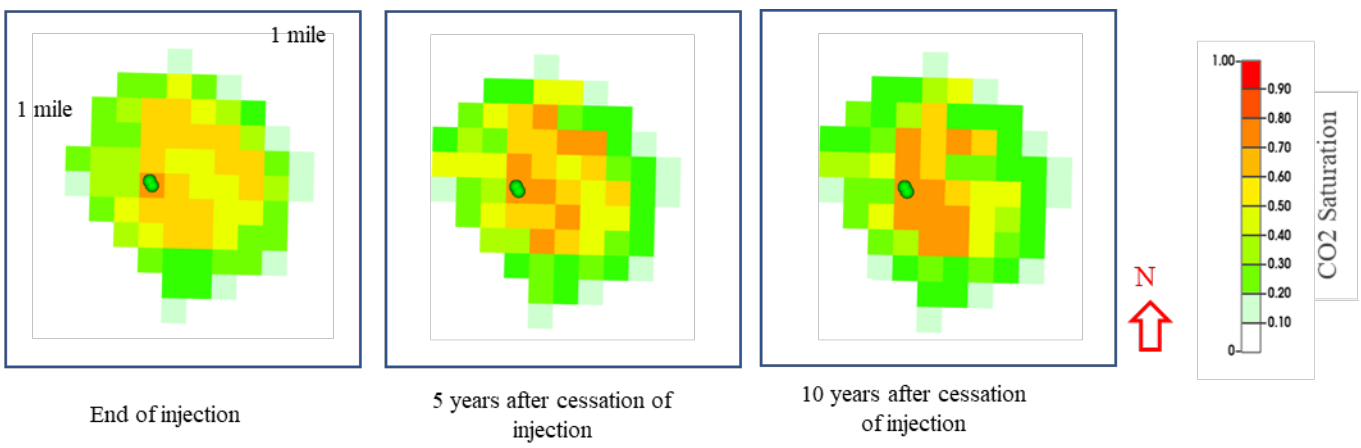


Figure 2-32: CO_2 plume at layer 153 (used to delineate AoR) for the base case at the end of injection, 5 years after injection stopped, and 10 years after injection stopped.

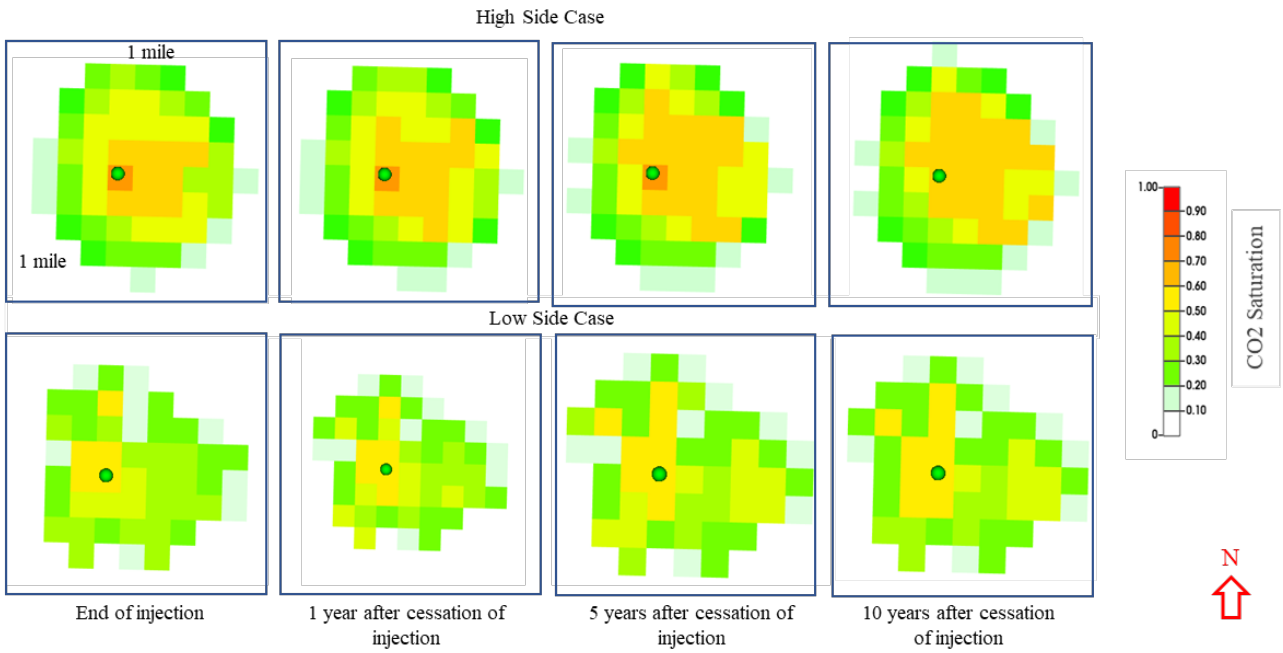


Figure 2-33: CO_2 plume at layer 153 (used to delineate AoR) at the end of injection and after, 1, 5 and 10 years after cessation of injection for the high side case (top row) and low side case (bottom row).

2.3 AoR Delineation

2.3.1 Critical Pressure Calculations

The critical pressure corresponds to the pressure needed to move fluids from the storage formation into a USDW through a hypothetical open conduit such as an uncemented well. Different methods can be used to calculate the required pressure to move fluid from the reservoir into a USDW. A simple hydrostatic head calculation (density of injection zone brine × depth distance between lowest USDW and top of injection zone × gravity constant) was used to estimate such required pressure. Using parameters listed in Table 2-5, the hydrostatic pressure required to move fluid was calculated to be 477 psi for the site. This pressure was calculated based on depth and pressure gradient and is the difference in hydrostatic pressure between the first perforation depth and lowest USDW. The storage formation overpressure would need to increase to values equal to or above 477 psi to move storage formation fluids into the USDW. This method was chosen for critical pressure calculation, since it is expected that pressure will dissipate early after shut-in due to the high permeability in the storage formation.

Input Data (Available)		
Attribute	**Zone**	**Value**
Depth	Deepest known USDW (Gunter)	2,140 ft, MD
	Top of the first injection zone (Mt. Simon Sandstone)	3,226 ft, MD
Pore pressure gradient (to estimate pressure)	All zones	0.44 psi/ft
Input Data (Calculated)		
Attribute	**Zone**	**Value**
Pressure	USDW	956.3 psi
	Topmost injection zone (Mt. Simon Sandstone)	3226 ft, MD

Table 2-5: Input data used for critical pressure calculation.

2.3.2 AoR Delineation

For the purposes of AoR determination, the extent of the CO_2 plume has been assessed at each vertical layer of the storage reservoir in the computational model. As discussed above, the plume size at layer 153 represents the average plume size of all the layers during injection and post-injection. The AoR is established by expanding the plume by 0.25 mi in all directions. Figure 2-34 shows the CO_2 plume extent and AoR delineation predicted by the computational modeling during the project lifetime.

2.4 Corrective Action

2.4.1 Tabulation of Wells within the AoR

Wells within the AoR were identified using well databases held by the ISGS. Available well information indicates that wells inside the AoR are all shallow groundwater wells less than 220 ft MD. A total of seven water wells are present within the AoR. Table 2-6 details these wells and includes the locations, dates drilled, total depths and aquifer depths, and compositions of the aquifers. One of the wells was deepened after being drilled and is represented twice in the table (API 121552046800 and API 121552052200). The wells correlate with the map provided in Figure 2-36, where existing wells are labeled by the corresponding total depth. No wells currently penetrate either the confining or injection zones within the AoR. The only wells in the AoR that will penetrate the confining zone will be wells related to the project. It is not believed that there are any deep historical wells in the area that have not been captured by these data sources.

API Number	Latitude	Longitude	Date Drilled	Total Depth (ft)	Total Depth Lithology	Bedrock top depth (ft)	Aquifer Top Depth (ft)	Aquifer Bottom Depth (ft)	Aquifer Description	Static Water Level (ft)
121552046800	41.263135	-89.30066	3/25/1996	216	SH/CL	216	206	216	S	169
121552052200	41.263135	-89.30066	10/31/1999	195	SH/CL		166	204	S	164
121552076400	41.277758	-89.31269	9/8/2006	210	SH	188	133	187	S	99
121552082100	41.278067	-89.30605	11/18/2007	190	SH	166	138	165	S	80
121552084100	41.27699	-89.30599	2/13/2011	177	SH	175	141	175	SG	86
121552084200	41.277739	-89.3055	4/19/2011	194	SH	192	136	193	SG	78
121552084300	41.27549	-89.3121	5/4/2011	181	SH	180	150	179	SG	74
121552085800	41.271028	-89.29614	7/24/2014	179	S		150	179	S	130

Lithology Key: SH = shale, CL = clay, S = sand, SG = sand & gravel.

Table 2-6: Tabulation of wells within the AoR

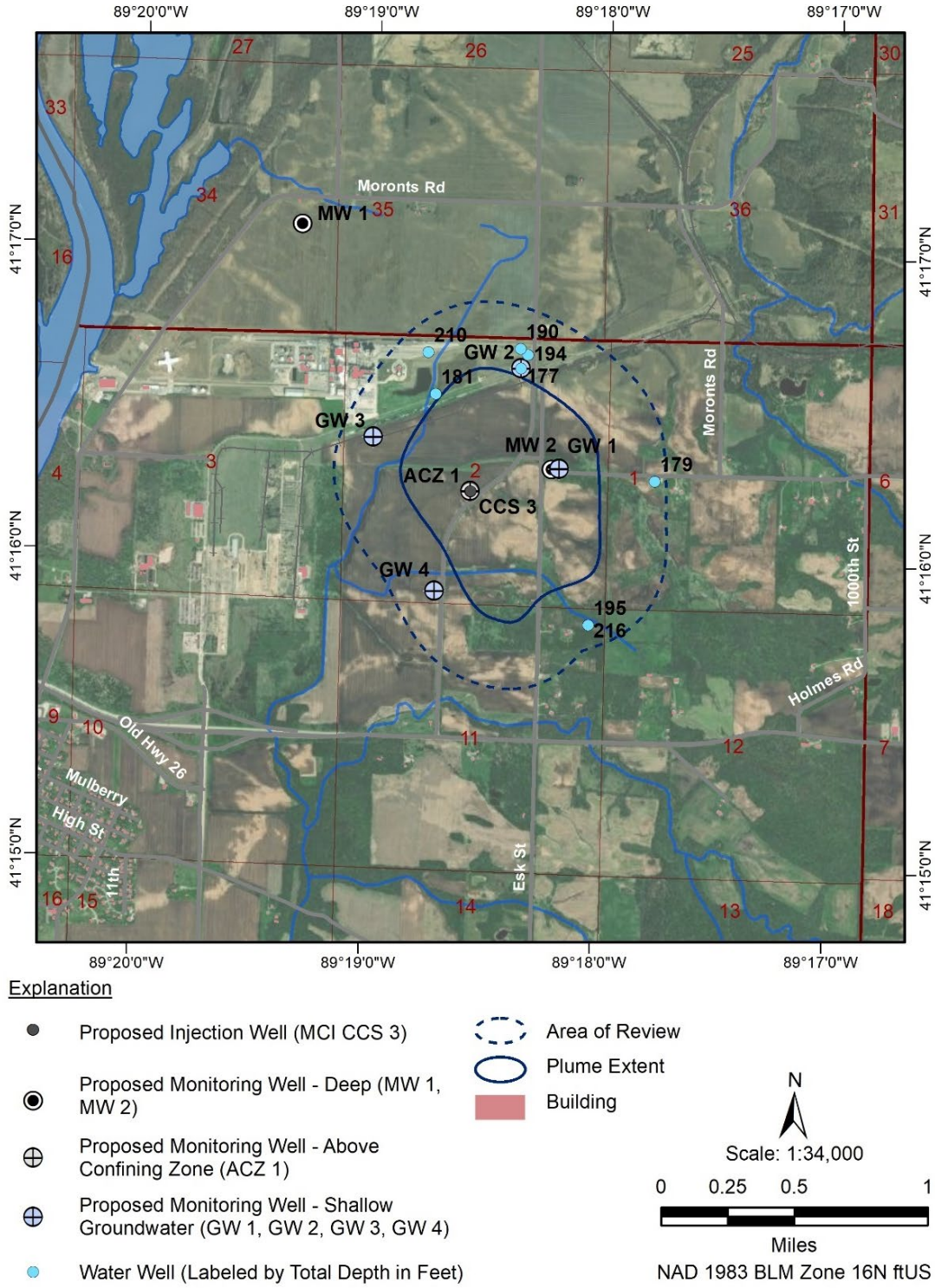


Figure 2-34: Map showing the modeled CO_2 plume footprint, AoR, and existing and proposed project wells within the AoR. Well data is summarized in 2-6.

2.4.2 Wells Penetrating the Confining Zone

The total depths of wells within the AoR were determined using the ISGS well databases. These well databases indicate that no wells within the AoR penetrate the confining zone. The deepest wells within the AoR are shallow groundwater wells less than 220 ft MD. Therefore, no corrective action will be needed.

2.4.3 Plan for Site Access

There are seven shallow groundwater wells (less than 220 ft MD) within the AoR. Five of the wells are located on property owned by Marquis. The other two wells are located within the AoR but outside of the CO_2 plume. However, of the existing seven wells, only one of the wells has been designated for purposes of shallow groundwater monitoring. Three additional shallow groundwater wells will be drilled within the AoR on land owned by Marquis. Because the wells are located on flat farmland owned by Marquis in a location that is free of obstructions and away from residential areas, the shallow groundwater monitoring wells are easily accessible.

Additionally, since none of the existing or future groundwater wells within the AoR have total depths deeper than 220 ft MD, there are no wells within the AoR that penetrate the Eau Claire Shale. Therefore, no corrective action activities have been proposed as part of the Marquis BioCarbon Project.

2.4.4 Corrective Action Schedule

It is not expected that any of the groundwater wells in the AoR will require corrective action. No corrective action schedule has been developed due to the absence of wells penetrating the confining zone within the AoR. The AoR will be re-evaluated every five years during the injection and post-injection phases unless an event occurs that triggers an AoR re-evaluation sooner. If the results of testing and monitoring and/or AoR re-evaluation throughout the project lifecycle indicate potential interference with any wells penetrating the confining zone, an amended corrective action plan will be implemented and submitted to the EPA (40 CFR 146.84 (e)(4)).

2.5 Re-evaluation Schedule and Criteria

2.5.1 AoR Re-evaluation Cycle

Marquis BioCarbon Project will re-evaluate the above described AoR every five years during the injection and post-injection phases pursuant to 146.84 (e).

The workflow (procedures) for incorporating the new data into the models as the project progresses is detailed in Figure 2-35.

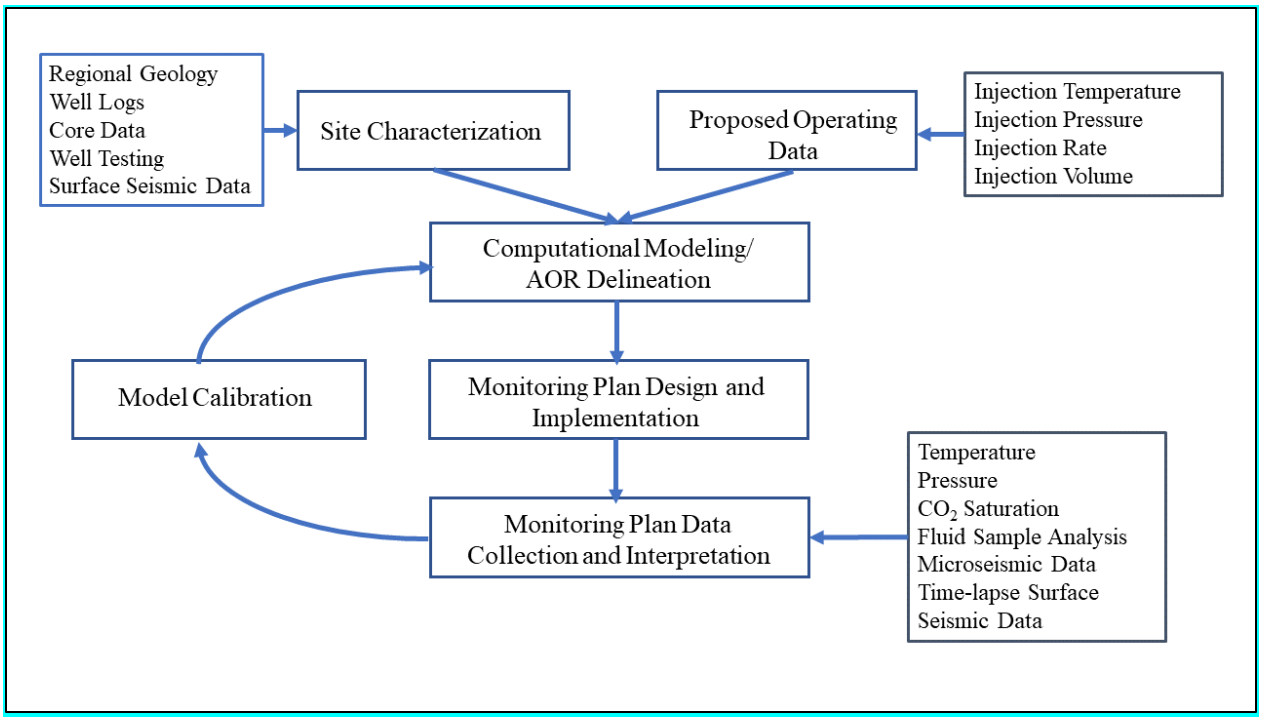


Figure 2-35: Workflow used to update the SEM and computational modeling.

With new data, model refinement is anticipated. The comparison of the original modeling with the updated modeling can take the form of several key evaluation metrics. This includes a comparison of:

- Changes to the static CO_2 resource estimate
- Differences in CO_2 plume geometry and volume
- Changes in pressure response

Any updates to the AOR will include an assessment of any additional wells that might be in the re-evaluated AoR that may need corrective action as well as an amended AoR and corrective action plan (40 CFR 146.84 (e)).

Once the injection phase of the project commences, both operational and verification monitoring data will be used to calibrate and update the computational model. Figure 2-35 illustrates the workflow and data inputs used to inform and calibrate the computational modeling. Operational monitoring data will be recorded on a continuous basis through the injection phase of the project. Pressure sensors located in the Mt. Simon Sandstone in the MCI MW 2 well will be retrieved on a quarterly basis for data download. In addition, pulsed neutron logs will be acquired in the MCI MW 2 well on a yearly basis to monitor CO_2 saturations along the well bores. The pressure and CO_2 saturation data from the MCI MW 2 well will be particularly useful in calibrating the computational model, as it will provide data on how the pressure plume is propagating through the Mt. Simon Sandstone away from the injection well. Computational model updates are also

expected to occur when the time-lapse surface seismic data are acquired on a four-year schedule. For more details on the Testing and Monitoring Plan and schedule refer to Permit Section 7.

The computational modeling will be updated with the downhole pressure and operational monitoring data on a quarterly basis for the first year of injection. If the system stabilizes, model updates will be scaled back to semi-annual updates to coincide with EPA reporting requirements (40 CFR 146.01). Any significant divergence of the monitoring data from the model predictions will be identified during the regular model updates and investigated. Model calibration with early monitoring data is expected to improve model predictions over the course of injection. It should be noted that model history-matching and calibration are not expected to trigger AoR reevaluations on a regular basis.

2.5.2 Triggers for AoR Reevaluations Prior to the Next Scheduled Reevaluation

The AoR will be updated on a 5-year schedule. However, Marquis Carbon Injection LLC will discuss any events that could impact the AoR with the UIC Director to determine if an AoR re-evaluation is required. If an unscheduled re-evaluation is triggered, Marquis Carbon Injection LLC will perform the steps described at the beginning of this section of this Plan. A report will be submitted to the UIC Director within 90 days of the AoR re-evaluation.
Monitoring and operational conditions that may warrant a re-evaluation of the AoR include (EPA, 2013):

- Changes in site operations that might alter the model predictions or the AoR delineation
- Site characterization data that may significantly change the computational model predictions and delineated AoR
- Monitoring results that indicate that the areal extent of the CO_2 plume or pressure front differ significantly from the model predictions
- Monitoring results indicate that the CO_2 has migrated beyond the confining zone

Table 2-7 details the operational changes and site characterization data that may warrant a reevaluation of the AoR. Table 2-8 specifies the observed changes and monitoring technologies that may trigger a re-evaluation of the AoR. Refer to the Testing and Monitoring Plan for more details on the proposed monitoring technologies for the project (Permit Section 7).

Area of Change	Variable
Operational Changes	• Increase in number of Class VI injection wells injecting in the Mt. Simon Sandstone in the immediate project area • Increase in CO_2 injection rates or volumes • Injection pressures more than the maximum allowable injection pressure for the project
Site Characterization Data	• Identification of a potential conduit for CO_2 or brine migration through the confining zone • Further characterization of storage formation heterogeneity that significantly effects CO_2 and pressure plume development

Table 2-7: Changes in operations and site characterization that may trigger AoR re-evaluation.

Observed Change	Monitoring Technology
Significantly larger pressure increases in the Mt. Simon Sandstone in the monitor well than were predicted by the model	Pressure sensors
Early breakthrough of CO_2 at the monitor well	Fluid sampling Pulsed neutron logging
CO_2 plume expands much faster than predicted by model	Time-lapse surface seismic data
Sustained pressure increases observed in above confining zone (ACZ) monitoring intervals	Pressure sensors
Geochemical changes in the ACZ monitoring intervals indicate potential CO_2 or brine migrations above the confining layer	Fluid sampling
CO_2 accumulations identified in the ACZ intervals	Pulsed neutron logging Time-lapse surface seismic data

Table 2-8: Observed changes in monitoring data that may trigger an AoR re-evaluation.

If the re-evaluated AoR is substantially different from the previous AoR, the project will identify all active and abandoned wells that penetrate the confining zone in the re-evaluated AoR and will perform corrective actions on those wells (40 CFR 146.84 (e)). As needed, all other plans, such as the Emergency and Remedial Response Plan, will be revised to account for the re-evaluated AoR and will submit those plans to the UIC Director for review and approval (40 CFR 146.84 (f)).

Note that seismic events are covered under the Emergency and Remedial Response Plan. A tiered approach to responding to seismic events will be based on magnitude and location. A notification procedure is provided in that plan.

2.6 References

Atherton, E., 1971, Tectonic development of the Eastern Interior Region of the United States: Illinois State Geological Survey Illinois Petroleum 96, p. 29-43.

Birkholzer JT, Nicot JP, Oldenburg CM, Zhou Q, Kraemer S, Bandilla K. Brine flow up a well caused by pressure perturbation from geologic carbon sequestration: Static and dynamic evaluations. International journal of greenhouse gas control 2011;5(4):850-61.

Burger C, Wortman D, Brown C, Hassan S, Humphreys K, Willford M. FutureGen 2.0 Pipeline and Regional Carbon Capture Storage Project-Final Report. Futuregen Industrial Alliance, Inc., Washington, DC (United States); 2016.

CMG-GEM. Advance compositional and GHG reservoir simulator user's guide. Calgary, Alberta 2016.

Cornet F. Results from the In-Situ Stress Characterization Program, Phase 1: Geomechanical Tests Conducted in the FutureGen Stratigraphic Well (FGA#1). The FutureGen Industrial Alliance, Inc. 2014.

DOE/EIS-0460. Final Environmental Impact Statement for the FutureGen 2.0 Project, Morgan County, Illinois. 2013.

Engelder T. Stress regimes in the lithosphere: Princeton University Press, 1992.
Enick RM, Klara SM. CO_2 solubility in water and brine under reservoir conditions. Chemical Engineering Communications 1990;90(1):23-33.

Fischietto NE. Lithofacies and Depositional Environments of the Cambrian Mount Simon Sandstone in the Northern Illinois Basin: Implications for CO_2 Sequestration (M.S. thesis, Purdue University); 2009.

Freiburg JT, Holland ME, Malone DH, Malone SJ. Detrital zircon geochronology of basal Cambrian strata in the deep Illinois Basin, USA: evidence for the Paleoproterozoic-Cambrian tectonic and sedimentary evolution of central Laurentia. The Journal of Geology. 2020 May 1;128(3):303-17.

Freiburg JT, Morse DG, Leetaru HE, Hoss RP, Yan Q. A Depositional and Diagenetic Characterization of the Mt. Simon Sandstone at the Illinois Basin - Decatur Project Carbon Capture and Storage Site, Decatur, Illinois, USA. Illinois State Geological Survey Circular 583. 2014

FutureGen Alliance, 2013, Underground Injection Control Permit Applications for FutureGen 2.0 Morgan County Class VI UIC Wells 1, 2, 3, and 4, FG-RPT-017.

Hall HN. Compressibility of reservoir rocks. Journal of Petroleum Technology 1953;5(01):17-9.

Jahediesfanjani H, Warwick PD, Anderson ST. 3D Pressure-limited approach to model and estimate CO_2 injection and storage capacity: saline Mount Simon Formation. Greenhouse Gases: Science and Technology 2017;7(6):1080-96.

Kestin J, Khalifa HE, Correia RJ. Tables of the dynamic and kinematic viscosity of aqueous NaCl solutions in the temperature range 20–150 C and the pressure range 0.1–35 MPa. Journal of physical and chemical reference data 1981;10(1):71-88.

Krevor SC, Pini R, Zuo L, Benson SM. Relative permeability and trapping of CO_2 and water in sandstone rocks at reservoir conditions. Water resources research 2012;48(2).

Kumar A, Noh M, Pope G, Sepehrnoori K, Bryant S, Lake L. Reservoir simulation of CO_2 storage in deep saline aquifers. SPE/DOE Symposium on Improved Oil Recovery: Society of Petroleum Engineers; 2004.

Land CS. Calculation of imbibition relative permeability for two-and three-phase flow from rock properties. Society of Petroleum Engineers Journal 1968;8(02):149-56.

Li YK, Nghiem LX. Phase equilibria of oil, gas and water/brine mixtures from a cubic equation of state and Henry's law. The Canadian Journal of Chemical Engineering 1986;64(3):486-96.

Lovell TR. An Intracratonic Record of North American Tectonics (Doctoral dissertation, Purdue University); 2017.

McCutcheon SC, Martin J, Barnwell T, Maidment D. Handbook of hydrology. Handbook of hydrology New York: McGraw-Hill 1993.

Mehnert E, Weberling PH. Groundwater Salinity within the Mt. Simon Sandstone in Illinois and Indiana. Illinois State Geological Survey, Prairie Research Institute.; 2014.

Nelson WJ. Structural features in Illinois. Illinois State Geological Survey, Bulletin no. 100. 1995.

Nghiem L, Sammon P, Grabenstetter J, Ohkuma H. Modeling CO_2 storage in aquifers with a fully-coupled geochemical EOS compositional simulator. SPE/DOE symposium on improved oil recovery: Society of Petroleum Engineers; 2004.

Nghiem L, Shrivastava V, Tran D, Kohse B, Hassam M, Yang C. Simulation of CO_2 storage in saline aquifers. SPE/EAGE Reservoir Characterization & Simulation Conference: European Association of Geoscientists & Engineers; 2009a. p. cp-170-00063.

Nghiem L, Shrivastava V, Tran D, Kohse B, Hassam M, Yang C. Simulation of CO_2 storage in saline aquifers. SPE/EAGE Reservoir Characterization & Simulation Conference2009b.

Nicot J-P, Oldenburg CM, Bryant SL, Hovorka SD. Pressure perturbations from geologic carbon sequestration: Area-of-review boundaries and borehole leakage driving forces. Energy Procedia 2009;1(1):47-54.

Palkovic MJ. Depositional characterization of the Eau Claire Formation at the Illinois Basin-Decatur Project: facies, mineralogy and geochemistry (M.S. thesis, University of Illinois at Urbana-Champaign); 2015.

Peng D-Y, Robinson DB. A new two-constant equation of state. Industrial & Engineering Chemistry Fundamentals 1976;15(1):59-64.

Raziperchikolaee S, Alvarado V, Yin S. Effect of hydraulic fracturing on long-term storage of CO_2 in stimulated saline aquifers. Applied energy 2013;102:1091-104.

Reesink AJ, Best J, Freiburg JT, Webb ND, Monson CC, Ritzi RW. Interpreting pre-vegetation landscape dynamics: The Cambrian Lower Mount Simon Sandstone, Illinois, USA. Journal of Sedimentary Research. 2020 Nov;90(11):1614-41.

Rowe Jr AM, Chou JC. Pressure-volume-temperature-concentration relation of aqueous sodium chloride solutions. Journal of Chemical and Engineering Data 1970;15(1):61-6.

Roy P, Morris JP, Walsh SD, Iyer J, Carroll S. Effect of thermal stress on wellbore integrity during CO_2 injection. International Journal of Greenhouse Gas Control 2018;77:14-26.

United States Environmental Protection Agency. Geologic Sequestration of Carbon Dioxide: Underground Injection Control (UIC) Program Class VI Well Area of Review Evaluation and Corrective Action Guidance. 2013: 96 p.

Willman, H.B., Atherton, E., Buschbach, T.C., Collinson, C., Frye, J.C., Hopkins, M.E. Lineback, J.A. and Simon, J.A. 1975. Handbook of Illinois Stratigraphy. Champaign, Illinois: Illinois State Geological Survey, Bulletin 95.

Boundary Conditions

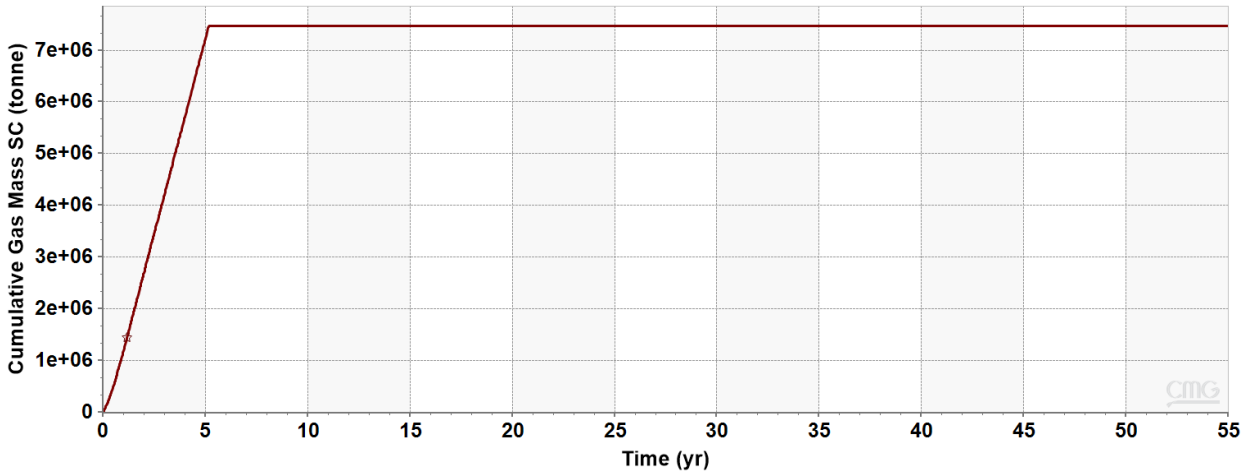
The model's lower boundary was the top of the Precambrian basement rock. While this surface is expected to have some topographical features, in general, it is assumed to dip to the southeast in the Putnam County area. The size of the static earth model was 7 mi × 7 mi. A single injection well was used at the center of the model so that the CO_2 plume and pressure buildup would be far from the computational model boundary (7 mi × 7 mi) and the model would be able to capture the multiphase flow phenomena. The model lateral boundary is assumed to be an infinite or open boundary reservoir. To model an open boundary reservoir, a volume modifier was used for the grids at the model boundary as recommended by CMG-GEM.

Critical Pressure

The critical pressure corresponds to the pressure needed to move fluids from the storage formation into a USDW through a hypothetical open conduit such as an uncemented well. Different methods can be used to calculate the required pressure to move fluid from the reservoir into a USDW. A simple hydrostatic head calculation (density of injection zone brine × depth distance between lowest USDW and top of injection zone × gravity constant) was used to estimate such required pressure. Using parameters listed in the table below, the hydrostatic pressure required to move fluid was calculated to be 477 psi for the site. This pressure was calculated based on depth and pressure gradient and is the difference in hydrostatic pressure between the first perforation depth and lowest USDW. The storage formation overpressure would need to increase to values equal to or above 477 psi to move storage formation fluids into the USDW. This method was chosen for critical pressure calculation, since it is expected that pressure will dissipate early after shut-in due to the high permeability in the storage formation.

Input Data (Available)		
Attribute	**Zone**	**Value**
Depth	Deepest known USDW (Gunter)	2,140 ft, MD
	Top of the first injection zone (Mt. Simon Sandstone)	3,226 ft, MD
Pore pressure gradient (to estimate pressure)	All zones	0.44 psi/ft
Input Data (Calculated)		
Attribute	**Zone**	**Value**
Pressure	USDW	956.3 psi
	Topmost injection zone (Mt. Simon Sandstone)	3226 ft, MD

Cumulative CO2 Injected Plot



Fracture Pressure and Fracture Gradient

The average fracture propagation pressure gradient measured at the MCI MW 1 well in the Mt. Simon, estimated during the analysis of the minifrac tests was 0.76 psi/ft. This value is consistent with literature and results from the hydraulic fracture tests performed in the FutureGen 2.0 site located in Morgan County, Illinois discussed in (Cornet, 2014).

This fracture gradient was used to constrain the wellbore pressure at the top of the perforation interval in CMG-GEM. The assigned well pressure in this case is 2,207 psi (3,226 ft MD × 0.76 psi/ft × 90%) following EPA guidelines.

The measured average fracture gradient for the Eau Claire Caprock is 0.95 psi/ft. A higher fracture gradient in the caprock compared to the Mt. Simon implies that even if a fracture were to be created in the Mt. Simon reservoir (e.g., due to inadvertent injection pressures), it would not extend or penetrate the overlying Eau Claire caprock layer.

Injection Pressure Details	**MCI MW 1**
Fracture gradient	0.76 psi/ ft
Maximum injection pressure (90% of fracture pressure)	2207 psi
Elevation corresponding to maximum injection pressure (MSL)	-2694 ft (3226 ft MD)

Table 2-1: Injection pressure details.

Heat Conductivity Equation in GEM

Ideal gas enthalpies are determined from a polynomial correlation for all components in the oil and gas phases. The coefficients in this polynomial are input via the *ENTHCOEF keyword in the Fluid Model section. These coefficients are available for library components in GEM, and are also included in the GEM fluid model file generated by WinProp. Final oil and gas phase enthalpies are calculated by adding the enthalpy departure term from the EOS to the ideal gas enthalpy.

The thermal option is invoked with the keyword *THERMAL *ON in the Fluid Model section. The rock heat capacity and thermal conductivity are input in the Reservoir Description section via *CP-ROCK and *THCONR0 keywords under *CROCKTYPE. The input is quite general in the sense that any selection of grid-blocks or any part of the reservoir can have its own set of rock heat capacity or thermal conductivity.

The ideal enthalpy at a given temperature T is calculated from a polynomial expression that takes the following form:

$$H_{ideal} = H_A + H_B * T + H_C * T^2 + H_D * T^3 + H_E * T^4 + H_F * T^5$$

where the temperature T is in °R. The ideal enthalpy coefficients H_A through H_F should be specified in units to give H_{ideal} in Btu/lb.

Coordinate System	NAD 1983 BLM Zone 16N ftUS		
Horizontal Datum	NAD83		
Coordinate System Units	Field = feet		
Zone	UTC -06:00 Central Time (US & Canada)		
FIPSZONE	1202		
Coordinate of X min	987293.52	**Coordinate of Y min**	14979542.23
Elevation of bottom of domain	-4473.32	**Elevation of top of domain**	-2117.49

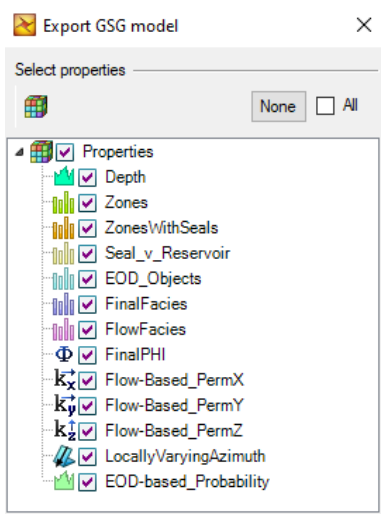
Grid Description

A 49 mi^2 SEM centered on the Marquis BioCarbon Project site was used to assess potential CO_2 storage and estimate the extent of the CO_2 plume. To mitigate potential edge-effects in simulation, the 7-mi by 7-mi model grid was designed to encase the entirety of the plume and pressure front for the intended injection period. The grid size is set at 500-ft by 500-ft with an average of 10 ft layers in the injection zone and 12 ft layers in the confining unit. The model grid is centered around the Marquis CCS 3 well, extending approximately 3.4 mi away from it in the X and Y directions.

The model framework for the Marquis BioCarbon Project includes 10 model zones from the top of the Eau Claire Shale to the Precambrian Basement. Each of the 10 model zones were divided into proportional layers, resulting in an average layer thickness of 12 feet in the Confining units and 10 feet in the Injection interval. Zone divisions and layering methods are listed

Zone	Formation	Depth (ft, MD)	Layer Method	Layers
Confining	Eau Claire Shale	2,722	Proportional	16
	Eau Claire Sand 1	2,913	Proportional	7
	Upper Elmhurst	2,998	Proportional	6
Injection	Lower Elmhurst	3,074	Proportional	4
	Mt. Simon 1	3,125	Proportional	43
	Mt. Simon 2	3,561	Proportional	21
	Mt. Simon 3	3,784	Proportional	20
	Mt. Simon 4	3,970	Proportional	35
	Mt. Simon 5	4,364	Proportional	23
	Mt. Simon 6	4,607	Proportional	10
	Mt. Simon 7	4,716	Proportional	15
	Precambrian Basement	4,880		

For the purpose of this submission, the model is being provided as a Generic Simulation Grid (gsg) containing the properties shown below:



Explanation

- Proposed Injection Well (MCI CCS 3)
- Model Boundary

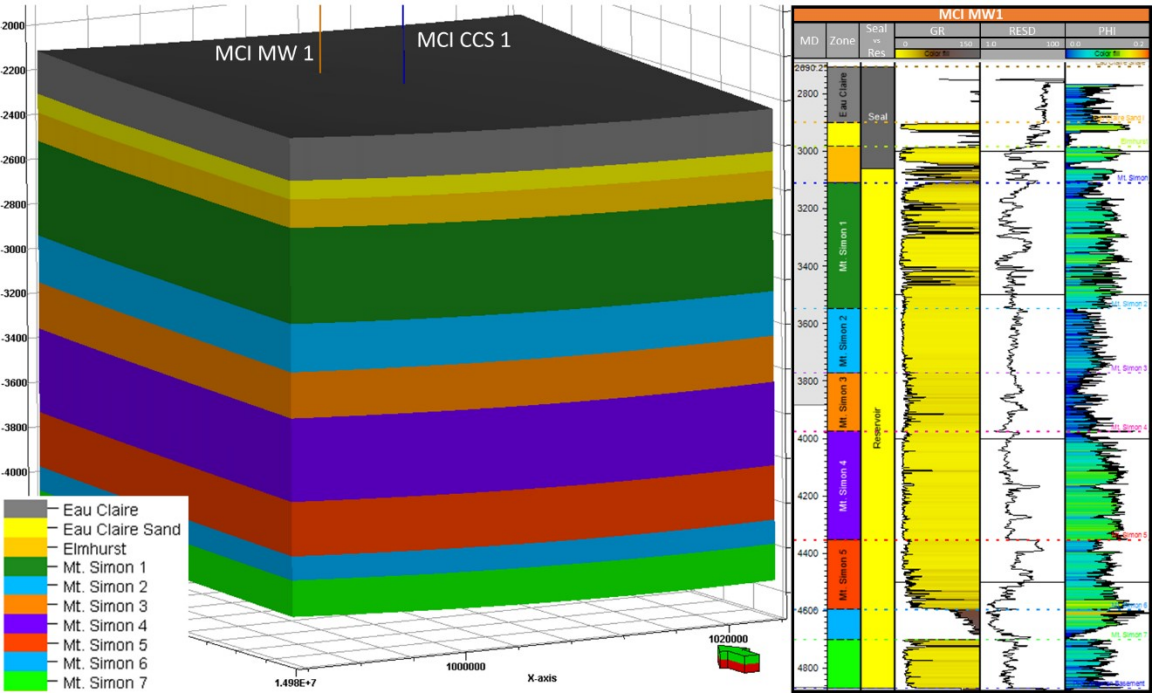
N

Scale: 1:85,000

0 0.5 1 2

Miles

NAD 1983 BLM Zone 16N ftUS


MCI MW 1
MCI CCS 1
-2000
-2200
-2400
-2600
-2800
-3000
-3200
-3400
-3600
-3800
-4000
Eau Claire
Eau Claire Sand
Elmhurst
Mt. Simon 1
Mt. Simon 2
Mt. Simon 3
Mt. Simon 4
Mt. Simon 5
Mt. Simon 6
Mt. Simon 7
1.498E+7
1000000
1020000
X-axis
MCI MW1
MD
Zone
Seal vs Res
GR
RESD
PHI
Eau Claire
Mt. Simon 1
Mt. Simon 2
Mt. Simon 3
Mt. Simon 4
Mt. Simon 5
Seal
Reservoir
2690.22
2800
3000
3200
3400
3600
3800
4000
4200
4400
4600
4800

Model and Simulator Description

Computational modeling at the Marquis BioCarbon Project site was completed to delineate the plume size and shape, area of pressure buildup, and Area of Review (AoR) for injected carbon dioxide (CO_2). A Static Earth Model (SEM) named Marquis_SEM_1 was prepared by Battelle using the Schlumberger Petrel® modeling software. The SEM is a three-dimensional (3D) geocellular model that represents petrophysical properties within the stratigraphic formation intended for CO_2 storage, as well as the overlying confining layer. This type of model offers the best options for quantifying, visualizing, and simulating dynamic behavior through the subsurface geology at the site. By integrating multiple data types, the model represents the spatial distribution of available pore space and flow potential (permeability), enabling a data-driven estimation of CO_2 storage capacity. The SEM serves as the framework (in terms of delineating zones, surfaces, porosity, and permeability) for dynamic simulation of CO_2 injection.

Computational modeling to simulate CO_2 injection into the saline aquifer was completed by Battelle using Computer Modeling Group's (CMG) 3D multiphase flow simulator CMG-GEM version 2016 (CMG-GEM, 2016). In addition to the geological framework and associated properties imported from the SEM, parameters such as relative permeability, initial reservoir conditions, phase behavior, and well completion were added to the dynamic model for simulation. CMG-GEM is an equation-of-state based compositional simulator that models the phase behavior of brine and CO_2 plumes during the injection and post-injection stages of a project.

Aqueous, gaseous, and supercritical phases of CO_2 were accounted for in the computational model. Component transport equations, which describe the thermodynamic equilibrium between gaseous or supercritical with aqueous phases, were used in the compositional simulator to model CO_2 injection into the saline aquifer (Nghiem et al., 2004). The Peng-Robinson equation of state was used to model the fluid properties of the injected CO_2 in gaseous/supercritical phases (Peng and Robinson, 1976). The solubility of the injected CO_2 in brine is modeled as a phase equilibrium process, which is computed using Henry's law to estimate the fugacity of the gaseous and aqueous phases as functions of pressure and temperature (Li and Nghiem, 1986; Enick and Klara, 1990; Nghiem et al., 2009a). Additionally, the viscosity and density of the aqueous phase were calculated as functions of pressure, temperature, and salinity. Rowe and Chow (1970) equation was used to estimate aqueous phase density, and the Kestin et al. (1981) correlation was used to estimate the viscosity of the aqueous fluids.

ResearchGate

See discussions, stats, and author profiles for this publication at: https://www.researchgate.net/publication/231293953

New Two-Constant Equation of State

Article *in* Industrial & Engineering Chemistry Fundamentals · February 1976

DOI: 10.1021/i160057a011

CITATIONS
9,746

READS
3,946

2 authors, including:

Ding-yu Peng
University of Saskatchewan

59 PUBLICATIONS **10,710** CITATIONS

SEE PROFILE

All content following this page was uploaded by Ding-yu Peng on 19 July 2018.

The user has requested enhancement of the downloaded file.

Palmer, H. J., Berg, J. C., *J. Fluid Mech.*, **51**, 385 (1972).
Palmer, H. J., Berg, J. C., *A.I.Ch.E. J.*, **19**, 1082 (1973).
Plevan, R. E., Quinn, J. A., *A.I.Ch.E. J.*, **12**, 894 (1966).
Rhodes, F. H., Bridges, C. H., *Ind. Eng. Chem.*, **30**, 1401 (1938).
Robb, I. D., Alexander, A. E., *J. Colloid Interface Sci.*, **28**, 1 (1968).
Rosano, H., LaMer, V. K., *J. Phys. Chem.*, **60**, 348 (1956).
Springer, T. G., Pigford, R. L., *Ind. Eng. Chem., Fundam.*, **9**, 458 (1970).
Van Stralen, S. J. D., *Netherl., J. Agric. Sci.*, **4**, 107 (1956).
Van Stralen, S. J. D., *Int. J. Heat Mass Transfer*, **10**, 1469 (1967).
Van Stralen, S. J. D., 4th Intl. Heat Transfer Conf., Paris-Versailles, "Heat Transfer 1970", Vol. VI, paper B.7.b, 1970.

Received for review December 11, 1974
Accepted October 14, 1975

This work was supported by the Office of Saline Water under Contract No. 14-30-2964 and No. 14-30-2572.

A New Two-Constant Equation of State

Ding-Yu Peng and Donald B. Robinson*

Department of Chemical Engineering, University of Alberta, Edmonton, Alberta, Canada

The development of a new two-constant equation of state in which the attractive pressure term of the semiempirical van der Waals equation has been modified is outlined. Examples of the use of the equation for predicting the vapor pressure and volumetric behavior of single-component systems, and the phase behavior and volumetric behavior of binary, ternary, and multicomponent systems are given. The proposed equation combines simplicity and accuracy. It performs as well as or better than the Soave–Redlich–Kwong equation in all cases tested and shows its greatest advantages in the prediction of liquid phase densities.

Introduction

Ever since the appearance of the van der Waals equation in 1873 (van der Waals, 1873), many authors have proposed variations in the semiempirical relationship. One of the most successful modifications was that made by Redlich and Kwong (1949). Since that time, numerous modified Redlich–Kwong (RK) equations have been proposed (Redlich and Dunlop, 1963; Chueh and Prausnitz, 1967; Wilson, 1969; Zudkvitch and Joffe, 1970; and others). Some have introduced deviation functions to fit pure substance *PVT* data while others have improved the equation's capability for vapor–liquid equilibrium (VLE) predictions. A review of some of the modified RK equations has been presented (Tsonopoulos and Prausnitz, 1969). One of the more recent modifications of the RK equation is that proposed by Soave (1972). The Soave–Redlich–Kwong (SRK) equation has rapidly gained acceptance by the hydrocarbon processing industry because of the relative simplicity of the equation itself as compared with the more complicated BWRS equation (Starling and Powers, 1970; Lin et al., 1972) and because of its capability for generating reasonably accurate equilibrium ratios in VLE calculations.

However, there still are some shortcomings which the SRK equation and the original RK equation have in common. The most evident is the failure to generate satisfactory density values for the liquid even though the calculated vapor densities are generally acceptable. This fact is illustrated in Figure 1 which shows the comparison of the specific volumes of *n*-butane in its saturated states. The literature values used for the comparison were taken from Starling (1973). It can be seen that the SRK equation always predicts specific volumes for the liquid which are greater than the literature values and the deviation increases from about 7% at reduced temperatures below 0.65 to about 27% when the critical point is approached. Similar results have been obtained for other hydrocarbons larger than methane. For small molecules like nitrogen and methane the deviations are smaller.

Although one cannot expect a two-constant equation of state to give reliable predictions for all of the thermodynamic properties, the demand for more accurate predictions of the volumetric behavior of the coexisting phases in VLE calculations has prompted the present investigation into the possibility that a new simple equation might exist which would give better results than the SRK equation. In this paper, an equation is presented which gives improved liquid density values as well as accurate vapor pressures and equilibrium ratios.

Formulation of the Equation

Semiempirical equations of state generally express pressure as the sum of two terms, a repulsion pressure P_R and an attraction pressure P_A as follows

$$P = P_R + P_A \tag{1}$$

The equations of van der Waals (1873), Redlich and Kwong (1949), and Soave (1972) are examples and all have the repulsion pressure expressed by the van der Waals hard sphere equation, that is

$$P_R = \frac{RT}{v - b} \tag{2}$$

The attraction pressure can be expressed as

$$P_A = -\frac{a}{g(v)} \tag{3}$$

where $g(v)$ is a function of the molar volume v and the constant b which is related to the size of the hard spheres. The parameter a can be regarded as a measure of the intermolecular attraction force. Applying eq 1 at the critical point where the first and second derivatives of pressure with respect to volume vanish one can obtain expressions for a and b at the critical point in terms of the critical properties. While b is usually treated as temperature independent, a is constant only in van der Waals equation. For the RK equation and the SRK equation, dimensionless scaling

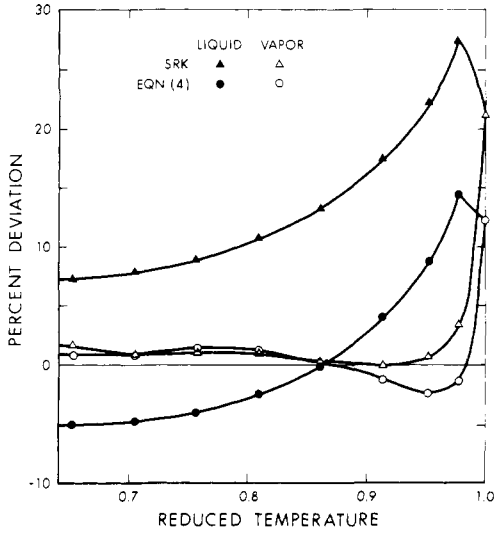


Figure 1. Comparison of predicted molar volumes for saturated n-butane.

factors are used to describe the temperature dependence of the energy parameter.

A study of the semiempirical equations having the form of eq 1 indicates that by choosing a suitable function for $g(v)$, the predicted critical compressibility factor can be made to approach a more realistic value. The applicability of the equation at very high pressures is affected by the magnitude of b/v_c where v_c is the predicted critical volume. Furthermore, by comparing the original RK equation and the SRK equation, it is evident that treating the dimensionless scaling factor for the energy parameter as a function of acentric factor in addition to reduced temperature has significantly improved the prediction of vapor pressures for pure substances and consequently the equilibrium ratios for mixtures.

We propose an equation of the form

$$P = \frac{RT}{v - b} - \frac{a(T)}{v(v + b) + b(v - b)} \tag{4}$$

Equation 4 can be rewritten as

$$Z^3 - (1 - B)Z^2 + (A - 3B^2 - 2B)Z - (AB - B^2 - B^3) = 0 \tag{5}$$

where

$$A = \frac{aP}{R^2T^2} \tag{6}$$

$$B = \frac{bP}{RT} \tag{7}$$

$$Z = \frac{Pv}{RT} \tag{8}$$

Equation 5 yields one or three roots depending upon the number of phases in the system. In the two-phase region, the largest root is for the compressibility factor of the vapor while the smallest positive root corresponds to that of the liquid.

Applying eq 4 at the critical point we have

$$a(T_c) = 0.45724\frac{R^2T_c^2}{P_c} \tag{9}$$

$$b(T_c) = 0.07780\frac{RT_c}{P_c} \tag{10}$$

$$Z_c = 0.307 \tag{11}$$

At temperatures other than the critical, we let

$$a(T) = a(T_c) \cdot \alpha(T_r, \omega) \tag{12}$$

$$b(T) = b(T_c) \tag{13}$$

where $\alpha(T_r, \omega)$ is a dimensionless function of reduced temperature and acentric factor and equals unity at the critical temperature. Equation 12 was also used by Soave (1972) for his modified RK equation.

Applying the thermodynamic relationship

$$\ln\frac{f}{p} = \int_0^P \left(\frac{v}{RT} - \frac{1}{P}\right) dP \tag{14}$$

to eq 4, the following expression for the fugacity of a pure component can be derived

$$\ln\frac{f}{p} = Z - 1 - \ln(Z - B) - \frac{A}{2\sqrt{2}B}\ln\left(\frac{Z + 2.414B}{Z - 0.414B}\right) \tag{15}$$

The functional form of $\alpha(T_r, \omega)$ was determined by using the literature vapor pressure values (Reamer et al., 1942; Rossini et al., 1953; Reamer and Sage, 1957; Starling, 1973) and Newton's method to search for the values of α to be used in eq 5 and 15 such that the equilibrium condition

$$f^L = f^V \tag{16}$$

is satisfied along the vapor pressure curve. With a convergence criterion of $|f^L - f^V| \leq 10^{-4}$ kPa about two to four iterations were required to obtain a value for α at each temperature.

For all substances examined the relationship between α and T_r can be linearized by the following equation

$$\alpha^{1/2} = 1 + \kappa(1 - T_r^{1/2}) \tag{17}$$

where κ is a constant characteristic of each substance. As shown in Figure 2, these constants have been correlated against the acentric factors. The resulting equation is

$$\kappa = 0.37464 + 1.54226\omega - 0.26992\omega^2 \tag{18}$$

It is interesting to note that eq 17 is similar to that obtained by Soave (1972) for the SRK equation although eq 17 is arrived at for each substance using vapor pressure data from the normal boiling point to the critical point whereas Soave used only the critical point and the calculated vapor pressure at $T_r = 0.7$ based on the value of acentric factor.

The fugacity coefficient of component k in a mixture can be calculated from the following equation

$$\ln\frac{f_k}{x_k P} = \frac{b_k}{b}(Z - 1) - \ln(Z - B) - \frac{A}{2\sqrt{2}B} \times \left(\frac{2\Sigma_i X_i a_{ik}}{a} - \frac{b_k}{b}\right) \ln\left(\frac{Z + 2.414B}{Z - 0.414B}\right) \tag{19}$$

The mixture parameters used in eq 5 and 19 are defined by the mixing rules

$$a = \sum_i\sum_j x_i x_j a_{ij} \tag{20}$$

$$b = \sum_i x_i b_i \tag{21}$$

where

$$a_{ij} = (1 - \delta_{ij})a_i^{1/2}a_j^{1/2} \tag{22}$$

In eq 22 δ_{ij} is an empirically determined binary interaction coefficient characterizing the binary formed by component i and component j. Equation 22 has been used previously by Zudkevitch and Joffe (1970) for their modified RK equation in calculating vapor–liquid equilibrium ratios.

Table I. Comparison of Vapor Pressure Predictions

Substance	No. of data points	Absolute error, psia						Relative error, %					
		AAD		BIAS		RMS		AAD		BIAS		RMS	
		SRK	Eq 4	SRK	Eq 4	SRK	Eq 4	SRK	Eq 4	SRK	Eq 4	SRK	Eq 4
C_1	28	3.08	1.82	2.82	1.72	4.31	2.83	1.44	0.66	0.47	0.38	1.57	0.77
C_2	27	1.12	0.58	0.87	−0.58	1.38	0.65	0.70	0.34	−0.10	−0.34	0.95	0.38
C_3	31	2.68	1.09	2.66	1.06	3.37	1.47	0.98	0.36	0.87	0.31	1.10	0.42
i-C_4	27	1.83	0.54	1.78	0.50	2.33	0.71	1.06	0.32	0.82	0.16	1.18	0.34
n-C_4	28	1.45	0.50	1.38	0.03	2.05	0.62	0.75	0.37	0.47	−0.22	0.86	0.42
i-C_5	15	0.64	0.95	0.22	−0.95	0.86	1.48	0.46	0.54	0.17	−0.53	0.49	0.60
n-C_5	30	1.65	0.69	1.56	0.28	2.26	0.95	0.92	0.58	0.50	−0.29	1.02	0.66
n-C_6	29	2.86	1.69	2.81	1.53	3.97	2.65	1.55	0.90	1.31	0.37	1.75	1.06
n-C_7	18	2.29	1.34	2.29	1.30	3.24	2.02	1.51	0.79	1.48	0.63	1.88	1.04
n-C_8	16	2.61	1.55	2.61	1.54	3.30	2.08	1.99	1.04	1.97	1.02	2.24	1.26
N_2	17	0.74	0.38	0.60	−0.10	1.07	0.48	0.56	0.31	0.00	−0.02	0.75	0.37
CO_2	30	2.77	1.95	2.73	−0.82	3.87	2.44	0.53	0.62	0.50	−0.49	0.63	0.71
H_2S	30	1.68	1.18	1.57	−0.53	2.52	1.42	0.66	0.96	0.34	0.42	1.00	1.48

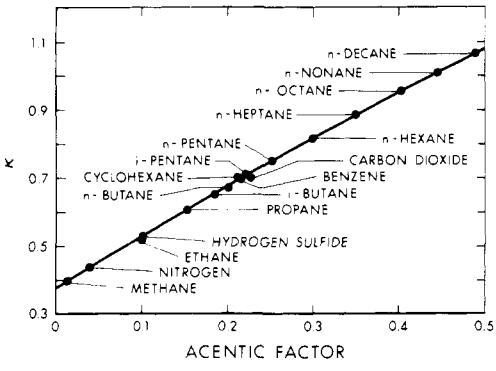


Figure 2. Relationship between characterization constants and acentric factors.

In this study δ_{ij}'s were determined using experimental binary VLE data. The value of δ_{ij} obtained for each binary was the one that gave a minimum deviation in the predicted bubble point pressures. The importance of the interaction coefficient is illustrated in Figure 3 for the binary system isobutane-carbon dioxide (Besserer and Robinson, 1973). It can be seen that the use of an interaction coefficient has greatly improved the predictions.

The enthalpy departure of a fluid which follows eq 4 is given by

$$H - H^* = RT(Z-1) + \frac{T\frac{da}{dT} - a}{2\sqrt{2}b} \ln\left(\frac{Z + 2.44B}{Z - 0.414B}\right) \quad (23)$$

This is obtained by substituting eq 4 into the thermodynamic equation

$$H - H^* = RT(Z-1) + \int_{\infty}^{v} \left[T\left(\frac{\partial P}{\partial T}\right)_v - P\right] dv \quad (24)$$

Comparisons

Since two-constant equations of state have their own purposes we do not compare the equation obtained in this study with the more complicated BWR (Benedict et al., 1940) or BWRS equations although in some circumstances these may give more accurate predictions at the expense of more computer time and computer storage space. The following comparisons are intended to show that in regions where engineering calculations are most frequently encountered better results can usually be obtained with the equation presented in this study than with the SRK equation. The symbols AAD, BIAS, and RMS are used to denote respectively the average absolute deviation, the bias, and the

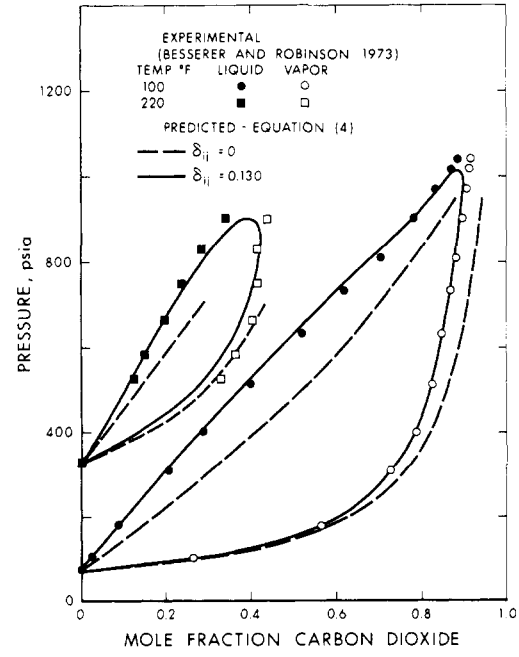


Figure 3. Pressure–equilibrium phase composition diagram for isobutane–carbon dioxide system.

root-mean-square deviation

$$\text{AAD} = \frac{\sum_{i=1}^{N} |d_i|}{N} \quad (25)$$

$$\text{BIAS} = \frac{\sum_{i=1}^{N} d_i}{N} \quad (26)$$

$$\text{RMS} = \frac{\sum_{i=1}^{N} d_i^2}{N} \quad (27)$$

where the d_i are the errors (either absolute or relative) and N is the number of data points.

Pure Substances

Vapor Pressures. Both the SRK equation and eq 4 are designed with a view to reproduce accurately the vapor pressures of pure nonpolar substances. Nevertheless eq 4 gives better agreement between calculated vapor pressures and published experimental values. A comparison of the predictions is presented in Table I for ten paraffins and

Table II. Comparison of Enthalpy Departure Predictions

Substance	No. of data points	Reference	Temperature range, °F	Pressure range, psia	Error, BTU/lb AAD SRK	AAD Eq 4	BIAS SRK	BIAS Eq 4	RMS SRK	RMS Eq 4
Nitrogen	48	(Mage, 1963)	−250–50	200–2000	0.57	1.13	0.24	−0.58	0.80	1.25
Methane	35	(Jones, 1963)	−250–50	250–2000	2.58	1.97	−1.13	−0.78	3.58	2.52
n-Pentane	160	(Lenoir, 1970)	75–700	200–1400	1.43	1.18	0.78	0.25	1.82	1.61
n-Octane	70	(Lenoir, 1970)	75–600	200–1400	2.47	2.43	2.18	2.36	3.36	3.16
Cyclohexane	113	(Lenoir, 1971)	300–680	200–1400	2.83	2.48	2.16	1.75	3.60	3.26

Table III. Compressibility Factor of the *n*-Butane–Carbon Dioxide System (Data by Olds et al., 1949)

Temp, °F	Pressure, psia	Mole fraction *n*-Butane 0.9 SRK	0.9 Eq 4	0.9 Expt	0.5 SRK	0.5 Eq 4	0.5 Expt	0.1 SRK	0.1 Eq 4	0.1 Expt
100	600	0.170	0.151	0.158			—	0.743	0.722	0.740
	1000	0.279	0.248	0.260	0.242	0.215	0.218			—
	2000	0.542	0.482	0.510	0.452	0.404	0.418	0.374	0.339	0.325
	3000	0.793	0.707	0.753	0.649	0.580	0.610	0.505	0.455	0.454
	4000	1.037	0.926	0.989	0.838	0.750	0.794	0.631	0.568	0.580
280	600				0.804	0.782	0.798	0.924	0.908	0.918
	1000	0.320	0.289	0.274	0.665	0.638	0.644	0.876	0.852	0.862
	2000	0.536	0.482	0.489	0.584	0.545	0.525	0.786	0.750	0.744
	3000	0.740	0.665	0.694	0.702	0.645	0.642	0.766	0.722	0.699
	4000	0.934	0.840	0.888	0.838	0.765	0.782	0.801	0.749	0.727
460	600	0.830	0.804	0.818	0.928	0.910	0.920	0.976	0.965	0.968
	1000	0.730	0.696	0.694	0.889	0.862	0.870	0.964	0.946	0.948
	2000	0.690	0.643	0.627	0.843	0.803	0.796	0.947	0.915	0.912
	3000	0.808	0.744	0.746	0.871	0.822	0.806	0.949	0.908	0.898
	4000	0.950	0.869	0.895	0.942	0.881	0.877	0.969	0.921	0.906

three commonly encountered nonhydrocarbons. It can be seen that the absolute errors are greatly reduced using eq 4 for all substances except isopentane. The slightly larger overall relative errors shown for carbon dioxide and hydrogen sulfide resulted from the higher percentage errors at the lower pressure regions. The consistently larger deviation shown by eq 4 for isopentane could be due to errors in the experimental results in the high-temperature region where differences between the predicted and experimental values as large as 4 psi (equivalent to 1%) occurred.

Densities. Generally, saturated liquid density values calculated from the SRK equation are lower than literature values. This is true except for small molecules like nitrogen and methane at very low temperatures where the predicted values are slightly higher. Equation 4 predicts saturated liquid densities which are higher at low temperatures and lower at high temperatures than the experimental values. As an example, the prediction for *n*-butane is presented in Figure 1. The fact that eq 4 gives a universal critical compressibility factor of 0.307 as compared with SRK's 0.333 has improved the predictions in the critical region.

The specific volumes of saturated vapors have also been compared. The results for *n*-butane are included in Figure 1. It can be seen that both equations yield acceptable values except that in the critical region better results have been obtained with eq 4. The improvement is more evident for large molecules although both equations work well for small molecules.

Enthalpy Departures. Experimental values of enthalpy departures for five pure substances have been used to compare with the values calculated from the SRK equation and from eq 4. The results are presented in Table II. It is fair to say that both equations generate enthalpy values of about the same reliability.

Mixtures

PVT **Calculations.** In order to illustrate the usefulness of eq 4 for predicting the volumetric behavior of binary mixtures in the single phase region, the *n*-butane–carbon dioxide system studied by Olds and co-workers (1949) was selected for comparison. For the SRK equation and eq 4 the interaction coefficients for this binary were 0.135 and 0.130, respectively. The compressibility factors at three temperatures and five pressures for three compositions are presented in Table III. The improvement resulting from eq 4 is evident.

VLE Calculations. One of the advantages of using simple two-constant equations of state is the relative simplicity with which they may be used to perform VLE calculations. Multi-constant equations of state, for example the BWRS equation, require the use of iteration procedures to solve for the densities of the coexisting phases while simple equations like the SRK equation and eq 4 can be reduced to cubic equations similar to eq 5 and the roots can be obtained analytically.

Vapor–liquid equilibrium conditions for a number of paraffin–paraffin binaries were predicted using eq 4. It was found that the optimum binary interaction coefficients were negligibly small for components with moderate differences in molecular size. However, systems involving components having relatively large differences in molecular size required the use of a nontrivial interaction coefficient in order to get good agreement between predicted and experimental bubble point pressures.

As an example of the use of eq 4 to predict the phase behavior of a ternary paraffin hydrocarbon system, the data of Wichterle and Kobayashi (1972) on the methane–ethane–propane system were compared to predicted values. As

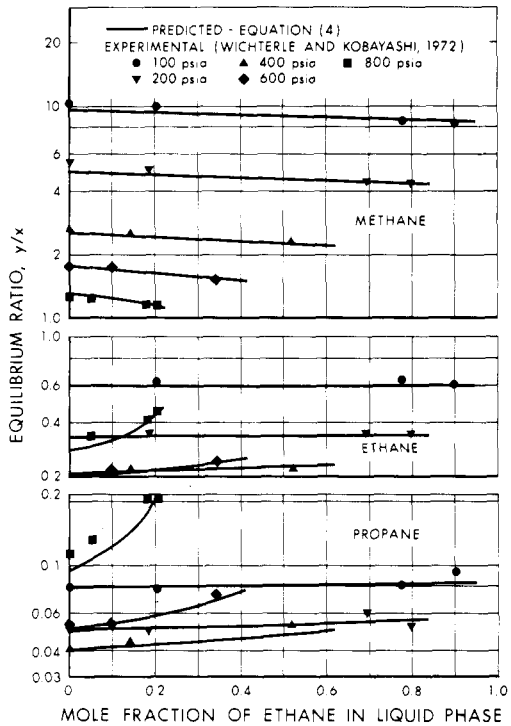


Figure 4. Comparison of equilibrium ratios for methane–ethane–propane system at −75°F.

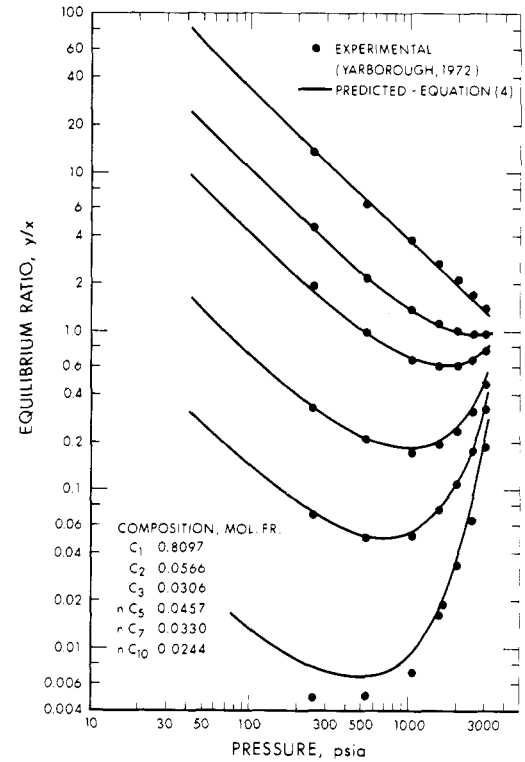


Figure 5. Comparison of equilibrium ratios for Yarborough mixture no. 8 at 200°F.

indicated in Figure 4, agreement was excellent. No interaction coefficients were used.

In a previous study (Peng et al., 1974), the binary interaction coefficients required for use with the SRK equation were determined and used to predict the phase and volumetric behavior of selected systems used in a study by Yarborough (1972). Good agreement was obtained between the predicted equilibrium ratios and the experimental values. In this study these systems have been tested using eq 4 and good results have also been obtained. The equilibrium ratios for a mixture containing only paraffins are shown in Figure 5. The volumetric behavior of this mixture is presented in Figure 6. Although both the SRK equation and eq 4 generate reliable equilibrium ratios, the new equation predicts much more accurate volumetric behavior. A paper concerning the binary interaction coefficients required for use in eq 4 for systems involving nonhydrocarbons is currently in preparation.

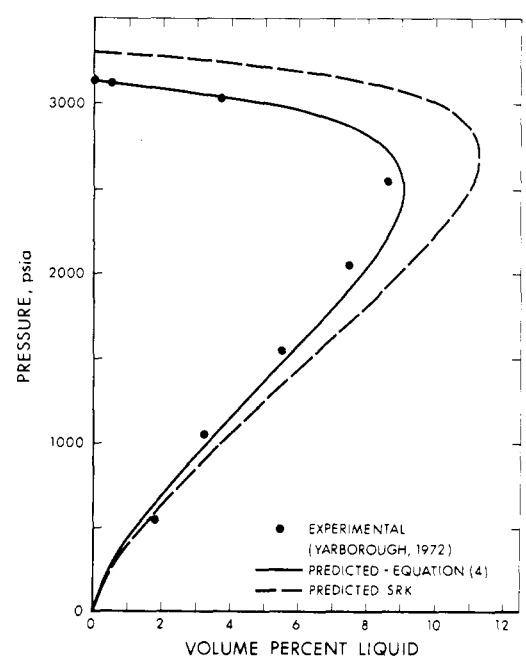


Figure 6. Volumetric behavior of Yarborough mixture no. 8 at 200°F.

Conclusions

By modifying the attraction pressure term of the semiempirical van der Waals equation a new equation of state has been obtained. This equation can be used to accurately predict the vapor pressures of pure substances and equilibrium ratios of mixtures.

While the new equation offers the same simplicity as the SRK equation and although both equations predict vapor densities and enthalpy values with reasonable accuracy, more accurate liquid density values can be obtained with the new equation. In regions where engineering calculations are frequently required the new equation gives better agreement between predictions and experimental *PVT* data.

Since two-constant equations have their inherent limitations, and the equation obtained in this study is no exception, the justification for the new equation is the compromise of its simplicity and accuracy.

Acknowledgment

The financial support provided by the Alberta Research Council and the National Research Council of Canada for this work is sincerely appreciated.

Nomenclature

A = constant defined by eq 6
a = attraction parameter
B = constant defined by eq 7

b = van der Waals covolume
f = fugacity
H = enthalpy
P = pressure
R = gas constant
T = absolute temperature
v = molar volume
x = mole fraction
Z = compressibility factor

Greek Letters

α = scaling factor defined by eq 12
δ = interaction coefficient
κ = characteristic constant in eq 17
ω = acentric factor

Superscripts

L = liquid phase
V = vapor phase
* = ideal gas state

Subscripts

A = attraction
c = critical property
R = repulsion
r = reduced property
i, j, k = component identifications

Literature Cited

Benedict, M., Webb, G. B., Rubin, L. C., *J. Chem. Phys.*, **8**, 334 (1940).
Besserer, G. J., Robinson, D. B., *J. Chem. Eng. Data*, **18**, 298 (1973).
Chueh, P. K., Prausnitz, J. M., *A.I.Ch.E. J.*, **13**, 896, 1099 (1967); *Ind. Eng. Chem., Fundam.*, **6**, 492 (1967).
Jones, M. L., Jr., Mage, D. T., Falkner, R. C., Jr., Katz, D. L., *Chem. Eng. Prog. Symp. Ser.*, **59**, No. 44, 52 (1963).
Lenoir, J. M., Robinson, D. R., Hipkin, H. G., *J. Chem. Eng. Data*, **15**, 23, 26 (1970).
Lenoir, J. M., Kuravila, G. K., Hipkin, H. G., *J. Chem. Eng. Data*, **16**, 271 (1971).
Lin, C. J., Kwok, Y. C., Starling, K. E., *Can. J. Chem. Eng.*, **50**, 644 (1972).
Mage, D. T., Jones, M. L., Jr., Katz, D. L., Roebuck, J. R., *Chem. Eng. Prog. Symp. Ser.*, **59**, No. 44, 61 (1963).
Olds, R. H., Reamer, H. H., Sage, B. H., Lacey, W. N., *Ind. Eng. Chem.*, **41**, 475 (1949).
Peng, D., Robinson, D. B., Bishnoi, P. R., 9th World Petroleum Congress, Transactions, Tokyo, Japan, May 1975.
Reamer, H. H., Olds, R. H., Sage, B. H., Lacey, W. N., *Ind. Eng. Chem.*, **34**, 1526 (1942).
Reamer, H. H., Sage, B. H., *Chem. Eng. Data Ser.*, **2**, 9 (1957).
Redlich, O., Kwong, J. N. S., *Chem. Rev.*, **44**, 233 (1949).
Redlich, O., Dunlop, A. K., *Chem. Eng. Prog. Symp. Ser.*, **59**, No. 44, 95 (1963).
Rossini, F. D., Ed., "Selected Values of Physical and Thermodynamic Properties of Hydrocarbons and Related Compounds," Carnegie Press, Pittsburgh, Pa., 1953.
Soave, G., *Chem. Eng. Sci.*, **27**, 1197 (1972).
Starling, K. E., Powers, J. E., *Ind. Eng. Chem., Fundam.*, **9**, 531 (1970).
Starling, K. E., "Fluid Thermodynamic Properties for Light Petroleum Systems," Gulf Publishing Co., Houston, Texas, 1973.
Tsonopoulos, C., Prausnitz, J. M., *Cryogenics*, **9**, 315 (1969).
van der Waals, J. D., Doctoral Dissertation, Leiden, 1873.
Wichterle, I., Kobayashi, R., *J. Chem. Eng. Data*, **17**, 13 (1972).
Wilson, G. M., paper presented at the 65th National A.I.Ch.E. Meeting, Cleveland, Ohio, 1969.
Yarborough, L., *J. Chem. Eng. Data*, **17**, 129 (1972).
Zudkevitch, D., Joffe, J., *A.I.Ch.E. J.*, **16**, 112 (1970).

Received for review May 5, 1975
Accepted September 26, 1975

Creation and Survival of Secondary Crystal Nuclei. The Potassium Sulfate–Water System

Alan D. Randolph* and Subhas K. Sikdar

Department of Chemical Engineering, University of Arizona, Tucson, Arizona 85721

Formation of secondary nuclei of K_2SO_4 was observed in a continuous flow, mixed-magma crystallizer by counting particles in the crystal effluent with a Coulter Counter. Spontaneous birth of secondary nuclei occurs over at least the 1–5 μm size range. Only a fraction of originally formed nuclei survive to populate the larger size ranges. The fraction of such surviving nuclei increases with the supersaturation level in the growing environment. The number of originally formed nuclei depends on stirrer RPM, supersaturation, and the fourth moment of the parent crystal size distribution.

Introduction

In the past several years there has been an increasing recognition of the importance of secondary nucleation as grain source in typical crystallizers of the mixed-magma type. The so-called MSMPR crystallizer with its simple distribution form (Randolph and Larson, 1971) provided a means of quantitatively measuring the effective nucleation rate under realistic mixed-magma conditions. This led to the correlation of such nucleation data in simple power-law forms of the type

$$B^0 = k_N(\mathrm{T}, \mathrm{RPM}) M_T{}^j s^i \quad \text{(Class I System)} \qquad (1a)$$

or

$$B^0 = k_N(\mathrm{T}, \mathrm{RPM}) M_T{}^j G^i \quad \text{(Class II System)} \qquad (1b)$$

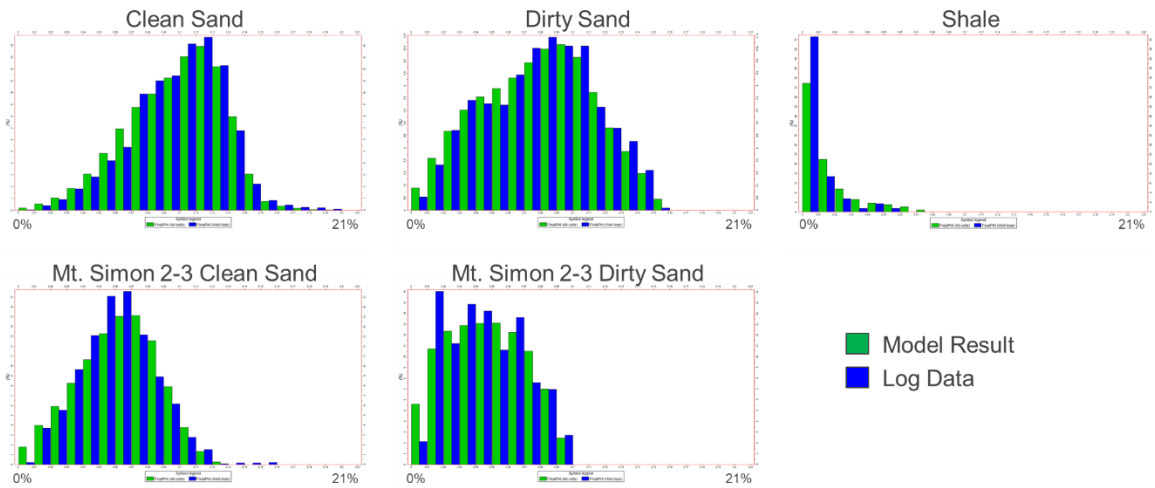
The dependence of these kinetics on agitation level and solids concentration together with a low-order supersaturation dependence confirm a secondary mechanism which is at variance with homogeneous nucleation theory.

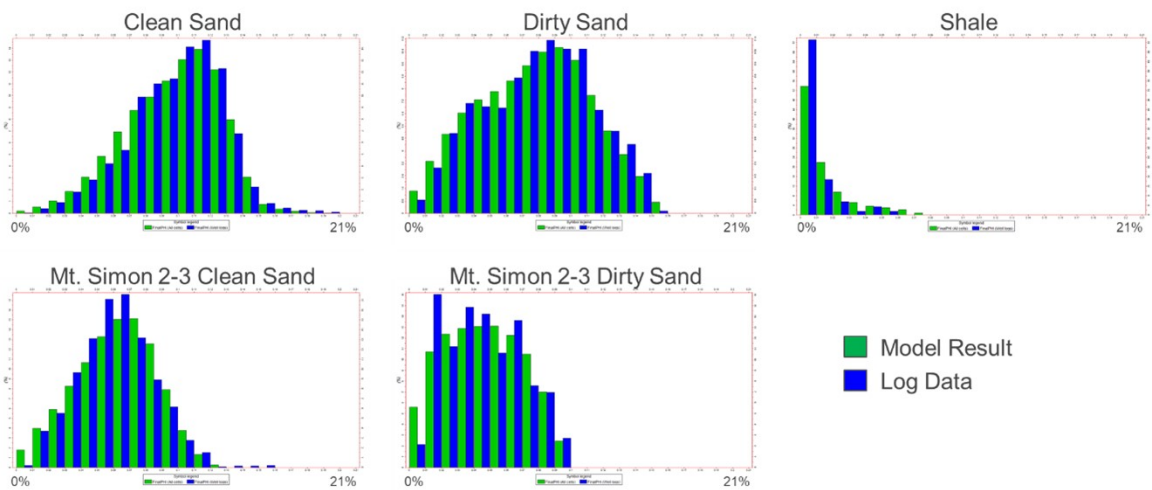
Clontz and McCabe (1971) conducted a now-classical experiment in which they demonstrated that nuclei could be generated in a slightly supersaturated solution by low energy metal/crystal or crystal/crystal contacts. No visible damage to the contacting crystals could be determined even after continued secondary nuclei breeding in the experiment. Ottens and de Jong (1973) and Bennett et al. (1973) take the contact nucleation mechanisms detailed by McCabe and hueristically derive the form of power-law kinetics to be expected in a mixed-magma crystallizer. These formulations were supported with additional MSMPR data.

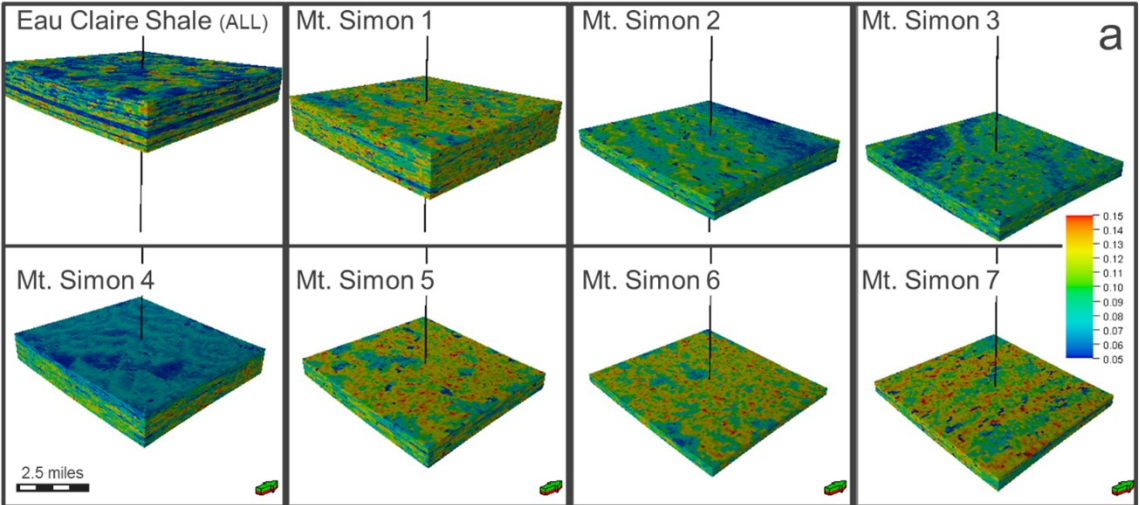
Porosity Modeling

Each facies used in the model had a unique distribution of porosity values which were utilized during the porosity property modeling process. Clean sand and dirty sand histograms had a distinctly different distribution in the Mt. Simon 2 and Mt. Simon 3 intervals, where normal distributions were centered around means which were shifted several porosity percentage points to the left (lower).

Porosity was modeled using Sequential Gaussian Simulation, with a locally varying azimuth which was derived from the object-based depositional bodies. The porosity variogram type was spherical, with an anisotropic range of 2500 x 1000 ft, and nugget of 0. A lateral trend was applied based on the EOD property to influence the relative distribution of porosity values relative to depositional bodies. This trend property was an inversed and normalized version of the ”distance” property automatically generated during the object-based-modeling step in Petrel and is included as one of the output properties in the provided grid (“EOD_based_probability”).



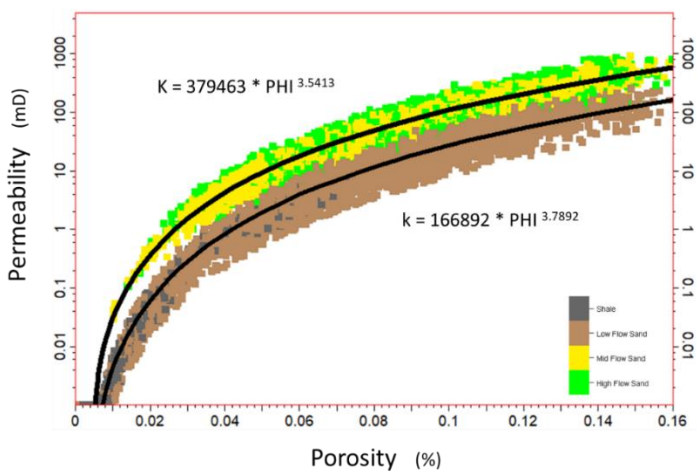

Clean Sand
0%
21%
Dirty Sand
0%
21%
Shale
0%
21%
Mt. Simon 2-3 Clean Sand
0%
21%
Mt. Simon 2-3 Dirty Sand
0%
21%
Model Result
Log Data


Eau Claire Shale (ALL)
Mt. Simon 1
Mt. Simon 2
Mt. Simon 3
a
Mt. Simon 4
Mt. Simon 5
Mt. Simon 6
Mt. Simon 7
0.15
0.14
0.13
0.12
0.11
0.10
0.09
0.08
0.07
0.06
0.05
2.5 miles

Permeability Modeling

The porosity property was used as a direct input into the Permeability property, which was calculated in millidarcies (mD) using porosity-permeability transform functions. The porosity-permeability function was applied based on flow-based facies, which were defined using a flow zone indicator (FZI) log. The FZI data resulted in four additional "flow-based" facies types: High-Flow Sand, Mid-Flow Sand, Low-Flow Sand and Shale. Each lithofacies contained a component of each FZI and were subsequently divided into the corresponding amount of flow facies, which represented variabilities in pore-throat size and directly correlates to flow-potential. Two transforms were defined from this data, an upper transform for the High- and Mid-Flow Sands, and a lower transform for the Shale and Low-Flow Sands. These transforms were directly calculated into the Permeability property, and a multiplier property was applied to introduce scatter in poro-perm space consistent with scatter seen in the log data. Settings to create the scatter property are shown in the table below:

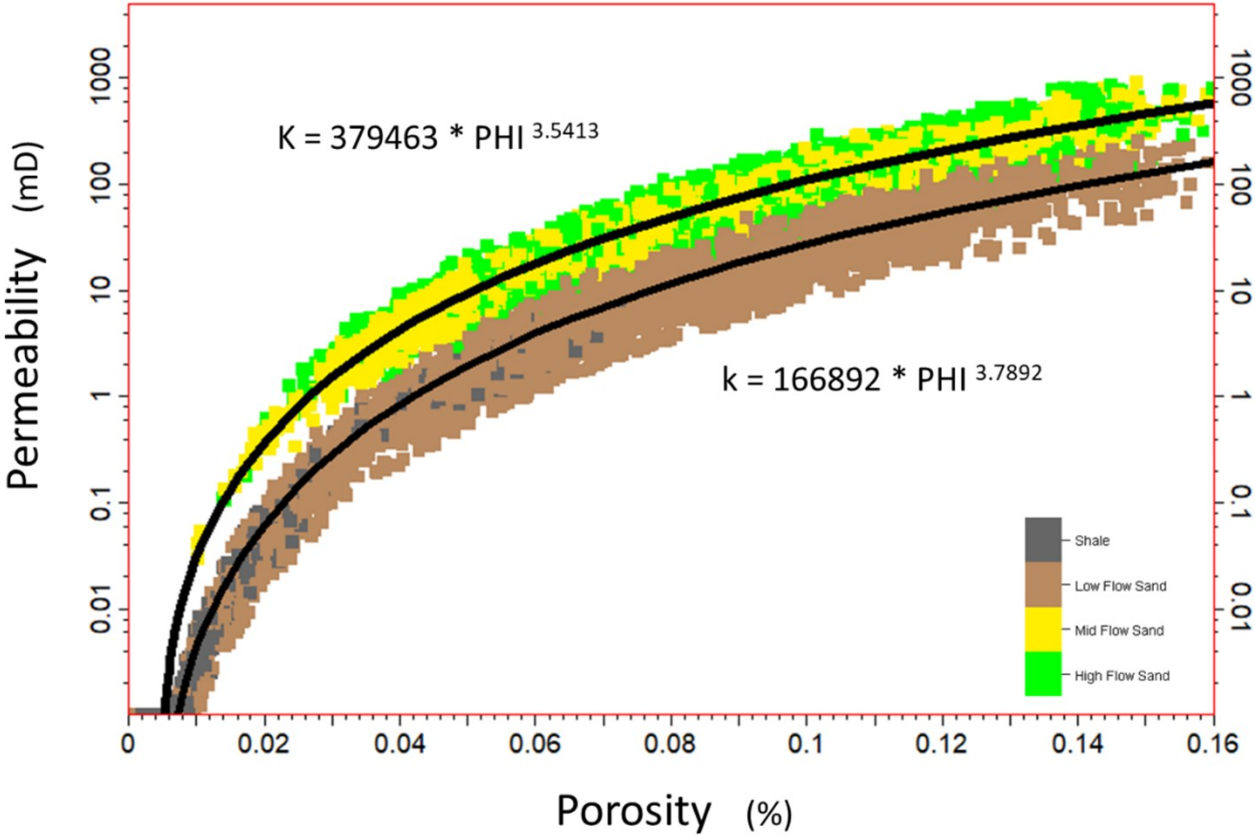
Facies	**FZI Value Ranges**	**Scatter Settings**			
		Min	**Mean**	**Max**	**SD**
High-Flow	10+	0.25	1	3	0.5
Mid-Flow	4-10	0.4	1	2.1	0.4
Low-Flow	0-4	0.3	1	2.75	0.4
Shale	*all shales*	0.3	1	2.5	0.4



Porosity-Permeability cross-plot colored by flow facies showing the utilization of two different transforms, applied by flow-based rock classifications.

Permeability in the X direction was set equal to permeability in the Y direction. Vertical permeability was a multiplier of permeability X/Y based on Facies type:

Clean Sand = 0.2 * PermX | Dirty Sand = 0.1 * PermX | Shale = 0.01 * PermX


K = 379463 * PHI 3.5413
k = 166892 * PHI 3.7892
Permeability (mD)
1000
100
10
1
0.1
0.01
Porosity (%)
0
0.02
0.04
0.06
0.08
0.1
0.12
0.14
0.16
Shale
Low Flow Sand
Mid Flow Sand
High Flow Sand

Facies Modeling

Depositional environments for each of the modeled formations were defined on a zone-by-zone basis and incorporated into the model as objects representing channels and eolian sand deposits. These objects provided a way to constrain facies distribution throughout the model, where environmental controls on the deposition of clean sand and shale components could be represented.

Zone	Formation	Depth (ft, MD)	Layer Method	Layers	Lithology
Confining	Eau Claire Shale	2,722	Proportional	16	Shallow Marine
	Eau Claire Sand 1	2,913	Proportional	7	Shallow Marine
	Upper Elmhurst	2,998	Proportional	6	Shallow Marine
Injection	Lower Elmhurst	3,074	Proportional	4	Shallow Marine
	Mt. Simon 1	3,125	Proportional	43	Shallow Marine / Peritidal
	Mt. Simon 2	3,561	Proportional	21	Fluvial
	Mt. Simon 3	3,784	Proportional	20	Distal Braid Plain
	Mt. Simon 4	3,970	Proportional	35	Eolian Sand Sheet
	Mt. Simon 5	4,364	Proportional	23	Eolian
	Mt. Simon 6	4,607	Proportional	10	Eolian
	Mt. Simon 7	4,716	Proportional	15	Fluvial
	Precambrian Basement	4,880	Proportional		

Facies used were defined with a clay fraction (vClay) log to separate the rock into three main types: Clean Sand (<8.5% clay), Dirty Sand (>8.5% clay, <20% clay), and Shale (>20% clay). Lithofacies were distributed using Sequential Indicator Simulation with EOD-based variograms as shown in the table below, and a locally varying azimuth derived from the EOD bodies.

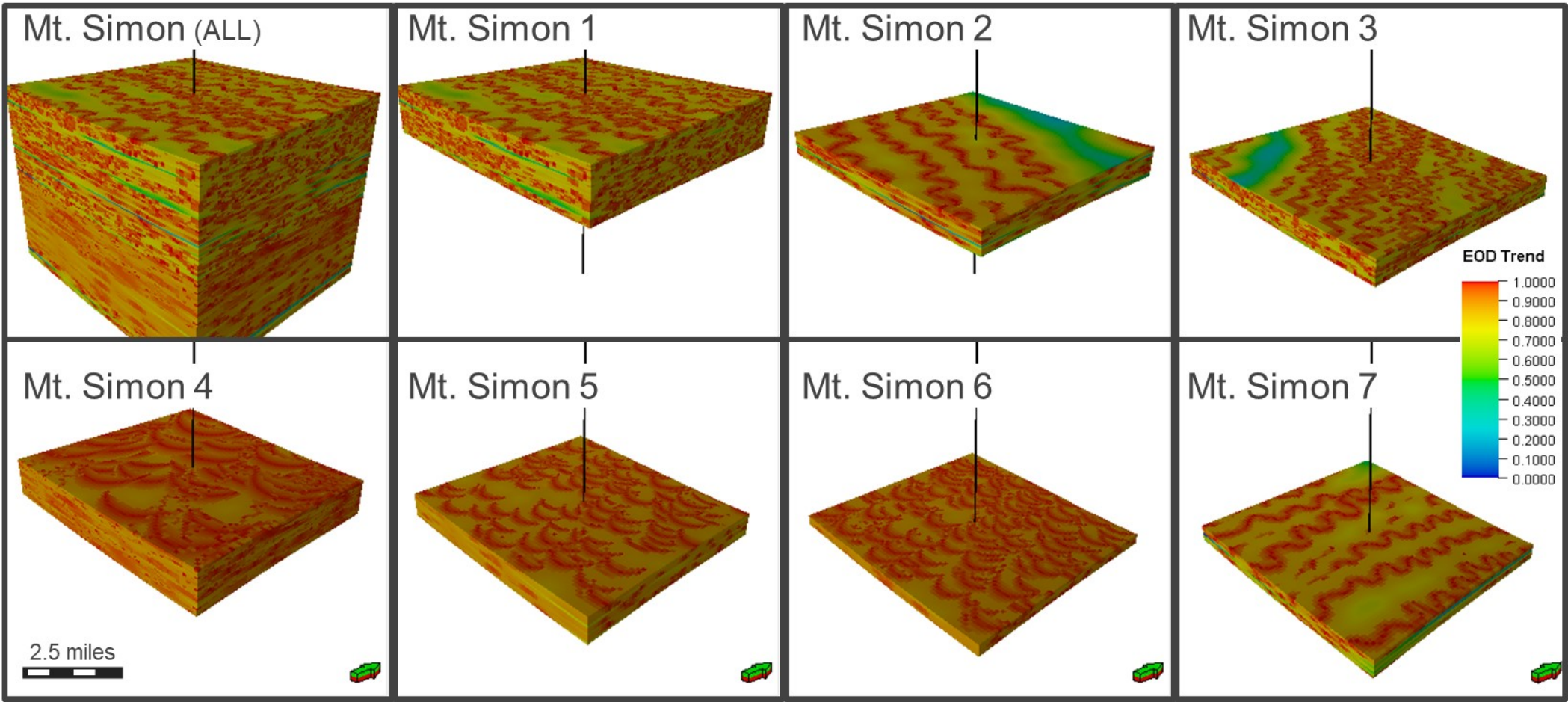
EOD	Major Dir.	Minor Dir.	Vertical
Tidal	2500	1500	20
Dune	2500	1500	20
Flood Plain	2500	2000	20
Braided Channel	3500	1000	20
Overbank	2500	1000	20
Channel	2500	500	20

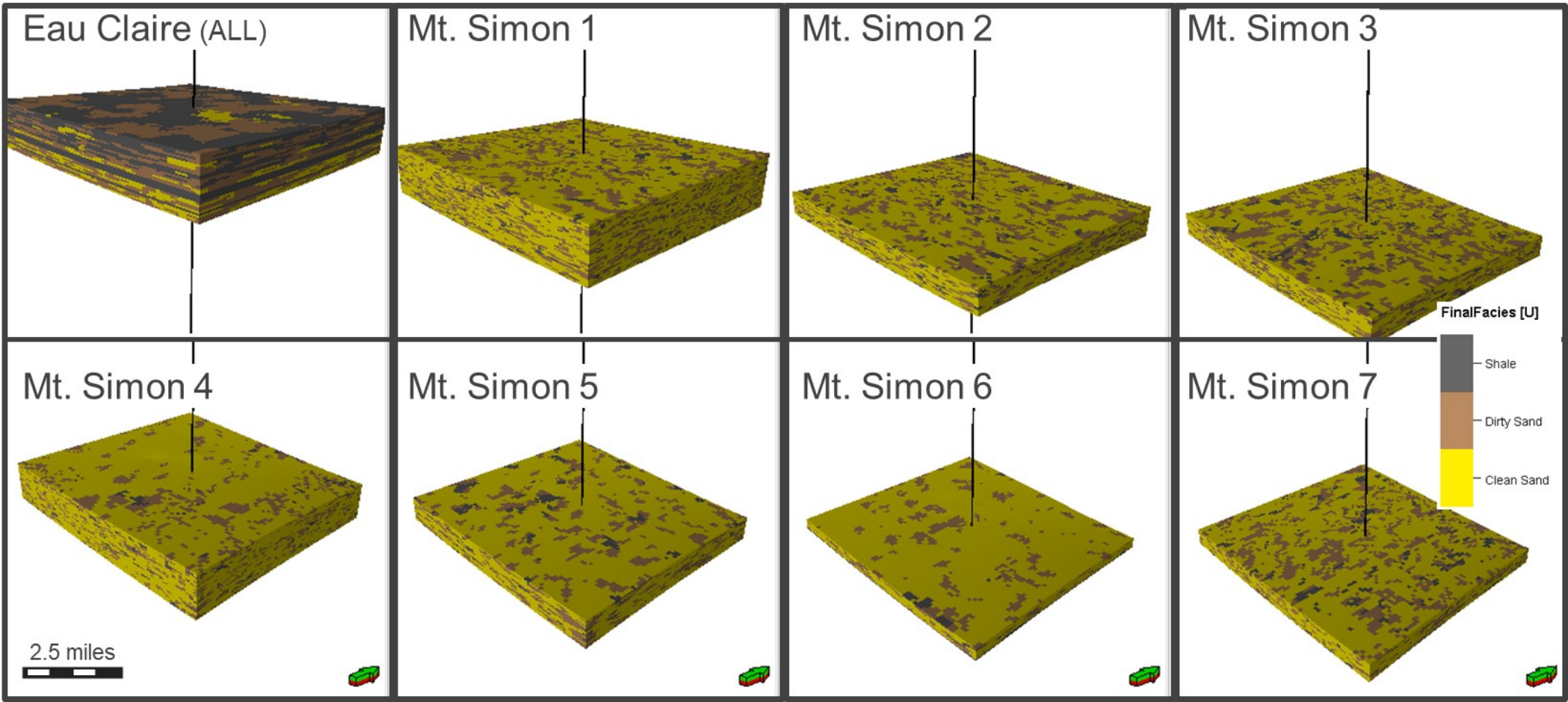
Lithofacies proportions defined by depositional environment are shown below.

Facies	Tidal	Dune	Flood Plain	Braided Channel	Overbank	Channel
Clean Sand	70	95	60	75	65	80
Dirty Sand	25	5	30	20	30	15
Shale	5	0	10	5	5	5

For permeability modeling, additional rock types were broken out by flow-potential, using a Flow Zone Indicator (FZI) log. The FZI data resulted in four additional facies types: High-Flow Sand, Mid-Flow Sand, Low-Flow Sand and Shale. Each of the previously used sands (clean sand, dirty sand) contained a component of each FZI and were subsequently divided into the corresponding amount of flow facies, which represented variabilities in pore-throat size and directly correlates to flow-potential. Flow-based facies proportions used for each sand type are shown below. Shales in the lithofacies property remained shales in the flow-based facies property. Flow-based facies were distributed using Sequential Indicator Simulation with a variogram of 5000 x 3000 x 10 and a locally varying azimuth derived from the EOD bodies.

Formation	Sand Type	Low Flow	Mid Flow	High Flow
Elmhurst	Sand	60	40	
	Dirty Sand	100		
Mt. Simon 1	Sand	40	40	20
	Dirty Sand	60	40	
Mt. Simon 2	Sand	100		
	Dirty Sand	100		
Mt. Simon 3	Sand	85	15	
	Dirty Sand	100		
Mt. Simon 4	Sand		40	60
	Dirty Sand		100	
Mt. Simon 5	Sand		40	60
	Dirty Sand	20	40	40
Mt. Simon 6	Sand	85	15	
	Dirty Sand	100		
Mt. Simon 7	Sand	60	30	10
	Dirty Sand	100		


Mt. Simon (ALL)
Mt. Simon 1
Mt. Simon 2
Mt. Simon 3
Mt. Simon 4
Mt. Simon 5
Mt. Simon 6
Mt. Simon 7
EOD Trend
1.0000
0.9000
0.8000
0.7000
0.6000
0.5000
0.4000
0.3000
0.2000
0.1000
0.0000
2.5 miles


Eau Claire (ALL)
Mt. Simon 1
Mt. Simon 2
Mt. Simon 3
Mt. Simon 4
Mt. Simon 5
Mt. Simon 6
Mt. Simon 7
FinalFacies [U]
Shale
Dirty Sand
Clean Sand
2.5 miles

Sensitivity Analysis

Subsurface uncertainty is also addressed through the creation and simulation of alternative geological scenarios. Sensitivity runs were performed for different porosity and permeability relationships as shown in Figure 1. All model parameters were the same as the base case apart from the porosity and permeability.

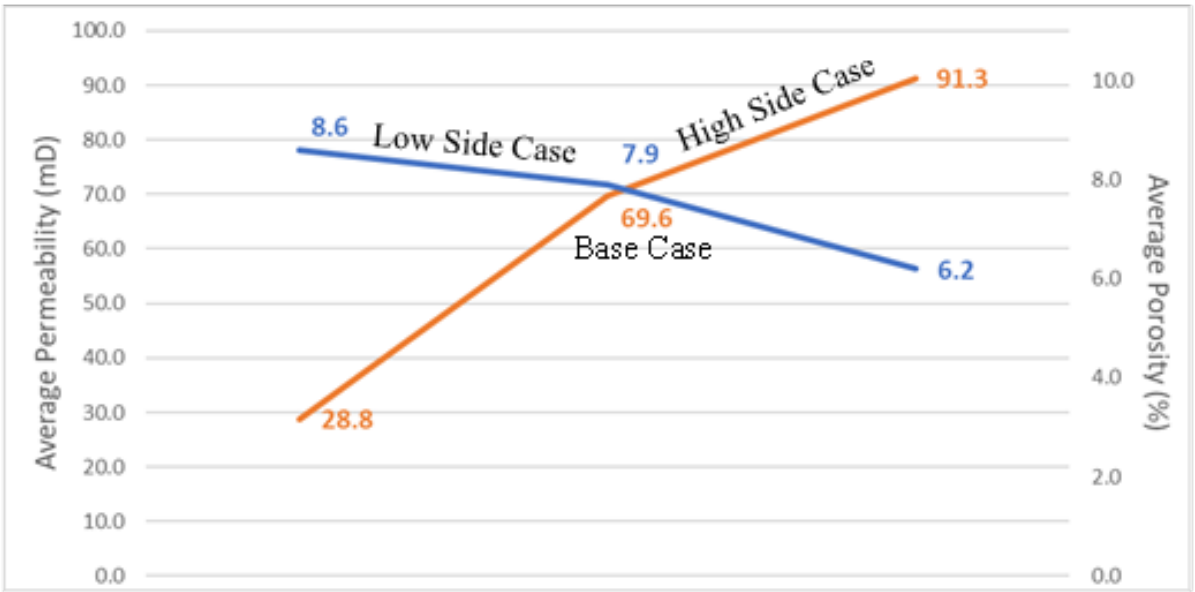


Figure 1: Porosity and permeability relationships for high side case (orange line) and low side case (blue line) showing an inverse relationship between the two scenarios. The numbers on the orange are permeability values, number on the blue line are porosity values.

The plume side views for the base, high side and low side cases after 3 years of injection are compared in Figure 2. The low side case scenario results in a larger overall plume diameter compared to the other two cases. Figure 3 shows the CO_2 plume in map view at layer 153, at the end of injection period and 5 and 10 years after the injection stops for the base case scenario. Results of the sensitivity analysis (high side case and low side case) shown in Figure 4 for CO_2 plume at layer 153 show that the AoR is smaller compared to base case scenario at the end of injection and post injection. It is also shown in Figure 4 that the plume size in the high and low side scenarios remains unchanged after 1 year post injection.

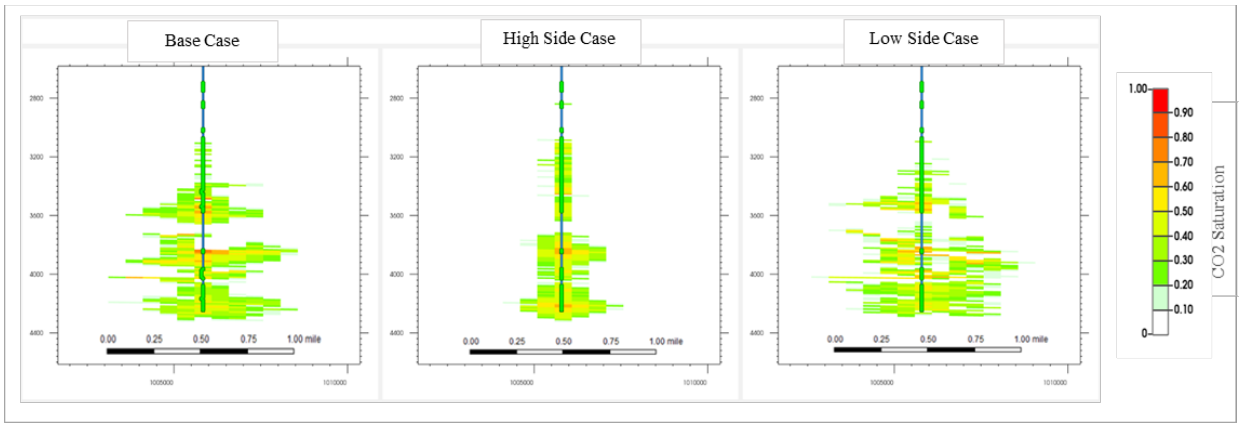


Figure 2: CO_2 plume at wellbore cross section after 3 years of injection. The left plume diagram represents the base case, middle represents the high side case, and the right plume diagram represents the low side case.

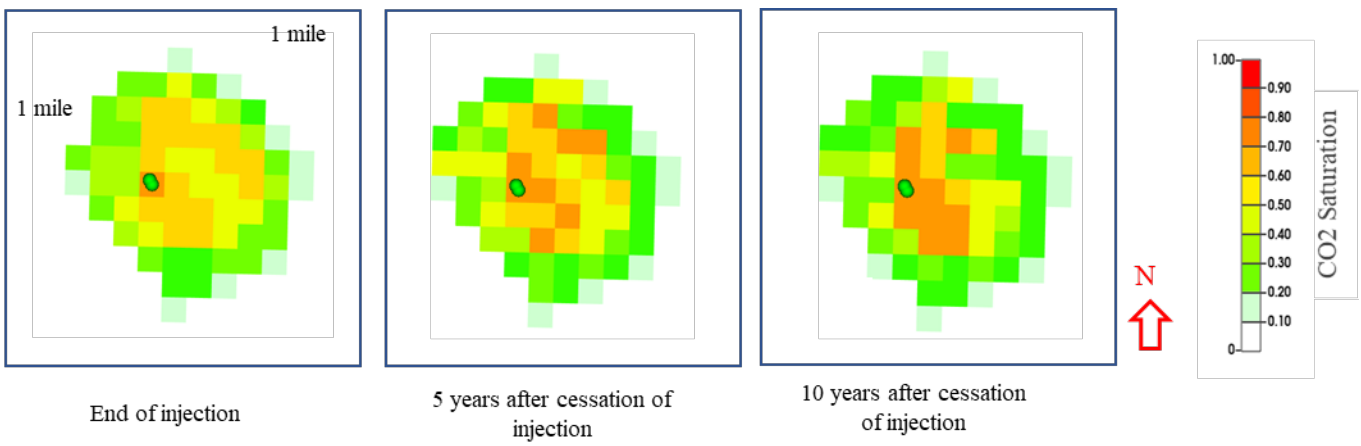


Figure 3: CO_2 plume at layer 153 (used to delineate AoR) for the base case at the end of injection, 5 years after injection stopped, and 10 years after injection stopped.

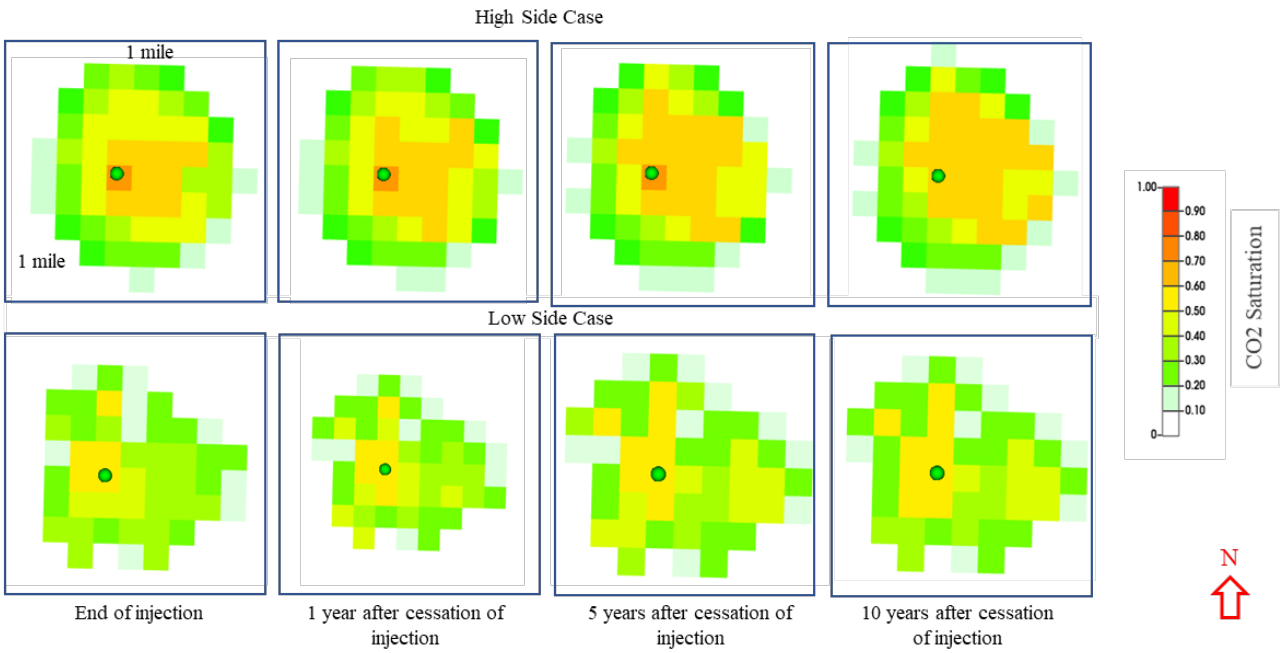


Figure 4: CO_2 plume at layer 153 (used to delineate AoR) at the end of injection and after, 1, 5 and 10 years after cessation of injection for the high side case (top row) and low side case (bottom row).

This is not required as IL does not have primacy.