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

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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

Abbreviation	Description
CO_2	Carbon dioxide
cP	Centipoise
DOT	Department of Transportation
DST	Drill stem test
DT	Delta time
DTS	Distributed Temperature Sensing
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
GL	Ground level
GS	Geologic sequestration
ID	Identification
ISIP	Instantaneous shut-in pressure

Abbreviation	Description
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

Abbreviation	Description
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

Abbreviation	Description
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
TVD	True Vertical Depth
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

Abbreviation	Description
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 of over a million tons per year of pure biogenic CO_2 upon project completion without the requirement of any advanced stack gas cleanup technologies. Additionally, carbon capture and storage can play a key role in reducing the carbon intensity for clean 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 includes drilling, logging, reservoir testing, and core sampling a deep characterization well (MCI MW 1), 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 is tied to the site characterization well data and the velocity model in order to provide the most accurate prediction of the CO_2 plume development over time. The 3D seismic data is a baseline survey for future time-lapse 3D surface seismic surveys. The information collected did not show 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 rules.

A robust Static Earth Model (SEM) has been built and calibrated using this new data; the 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:

- Sequester compressed CO_2 from an ethanol facility;
- Build the infrastructure needed to transport CO_2 to the on-site injection and storage site;
- Drill injection (MCI CCS 3) and monitoring (MCI MW 1, 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); and
- Upon completion of the injection phase of the project, verify stability of the CO_2 plume and decline of storage formation pressure to pre-injection levels, verify plume predictions made by the computational modeling, 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 21 years. This includes:

- 2 years for permit approval;
- Construction during the second year;
- 6 years of CO_2 injection and monitoring; and
- 12 years of post-injection site care (PISC) and monitoring.

		Elapsed years																			
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21
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 9,000,000 million tonnes (MT). This equals an annual average injection rate of 1,500,000 tonnes/ year over the 6-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 and have the following stream composition outlined in **Table 1-3**.

Component	CO2 Specifications	Presence
CO_2	>99%+	Major constituent of CO_2 stream
Oxygen	<0.05%	Indicator of atmospheric contribution
Nitrogen	<1%	Minor constituent of CO_2 stream
Water Vapor	<30 lb/MMSCF	Present in CO_2 gas
Hydrogen sulfide (H_2S)	<0.002%	Not Expected to be Present
Total Hydrocarbons	<0.005%	If present, minor constituents in carry-through gas from CO_2 compressor dehydration system
Triethylene Glycol (TEG)	<0.0005%	

Table 1-3 Anticipated composition of the CO_2 stream injected 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 (Applicant/Owner/Operator)	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
SIC Code: (Note 1) NAICS Code:	2869: Industrial Organic Chemicals, not elsewhere classified, including industrial ethanol 325193: Ethyl Alcohol
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.	

Note 1: There is no SIC code for carbon injection or sequestration. Therefore, SIC and NAICS Codes associated with the ethanol plant generating the CO_2 gas that will be sequestered have been provided.

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 (MCI) will be required to obtain a General Stormwater Permit for Industrial Activities under the Clean Water Act for the surface equipment associated with the injection well.

MCI obtained a permit from the Illinois Department of Natural Resources to drill the stratigraphic test well which will be converted to a deep monitoring well (MCI MW-1) under the Class VI permit.

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. MCI will utilize the MCI MW 1 well as an extended range monitoring well under the Class VI permit, and the new MCI MW 2 deep monitoring well will be adjacent to MCI CCS (CO_2 injection well). 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 3,094 ft measured depth (MD) 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 member, the Elmhurst which also has shale and sandstone layers. The upper portion of the Eau Claire Formation acts as a thick, confining layer for the underlying sandstones. The Eau Claire is 2,690 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 Permit **Section 2.1.2** (Site Geology and Hydrology) of Permit **Section 2** (AoR and Corrective Action Plan).

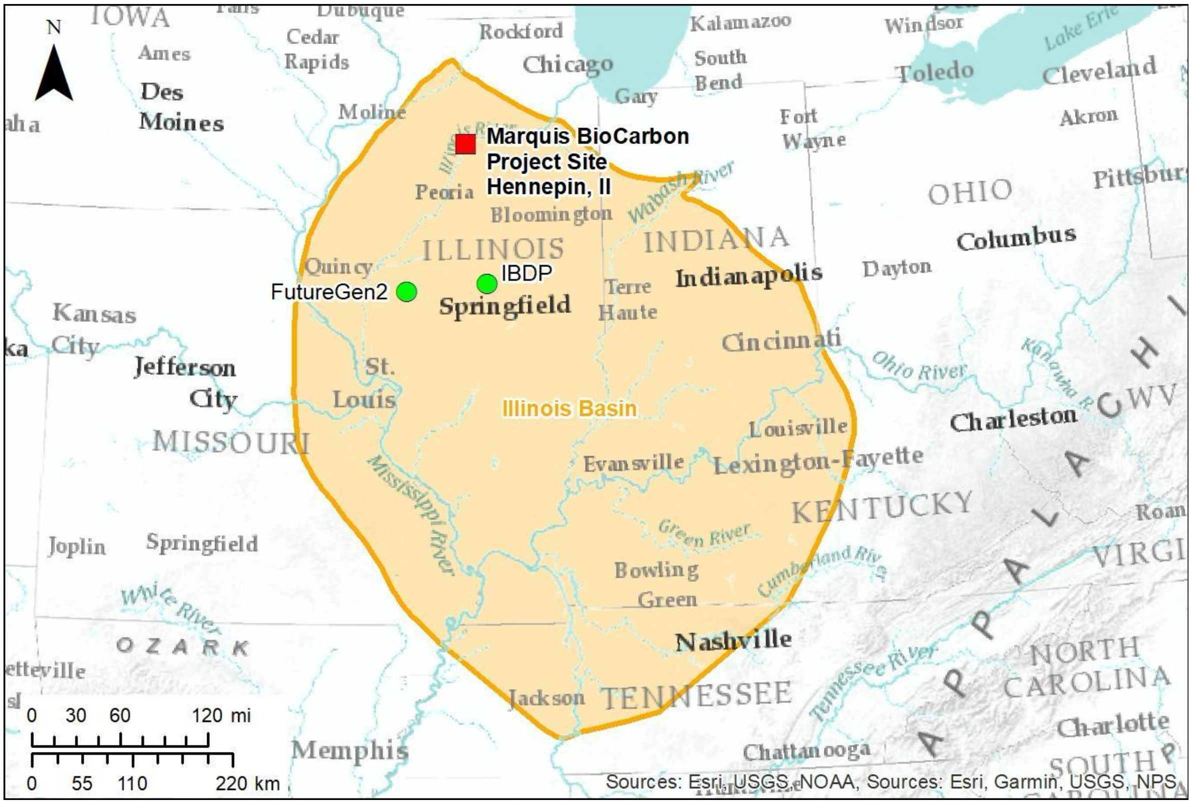


Figure 1-1: The Marquis Biocarbon Project site sits on the northern edge of the Illinois Basin (denoted in the yellow). The Mt. Simon Sandstone in Hennepin, Illinois has been identified as the target injection zone for CO_2 storage. Also shown are the FutureGen2 and the Illinois Basin Decatur Project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

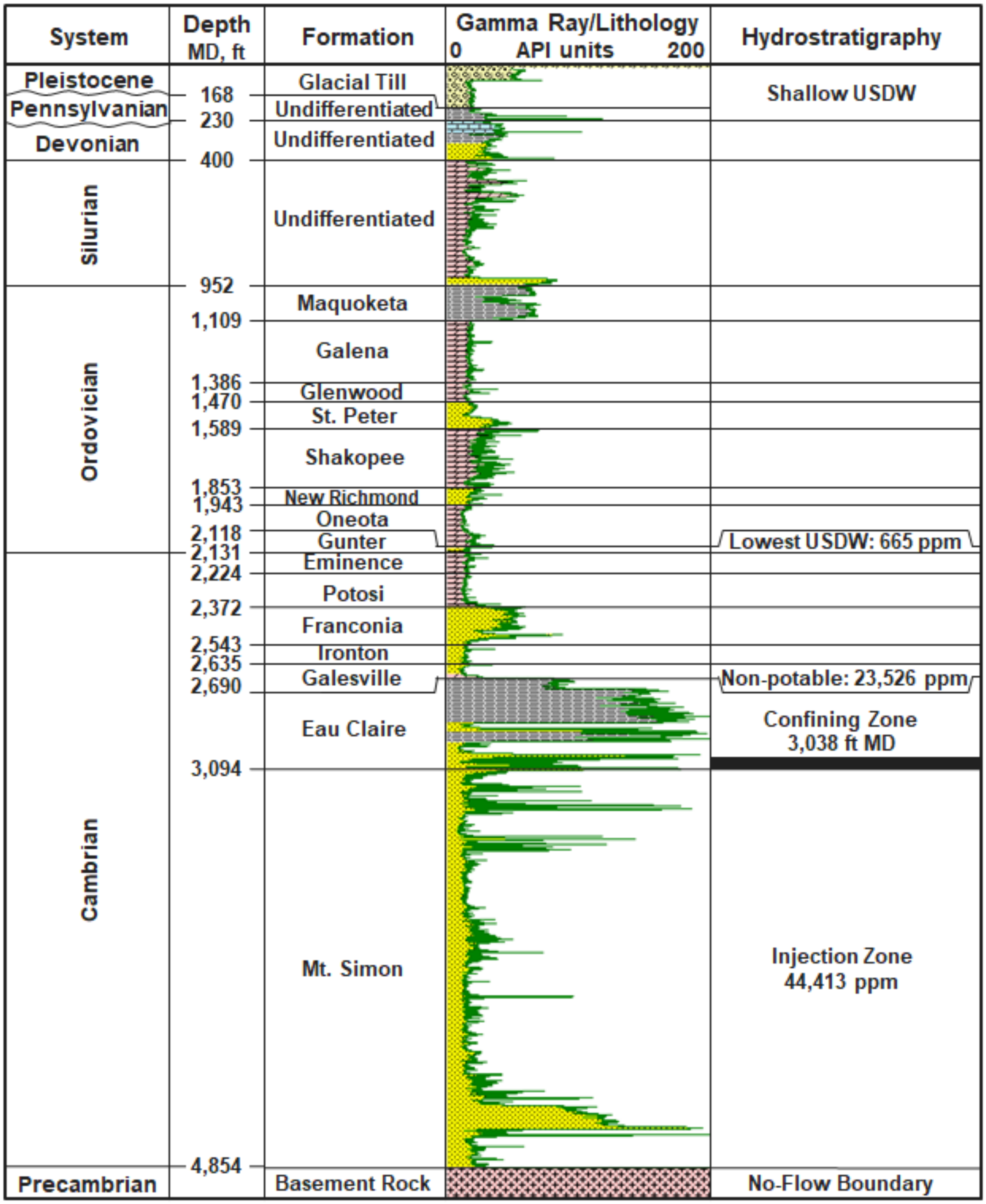


Figure 1-2 : Stratigraphic column with lithology and hydrostratigraphy for the Marquis Biocarbon Project site based on data from the characterization well, MCI MW 1. ft = feet; MD = measured depth; ppm = parts per million; USDW = underground source of drinking water.

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. The 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 have occurred 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 edge of the eastern border of the Marquis Biocarbon Project 29-mile diameter AoR traverses the Peru Monocline. See **Figure 2-17** in Permit **Section 2**. 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.

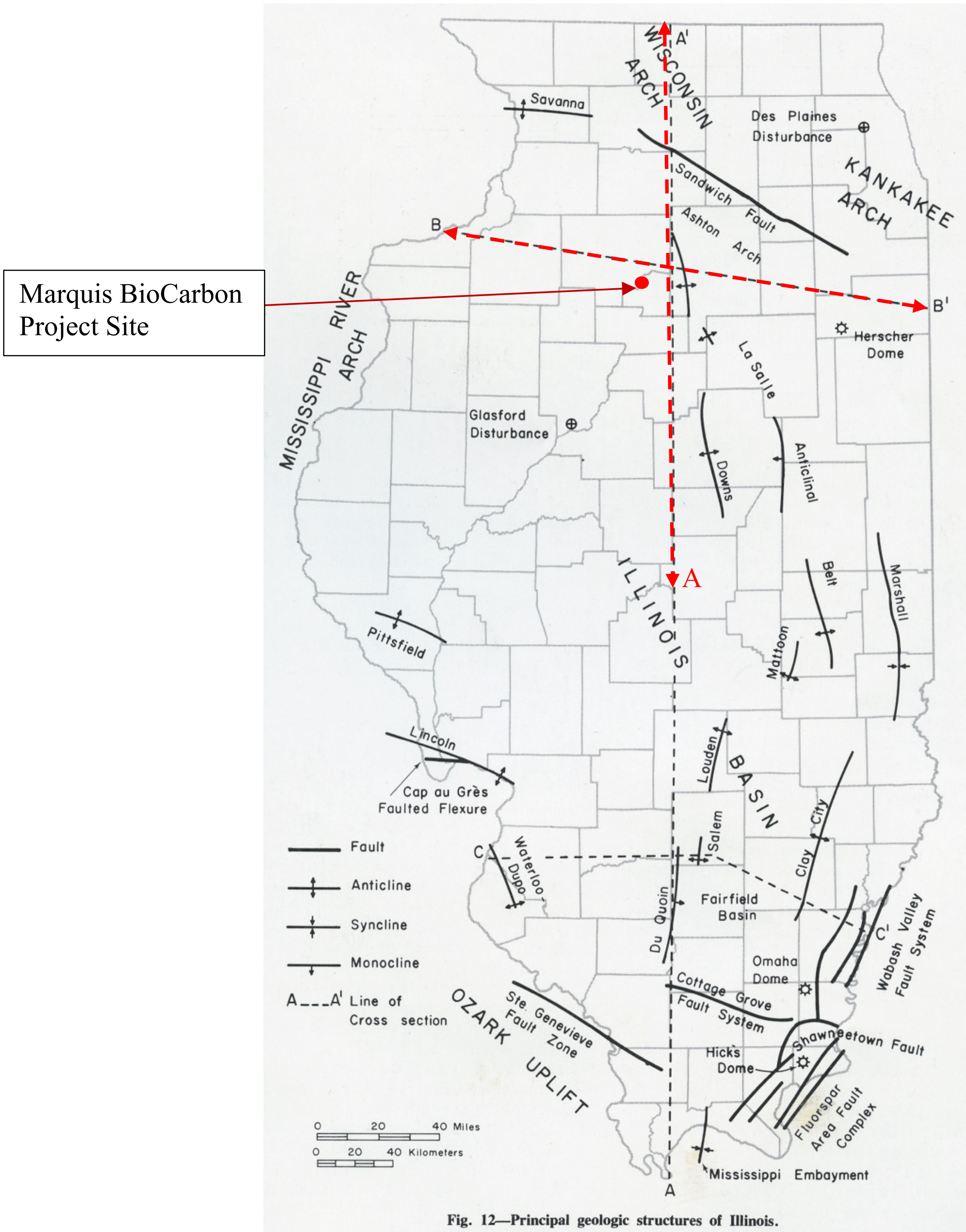


Figure 1-3: Principle geologic structures of Illinois (modified from Willman et al., 1975). Red Lines A-A’ and B-B’ are cross section of the region, see Figure 1-5.

1.2.2 Wells, 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. Based on data from the J&L Well, the MCI MW 1 well and 3D seismic, it is expected that the Gunter Sandstone will be approximately 14 ft thick at the MCI CCS 3 well. A map of the CO_2 plume, existing wells within the plume and corresponding total depths, and proposed project wells are shown in **Figure 1-4**. A total of five shallow groundwater wells are present within ¼ mile of the CO_2 plume. See **Appendix V.6** which details the well locations and Marquis ownership.

Maps showing the MCI CCS 3 well, wells, boreholes, State or EPA approved surface cleanup sites, surface bodies of water, springs, mines, quarries, water wells and other pertinent surface features, including structures intended for human occupancy, and roads are included in **Appendices V.7** and **V.8**. Also included in **Appendix V** are lists of the wells and the other pertinent features and structures. See **Appendix V** cover page for maps, well records lists, well records, and location map reference table.

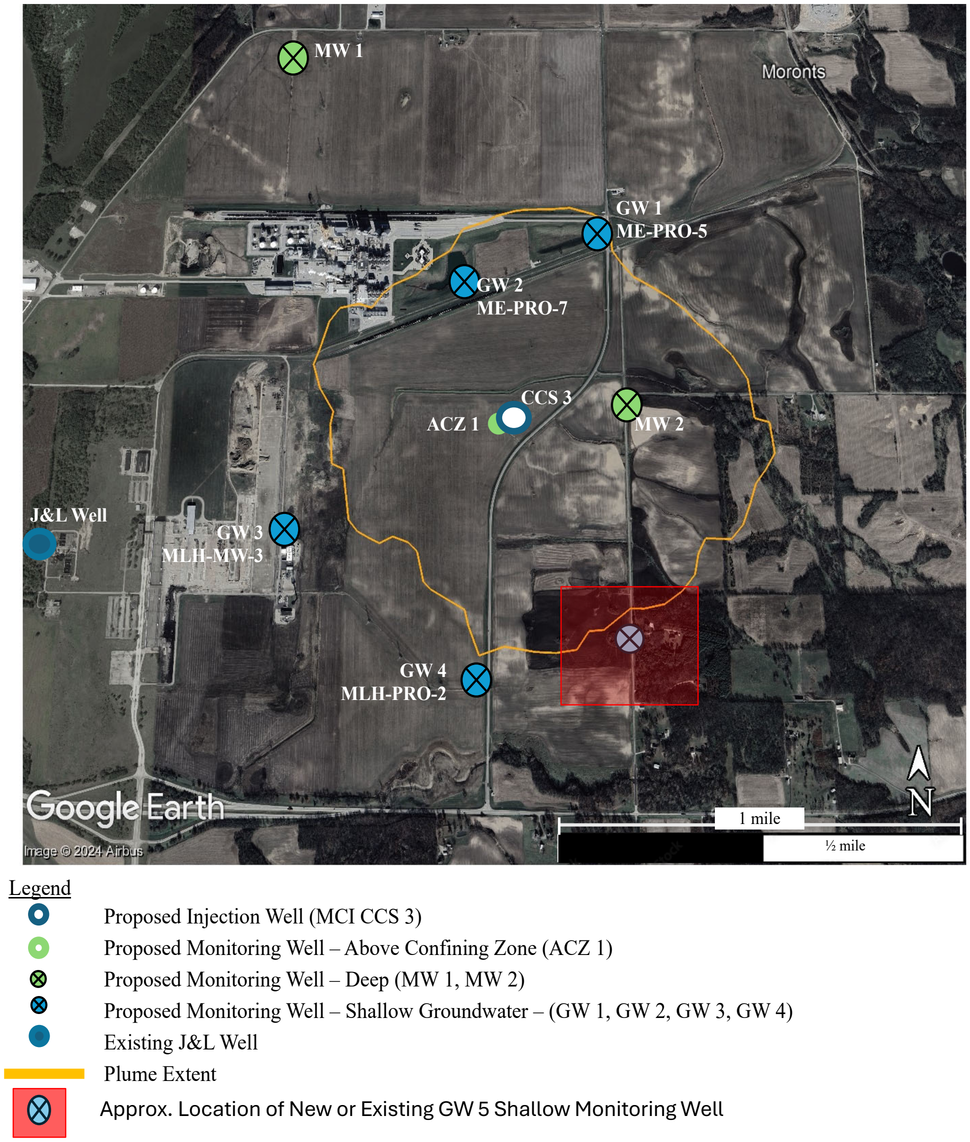


Figure 1-4: Map showing the modeled CO_2 plume footprint, and existing and proposed project wells within or near the plume.

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 (J&L Well), as well as 2D and 3D 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. The Cambrian formation is regionally affected by the La Salle Anticline northeast of Putnam County. The AoR Model resulted in a 29-mile diameter AoR. See Permit **Section 2.5.3.** No faulting was observed from the 3D seismic data collected at the Marquis BioCarbon site.

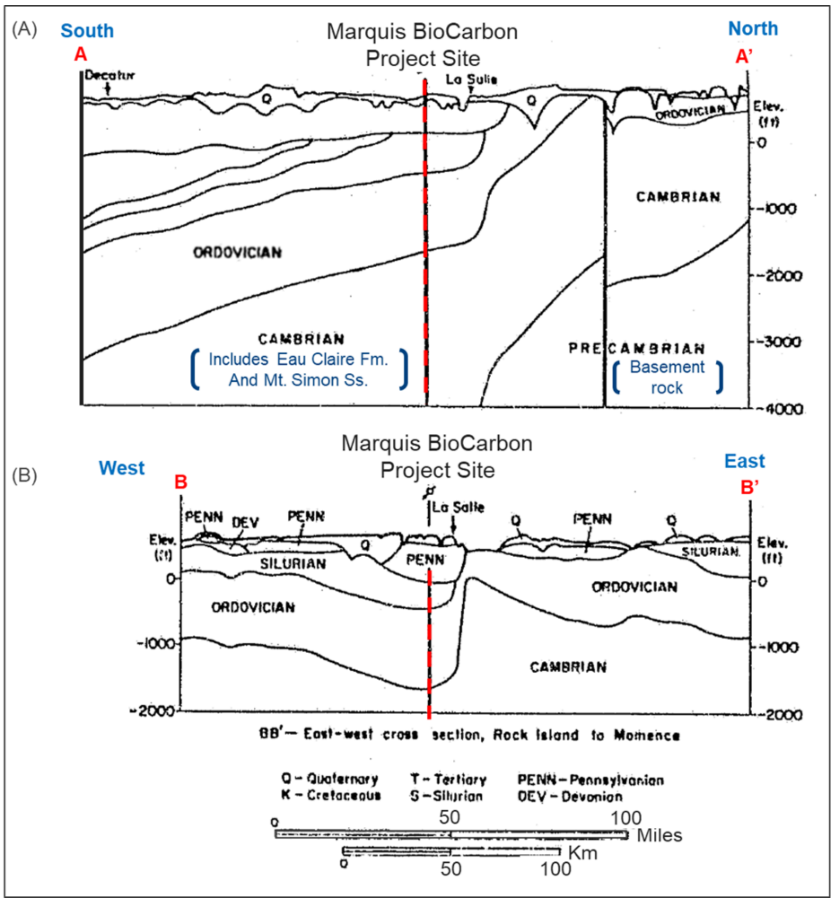


Figure 1-5: Geologic cross sections near Putnam County featuring the structural configuration of Cambrian strata that contains the target injection zone and caprock. Modified from Willman et al., 1975.

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 AoR encounters the Peru Monocline on the east side. Additionally, the AoR does **not** encompass the Saline Spring Anomaly, faulting associated with the Troy Grove Dome or the Sandwich Fault. See **Figure 1-17** and Permit **Section 2.1.2.**

Additionally, a 2D seismic program was completed in 2021 and a 3D seismic program was complete in early 2022 to assess any large-scale faulting in the area. The programs 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**.

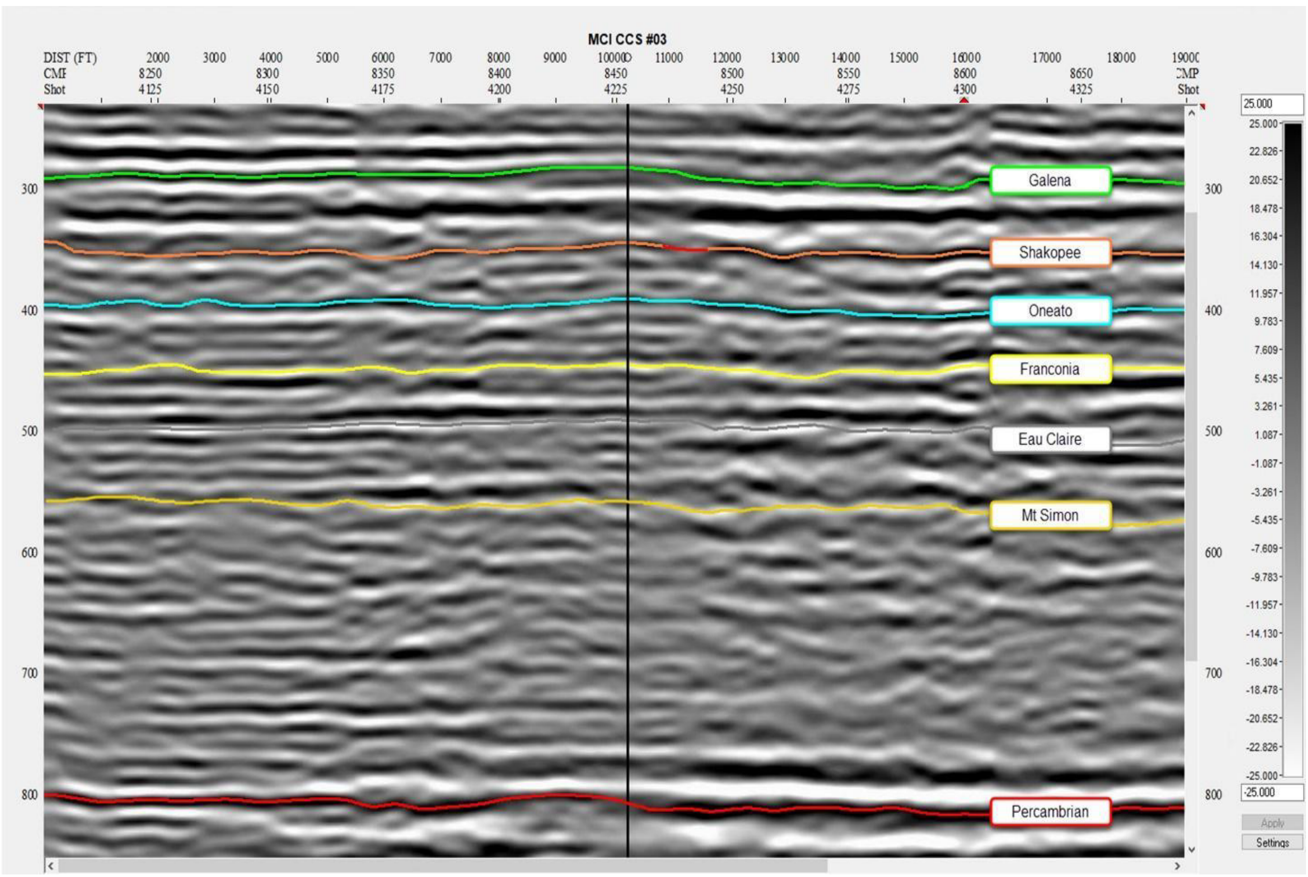


Figure 1-6 Example of 2D seismic line acquired in 2020.

After acquisition of the 3D seismic survey, the data were processed and included in the static earth model. Further interpretation augmented the 2D results confirming no basement highs or faults in the Confining layer.

Marquis also installed surface micro-seismic stations across the site to conduct baseline micro-seismic monitoring prior to CO_2 injection which will continue throughout the injection period.

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, sits at 2,983 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 (2,690 ft MD at MCI MW 1) through an 11-foot-thick shale within the upper Elmhurst (3,027-3,038 ft MD) as shown in **Figure 1-2**. 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, it is unclear if the Mt. Simon sands and lower Elmhurst sands are hydraulically connected from the base of the intra-Elmhurst shale down. Certain references in the area would suggest they are, but no evidence has been found at the Marquis Biocarbon project site (Golden StrataServices, 1984). For this reason, the injection well is being designed so the lower portion of the Elmhurst is not included in the sealing layers or injection zone. 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 2,500 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 3,094 ft MD and 1,760 ft thick and has a shallow dip of 28 ft per mile (0.5% grade) to the southeast. This data corroborates the maps shown in **Figure 1-7** and **Figure 1-8.** The map provided in **Figure 1-8** shows the structure on top of the Mt. Simon Sandstone in elevation with reference to mean sea level, which is common for structure maps given the regional nature of the associated data. With a ground level of approximately 532 ft at the MCI MW 1 well, the elevation of the Mt. Simon Sandstone at the Marquis Biocarbon Project site in **Figure 1-8** (approximately -2,500 ft) is consistent with the depth below ground surface reported above. 2D and 3D seismic data show no basement highs or pinch outs in the modeled area.

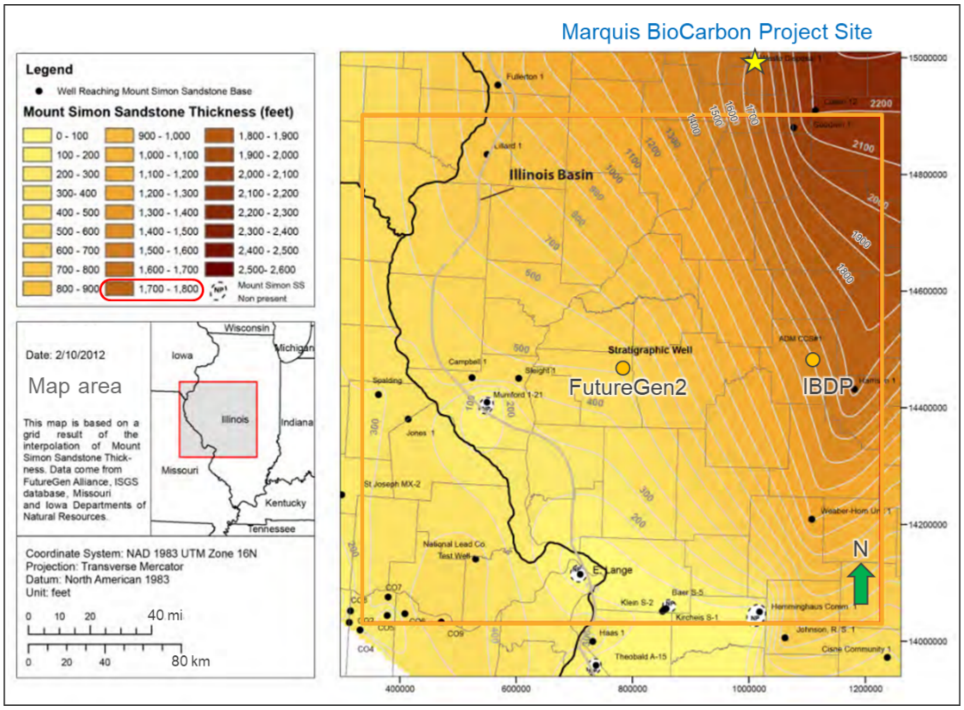


Figure 1-7: Mt. Simon Sandstone thickness map over the west-central portion of the Illinois Basin (modified from FutureGen Alliance, 2013).

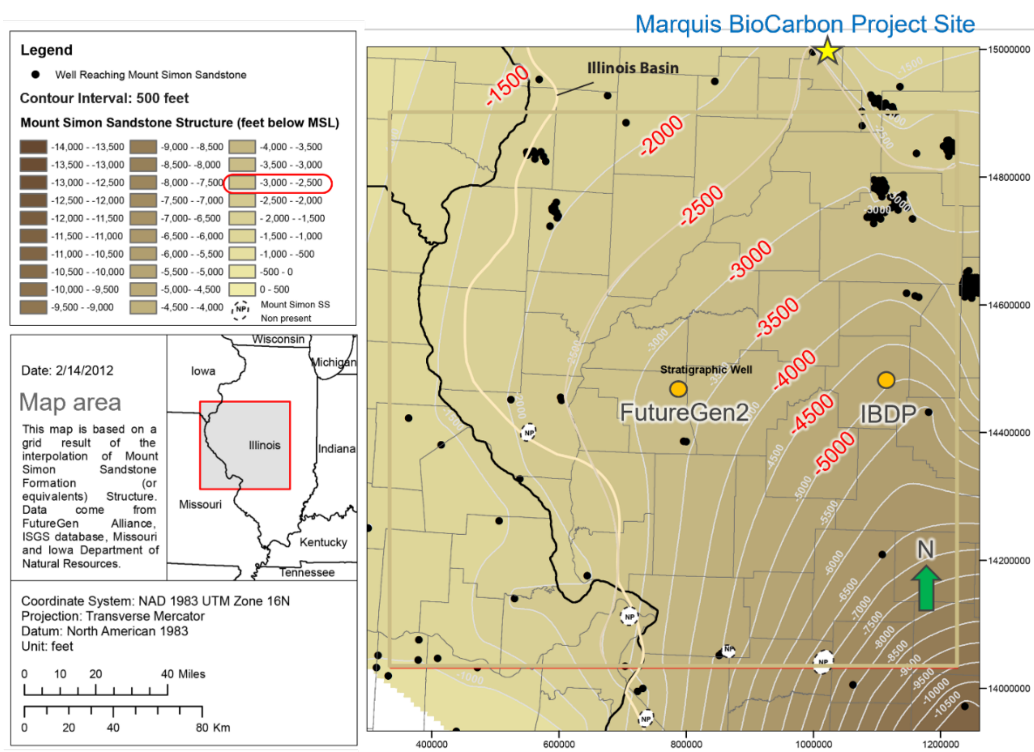


Figure 1-8: Mt. Simon Sandstone elevation depth map over the west-central portion of the Illinois Basin (modified from FutureGen Alliance, 2013).

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.

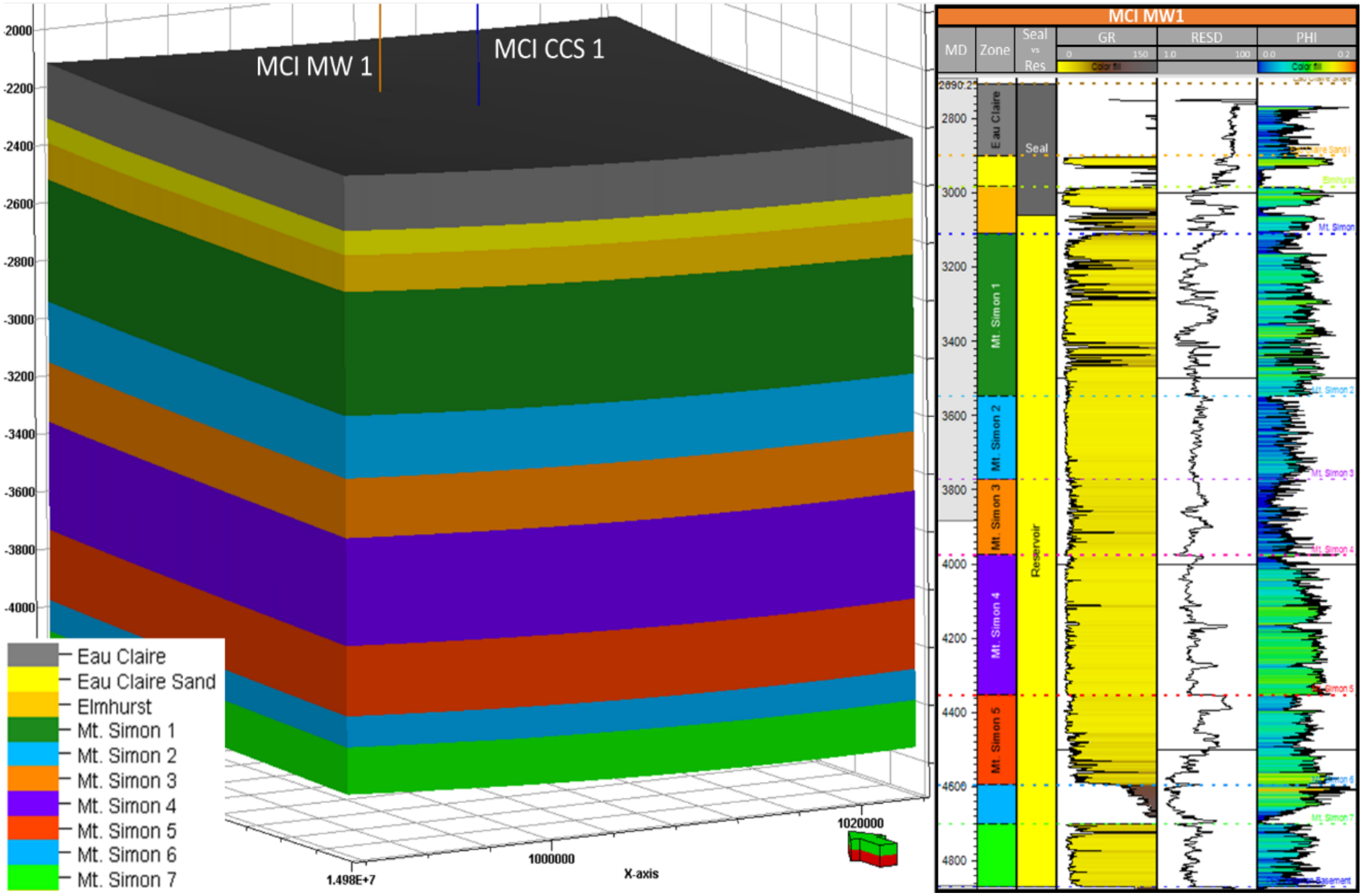


Figure 1-9: Model Zones and corresponding gamma ray, resistivity, and porosity logs.

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 8 whole cores, 29 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.

A rigorous formation evaluation program was completed in the MCI MW 1 well which allowed the project area to be characterized. This data will be used to define the site properties as shown in Permit **Section 5**.

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 1-10**). 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.

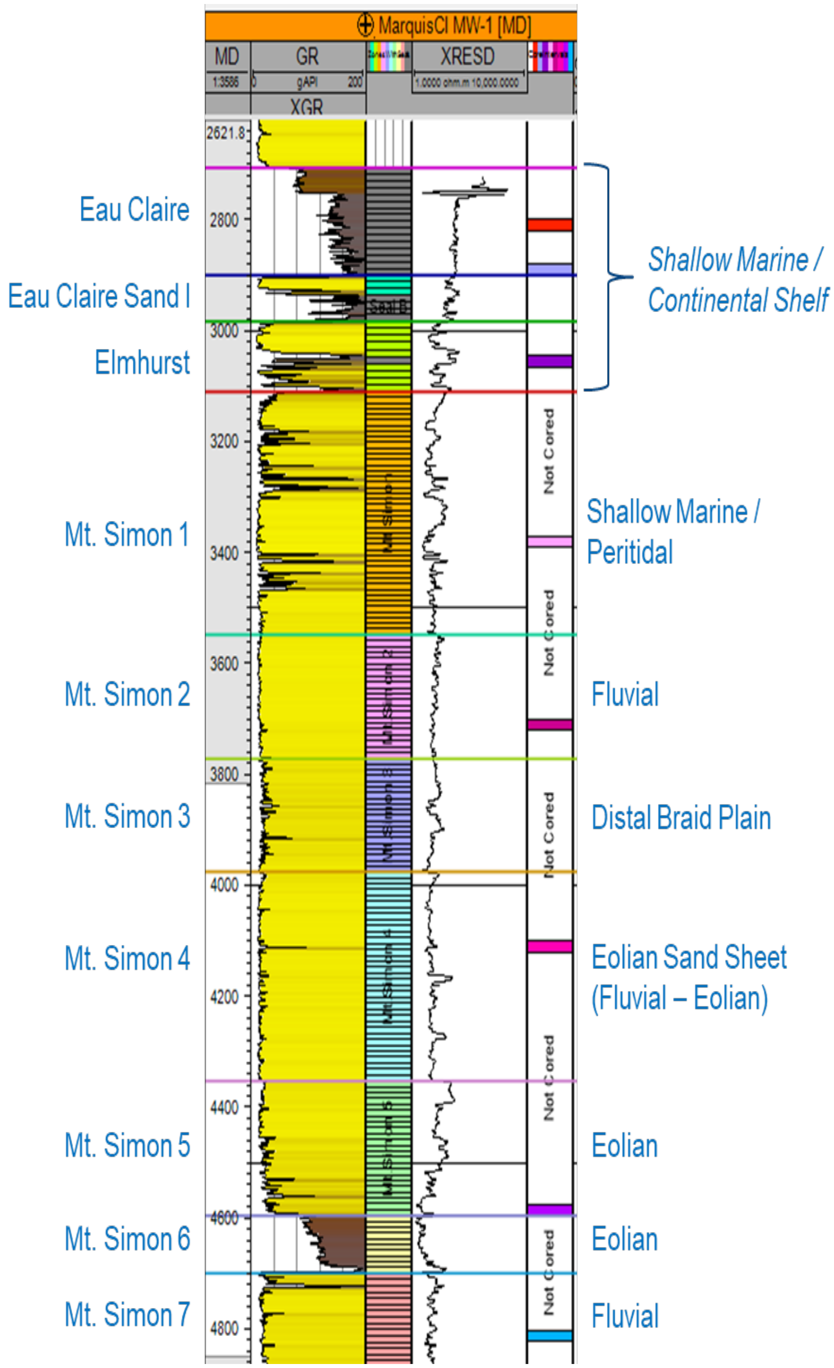


Figure 1-10: Interpreted Mt. Simon depositional environments and corresponding intraformational zones.

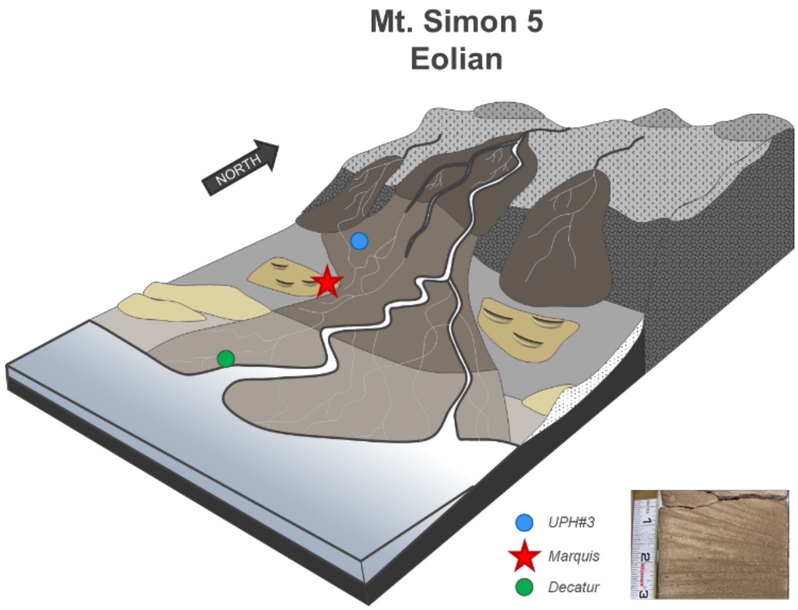


Figure 1-11: Example conceptual schematic drawing of the Mt. Simon Zone 5 representing the eolian depositional environment and interpreted orientations at the Marquis site (not to scale), as well as representative bedding features in whole core (insert) acquired from Mt. Simon Zone 5. Modified from Freiburg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

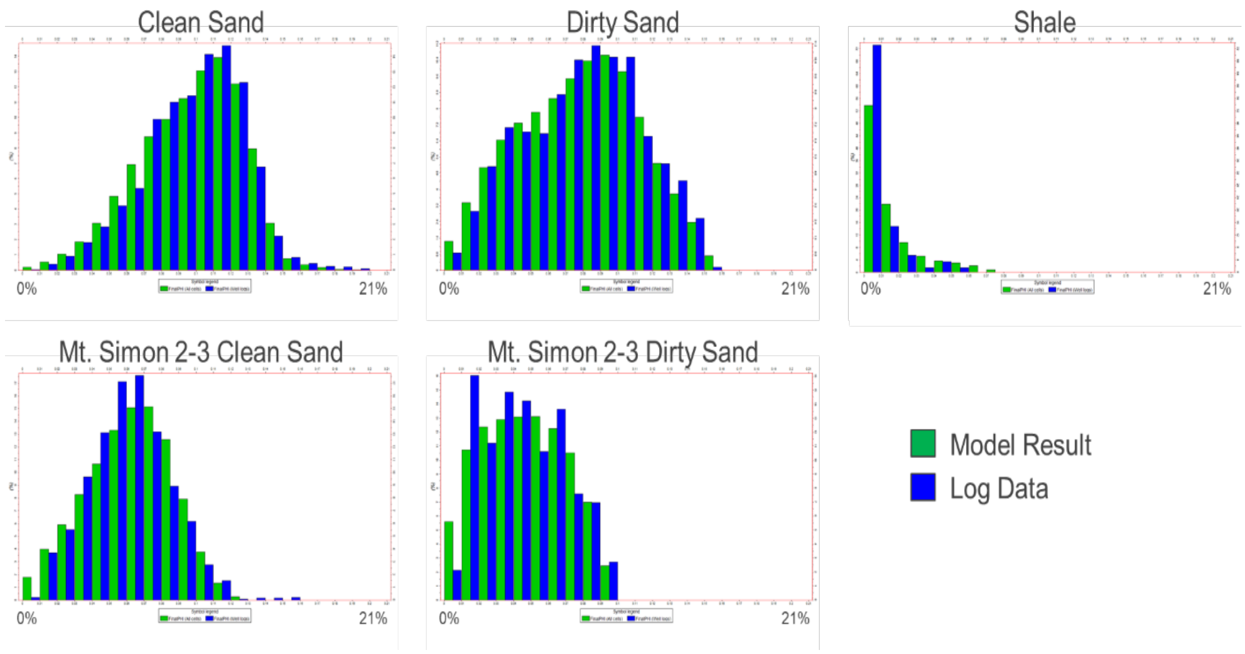


Figure 1-12: Histograms of porosity ranges by facies type showing correlative distributions for the clean sand, dirty sand, and shale facies. Distinctly different distributions for clean sand and dirty sand in Mt. Simons 2 and 3, where normal distribution means are lower.

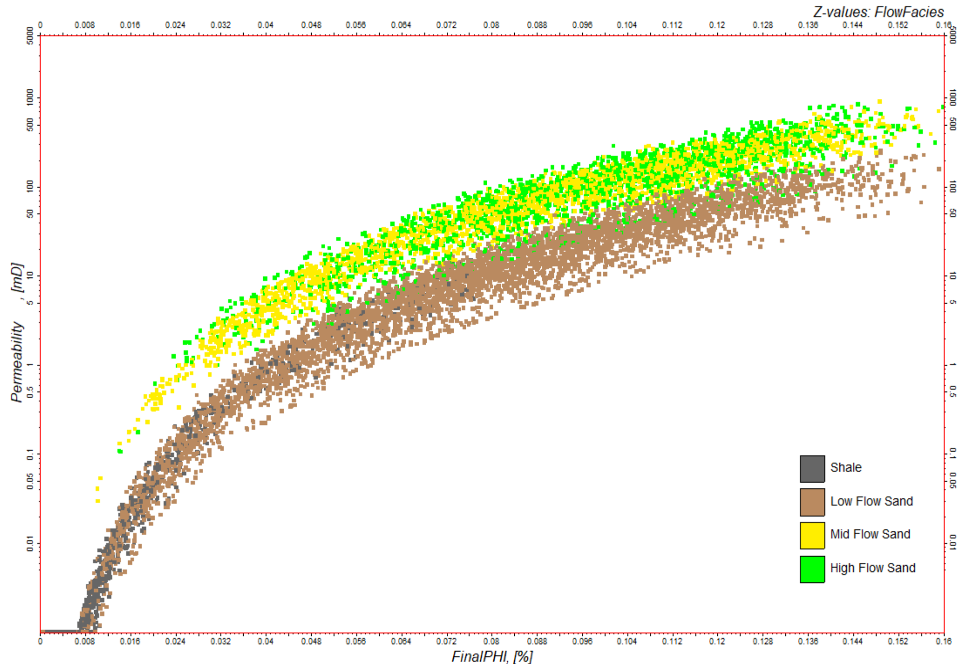


Figure 1-13: Porosity-Permeability cross-plot colored by flow facies showing the utilization of two different transforms, applied by flow-based rock classifications.

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	7.6	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 1-5: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.

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 MW 1 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 2,207 psi (3,226 ft MD*0.76*90%) following USEPA's guidelines. Using this pressure constraint, the results from the dynamic modeling shows that 9 MM tonnes can be injected in 6 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 existing mini frac test data will be used during construction of the MCI CCS 3 well.

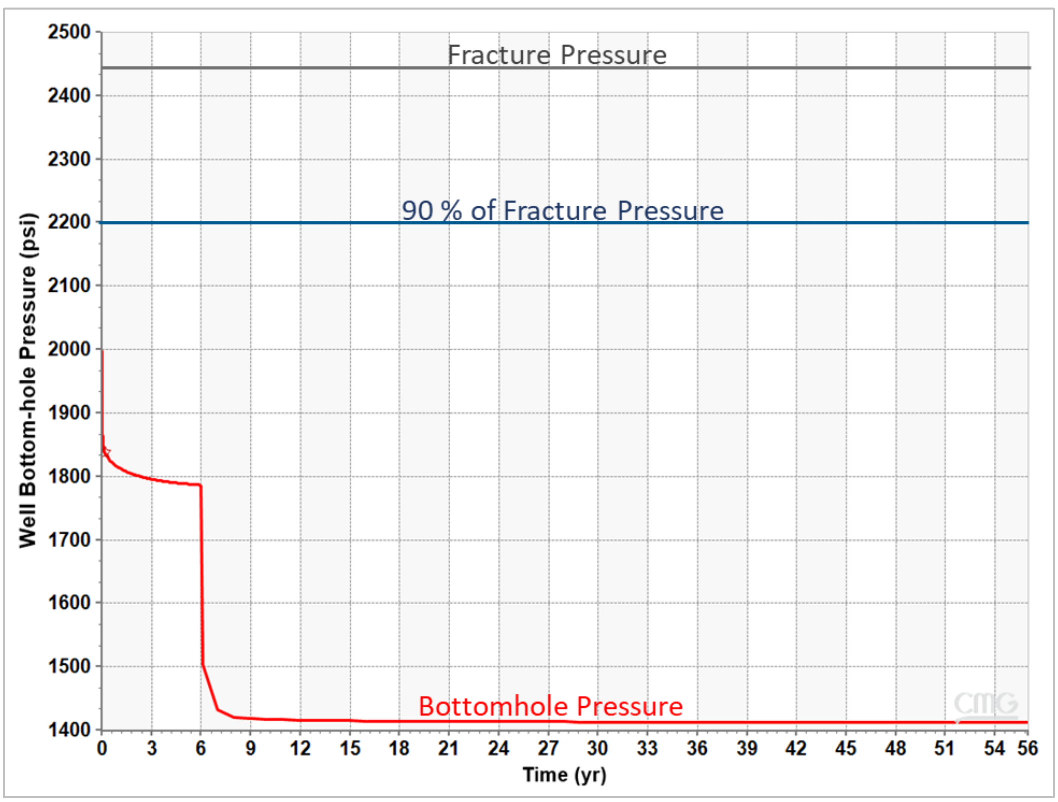


Figure 1-14: Plot of Cumulative CO_2 injection (blue) and Bottom Hole Pressure (grey).

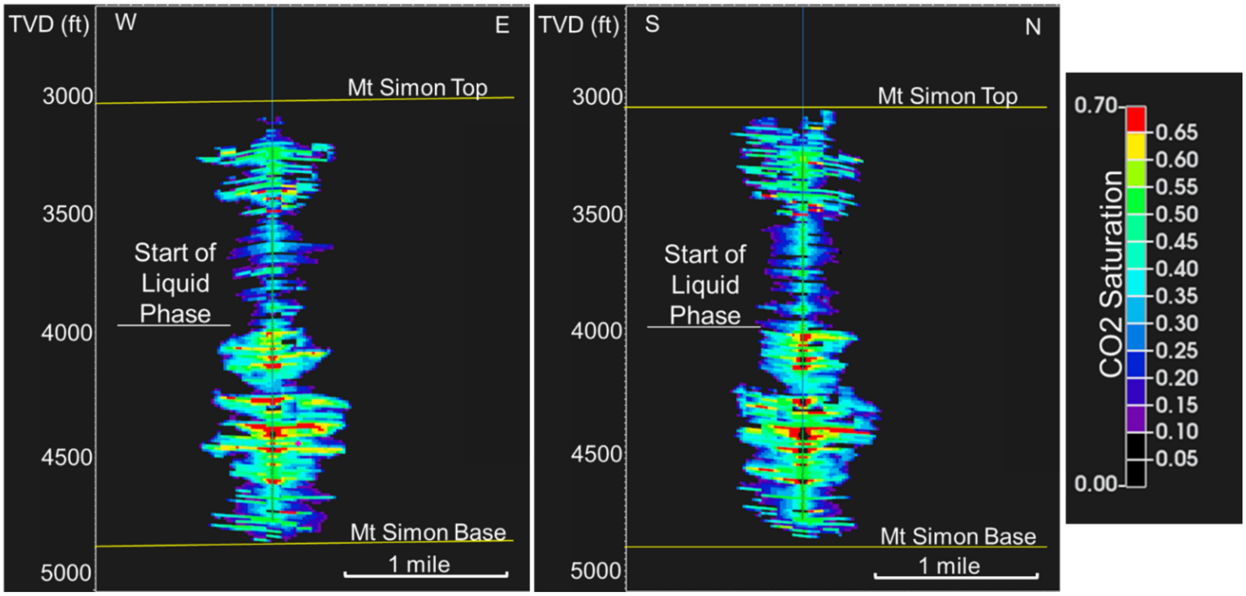


Figure 1-15: Development of CO_2 plume after 6 years of injection.

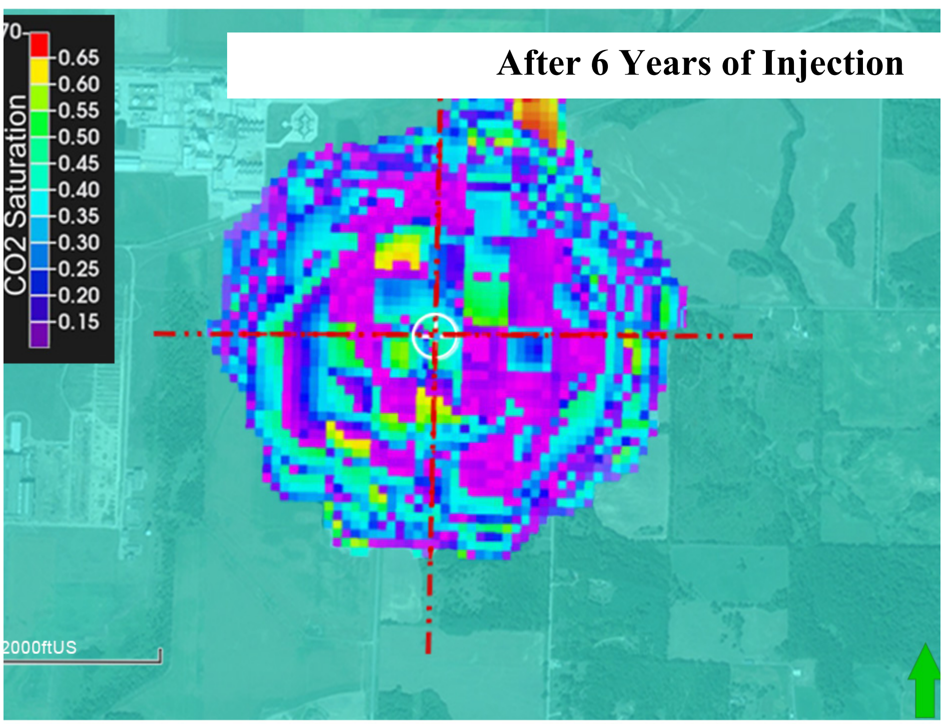


Figure 1-16: CO_2 plume in plan view.

The Area of Review (AoR) is determined by using the overall pressure plume size for the model at the end of the 6-year injection period. See **Figure 1-17**.

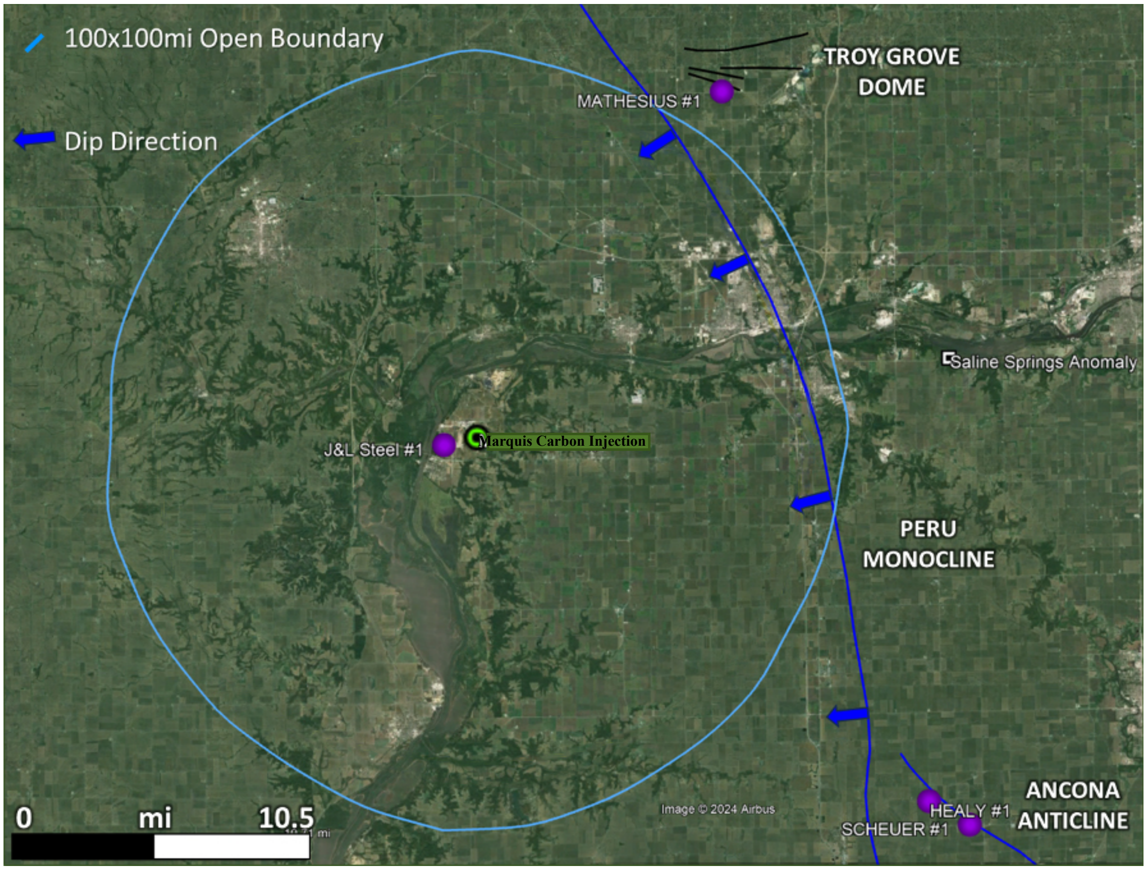


Figure 1-17: AoR (29-Mile Diameter)

Uncertainty

The Plume Model shown above uses parameters derived from field data acquired in the characterization well, as well as assumptions based on compressor and system design. The parameters that were analyzed for effect on the plume are porosity, permeability, vertical permeability, injection temperature, and flowrate. 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 and surface conditions 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 1-6**. Each scenario resulted in its own Static Earth Model (SEM) realization, and subsequent dynamic simulation. High-high, high-low, low-high and low-low side case runs were performed in addition to the Plume Model to assess the effects of varying porosity/permeability relationships on the CO_2 plume and by extension the AoR. The permeability vs porosity parameters for each case in the Mt. Simon is shown **Table 1-6**. All cases were imported from the

Petrel geological (SEM) model into CMG. In each sensitivity case, every parameter was the same as the Plume Model except for the variable parameter, or in the case of porosity and permeability, variable parameters. Final results of all sensitivity scenarios are shown in **Table 1-8.**

Case #	Case Name	Altered Parameter	Value of Altered Parameter
BASE	Plume Model	NA	Wellhead Temperature: 105ºF Porosity: 7.9% Permeability: 79.9 mD Vertical Perm: 1%-20% (Dependent on flow facies) Rate: 1.5 tonnes/year
1	High Porosity High Permeability "High High case"	Porosity/Permeability Transform	Average Porosity: 8.7%, Average Horizontal Permeability: 169.2 mD
2	High Porosity Low Permeability "High Low case"		Average Porosity: 8.7%, Average Horizontal Permeability: 31.5 mD
3	Low Porosity High Permeability "Low High case"		Average Porosity: 6.9%, Average Horizontal Permeability: 111.1 mD
4	Low Porosity Low Permeability "Low Low case"		Average Porosity: 6.9%, Average Horizontal Permeability: 19.8 mD
5	High Vertical Permeability	Vertical to Horizontal Permeability Ratio	0.7%-50% based on flow facies type
6	Low Vertical Permeability		0.1%-0.4% based on flow facies type
7	93.2 ºF Wellhead Temperature	Wellhead Temperature	93.2 ºF
8	115 ºF Wellhead Temperature		115 ºF
9	Reduced Rate to 600,000 tonnes/year	CO_2 Injection Rate	600,000 tonnes/year

Table 1-6: Summary of alternative scenarios / sensitivities for the Marquis Biocarbon Project.

Scenario	Phi	Kxy	Kz
High-High	8.7	169.2	21.4
High-Low	8.7	31.5	2.5
Base Case	7.9	79.9	10.4
Low-High	6.9	111.1	12.8
Low-Low	6.9	19.8	1.5

Table 1-7: Porosity and permeability relationships for porosity and permeability sensitivity cases

Results from the porosity and permeability sensitivities are included below in **Figures 1-18 and 1-19**. 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**).

Case	Time to Plume Sensitivity Boundary (yr)	Average Yearly Mass Rate (MMt/year)	Cumulative CO2 (MMt)
Plume Model	6	1.5	9
High Porosity Low Permeability	10	1.2	11.9
High Porosity High Permeability	5	1.5	7.5
Low Porosity High Permeability	3	1.5	4.5
Low Porosity Low Permeability	4	0.9	3.5
High Side Vertical Permeability	6	1.5	9
Low Side Vertical Permeability	4	1.4	5.6
93.2 ºF Wellhead Temperature	6	1.5	9
115 ºF Wellhead Temperature	12	0.3	3.75
Reduced Rate to 600,000 tonnes/year	12	0.6	7.2

Table 1-8: Summary Table of Sensitivity Cases and Results

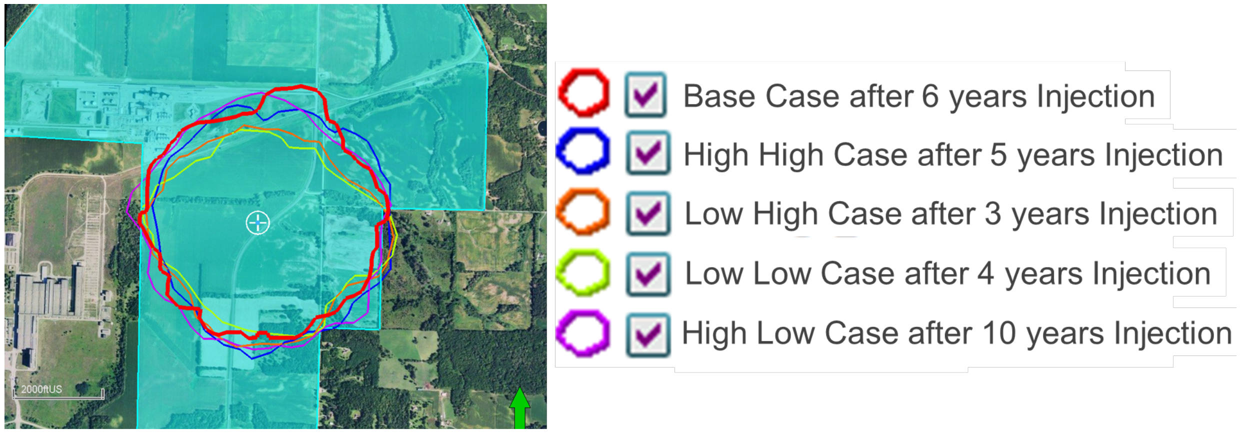


Figure 1-18 : CO_2 plume at the end of injection for porosity and permeability sensitivity cases.

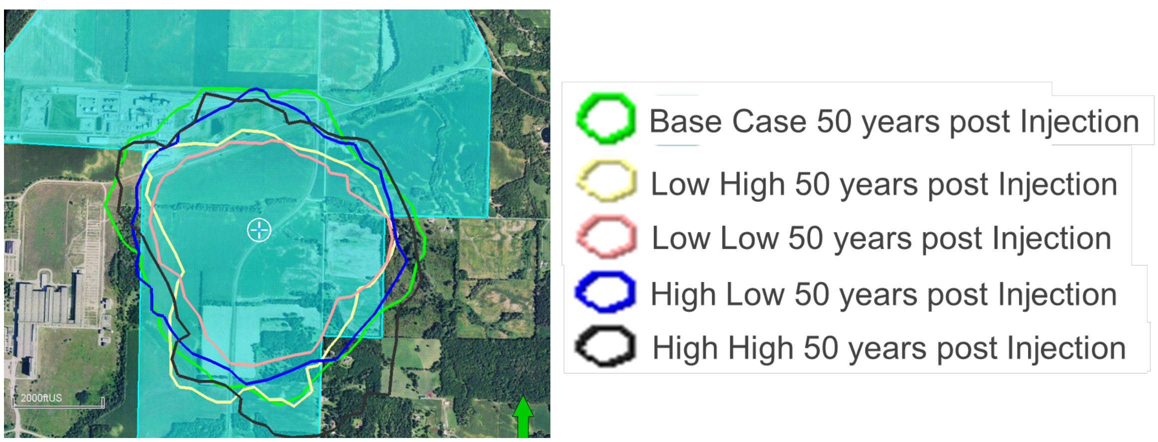


Figure 1-19: CO_2 plume at 50 years post injection for porosity and permeability sensitivity cases.

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. 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 **Tables 5-7** and **5-8** (Permit **Section 5**) 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**. Additional data will be-acquired during construction of the MCI CCS 3 well. A full description is given in the Pre-Operational Testing Program (Permit **Section 5**).

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 1-20**). 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. Most of the seismic events in Illinois occurred at depths deeper than 3 km (**Figure 1-21**).

Within the precision of the seismographic data, two earthquakes in 1999 (magnitude mb 3.5) and 1972 (magnitude mb 4.6) were located 5 and 13 km (3 and 8 miles), respectively, below the Peru monocline (Larson, 2001). The 1972 event occurred about 10 miles southeast of the 1999 event. A focal mechanism solution from the 1972 earthquake indicates movement on a high-angle, strike-slip fault, with either right-lateral to the north-northwest or left-lateral to the east-northeast (Hermann, 1979). Noting the proximity of this earthquake to the Peru monocline, Heigold (1972) suggests that the earthquake was the result of faulting related to a zone of weakness near the region where the monocline merges with the Ashton anticline. A third earthquake which occurred on May 27, 1991, also might be related to the Peru monocline based on damage reports from LaSalle, which sits directly on the Peru moncoline, but an exact location of this event is not known. (Larson, 2011). There was also an earthquake in 2004 that was approximately 25.0 miles northeast of the site (**//?**). This event had a magnitude of 4.2 and an approximate depth of 6.2 mi in basement rock (USGS, 2024).

On November 15, 2023, an earthquake occurred approximately 7.35 miles southeast of the site. The earthquake occurred south-southwest of Standard, Illinois, and it had a magnitude of 3.6 and an approximate depth of 5.7 kilometers (3.54 miles), and it was likely related to the Sandwich Fault (USGS, 2024).

Marquis Biocarbon Project will inject to an approximate depth of 0.95 miles and does not encounter the Sandwich Fault. Additionally, given the very low pressure buildup in the area and the separation from the underlying Precambrian rocks, any seismic impact from injection is highly unlikely.

Based on regional seismic hazard maps published by the USGS, 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 1-22**). (See Permit **Section 2.5.3**).

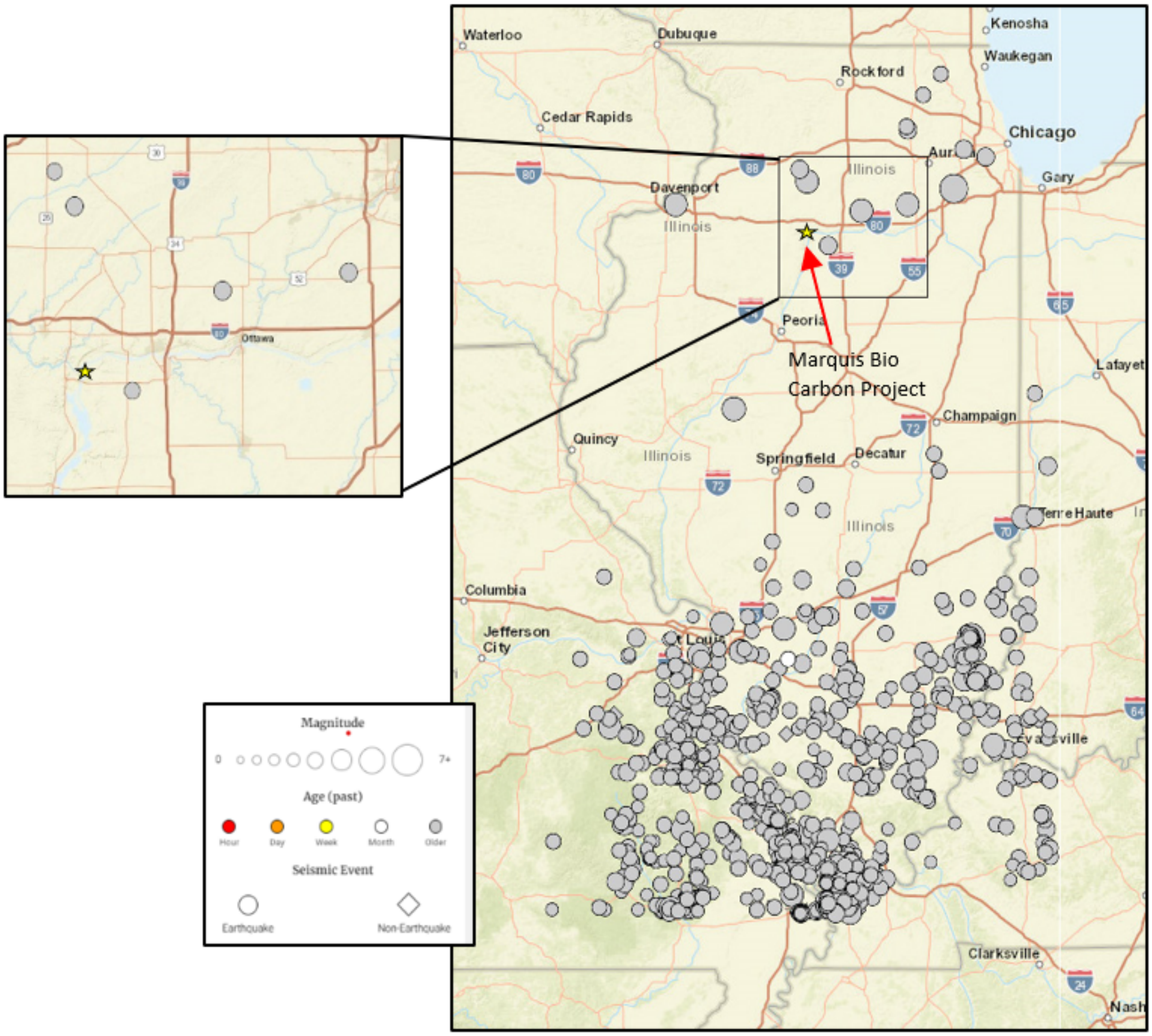
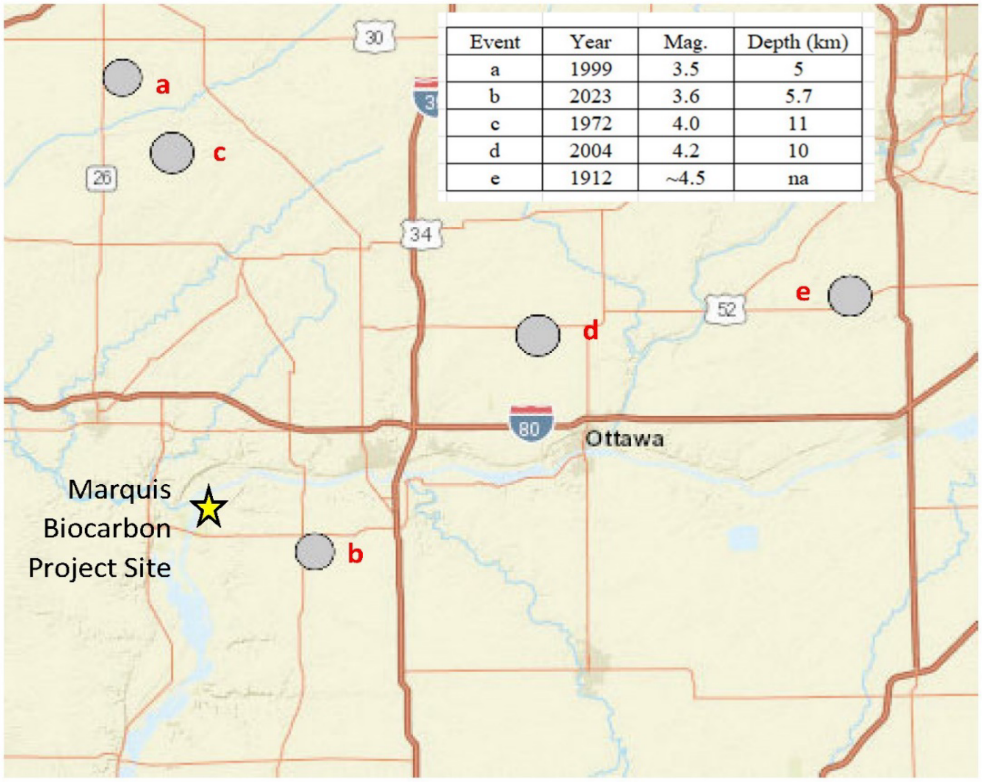


Figure 1-20: Regional Historic Earthquakes, Updated 2024. Source: USGS.gov.
(Close-up map shown in subsequent figure).



Event	Year	Mag.	Depth (km)
a	1999	3.5	5
b	2023	3.6	5.7
c	1972	4.0	11
d	2004	4.2	10
e	1912	~4.5	na

Figure 1-21: Local earthquakes since 1900 (modified from USGS, 2024).

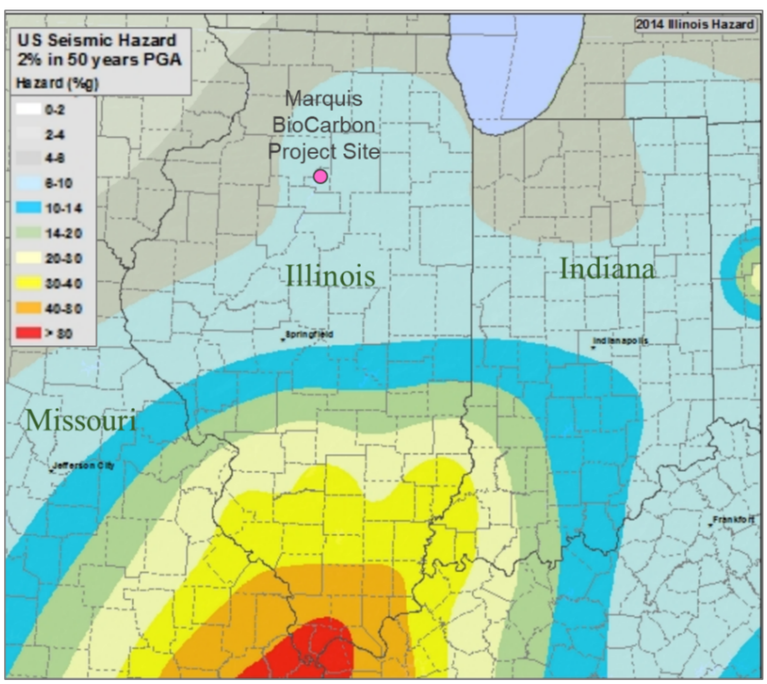


Figure 1-22: 2014 Regional seismic hazard Map for Illinois (USGS, 2014).

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. Based on data from the MCI MW 1 well and seismic data, the Gunter is approximately 14 feet thick at the location of the MCI CCS 3 well. 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**).

While naturally occurring springs and upwellings of Cambrian brines can occur within the Illinois basin, the conditions under which they occur require factors which are not present in the formations of the AoR of MCI CCS 3 well. The AoR of MCI CCS 3 well is not situated in an area where a water feature, such as a stream or river, intersects the basin edge. A basin edge is an area where older formations trend toward the surface and outcrops occur allowing communication with fluids in those formations. While the site does sit next to the Illinois River, it is located 20+ miles from the basin edge, in a structurally quiet area with flat-lying strata. The Saline Springs Anomaly is east of the AoR as shown on **Figure 1-17.**

In addition to the above data-supported conditions at Marquis, the MCI MW 1 well, located approximately 1.2 miles from the injection site, acquired subsurface water samples that did not show any signs of seepage of brine waters into fresh waters. The deepest measured USDW occurred in the Gunter Sandstone and had a salinity of 665 ppm, while samples taken from the Cambrian Mt. Simon formation measured at 44,413 ppm.

For purposes of the Marquis BioCarbon Project, a tabulation of all wells within the AoR were identified using well databases held by the Illinois State Geologic Survey (ISGS). Available well information indicates approximately 3,085 well records identified within the 29-mile AoR. Except for one well (J&L well), there were a few other wells that penetrated into the top of the Eau Claire, but those other wells did not penetrate through the confining layer. Those other wells identified in the AoR that terminate in the top of the Eau Claire unit have been identified and logs included in **Appendix V**. As detailed in the well logs, since those wells did not fully penetrate the cap rock and were properly sealed, these wells have not been identified as potential leakage pathways, and no corrective action is required.

The one well located within the AoR that fully penetrates through the Eau Claire sealing unit and into the injection zone, that is not part of the Marquis Biocarbon Project, is the J&L Well. However, the J&L well was abandoned and closed, and final approval was received from the Illinois EPA in 2013. See **Appendix W**. Marquis has included a summary map and list as generated by the ISGS mapper service in **Appendix V**.

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 and for site-specific corrosion modeling. See **Appendix Y**.

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 1-23** displays the chloride and TDS concentrations of 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.

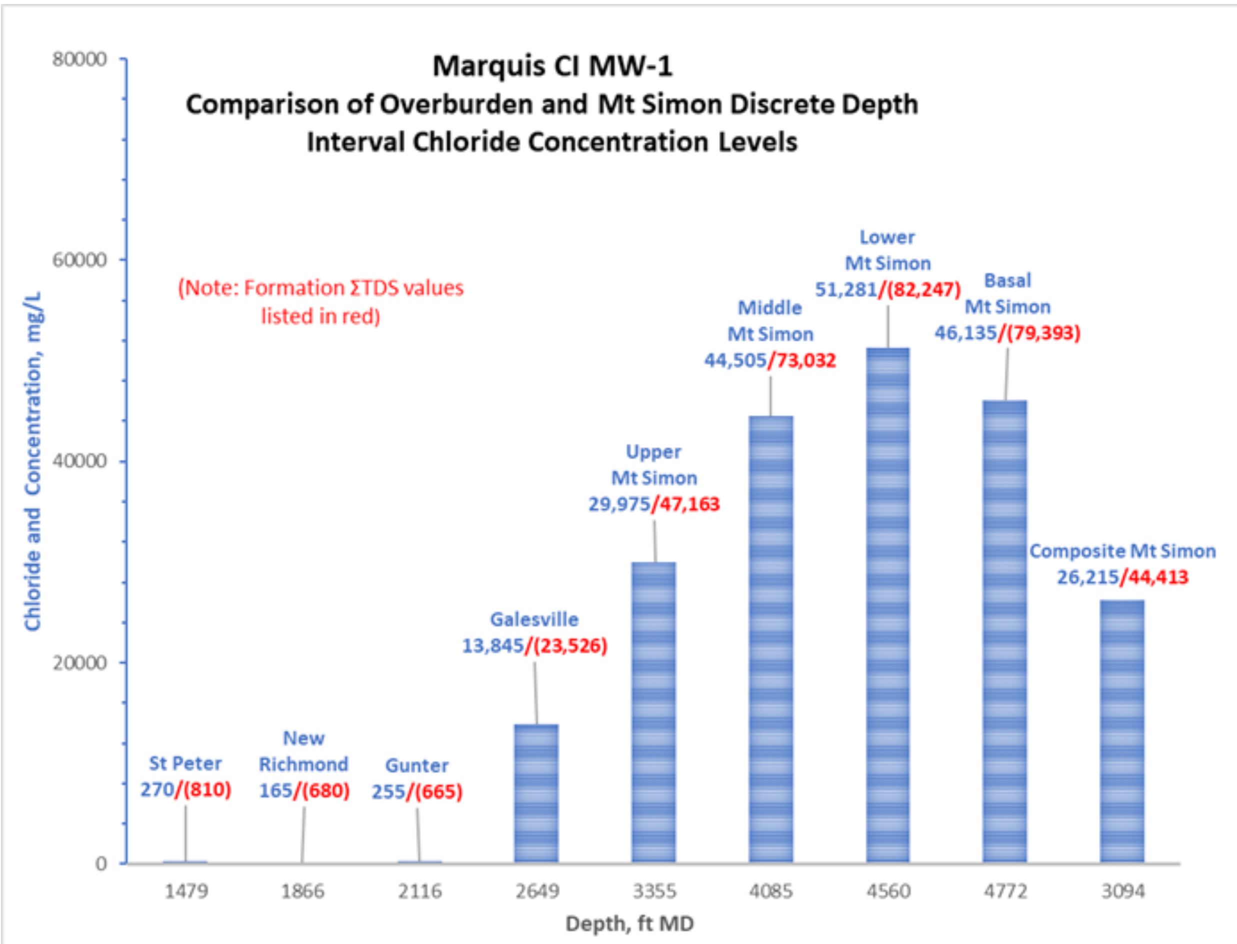


Figure 1-23: Chloride and TDS concentrations in the water/brine samples collected from the MCI MW 1 characterization well.

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 has 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. As mentioned in **Section 1.2.4** above, based on the current well design, the lower Elmhurst is not included in the confining interval. 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), 40 CFR 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 (SEM) 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 2022 version. 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 plume 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. The processes that were included and excluded in the simulation are summarized in **Table 1-9**.

Process	Computational Method	Included
Salinity Interactions	Aqueous Density: Rowe-Chou, 1970, Aqueous phase viscosity: Kestin et al, 1981	Yes
CO_2 Solubility	Henry's Law	Yes
Residual Phase Trapping	Land Model	Yes
Heat Transport	Using PIPESIM model and temperature gradient from logs	Yes
Mineral Precipitation	Kharaka et al, 1989, and Delany and Lundeen, 1990	No
Adsorption	Arri et al, 1992 and Hall et al, 1994	No
Diffusion and Dispersion	Sigmund, 1976	No

Table 1-9: Summary of processes that were included and excluded in the dynamic reservoir simulation.

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); and
- 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. See **Appendix V** for the ISGS map of oil and gas zones.

1.5.3 Casing and Cementing

The injection well (MCI CCS 3) will be designed using Chrome 13 (13Cr) and Super Chrome 25 corrosion resistant materials. The deep long string casing will incorporate a highly corrosion-resistant material, Super Chrome 25 (25Cr), across the reservoir from the caprock to total depth (TD) and Chrome 13 (13Cr) from above the caprock to the surface. The lower section of the wellbore is expected to have intermittent exposure to CO_2 and formation fluids especially in the initial phases of injection and intermittently when well inspections and maintenance are being performed. The exposed components of the injection packer will be specially constructed from corrosion-resistant materials including 25Cr in addition to specially designed polymers for the elements. Although the expected water content of the injectate stream will be less than 30 lb/mmscf, the injection tubing string and flow-wetted injection stream components will be composed of 25Cr corrosion-resistant materials. The upper section of the wellbore is not expected to have any exposure to CO_2 or formation fluids; however, 13Cr corrosion-resistant material will be used in the upper section of the long string casing as an enhanced corrosion prevention measure.

Carbon steel will be used for the conductor, surface and intermediate casing and tubulars that are not expected to be in contact with a mixture of the injectate (CO_2) and water. See **Figure 4-1** in **Section 4.0** of the application.

Viking Engineering, Marquis' third-party contractor, performed corrosion modeling to predict the corrosion rates and assess the risk for injecting Marquis' site-specific CO_2 into the aqueous environment of the Mt. Simon. Based on the CO_2 corrosion risk analysis conducted, the corrosion modeling estimates the corrosion rate to be in the order of 0.006 millimeter/year (0.05% per year based upon the thickness of the casing) and that the service life for the materials under those conditions exceeds the duration of the project. While the Viking Report demonstrates that the site-specific characteristics of the CO_2 and the brine within the injection zone present a very low corrosivity risk with very low potential thickness loss (**Appendix Y**), MCI is enhancing the CCS3 well and deep monitoring wells (MW-1 and MW-2) design by installing Super Chrome 25 (25Cr). Additionally, in CCS3 injection well, 13Cr will be installed in the upper portion of the long string casing above the Eau Claire caprock. By Marquis utilizing the Super Chrome material grade, which is a Super Duplex Stainless Steel, these well designs have increased pitting and corrosion resistance to formation fluids combined with CO_2.

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 2,735 ft; and a 9 5/8-inch long string set at a depth of approximately 4,854 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 1-10 and a summary of cement types is shown in **Table 1-11**.

Casing String Name	**Open Hole Size (in.)**	**Outside Diameter (in.)**	**Setting Depth (ft MD)**	**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	2,735	68	0.38	J/K-55	Buttress or Long Round Thread
Long String	12-1/4"	9.625	2,690 4,854	47 47	0.482 0.482	13Cr80 25Cr80	Premium Premium
Injection	n/a	5.5	3,100	23	0.415	25CrW125	Premium

Casing String Name	**Open Hole Size (in.)**	**Outside Diameter (in.)**	**Setting Depth (ft MD)**	**Weight (lb/ft)**	**Wall Thickness (in.)**	**Grade**	**Connection**
Tubing							

Table 1-10: Casing details.

Casing String	Appx. Depth Range (ft, MD)	Cement Type
Surface	0-350	Class A, G, or H
Intermediate	0-2,735	Class G or H
Deep	0-4,854	CO_2-Resistant tail slurry /Class G or H: Pozzolan 50:50 lead slurry

Table 1-11: 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. See Permit **Section 4.3**.

Additionally, the deep monitoring wells (MCI MW 1 and MCI MW 2) will be constructed with Super 25Cr casing and tubing corrosion resistant material in the lower portion below the Eau Claire caprock and within the Mt. Simon. In deep monitoring well MCI MW 2 that is located near the injection well13Cr will be installed in the upper portion of the long string casing above the Eau Claire caprock. MCI MW 1 (previously the Stratigraphic Test Well) is the far field deep monitoring well as it is located approximately 1.2 miles from the MCI CCS 3 injection well. Because of the distance outside of the CO_2 plume, the upper portion of the MCI MW 1 well casing will be constructed of L80 carbon steel. See **Figure 4-1 in Section 4.0** for deep monitoring well locations, and **Figures 7-4 (b) and (c) in Section 7.0** for the design of the deep monitoring wells.

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. Data from MCI MW 1, specifically the core analysis of the Eau Claire and Mt. Simon Formations, will be used for MCI CCS3. Field data will be collected during the drilling process. Open-hole wireline well logs and fluid sampling will be acquired to correlate and confirm the homogeneity between MCI MW1 and MCI CCS3. Additionally, an injection test will be performed after casing is run and tubing is in place. Details of the logging and testing program for the MCI CCS 3 well are described in **Section 5**.

1.7 Section 6.0: Well Operations Plan

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

A Well Operations Plan is included. See Permit **Section 6.0.** Permit **Section 6.0** 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 1555 psi (90% of the fracture propagation pressure). Pipesim modeling software was used to create a table of maximum allowable well head pressures at distinct flowrates and temperature. The operational parameters of the MCI CCS 3 well are provided in **Table 1-11**. See Pipesim Result in **Table 1-12.**

Parameters/Conditions	Limit or Permitted Value	Unit
Maximum Injection Pressure		
Surface (Note 1)	1,555	psi
Downhole (top perforation)	2,206	psi

Parameters/Conditions	**Limit or Permitted Value**	**Unit**
Average Injection Pressure		
Surface	1,370	psi
Downhole	1,837	psi
Maximum Injection Volume and/or Mass	1,500,000	MT/year
Average Injection Volume and/or Mass	1,200,000	MT/year
Surface Annulus Pressure Operational Parameters (Note 2 & 3)	120-800	psi
Maximum Annular Pressure	2,326	psi
Operational Packer Differential (Note 4)	120	psi
Maximum Surface Pressure Applied (Note 5)	956	psi

Note:

(1) Variability of the compressor could increase the pressure up to a maximum allowable wellhead pressure of 1,555 psi.
(2) The annular system will maintain wellhead pressure of the annular fluid between the tubing and long string casing within the permitted values. Annular pressure gauge on top of the annulus head tank will be monitored.
(3) See Section 4.3 for details concerning Annular Pressures and Design.
(4) When not injecting, the system will maintain a minimum annular pressure 100 psi above the pressure of the CO_2 in the injection tubing at the depth of the packer, which will be monitored by the WAMS control system.
(5) Maximum surface pressure applied is delivered from the WAMS and will be 956 psi at the maximum injection pressure which is 90% of the fracture pressure.

Table 1-12: Proposed operational procedures.

Rate (million tonnes per year)	**Bottomhole Pressure (BHP) (psi)**
0.6	2,064.5
1	1,986.23
1.3	1,904.34
1.5	1,837.47

Table 1-13: Pipsim Results

Based on initial design calculations, the anticipated CO_2 pressure at the pipeline outlet (i.e., at the well site) will be approximately 1,370 psi at an average temperature of 105°F (**Table 1-13).** Variability of the compressor could increase the pressure up to a maximum allowable wellhead pressure of 1,555 psi.

Injection Stream Parameter	**Wellhead Specification**
Ave Pressure (psi)	1,370
Ave CO_2 Temperature (ºF)	105
Ave Mass Flow Rate (MT/yr.)	1,200,000
Density (lb/ft^3)	34-45
Viscosity (cP)	0.073
Molecular Weight	43.99

Table 1-14: 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). Continuous recording devices to monitor injection temperature, pressure, rate, and volume will be used to confirm that storage formation pressures remain below the regulated limit while the storage formation pressure will be measured continuously with downhole pressure and temperature 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 1-14**. The operation monitoring data will be connected to the main facility through a remote link to the Data Control System (DCS) 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. After the MCI CCS3 well is drilled and prior to completion of the well, a baseline temperature profile will be obtained, and a distributed temperature sensing (DTS) fiber optical temperature monitoring system will be installed. The DTS system will monitor the well's annular temperature along the length of the tubing string and provide annual temperature monitoring. The DTS system will provide an enhanced method for early detection of temperature changes that may indicate a loss of well mechanical integrity.

Parameter	**Device(s)**	**Location**	**Min. Sampling Frequency (Notes 1 & 2)**	**Min. Recording Frequency (Notes 2 & 3)**
CO_2 stream surface injection pressure (wellhead)	Pressure Transducer	Wellhead	Every 1 min.	Every 1 min.
CO_2 downhole injection pressure	Pressure Transducer	Tubing string above injection packer	Every 1 min.	Every 1 min.
Mass injection rate	Coriolis Flow Meter	After compressor before wellhead (Pre-Wellhead)	Every 10 sec.	Every 10 sec.
Annulus surface pressure	Pressure Transducer	Wellhead Annulus Monitoring System (WAMS) Surface Skid	Every 1 min.	Every 1 min.
Annulus downhole pressure	Pressure Transducer	Above injection packer	Every 1 min.	Every 1 min
Annulus fluid volume added	Volume Level Instrument	WAMS Surface Skid	Every 1 min.	Every 1 min
CO_2 surface injection temperature	Thermocouple	Wellhead	Every 1 min.	Every 1 min.
CO_2 downhole injection temperature	Thermocouple	Tubing string above injection packer	Every 1 min.	Every 1 min.
Wellbore temperature profile	Distributed Temperature Sensing (DTS) Fiber Optic	On casing Outside Diameter (OD) to depth of injection packer	Annual	Annual

Parameter	Device(s)	Location	Min. Sampling Frequency	Min. Recording Frequency
Notes: (1) 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. (2) 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. (3) If system communication is lost for greater than 30 minutes, manual field monitoring of gauges will be conducted every 6 hours or twice per shift for both CO_2 surface injection pressure and annulus surface pressure. Logs will be maintained in the facility records				

Table 1-15: Sampling devices, locations, and frequencies for continuous monitoring of MCI CCS 3

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. After compression and prior to injection, the CO_2 gas stream will be continuously monitored for CO_2, nitrogen (N_2), oxygen (O_2), and water (H_2O) during the first quarter after startup, and for a seven-day period each quarter thereafter during the injection phase utilizing the dedicated real time Gas Chromatograph (GC).

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 proposed in this application;

- Providing data to validate and calibrate the geological and dynamic models used to predict the distribution of CO_2 within the injection zone; and
- Supporting 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; and
- 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 6-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; and
- 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 1-14** 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 fiberoptic temperature measurement (DTS system) 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.

An annular protection system which monitors the annular space from the surface to the top of the packer in CCS3 will be installed. The system will monitor the annulus between the tubing and the long string casing that is filled with annular fluid on a continuous basis. See Permit **Section 4.3.**

In MCI MW1, MCI MW 2, and MCI ACZ 1, the annulus between the tubing and long string casing also will be filled with the annular fluid at the time of well completion and sealed. The annular pressure gauge will be logged at the surface weekly. Some thermal expansion of the pressure in the fluid in the annulus space is expected due to ambient temperature changes. However, from weekly monitoring, trends will develop identifying normal pressure fluctuations and any increases that could indicate fluid leakage from MCI MW 1, MCI MW 2, and MCI ACZ 1.

Pulse neutron capture (PNC) logs will be acquired in the MCI CCS 3. Pressure fall-off tests (PFOs) will be conducted in the Mt. Simon Sandstone in the MCI CCS 3 well when it is 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 existing wells (MCI GW 1-4) that are located within the AoR as shown in **Figure 1-4**. An additional existing or new 5th groundwater well (GW 5) located southeast of MCI CCS3 within the AoR will also be included in the groundwater monitoring program. An evaluation and request to use the existing wells identified on **Figure 1-4** was submitted to the Program Director for use as part of the proposed groundwater monitoring program, and a pre-injection groundwater sampling program is being conducted.

Monitoring Activity	Baseline Data Frequency	Injection Phase Frequency (Note 1)	Location	Formation top / Depth Range (ft, MD) (Note 2)
Assurance Monitoring:				
Shallow Groundwater Sampling (Note 2)	Once/quarter	Twice/year	Existing MCI GW 1-4 Wells and Existing or New GW 5 Well within AoR	Shallower than 300 Feet below ground surface (Note 3)
Isotope Analysis	Once/quarter	Twice/year	Existing MCI GW 1-4 Wells and Existing or New GW 5 Well within AoR	Shallower than 300 Feet below ground surface (Note 3)
Operational Monitoring:				
CO_2 Stream Sampling and Lab Analysis	NA	Quarterly (Note 6)	After Last Stage of Compression and Before Injection	NA
Corrosion Coupon Analysis	NA	Quarterly	CO_2 Delivery Plant Piping to Wellhead	NA
CO_2 Stream Analysis, Including N_2, H_2O, and O_2	NA	Quarterly (Note 7)	CO_2 Delivery Plant Piping to Wellhead	NA

Monitoring Activity	Baseline Data Frequency	Injection Phase Frequency (Note 1)	Location	Formation top / Depth Range (ft, MD) (Note 2)
CO_2 Surface Injection Pressure (Injection Stream)	N/A	Continuous	Wellhead - MCI CCS 3	Surface- Wellhead
CO_2 Surface Injection Temperature	N/A	Continuous	Wellhead - MCI CCS 3	Surface-Wellhead
CO_2 Down hole Injection Pressure	Continuous	Continuous	MCI CCS 3	Tubing String Above Injection Packer
CO_2 Down hole Injection Temperature	Continuous	Continuous	MCI CCS 3	Tubing String Above Injection Packer
Mass CO_2 Injection Rate	NA	Continuous	Pre-Wellhead (Before the Wellhead and after the compressors)	Surface
Annulus Pressure	NA	Continuous	MCI CCS 3	Surface and Downhole
		Weekly	MCI MW 1	Surface
		Weekly	MCI MW 2	Surface

Monitoring Activity	Baseline Data Frequency	Injection Phase Frequency (Note 1)	Location	Formation top / Depth Range (ft, MD) (Note 2)
Annulus Pressure	NA	Weekly	MCI ACZ 1	Surface
Annulus Fluid Volume Added	NA	Continuous	MCI CCS3	Wellhead Annulus Monitoring System (WAMS) Surface Skid
Wellbore Temperature Profile (storage formation) (Distributed Temperature Sensing (DTS) System Fiber Optic)	Once	Annually	MCI CCS 3	0-3,100 (Upper Mt. Simon) On casing Outside Diameter (OD) to depth of injection packer
Monitoring well Temperature Profile (Storage Formation) (DTS Fiber Optic)	Once	Annually	MCI MW 1 MCI MW 2	0-3,100 (Upper Mt. Simon) On casing Outside Diameter (OD) to depth of injection packer
PFO Tests	Once	Every 5 years	MCI CCS 3	Surface
Verification Monitoring:				
Fluid Sampling				
Gunter Sandstone	Twice/year	Twice/year	MCI ACZ 1	2,118

Monitoring Activity	Baseline Data Frequency	Injection Phase Frequency (Note 1)	Location	Formation top / Depth Range (ft, MD) (Note 2)
Galesville Sandstone	Twice/year	Twice/year	MCI ACZ 1	2,635
Upper Mt. Simon Sandstone	Twice/year	Twice/year	MCI MW 2	3,225 (Note 4)
Isotope Analysis	Twice/year	Twice/year	MCI ACZ 1 MCI MW 2	All samples
Pressure – Temperature Sensors				
Gunter Sandstone	Continuous	Continuous	MCI ACZ 1	2,118
Galesville Sandstone	Continuous	Continuous	MCI ACZ 1	2,634
Upper Mt. Simon Sandstone	Continuous	Continuous	MCI MW 2	3,225
PNC Logging	Once	Once/ year	MCI MW 2 MCI ACZ 1	2,118 – Total Depth 2,118 – Total Depth
Microseismic Monitoring	4 to 6 months prior to injection	Continuous	Surface stations	Surface (Note 5) See Figure 7-10
Time-lapse 3D Surface Seismic Data	Once	Every 5 years or 4 million tonnes of CO_2	Surface	N/A

Monitoring Activity	**Baseline Data Frequency**	**Injection Phase Frequency (Note 1)**	**Location**	**Formation top / Depth Range (ft, MD) (Note 2)**
		injection, whichever occurs first		
Corrosion Monitoring – multi-finger caliper logging or ultrasonic casing evaluation	NA	Every 6 years after beginning of injection	MCI CCS3	Downhole – 25Cr casing and tubing
Modeling of CO_2 Plume / AoR:				
Dynamic Modeling	Once	Every 5 years or 4 million tonnes of CO_2 injection, whichever occurs first	Storage Formation	N/A

Monitoring Activity	Baseline Data Frequency	Injection Phase Frequency (Note 1)	Location	Formation top / Depth Range (ft, MD) (Note 2)

Notes:

(1) Minimum frequency

(2) All depths are estimates based on stratigraphic test well. Actual depths will be confirmed once wells are drilled, and installation plans are completed.

(3) An evaluation and request were submitted to the Program Director to utilize existing shallow wells located within the AoR as part of the groundwater monitoring program. For establishing baseline, sampling of the deep wells will occur during well drilling and prior to start of injection.

(4) The upper Mt. Simon at 3,225 ft is the location of the first perforation of the top most injection zone. Sampling frequency may be adjusted once model is updated post drilling to try and detect CO_2 fluid mixing front as it passes by the well.

(5) Microseismic stations have been installed to collect background data. See Figure 7-10 which shows current location of stations. Stations may be relocated if necessary, and documentation showing basis for the change and new location will be retained in the facility records.

(6) After construction of the injection well and initial startup of the well and reaching steady state, the first quarterly CO2 stream sampling and lab analysis will be conducted.

(7) After initial startup of the well and during the first quarter, continuous CO_2 stream analysis will be conducted by a dedicated real time Gas Chromatograph (GC). After the first quarter, continuous analysis will be collected by the GC for a 7-day period each quarter during the injection phase.

Table 1-16: 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**). The stratigraphic test well will be completed as a monitoring well (MCI MW 1) and 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 data 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**).

Marquis has installed surface seismic stations within the AoR and a baseline of any seismic activity is being obtained prior to injection. The passive seismic monitoring system processes microseismic data using statistical and waveform approaches that account for the layered earth structures. 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 1-15** 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	3,126−4,791	Mt. Simon Sandstone	Retainer	CO_2-Resistant	661 sacks
9-5/8-in. Casing Column	2,650-2,750	Eau Claire	Balance	Class A	35 sacks
9-5/8-in. Casing Column	250-350	Pennsylvanian	Balance	Class A	35 sacks

Table 1-17: 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 (See Figure 4-1). 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 12 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 less than 1% of pressure difference to pre-injection pressure levels within 12 years of post-injection, as described in Permit **Section 9**. 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 Stimulation Program [40 CFR 146.82(a)(9)]

CO_2 injection will occur through the perforations within the injection well casing. Due to the high porosity and permeability in the Mt. Simon and the local injection characteristics confirmed through the stratigraphic test well drilling and core testing and analysis, MCI has not proposed a stimulation program to enhance the injectivity of the Mt. Simon sandstone at this time.

If stimulation technique is necessary to improve wellbore injectivity in the Mt. Simon, notice will be provided to the Director prior to conducting the stimulation activities. MCI will provide a description of the fluids that would be used, including a demonstration that the stimulation activities will not interfere with CO_2 containment. In accordance with 40 CFR 146.91(d)(2), at least 30 days prior to conducting stimulation activities, MCI will submit the proposed procedures for all stimulation activities to the Program Director. The stimulation activities will be implemented in accordance with the Program Director's determination.

1.14 Other Information

Currently, there is 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.

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