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AREA OF REVIEW AND CORRECTIVE ACTION PLAN
40 CFR 146.84(b)

HOOSIER #1 PROJECT

Facility Information

Project Name:	Hoosier #1
Facility Name:	Cardinal Ethanol
Facility Contact:	Jeremey Herlyn, Project Manager 866-559-6026, jeremeyherlyn@cardinalethanol.com
Well Location:	1554 N. 600 E. Union City, IN 47390 Well Location for CCS1 Latitude 40.186587° Longitude -84.864284°
Operator Name:	One Carbon Partnership, LP 1554 N. 600 E. Union City, IN 47390

Several figures contained within this document contain Confidential Business Information (CBI) that is privileged and exempt from public disclosure – "Narrative without CBI". These images will be delivered to the United States (US) Environmental Protection Agency (EPA) in a separate document – "Narrative with CBI".

The figures listed below contain CBI and have been redacted from the publicly disclosed version of this document:

Figure 5: Confidential Business Information: Well log upscaling.

Figure 6: Confidential Business Information: Effective porosity and permeability cross plots with core plugs (grey).

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List of Acronyms

2D	Two-dimensional
3D	Three-dimensional
AoR	Area of Review
BHP	Bottomhole Pressure
CCS	Carbon Capture and Sequestration
CCS1	Injection Well
CH_4	Methane
CMG	Computer Modeling Group
CO_2	Carbon Dioxide
EOS	Equation of State
EPSG	European Petroleum Survey Group
FT	Feet
FBSL	Feet Below Sea Level
GEM	Generalized Equation Model
H_2O	Water
IDNR	Indiana Department of Natural Resources
IGWS	Indiana Geological and Water Survey
kv/kh ratio	vertical permeability divided by horizontal permeability
kh	Horizontal Permeability
kv	Vertical Permeability
MIT	Mechanical Integrity Test
MSL	Mean Sea Level
O&G	Oil and Gas
OBS1	Deep Observation Well
OCP	One Carbon Partnership, LLC
P&A	Plugged and Abandoned
PNL	Pulsed Neutron Logging
PSI/FT	Pounds per Square Inch per Foot
PSIA	Pounds per Square Inch Absolute
TDS	Total Dissolved Solids
UIC	Underground Injection Control
USDW	Underground Source of Drinking Water

This document describes how the geologic and hydrologic information were used to delineate the Area of Review (AoR). It also addresses the extent to which the Hoosier #1 Project needs to undertake corrective actions for features within the AoR that may penetrate the confining zone, and how such corrective actions will be taken if needed in the future. Section 1.1 describes the computational model that was used to delineate the AoR, including a description of the simulator and the physical processes modeled and a description of the conceptual model and numerical implementation. It also describes the AoR, and how the AoR will be re-evaluated over time. Section 4 describes the Hoosier #1 Project Corrective Action Plan. This document is intended to demonstrate compliance with 40 CFR 146.84.

1 Computational Modeling Approach (40 CFR 146.84(b)(1))

1.1 Model Background

1.1.1 Static Model

The Hoosier#1 project made use of two models (Figure 1). The first was a static model which incorporated local and regional data in a single model. The second was a smaller computational model. The model was developed using Rock Flow Dynamics' software tNavigator. Table 1 summarizes the steps and the workflow used to generate the final structural and static model.

Table 1: Summary of static modeling steps

Modeling Step	Input Data	Information
Injection and Confining Zone Details	• Core data from nine wells and well log data were downloaded from public data sources • Class I injection wells were used as calibration points	• Facies, porosity, and permeability of the Eau Claire Formation and Mt. Simon Sandstone • Petrophysical properties
Incorporate two-dimensional (2D) Seismic Survey	• Three 2D surface seismic lines	• Local detail of geologic structures
Formation Surfaces and Thickness	• Well logs	• Regional geologic structure
Static Model	• Data above	• Develop a model to represent subsurface facies, porosity, and permeability
Computational Model	• Static model	• CO_2 and pressure plume behavior

The formations or zones that were modeled and the number of layers in each zone have been summarized in Table 2. Figure 2 and Figure 3 show the stratigraphic column of horizons while Figure 2 and Figure 4 displays the zones used in the static model. The deepest underground source of drinking water (USDW) is plotted on these cross sections and is discussed in detail in the Project Narrative (Attachment 1: Narrative, 2022).

The static model was 141 miles (east-west) by 116 miles (north-south). The area was selected to include wells in the region that had reliable petrophysical data. The model contains 24.4 million cells. The static model cell size was selected to represent the subsurface heterogeneity and keep the cell count small enough to manageably run the computational modeling. Thinner cells were used in the injection zone where the computational modeling was focused on the CO_2 injection.

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Figure 1: Areas covered by the static and computational models

Table 2: Table of static model formations

Formation (Zone)	Layer Type	Number of Model Layers	X-Y Cell Length	Porosity and Permeability Data Source
Undifferentiated	Proportional	1	500ft	Not modeled
Trenton Limestone		1		Not modeled
Knox Formation		1		Not modeled
Davis Formation		1		Not modeled
Eau Claire Formation		150		Well logs and Class I wells
Mt Simon Sandstone		125		Well logs and Class I wells
Precambrian Basement		40		Not modeled

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Figure 2: CCS1 modeling stratigraphic column

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Figure 3: Cross Section A-A' stratigraphic formations.

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Figure 4: Cross Section A-A' static model formations.

1.1.2 Computational Model

Numerical simulation of carbon dioxide (CO_2) injection into deep geologic formations requires the modeling of complex, coupled hydrologic, chemical, and thermal processes including multi-fluid flow and transport, partitioning of CO_2 into the aqueous phase, and chemical interactions with aqueous fluids and rock minerals. The fluid flow model used for this application is Generalized Equation Model (GEM), a commercial simulator developed by Computer Modelling Group (CMG) of Calgary, Alberta.

GEM has been developed by CMG over many years primarily for modeling hydrocarbon reservoirs. This simulation software was selected because it has many advanced features for carbon sequestration modeling including relative permeability hysteresis, CO_2 solubility in water, water vaporization, geochemistry, mineralization, thermal, and geomechanical properties.

For this application, an equation of state (EOS) was developed with three components: CO_2, methane (CH_4), and water (H_2O). Since the computational model was originally designed for hydrocarbon reservoirs, it requires a hydrocarbon component (CH_4), but it is only present as a trace component. The phases modeled are supercritical CO_2, dissolved CO_2 in water, residual CO_2 (gas trapping), and CO_2 trapped by mineralization.

The model uses well established discretized fluid flow equations and an adaptive-implicit method for solving the resulting sparse matrix. Details can be found in the following publications: (Collins, D.A., Nghiem, L.X., Li, Y.-K. and Grabenstetter, J.E., May 1992), (Thomas, G.W. and Thurnau, D.H., October 1983), (Nghiem, L.X. and Li, Y.-K., September 4-8, 1989)

The model uses a cubic EOS with Peng-Robinson (PR) coefficients. Viscosity modeling is accomplished by using either the Jossi-Stiel-Thodos or Pedersen correlations. Key assumptions include:

- Eccentricity of molecules
- Use of random mixing rules
- Binary interaction parameter
- Minimum Gibbs energy as an equilibrium criterion
- Fugacity as a function of measurable properties
- Volume translation used to improve density prediction

The processes that were modeled for this application are:

- Convective and dispersive flow
- Relative permeability hysteresis
- Gas solubility in aqueous phase
- H_2O vaporization
- Mineralization

It is also possible to assess the confining layer integrity using geomechanics. An initial evaluation was conducted using data from the literature; this evaluation will be updated when data from the injection or monitoring wells has been acquired.

Table 3 describes all of the processes used in the computational modeling to model CO_2 trapping within the injection zone. All of these primary processes were included in the initial model. No new mechanisms are anticipated.

Table 3: Processes captured in the computational modeling

Computational Modeling Processes	Description
Convective Flow	Movement of CO_2 through the pore space during the injection period
Dispersive Flow	Result of gravity segregation and increasing CO_2 solubility in water
Relative Permeability Hysteresis	Trapping of CO_2 in pore spaces as a result of imbibition (increase in wetting phase saturation), which occurs during gravity segregation
CO_2 Solubility	Modeled by a modified form of Henry's law
H_2O Vaporization	Can occur around the wellbore as a result of high gas velocities and can lead to salt precipitation
Mineralization	Long-term trapping mechanism that occurs over thousands of years

The computational model is a subset of the static model, as it is not required to be as laterally extensive. The computational model is 7.9 miles (east-west) by 7.9 miles (north-south) and uses smaller 100 ft cells for horizontal gridding. The vertical layering remained consistent. The computational modeling focused on the Eau Claire Shale and the Mt Simon Sandstone.

1.2 Site Geology and Hydrology

All information regarding the site geology and hydrology are provided in the Project Narrative (Attachment 1: Narrative, 2022). This includes the associated figures such as geologic maps, hydrologic maps, cross sections, and local stratigraphic columns.

1.3 Model Domain

Model domain information is summarized in Figure 1, Table 4, and Table 5.

Table 4: Static Model domain information.

Static Model Domain Information			
Coordinate System	Indiana East European Petroleum Survey Group (EPSG) 2965		
Horizontal Datum	Indiana East EPSG 2965		
Coordinate System Units	feet		
Zone	Indiana East EPSG 2965		
FIPSZONE	Sensitive, Confidential, or Privileged Information [redacted]	ADSZONE	Sensitive, Confidential, or Privileged Information [redacted]
Coordinate of X min		Coordinate of X max	
Coordinate of Y min		Coordinate of Y max	
Elevation of bottom of domain (fbsl)		Elevation of bottom of domain	

Table 5: Computational Model domain information.

Computational Model Domain Information			
Coordinate System	Indiana East EPSG 2965		
Horizontal Datum	Indiana East EPSG 2965		
Coordinate System Units	feet		
Zone	Indiana East EPSG 2965		
FIPSZONE	Sensitive, Confidential, or Privileged Information [redacted]	ADSZONE	Sensitive, Confidential, or Privileged Information [redacted]
Coordinate of X min		Coordinate of X max	
Coordinate of Y min		Coordinate of Y max	
Elevation of bottom of domain (fbsl)		Elevation of bottom of domain	

A horizontal grid cell size of 500 feet (ft) was used. For the vertical cell size, proportional layering was used to generate cells approximately 4 ft high. The static model included horizons from ground level to the model base below the Precambrian horizon (Figure 4). Property modeling was focused on the Eau Claire Shale confining zone and the Mt Simon Sandstone injection zone.

1.4 Porosity and Permeability

1.4.1 Petrophysical Well Log Upscaling

The Project Narrative includes a discussion of the wells in the region that provided important porosity and permeability data for the project as well as the petrophysical analysis that was completed on these wells (Attachment 1: Narrative, 2022). The well log data was upscaled and distributed into the static model.

In order to upscale well logs, an average algorithm is applied to the high-resolution well logs to produce one log value for each model cell that is penetrated by the well. Cell height plays a significant role in how porosity and permeability logs are upscaled and balances the capture of vertical heterogeneity while maintaining a manageable cell-count. Porosity values were upscaled into the grid using the arithmetic method (Figure 5).

The proportional vertical layering captured the variability observed in the porosity and permeability core data. The intent of this was to honor thin intervals in the injection zone that may represent significant permeability streaks, and thus play a significant role in dynamic reservoir behavior. The permeability upscaled cell was calculated from the equations in Figure 6. Figure 5 displays how the vertical variation of the wells with core was captured in the vertical property interpretation where there are data gaps.

Figure 5: Confidential Business Information: Well log upscaling.

Figure 6: Confidential Business Information: Effective porosity and permeability cross plots with core plugs (grey).

1.4.2 Facies and Petrophysical Modeling

The upscaled core porosity from the nine wells provided high vertical resolution at each well for the static model; however, little was known about the porosity values between the wells. Therefore, variogram analysis was used to interpolate the data from the wells into the interwell space such that porosity represented the geological setting.

Facies were interpolated using the tNavigator Amazonas (Degterev, 2020) process that proved to be a reliable way to interpolate these facies data at these distances (Figure 7). The facies of the Eau Claire Formation consisted of primary shale with a thin layer of silty sandstone at the base which was modeled here to represent the Eau Claire Silt (potential secondary sequestration). The facies of the Mt Simon Sandstone were interpolated with two sandstone facies (Sandstone_1 and Sandstone_2). In the Precambrian, one facies was used. Figure 7shows the facies thickness maps within the Mt Simon Sandstone and the Eau Claire Formation.

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Figure 7: Facies thickness maps within the Mt. Simon Sandstone and Eau Claire Formation.

For each facies type, effective porosity was interpolated using Gaussian Random Function Simulation (GRFS) (Figure 8). Since the well data was sparse, a reliable horizontal variogram range and direction could not be extracted from variogram maps. To manage this issue, a horizontal variogram range of two miles was used in the horizontal direction. A vertical variogram range of approximately 10 feet was able to be extracted for each facies type. Figure 9 shows the relationship between the facies and effective porosity in the 3D model.

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Figure 8: Cross Section A-A’ formations and static model effective porosity.

The equations derived from Figure 6 were used to determine the effective porosity and permeability based on facies type (Figure 8 and Figure 10). The flow capacity of the injection zone can be characterized by the permeability-height product (kh) (Figure 11). The kh of the AoR compares favorably to the kh calculated from the fall-off test (FOT) reported in the INEOS (BP Lima) Nitrile disposal wells (INEOS USA LLC, 2015).

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Figure 9: 3D view of static model showing a) facies, b) effective porosity.

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Figure 10: Cross Section A-A' formations and static model permeability.

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Figure 11: Permeability*thickness (kh) Map of the Mt Simon Sandstone.

1.4.3 Geostatistical Summary

Geological property modelling is a complex process with many variables to optimize for each zone including variograms, co-kriging variables, data transformations, etc. A quality model should be statistically representative of the available well data and be geologically realistic. Statistical analyses were used throughout the static modeling in order to quickly identify potential errors and correct them.

Histogram displays from the model were generated for the AoR as part of the model quality control. Figure 12 shows the effective porosity and permeability histograms for the Eau Claire Shale, Eau Claire Silt, and Mt. Simon Sandstone for the AoR. Figure 13 displays the histograms of well log data, upscaled data (blocked wells) and the final property model to demonstrate how the facies properties were honored in the transition from the original well log data to the static model. Table 6 is a high-level summary of the geological characteristics of the static model.

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Figure 12: Effective porosity and permeability histograms for the 2.26-mile radius AoR around CCS1.

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Figure 13: Effective porosity and permeability histograms of the well logs, upscaled logs (blocked wells) and the final interpolated property.

Table 6: Summary of static model within the AoR.

Formation	Facies	Average Porosity	Average Permeability	KH	Thickness (ft)	Elevation (fbsl)	Depth Below Ground TVD (ft)
Eau Claire Shale (confining zone)	Shale	Sensitive, Confidential, or Privileged Information [redacted]					
Eau Claire Silt (secondary sequestration)	Silty Sandstone						
Mt Simon Sandstone (injection zone)	Sandstone_1 Sandstone_2						
Precambrian	Precambrian						

At present, the static model is a reliable representation of the subsurface given the current input data; however, uncertainty will exist until site specific data is acquired through the Pre-Operational Testing Program (Attachment 5: Pre-Op Testing Program, 2022). Site specific well log, core, well testing data, and 3D surface seismic data are collected during the pre-operational phase of the project. Once new data has been acquired and evaluated, the static model will be updated, and the accuracy will improve.

Wireline well logs from CCS1 and the deep observation well (OBS1) will be used to calibrate 3D surface seismic data and produce inversion products such as porosity and lithology cubes for the area of the surface seismic survey. The logs can also be used to generate a discrete facies log. The facies log can be combined with the lithology cube from the surface seismic data to provide more detail on the local depositional system. The updated static model will be used for a new update to the computational modeling as discussed in Section 4.5.

The conclusions of the geologic, petrophysical, and statistical analyses include:

- The Eau Claire Formation is a thick low permeability confining zone.
- The Mt Simon Sandstone's thickness and petrophysical properties make it a reliable injection zone.
- The Eau Claire Silt is a potential secondary sequestration zone.

1.5 Constitutive Relationships and Other Rock Properties

A generalized gas-liquid relative permeability curve was used in the model (Figure 14). Laboratory curves are not currently available, but the curves used are consistent with published curves in the literature and include gas relative permeability hysteresis that is an important gas trapping mechanism. Calculation of the imbibition gas relative permeability curve is described below, from the GEM user's manual:

> "For a non-wetting phase (gas) consider a typical drainage process (increasing gas saturation) reaching a maximum gas saturation, S_{gh}, followed by an imbibition process (decreasing gas saturation) leading to a trapped gas saturation, S_{grh}."

The gas relative permeability on the drainage to imbibition scanning curve for a given value of the gas saturation, S_g, is given by:

$$k_{rg}(S_g) = k_{rg}^{drn}(S_{gf}) \tag{1}$$

where the free gas saturation S_{gf} is calculated from the following relationship:

$$S_{gf} = S_{gcrit} + \frac{(S_g - S_{grh})(S_{gh} - S_{gcrit})}{(S_{gh} - S_{grh})} \tag{2}$$

(S_{gh} is the reversal saturation)

Capillary pressure laboratory data is not currently available but is thought to be relatively insignificant for a gas-water system in a highly permeable zone.

The rock compressibility values used in the model were derived by from nearby carbon capture and sequestration (CCS) projects. Site specific rock compressibility values will be obtained when the wells are drilled for the project as per the Pre-operational Testing Program (Attachment 5: Pre-Op Testing Program, 2022).

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Figure 14: Gas-liquid relative permeability curves used in model, including hysteresis.

1.6 Boundary Conditions

In the computational model, an aquifer function (Carter-Tracy) was applied to the grid boundary (side). The top and bottom of the grid are considered no-flow boundaries. The formation was allowed to "leak", i.e., accept fluids from the grid. This approach was used to simulate the pressure response of an infinite-acting aquifer and is considered preferable to using large pore volumes on edge grid blocks.

1.6.1 Initial Conditions

Initial conditions for the model are given in Table 7. The parameters were estimated from the INEOS (BP Lima) Underground Injection Control (UIC) Class I wells (Figure 1).

Table 7: Initial conditions.

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1.6.2 Operational Information

The proposed injection well, CCS1, is part of the Hoosier #1 Project. Details of the proposed injection operations are presented in Table 8.

Table 8: Operating details.

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1.6.3 Fracture Pressure and Fracture Gradient

Calculated fracture gradient and maximum injection pressure values are given in Table 9. Fracture gradient was estimated from mini-fracs and step-rate tests performed for:

- INEOS (BP Lima) Nitriles USA LLC UIC Class I Application (INEOS (BP Lima) Nitriles, August 22, 2016),
- Cleveland-Cliffs Steel Corporation Well # 1, (AK Steel Cleveland-Cliffs Steel Corporation, March 15, 2021),
- Vickery Well Corporation Well # 4 (Vickery Environmental, 2021).

For each of these permit applications, the Mt Simon Sandstone was tested. The project plans to perform a step-rate test in the Mt. Simon Sandstone to determine the fracture gradient at the project site as part of the Pre-Operational Testing Program (Attachment 5: Pre-Op Testing

Program, 2022). The project specific fracture gradient will be updated in the computational model once it is available.

Table 9: Injection pressure details

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2 Computational Modeling Results

2.1 Predictions of System Behavior

The following figures have been created to display the predicted behavior of the CO_2 plume.

- Figure 15 CO_2 plume with contours that indicate the percentage of CO_2 contained 10-years post injection.
- Figure 16 and Figure 17 display the CO_2 plume in cross section view.
- Figure 18 shows the predicted CO_2 plume at 3-,12-, 20-, and 30-years after the start of injection and 10- and 50-years post injection.
- Figure 19 and Figure 20 show the CO_2 plume extent in cross section views.
- Figure 21 show three-dimensional (3D) views of the plume.

The CO_2 plume radius after 30-years of injection is predicted to be 1.646 miles and after 50-years post injection the radius is predicted to be 1.700 miles. Figure 18 demonstrates how quickly the CO_2 plume stabilizes after injection operations cease.

The pressure plume radius after 30-years of injection is 1.690 miles as shown in Figure 22. The pressure plume retracts rapidly post injection and is negligible after two years (Figure 23). The CO_2 and pressure plumes are irregular in shape due to the heterogeneity and dip of the formation.

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Figure 15: CO_2 plume with contours that indicate the percentage of CO_2 contained 10 years post injection. The AoR boundary is outlined in blue.

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Figure 16: Cross section A-A' with the predicted 10-year post injection CO_2 plume.

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Figure 17: Cross Section B-B' with the predicted 10-year post injection CO_2 plume.

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Figure 18: Time-lapse CO_2 plume development map over 3-, 12-, 20-, and 30-years of injection as well as 10- and 50-years post injection. Note the relative stability of the CO_2 plume radius after injection operations cease.

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Figure 19: Time-lapse CO_2 plume development cross-section A-A' at years 3-, 12-, and 20-years. Note how the heterogeneity of the injection zone affects the plume radius.

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Figure 20: Time-lapse CO_2 plume development cross-section A-A' at the end of 30-years of injection and 10- and 50-years post injection.

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Figure 21: Time-lapse CO_2 plume development in 3D space.

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Figure 22: Pressure plume based on a 227 psi delta pressure and the AoR.

The AoR was determined based on the maximum predicted pressure plume radius in addition to a 0.5 mi buffer (Section 3.2). If subsequent testing and monitoring data acquired over the operational phase of the project suggest that a larger CO_2 or pressure plume are likely to form, the AoR will be adjusted accordingly.

Key uncertainties include:

- Storativity (porosity x height)
- Injectivity or flow capacity (permeability x height)
- kv/kh ratio (vertical permeability divided by horizontal permeability)

When the first well is drilled for the project data will be gathered as part of the Pre-operational Testing Program to refine these parameters, and the model updated (Attachment 5: Pre-Op Testing Program, 2022). Significant changes in the AoR are not expected. The AoR was designed to account for the slight expansion of the CO_2 plume post injection or the maximum extent of the pressure plume (whichever is greater) and a 0.5-mile buffer. The pressure plume is expected to shrink rapidly post injection (Figure 23). The model will be refined and updated with injection well data and data from observation well.

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Figure 23: Predicted fall-off in bottomhole pressures (BHP) once injection operations cease after 30 years.

Figure 24 shows a breakdown of the mass of the CO_2 injected into three phases: supercritical fluid, dissolved gas, and trapped gas. After 50-years post-injection, the percentage breakdown are: 61%, 17%, and 22%, respectively. The percentages of dissolved gas and trapped gas will continue to increase over time while the supercritical gas will decrease. Mineralization takes place over a much longer time and has not been included in Figure 24.

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Figure 24: Chart showing supercritical gas, dissolved gas, and trapped gas over time. (Mineralization is not significant during this time frame.)

2.2 Model Calibration and Validation

History matching was not performed as there is no current injection data available. The model was constructed using all available reference information from the INEOS (BP Lima), A.K. Steel, and Vickery UIC projects, which included computational modeling studies (INEOS (BP Lima) Nitriles, August 22, 2016; AK Steel Cleveland-Cliffs Steel Corporation, March 15, 2021; Vickery Environmental, 2021).

The kv/kh ratio is a significant unknown given the lack of deep well data in the region. Sensitivity analysis was conducted to evaluate the effect of kv/kh ratio on the CO_2 plume size. The kv/kh value used in the base case is 0.003, which was estimated from a fall-off test from the INEOS (BP Lima) Project. Sensitivity cases were run with kv/kh values equal to 0.01 and 0.1. The individual simulations indicated that the CO_2 plume would be smaller with increasing values of kv/kh. As kv/kh values increase the rate of vertical migration of the CO_2 is higher resulting in more residual gas trapping. Lower values of kv/kh result in greater horizontal migration of the CO_2 and a larger CO_2 plume. Table 10 and Figure 26 demonstrate the effect of kv/kh on relative size of the CO_2 plume.

Table 10: Impact of varying kv/kh values on the CO_2 plume radius.

kv/kh	CO_2 Plume Radius (mi)
0.003	1.32
0.01	1.23
0.1	1.02

The effect of partial completion was also studied as a sensitivity. The modeling demonstrated that the entire interval would need to be perforated to sustainably achieve the required rate from the start of injection. A partial completion could result in higher rates of vertical gas migration which would result in higher rates of gas trapping and a smaller CO_2 plume. However, in this case, the difference in plume size was negligible (Figure 26).

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Figure 25: Effect of kv/kh ratio on CO_2 plume size. Increasing kv/kh results in smaller CO_2 plume size because of higher rates of residual gas trapping. a. kv/kh = 0.003, b. kv/kh = 0.01, c. kv/kh = 0.1.

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Figure 26: Effect of partial completion on CO_2 plume size. Although full completion is necessary to achieve the required injection rate, no difference in maximum radius over time was observed.

3 AoR Delineation

3.1 Critical Pressure Calculations

To delineate the pressure plume radius, a minimum (or critical) delta pressure was calculated. The delta pressure is the increase in pressure necessary to overcome the hydrostatic head of the injection zone fluid and would allow fluids to migrate up an open conduit to the lowermost USDW in the unlikely event that a conduit exists. The formula for calculating the delta pressure is given below (source: UIC Program Class VI Well Area of Review and Corrective Action Evaluation Guidance)

$$\Delta P_{if} = P_u + \rho_i * (z_u - z_i) - P \tag{3}$$

Where:

ΔPif = delta pressure,

Pu = initial pressure of the lowermost USDW,

ρi = fluid density of the injection zone,

g = acceleration due to gravity,

zu = elevation of the lowermost USDW,

zi = elevation of the injection zone, and

P = initial pressure of the injection zone. Substituting appropriate values into the equation, a minimum delta pressure was calculated to be 227 psi.

3.2 AoR Delineation

The AoR was initially selected by observing the delta pressure of each gridblock in the model after 30 years of injection. The gridblocks that had a delta pressure equal to or greater than the minimum delta pressure (calculated above) and considered to be in the AoR. A radius was measured from the wellbore location to the maximum extent of the pressure plume. A 0.5-mile buffer was added to be conservative. Through the Pre-operational Testing Program, uncertainties around the injection zone parameters will be addressed, and the static and computational models will be updated with the new data (Attachment 5: Pre-Op Testing Program, 2022) . The new computational model will be used to recalculate a new maximum radius and the AoR will be revised if necessary. OBS1 will be used to monitor changes in injection zone pressure and aqueous geochemistry at a distance from the injection well (Attachment 7: Testing And Monitoring, 2022). The computational model will be updated to match the observed data. If the injection zone does not perform as predicted, the AoR will be re-assessed if necessary.

4 Corrective Action

EPA Class VI regulations require the identification of all confining zone penetrations within the AoR because these wells could become a preferential pathway for leakage of CO_2 and/or formation brine fluids out of the injection zone. If necessary, corrective actions will need to be performed on the penetrations to prevent leakage that could potentially cause endangerment to a USDW. The following sections discuss the findings of an evaluation that was performed to:

- Identify existing penetrations within the vicinity of the AoR,
- Determine if any penetrations extend below the primary confining zone, thereby presenting a risk of leakage that may require corrective actions,
- Identify corrective actions and define the approach that will be taken to prevent leakage that could endanger a USDW.

4.1 Tabulation of Wells within the AoR

4.1.1 Oil and Gas Wells

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Figure 27: O&G wells within the AoR. There are only two active O&G wells within the AoR. The rest of the wells are either plugged and abandoned or have been converted to shallower water wells.

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Figure 28: Cross Section B-B' with O&G gas well penetrations in the AoR projected from 1 mile. None of the O&G wells penetrate the confining layer. The cyan lines denote the AoR boundaries.

Table 11: O&G well penetrations in the AoR. Note that only two wells penetrate the Knox Formation.

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[redacted]

4.1.2 Water Wells

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[redacted]

Figure 29: Groundwater wells within the AoR. O&G wells that have been converted to water wells in the area have been highlighted.

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[redacted]

Figure 30: Cross-section C-C' displaying groundwater wells. Wells were projected from one (1) mile. Note that one water well penetrates the Potosi Formation and IDNR has plans to plug this well. The cyan lines denote the AoR boundaries.

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[redacted]

Figure 31: Cross-section D-D' through groundwater wells. Wells were projected from one (1) mile. Note that one water well penetrates the Shakopee Formation within the AoR. The cyan lines denote the AoR boundaries.

4.2 Wells within the AoR

Details of the O&G, and water wells have been provided in the preceding section. The Indiana Geological and Water Survey (IGWS) and IDNR, Division of O&G sites were used to compile the data for this section. The Hoosier #1 Project is located at T20N R15E Section 17, Randolph County. No deep wells were identified in this Township and Range in a special Report 51(Table 12). Therefore, it is highly unlikely that there was historical drilling prior to the 1960's. It is not believed there are any historical wells in the area that are not captured in available data sources.

Table 12: Special Report 51 indicates no deep wells for immediate area (Sullivan, 1995).

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[redacted]

4.2.1 Wells Penetrating the Confining Zone

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[redacted] No wells have penetrated the Eau Claire Shale in the AoR, and no corrective action required.

4.3 Plan for Site Access

The four primary wells associated with the project (CCS1, OBS1, ACZ1, and USDW1) are located on Cardinal Ethanol property and have been sited to minimize issues with flooding or other stormwater related issues. Surface use agreements will be put in place to allow surface access for periodic 3D seismic data acquisition as well as periodic water sampling. As noted in these surface use agreements, proper notification will be given prior to accessing property to collect water samples.

4.4 Corrective Action Schedule

Currently no wells within the AoR require corrective action. As such, no corrective action schedule is necessary at this time.

4.5 Reevaluation Schedule and Criteria

4.5.1 AoR Reevaluation Cycle

The project will reevaluate the above described AoR every five years during the injection and post-injection phases of the project. Additionally, any significant changes to the CO_2 stream or an increase in the injection volumes will trigger a reevaluation of the AoR.

As part of this reevaluation, monitoring and operational data will be used to calibrate the performance of the well and injection zone to the computational modeling. In addition to reviewing the testing and monitoring data on five-year intervals, this data will also be assessed on an annual basis to monitor for any unexpected changes in behavior. The testing and monitoring data will be included in the model to help calibrate and fine tune the computation modeling (history matching). The testing and monitoring data will include of (but is not limited to) the following:

- Surface and bottomhole pressure
- Total mass injected and mass injection rates
- Mechanical integrity logs
    - Temperature logs
    - PNL
- Time-lapse 3D seismic data
- Microseismic monitoring

Should notable deviations from the computational modeling results occur, the modeling will be re-run, and a new AoR will be re-established. Notable deviations are defined in the following section.

4.5.2 Triggers for AoR Re-evaluations Prior to the Next Scheduled Reevaluation

Table 13 presents a non-exhaustive list of potential parameters that would trigger a reevaluation of the AoR prior to the next scheduled re-evaluation should notable deviations from anticipated values occur.

Table 13: List of potential parameters that could initiate re-evaluation of the AoR. (Note that this list is non-exhaustive.)

Monitoring Parameter	Description
Pressure	• Sustained variations in pressure outside of three standard deviations from the average
Temperature	• Variations in temperature observed during MIT logging activities that are determined to be a mechanical integrity issue • Sustained variations in temperature outside of three standard deviations
CO_2 Saturation	• Increased CO_2 saturations that indicate migration of CO_2 above the confining zone and are not a result of a mechanical integrity issues
Groundwater Constituent Concentrations	• Changes in fluid and chemical content concentrations that indicate migration of injection zone fluids into formations overlying the confining zone, which are not a result of a mechanical integrity issue • Should a statistically significant deviation from the baseline data collected from the above confining zone interval occur
Bottomhole Injection Pressure	• Should bottomhole pressure exceed 90 percent of the calculated fracture pressure
Well Integrity	• Change in pressure in the annulus system surrounding he injection well that indicates a loss of mechanical integrity in an injection well will be investigated
Seismic Monitoring and Induced Seismicity	• Microseismic monitoring indicates the re-activation of faults or fractures that could propagate into the confining layer and impact containment

Additional causes for AoR re-evaluation could include the extension of the CO_2 plume or pressure front beyond the initial plume predictions based on results of 3D seismic surveys; induced seismic events greater than M3.5 within the seismic monitoring area around the project; an exceedance of any operating conditions; or, if the data gathered during the Pre-Operational Testing Program result substantially changes to the current models and understanding of the subsurface.

Should any of the events occur that are detailed above, the project will discuss AoR re-evaluation procedures and timeline with the UIC Program Director to conclude if the re-evaluation is necessary.

5 References

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(2022). *Attachment 1: Narrative.* Class VI Permit Application Narrative; Project Hoosier#1, Vault 4401.

(2022). *Attachment 10: ERP.* Emergency And Remedial Response Plan; Project Hoosier#1, Vault 4401.

(2022). *Attachment 11: QASP.* Project Hoosier#1, Vault 4401.

(2022). *Attachment 2: AoR and Corrective Action.* Area Of Review And Corrective Action Plan; Project Hoosier#1, Vault 4401.

(2022). *Attachment 2: AOR and Corrective Action.* Area Of Review And Corrective Action Plan; Project Hoosier#1, Vault 4401.

(2022). *Attachment 3: Financial Responsibility.* Financial Responsibility; Project Hoosier#1, Vault 4401.

(2022). *Attachment 4: Well Construction.* Injection Well Construction Plan; Project Hoosier#1, Vault 4401.

(2022). *Attachment 5: Pre-Op Testing Program.* Pre-Operational Formation Testing Program; Project Hoosier#1, Vault 4401.

(2022). *Attachment 6: Well Operations.* Well Operation Plan; Project Hoosier#1, Vault 4401.

(2022). *Attachment 7: Testing And Monitoring.* Testing And Monitoring Plan; Project Hoosier#1, Vault 4401.

(2022). *Attachment 8: Well Plugging.* Project Hoosier#1, Vault 4401.

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