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

## Wabash CCS Project

**INSTRUCTIONS**

This template provides an outline and recommendations for the Post-Injection Site Care (PISC) and Site Closure Plan.

In this template, examples or suggestions appear in **blue text**. These are provided as general recommendations to assist with site- and project-specific plan development. The recommendations are not required elements of the Class VI Rule. This document does not substitute for those provisions or regulations, nor is it a regulation itself, and it does not impose legally binding requirements on the EPA, states, or the regulated community.

Please delete the **blue text** and replace the yellow highlighted text before submitting your document. Similarly, please adjust the example tables as necessary (e.g., by adding or removing rows or columns). Appropriate maps, figures, references, etc. should also be included to support the text of the plan.

Remember that, pursuant to 40 CFR 146.93(a), the requirement to maintain and implement an approved Post-Injection Site Care and Site Closure Plan is directly enforceable regardless of whether the requirement is a condition of the permit. For more information, see the Class VI guidance documents at https://www.epa.gov/uic/class-vi-guidance-documents. It is the responsibility of the owner or operator to maintain records of previous revisions to this plan.

## Facility Information

Facility name: Wabash Carbon Services
WVCCS1 & WVCCS2

Facility contact: Rory Chambers Vice President Operations
444 West Sandford Ave, West Terre Haute, IN, 47885
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Well location: WVCCS1 Clinton, Vermillion, IN
39$^0$ 37' 27.88'' N, 87$^0$ 29' 19.17'' W
WVCCS2 West Terre Haute, Vigo, IN
39º 33' 3.72" N, 87º 29' 16.60" W

This Post-Injection Site Care and Site Closure (PISC) plan describes the activities that Wabash Carbon Services (WCS) will perform to meet the requirements of 40 CFR 146.93. WCS will monitor ground water quality and track the position of the carbon dioxide plume and pressure front for the duration of the PISC period years. WCS may not cease post-injection monitoring until a demonstration of non-endangerment of USDWs has been approved by the UIC Program

Director pursuant to 40 CFR 146.93(b)(3). Following approval for site closure, WSC will plug all monitoring wells, restore the site to its original condition, and submit a site closure report and associated documentation.

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

The maximum pressure reached within the injection zone is predicted to reach 2,110 PSI at year 12 of injection, the final year. This pressure is well below the calculated limit of 2,815 PSI, based upon the requirements of 40 CFR 146.88 (a).

The following images display the post-injection pressures expected across the entire injection and confining sections. The pressure in the injection zone rapidly rises at the beginning of injection then increases to a peak value of 2,110 PSI (*Figure 1*, *Figure* ***2***, *Figure* ***3***, *Figure* ***4***). This pressure then rapidly drops to within 60 PSI of original pressure by year 16 (4 years post injection). Moving upward through the confining layers the pressure signal is significantly dampened. At the base of the Primary Seal, the Trenton Group, pressure does not display a measurable rise above native formation pressure at any time through the pre- and post-injection periods.

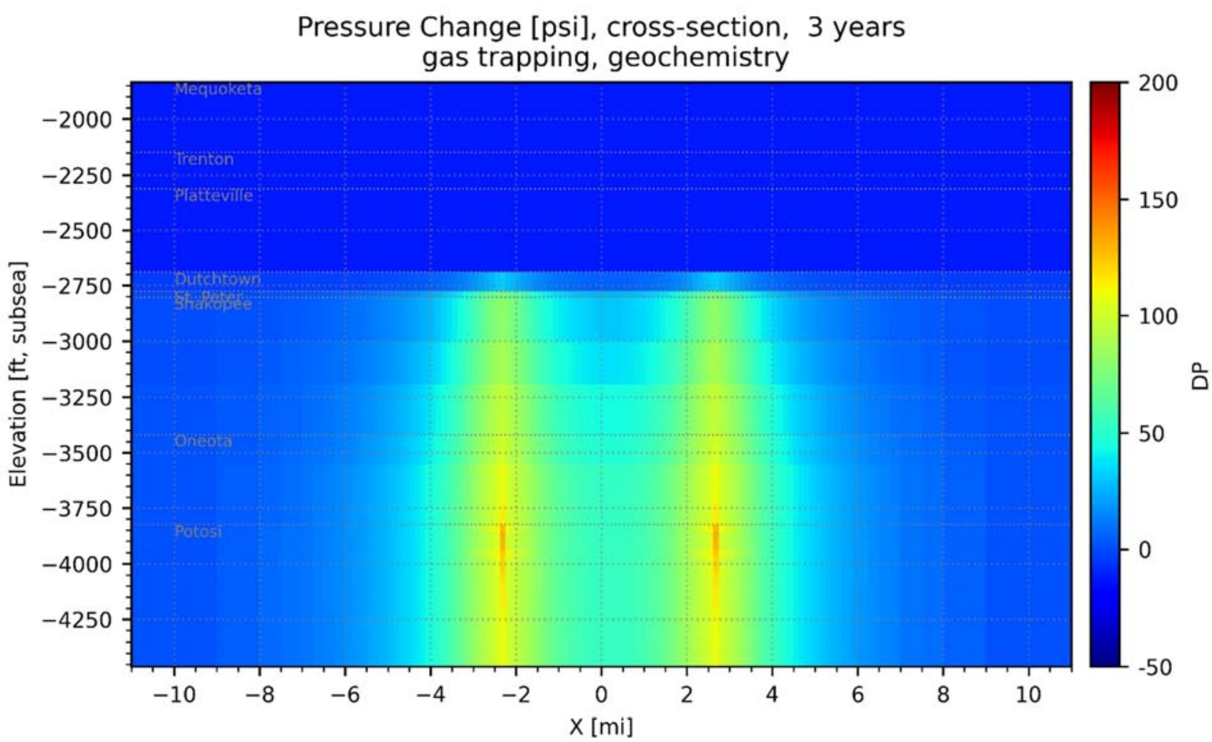


*Figure 1 Formation Pressure year 3 of injection.*

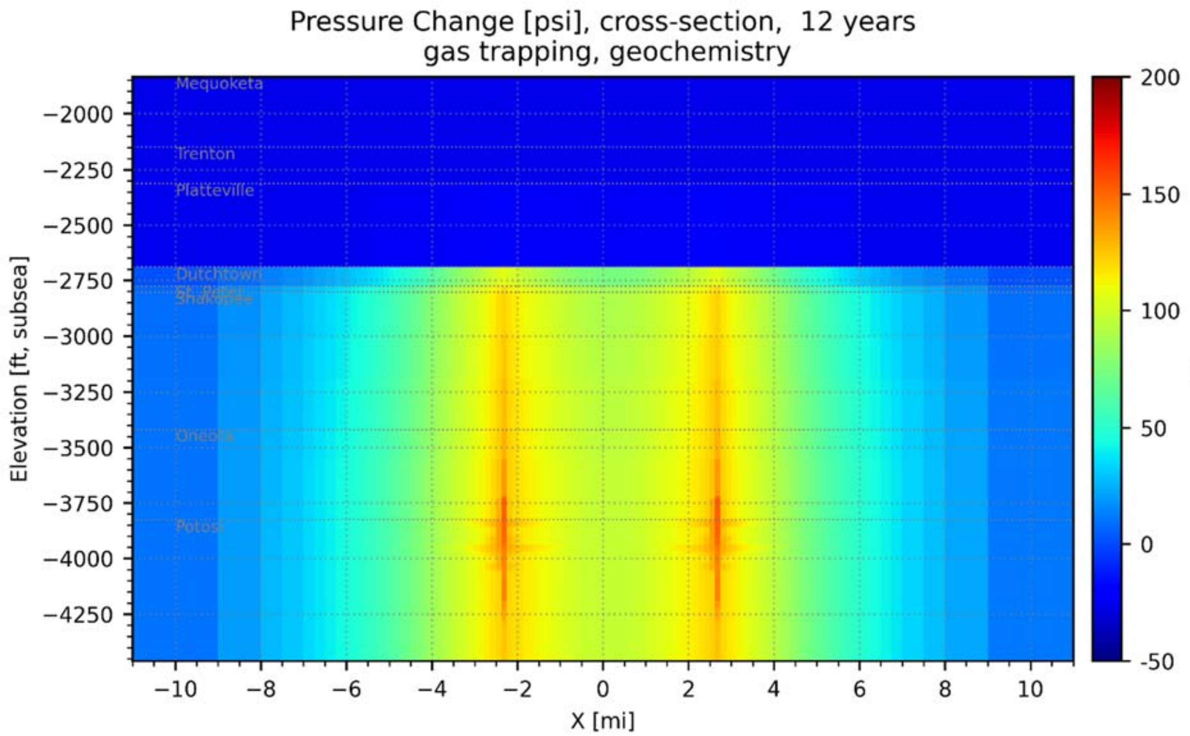


*Figure 2 Formation Pressure Year 12 of Injection (Cessation of Injection)*

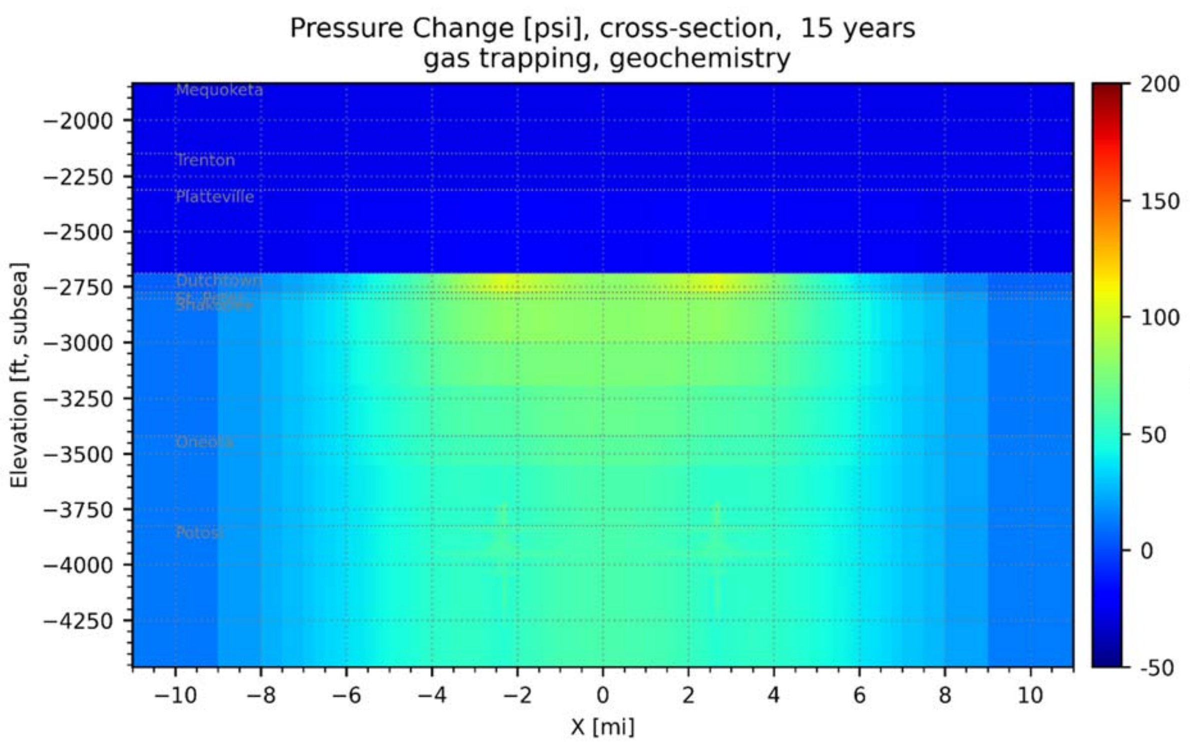


*Figure 3 Formation Pressure Year 3 Post-Injection*

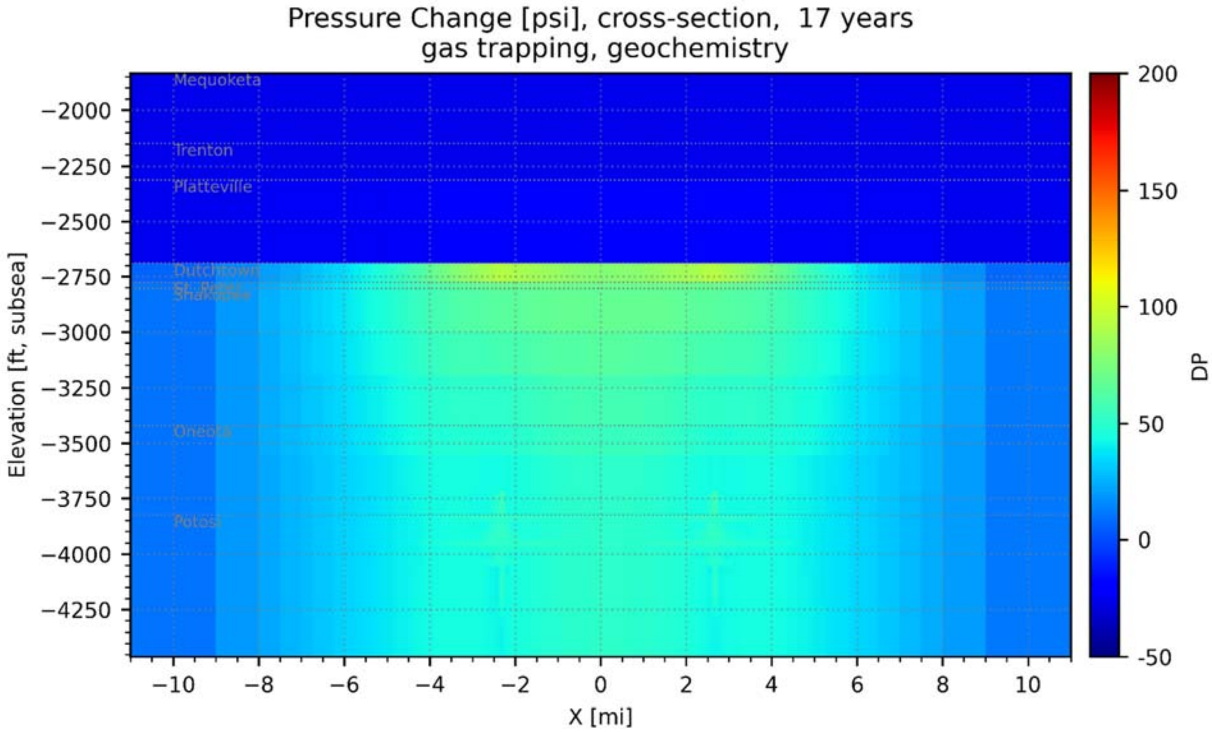


*Figure 4 Formation Pressure Year 5 Post-Injection*

**<u>Predicted Position of the $CO_2$ Plume and Associated Pressure Front at Site Closure [40 CFR 146.93(a)(2)(ii)]</u>**

Figure 5 shows the predicted extent of the $CO_2$ plume and pressure front at the end of the PISC timeframe, representing the maximum extent of the plume and pressure front. This map is based on the final AoR delineation modeling results submitted pursuant to 40 CFR 146.84.

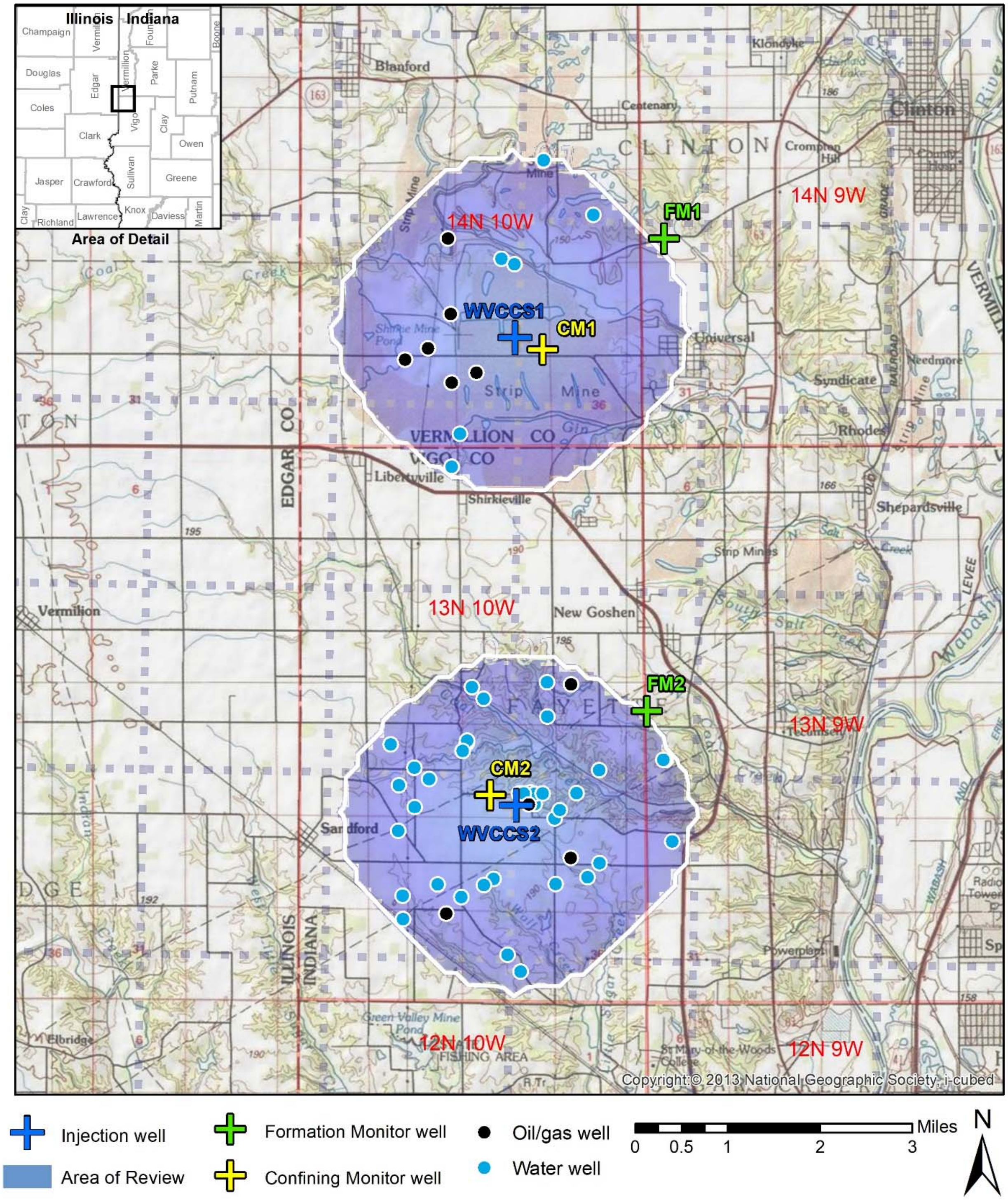


*Figure 5. Map of the predicted extent of the $CO_2$ plume and pressure front at site closure.*

## Post-Injection Monitoring Plan [40 CFR 146.93(b)(1)]

Performing ground water monitoring, LUSDW monitoring, injection formation pressure and temperature monitoring and, 2D/3D seismic monitoring as described in the following sections during the post-injection phase will meet the requirements of 40 CFR 146.93(b)(1). The results of all post-injection phase testing and monitoring will be submitted annually, within 60 days following the anniversary date of the date on which injection ceases or alternatively with the prior approval of the Director, as described under "Schedule for Submitting Post-Injection Monitoring Results," below.

A quality assurance and surveillance plan (QASP) for all testing and monitoring activities during the injection and post injection phases is provided in the Appendix to the Testing and Monitoring Plan.

For the PICS plan the following definitions apply for the frequencies given for the different testing protocols described.

- Continuous: Data is continuously sampled and recorded per the frequencies presented in Table 3 of this document
- Quarterly: Sampling will take place by no more than 5 days before the following dates each year: March 31$^{st}$, June 30$^{th}$, September 30$^{th}$, December 31$^{st}$.
- Semi-annual: Sampling will take place by the following dates each year: 6 months after the date of authorization of injection and 12 months after the date of authorization of injection.
- Annual: Up to 45 days before March 1$^{st}$ of each year following the reporting year or alternatively scheduled with the prior approval of the UIC Program Director.
- 5 Year: Up to 45 days before the 5$^{th}$ anniversary date of the authorization of injection or alternatively scheduled with the prior approval of the UIC Program Director.

### *Monitoring Above the Confining Zone*

Table 1 presents the monitoring methods, locations, and frequencies for monitoring above the confining zone. Table 2 identifies the parameters to be monitored and the analytical methods WCS will employ.

**Table 1. Monitoring of ground water quality and geochemical changes above the confining zone.**

| Target Formation | Monitoring Activity | Monitoring Location(s) | Spatial Coverage | Frequency |
|---|---|---|---|---|
| Pennsylvanian Strata | Fluid Sampling | GM1, GM2…GM10 | 10 wells at expected depth of 100 Feet | Semi Annual |
| | | | | |
| Silurian | Fluid Sampling | CM1, CM2 | 1 Sample Point @2,000 ft | Annual |
| | Pulse Neutron Logging | | Well bore. | |

**Table 2. Summary of analytical and field parameters for ground water samples.**

| Parameters | Analytical Methods |
|---|---|
| Formation: Pennsylvanian | |
| Cations:<br>Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Sb, Se, and Tl | ICP-MS<br>EPA Method 6020 |
| Cations:<br>Ca, Fe, K, Mg, Na, and Si | ICP-OES<br>EPA Method 6010B |
| Anions:<br>Br, Cl, F, $NO_3$, and $SO_4$ | Ion Chromatography,<br>EPA Method 300.0 |
| Dissolved CO2 | Gas Chromatographic EPA Method RSK 175 |
| Total Dissolved Solids | Gravimetry: SM 2540C |
| Alkalinity | Alkalinity by Titration SM:2320 B |
| pH (field) | Electrometric EPA-NERL: 150.1 |
| Specific conductance (field) | 4 AC electrode EPA-NERL: 120.1 |
| Temperature (field) | Thermistor EPA-NERL: 170.1 |
| Formation: Silurian | |
| Cations:<br>Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Sb, Se, and Tl | ICP-MS<br>EPA Method 6020 |
| Cations:<br>Ca, Fe, K, Mg, Na, and Si | ICP-OES<br>EPA Method 6010B |
| Anions:<br>Br, Cl, F, $NO_3$, and $SO_4$ | Ion Chromatography,<br>EPA Method 300.0 |
| Dissolved CO2 | Gas Chromatographic EPA Method RSK 175 |
| Isotopes: $\delta^{13}C$ of DIC | Isotope ratio mass spectrometry |
| Total Dissolved Solids | Gravimetry: SM 2540C |
| Water Density (field) | Oscillating body method ASTM D1217 |
| Alkalinity | Alkalinity by Titration SM:2320 B |
| pH (field) | Electrometric EPA-NERL: 150.1 |
| Specific conductance (field) | 4 AC electrode EPA-NERL: 120.1 |
| Temperature (field) | Thermistor EPA-NERL: 170.1 |

**Table 3. Sampling and recording frequencies for continuous monitoring.**

| Parameter | Device(s) | Location | Min. Sampling Frequency | Min. Recording Frequency |
|---|---|---|---|---|
| Pressure/Temperature | Gauge | Silurian (CM1 & CM2) | 1 Second | 1 Second |
| Pressure/Temperature | Gauge | Potosi (FM1 & FM2) | 1 Second | 1 Second |

Notes:

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

Sampling will be performed as described in section B.2 of the QASP; this section of the QASP describes the groundwater sampling methods to be employed, including sampling SOPs (section B.2.a/b, and sample preservation B.2.g.

Sample handling and custody will be performed as described in section B.3 of the QASP.

Quality control will be ensured using the methods described in section B.5 of the QASP.

Collection and recording of continuous monitoring data will occur at the frequencies described in Table 3.

### *Carbon Dioxide Plume and Pressure Front Tracking [40 CFR 146.93(a)(2)(iii)]*

WCS will employ direct and indirect methods to track the extent of the carbon dioxide plume and the presence or absence of elevated pressure.

**Table 4 presents the direct and indirect methods that WCS will use to monitor the $CO_2$ plume, including the activities, locations, and frequencies WCS will employ. WCS will conduct fluid sampling and analysis to detect changes in groundwater in order to directly monitor the carbon dioxide plume. The parameters to be analyzed as part of fluid sampling in the Potosi Dolomite (and associated analytical methods) are presented in**

Table 5. Indirect plume monitoring will be employed using pulsed neutron capture/reservoir saturation tool (RST) logs to monitor CO2 saturation and 3D surface seismic surveys.

Fluid sampling will be performed as described in B.2 of the QASP; sample handling and custody will be performed as described in B.3 of the QASP; and quality control will be ensured using the methods described in B.5 of the QASP.

**Table 4. Post-injection phase plume monitoring.**

| Target Formation | Monitoring Activity | Monitoring Location(s) | Spatial Coverage | Frequency |
|---|---|---|---|---|
| **DIRECT PLUME MONITORING** | | | | |
| Potosi | Fluid Sampling | FM1 & FM2 | 1 point location @4,500 Ft MD (4,000 Ft TVDss) | Annual |
| | Pressure/Temperature Monitoring | | | Continuous |
| **INDIRECT PLUME MONITORING** | | | | |
| Potosi | Pulse Neutron Logging/RST | FM1 & FM2 | Well Bore | Annual |
| | 3D surface seismic survey | Predicted Plume Radius | ~16 Square miles per injection well | 5 Year recurring |

**Table 5. Summary of analytical and field parameters for fluid sampling in the Potosi.**

| Parameters | Analytical Methods |
|---|---|
| **Potosi** | |
| Cations:<br>Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Sb, Se, and Tl | ICP-MS<br>EPA Method 6020 |
| Cations:<br>Ca, Fe, K, Mg, Na, and Si | ICP-OES<br>EPA Method 6010B |
| Anions:<br>Br, Cl, F, $NO_3$, and $SO_4$ | Ion Chromatography,<br>EPA Method 300.0 |
| Dissolved CO2 | Gas Chromatographic EPA Method RSK 175 |
| Isotopes: $\delta^{13}C$ of DIC | Isotope ratio mass spectrometry |
| Total Dissolved Solids | Gravimetry: SM 2540C |
| Water Density (field) | Oscillating body method ASTM D1217 |
| Alkalinity | Alkalinity by Titration SM:2320 B |
| pH (field) | Electrometric EPA-NERL: 150.1 |
| Specific conductance (field) | 4 AC electrode EPA-NERL: 120.1 |
| Temperature (field) | Thermistor EPA-NERL: 170.1 |

Table **6** presents the direct and indirect methods that WCS will use to monitor the pressure front, including the activities, locations, and frequencies WCS will employ. WCS will deploy in formation pressure/temperature monitors to directly monitor the position of the pressure front.

**Table 6. Post-injection phase pressure-front monitoring.**

| Target Formation | Monitoring Activity | Monitoring Location(s) | Spatial Coverage | Frequency |
|---|---|---|---|---|
| **DIRECT PRESSURE-FRONT MONITORING** | | | | |
| Potosi | Pressure/ temperature monitoring | FM1 & FM2 | 1 point location @4,500 Ft MD (4,000 Ft TVDss) | Continuous |

### *Schedule for Submitting Post-Injection Monitoring Results [40 CFR 146.93(a)(2)(iv)]*

All post-injection site care monitoring data and monitoring results (i.e., resulting from the groundwater monitoring and plume and pressure front tracking described above) will be submitted to the Director in annual reports. These reports will be submitted each year, within 60 days following the anniversary date of the date on which injection ceases or alternatively with the prior approval of the Director.

The annual reports will contain information and data generated during the reporting period, i.e., well-based monitoring data, sample analysis, and the results from updated site models.

## Alternative Post-Injection Site Care Timeframe [40 CFR 146.93(c)]

WCS will conduct post-injection monitoring for 4 years following the cessation of injection operations. A justification for this alternative PISC timeframe is provided below. Regardless of the alternative PISC timeframe, monitoring and reporting as described in the sections above will continue until WCS demonstrates, based on monitoring and other site-specific data, that no additional monitoring is needed to ensure that the project does not pose an endangerment to any USDWs, per the requirements at 40 CFR 146.93(b)(2) or (3).

### *Computational Modeling Results – 40 CFR 146.93(c)(1)(i)*

Model results indicate that after one year of $CO_2$ injection, the $CO_2$ at both injection wells had spread 0.5 mi to the east and 0.8 mi to the north. The $CO_2$ distribution around each well reaches lateral stabilization within the Potosi Dolomite 14 years after injection had begun (i.e., 2 years after cessation of injection (*Figure 7*). The maximum lateral extent is determined from the model layer having the broadest distribution of $CO_2$.

Within the Trenton Limestone directly below the primary confining Maquoketa Group layer, the pressure front resulting from $CO_2$ injection does not anywhere or at any time (within the model domain) exceed 90% of the calculated pressure threshold that would be required to potentially impact the lowermost USDW. As discussed in the AoR DELINEATION section of the AoR AND CORRECTIVE ACTION TEMPLATE the differential pressure in the Trenton Limestone does not exceed 0.137 PSI. Thus, the AoR is functionally based only on the lateral extent of the $CO_2$ saturation above a 1% cutoff. The AoR is expected to reach stabilization 14 years after injection begins, i.e., 2 years post injection (*Figure 6*; *Figure 6; Figure 8*). There are no known penetrations of the confining layer within 4 miles of either injection well. Vertical movement of $CO_2$ over the course of 62 years is restricted to base of the Oneota Dolomite (*Figure 10*; *Figure 11*; *Figure 13*).

As described in the MODEL CALIBRATION and VALIDATION section of the AoR and CORRECTIVE ACTION TEMPLATE a sensitivity analysis was performed to evaluate the impact of gas trapping and reactive transport within the reservoir. The results of the sensitivity study matched the experimental data discussed in the GEOCHEMISTRY section of the NARRATIVE TEMPLATE. Minimal impact was detected within the model when the impacts of gas trapping and reactive transport where not considered. For comparative purposes Figure 9 and Figure 14 have been added below to display the minimal variation in the modeling results when these processes are not considered.

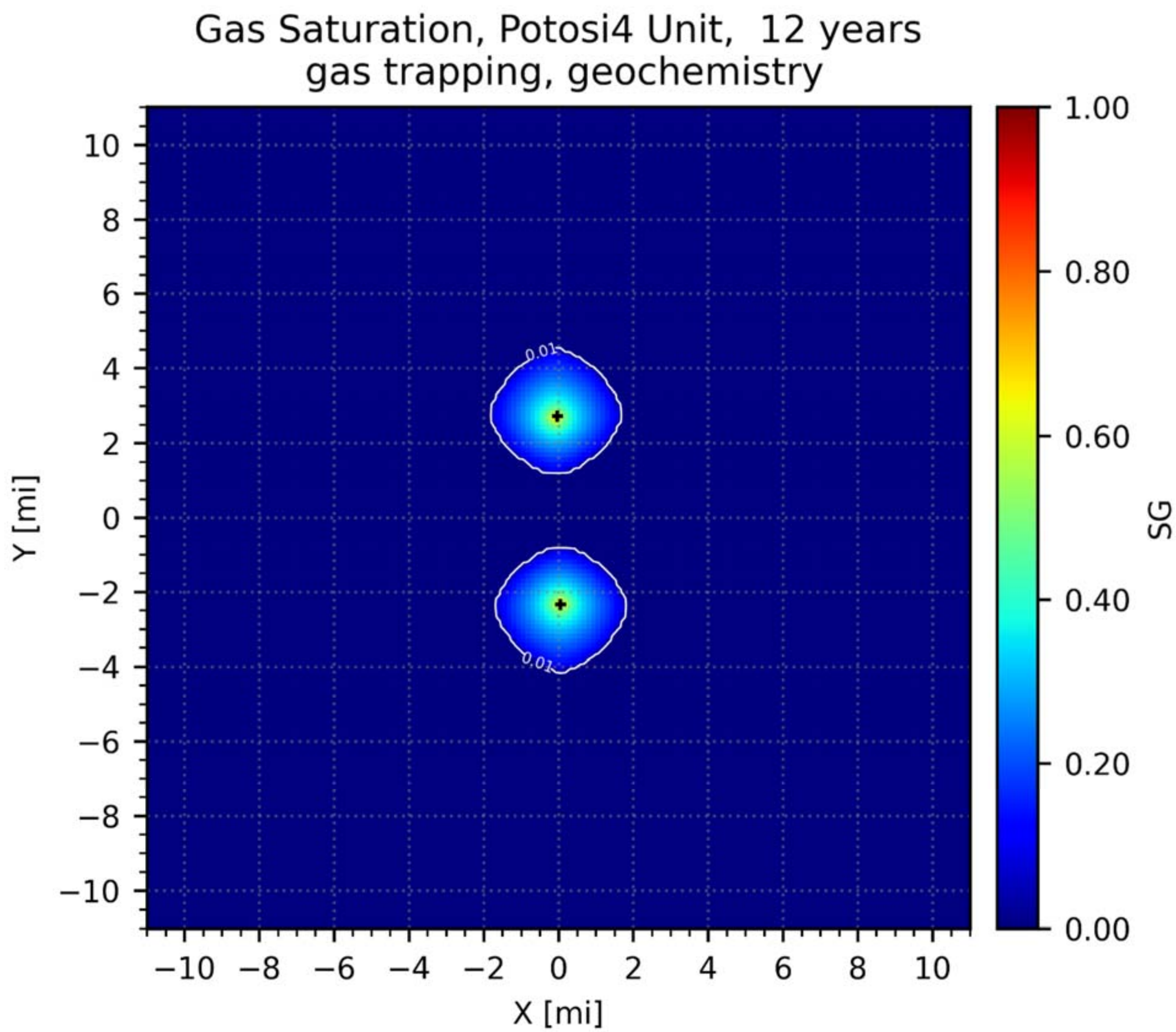


*Figure 6 CO2 Plume Year 12 (Cessation of Injection)*

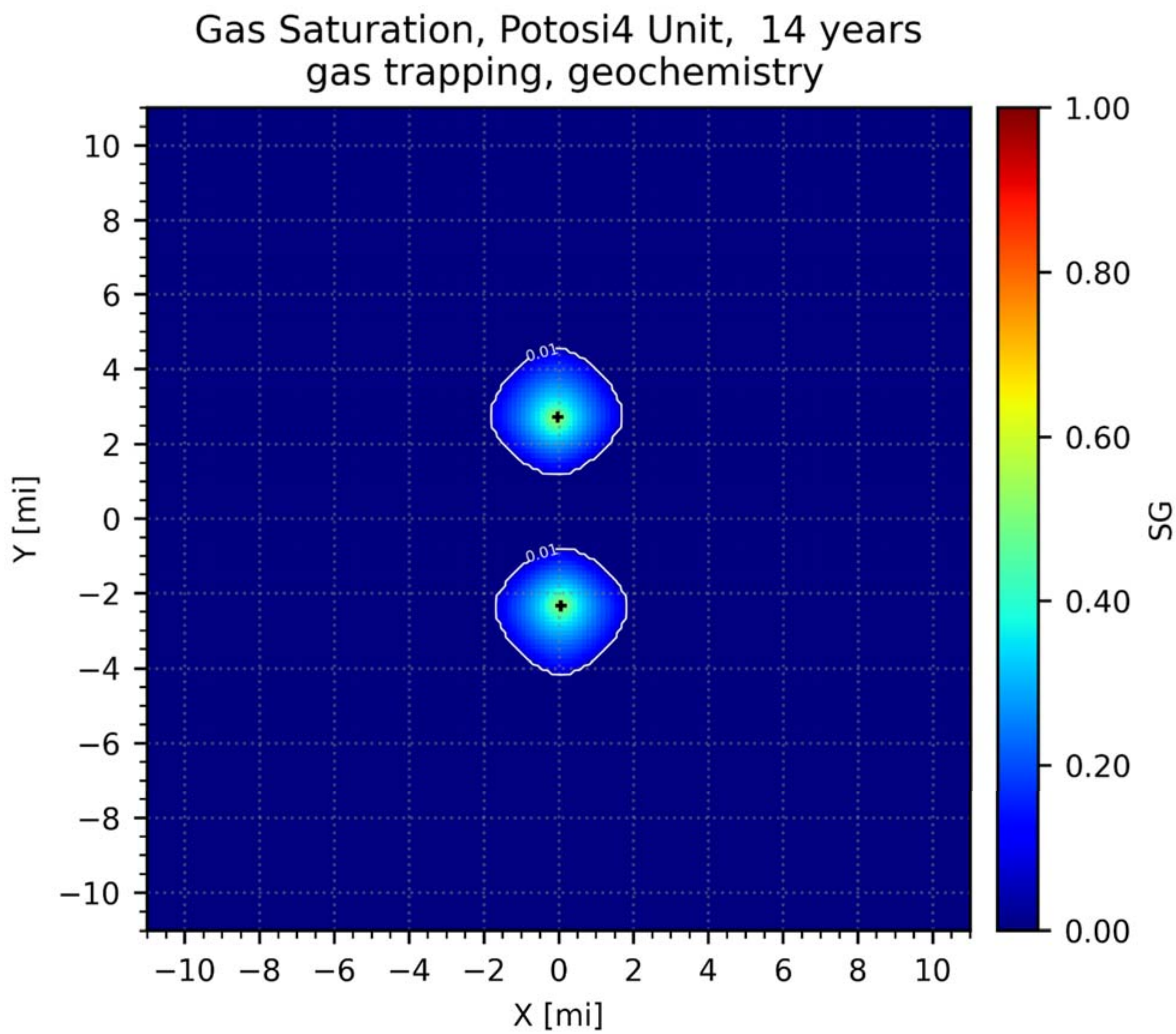


*Figure 7 CO2 Plume Year 14 (2 years post-injection)*

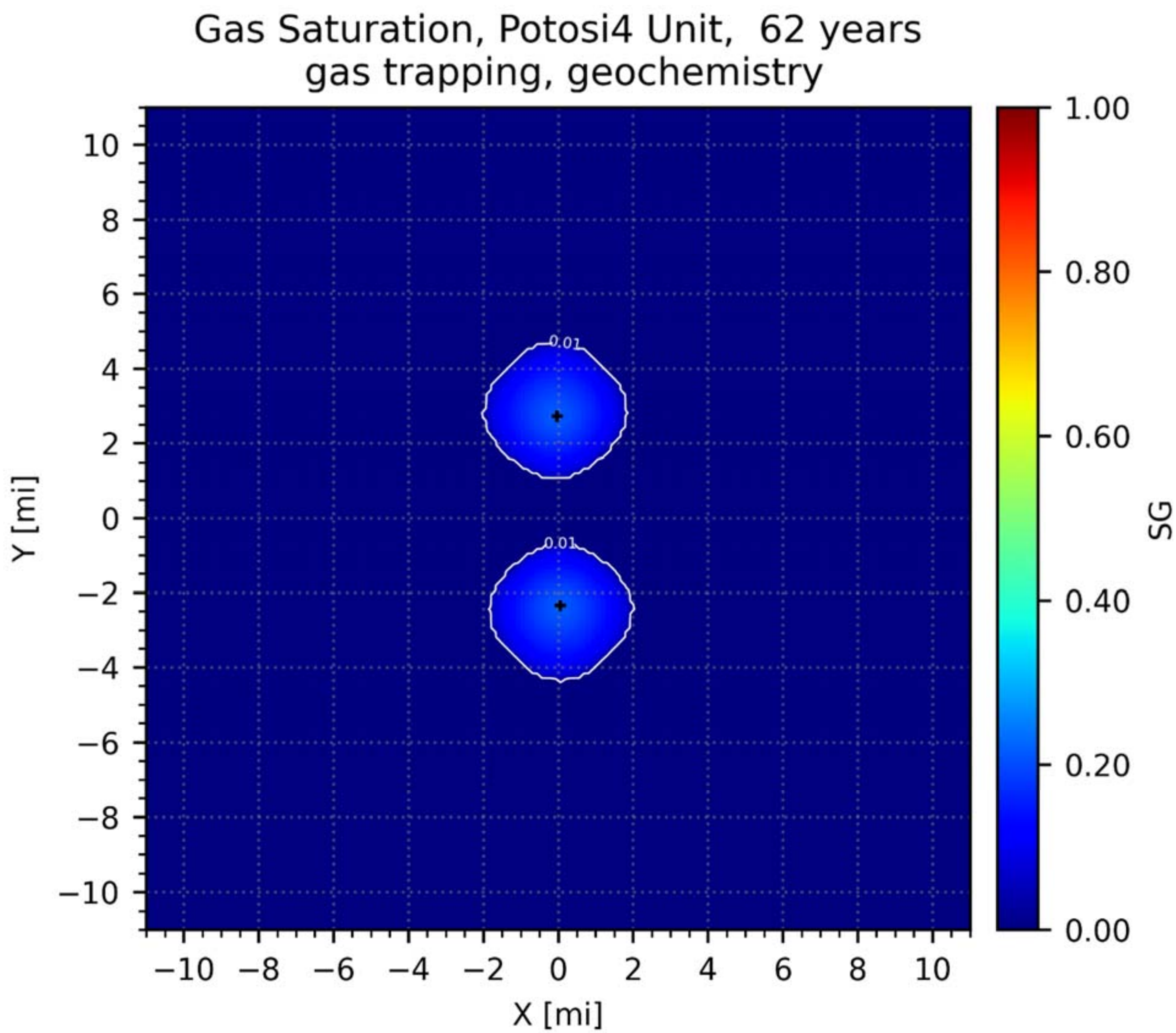


*Figure 8 CO2 plume year 62 (50 Years post-injection)*

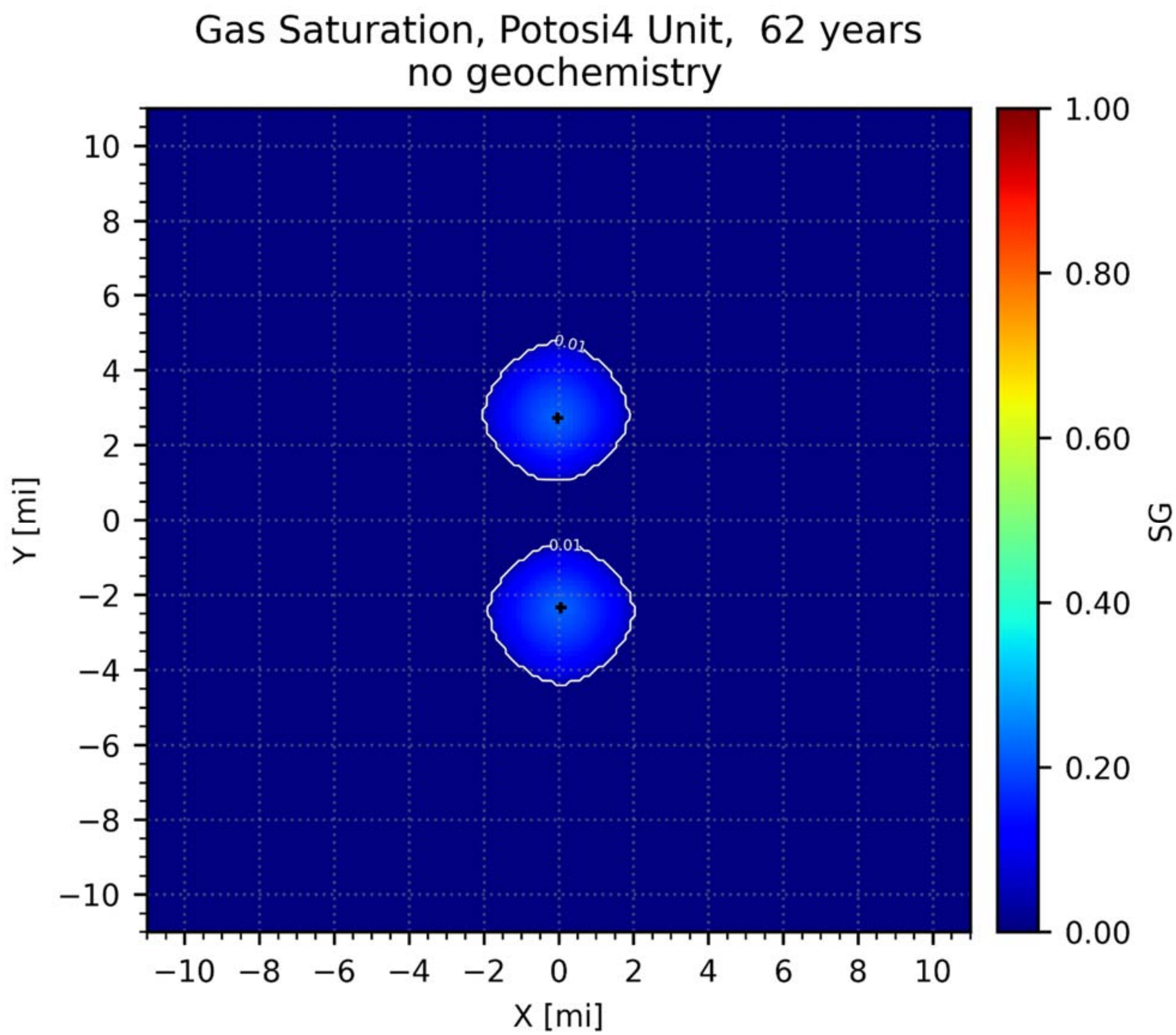


*Figure 9 CO2 plume year 62 (50 Years post-injection) no GeoChemistry*

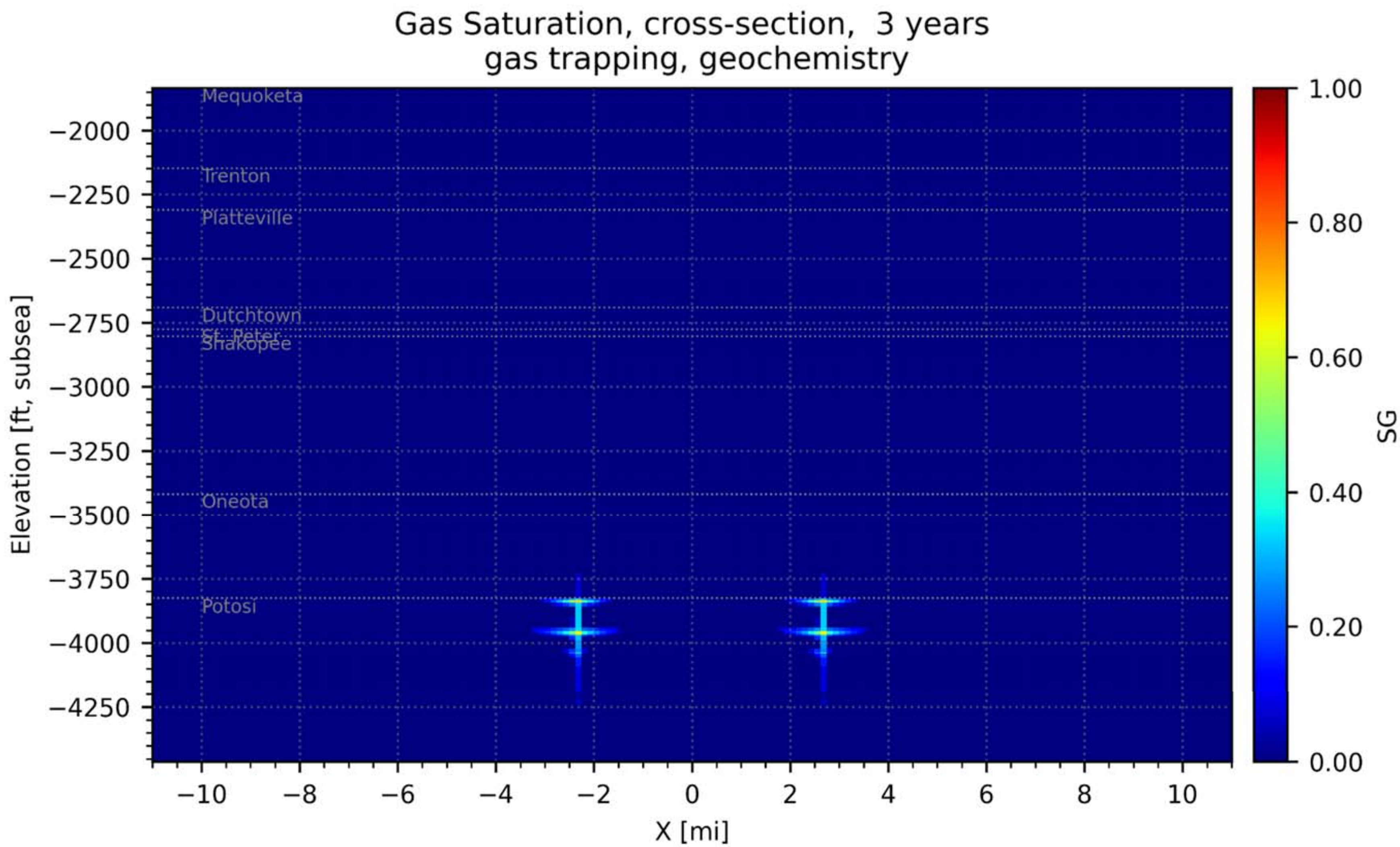


*Figure 10 CO2 Saturation Cross Section Year 3*

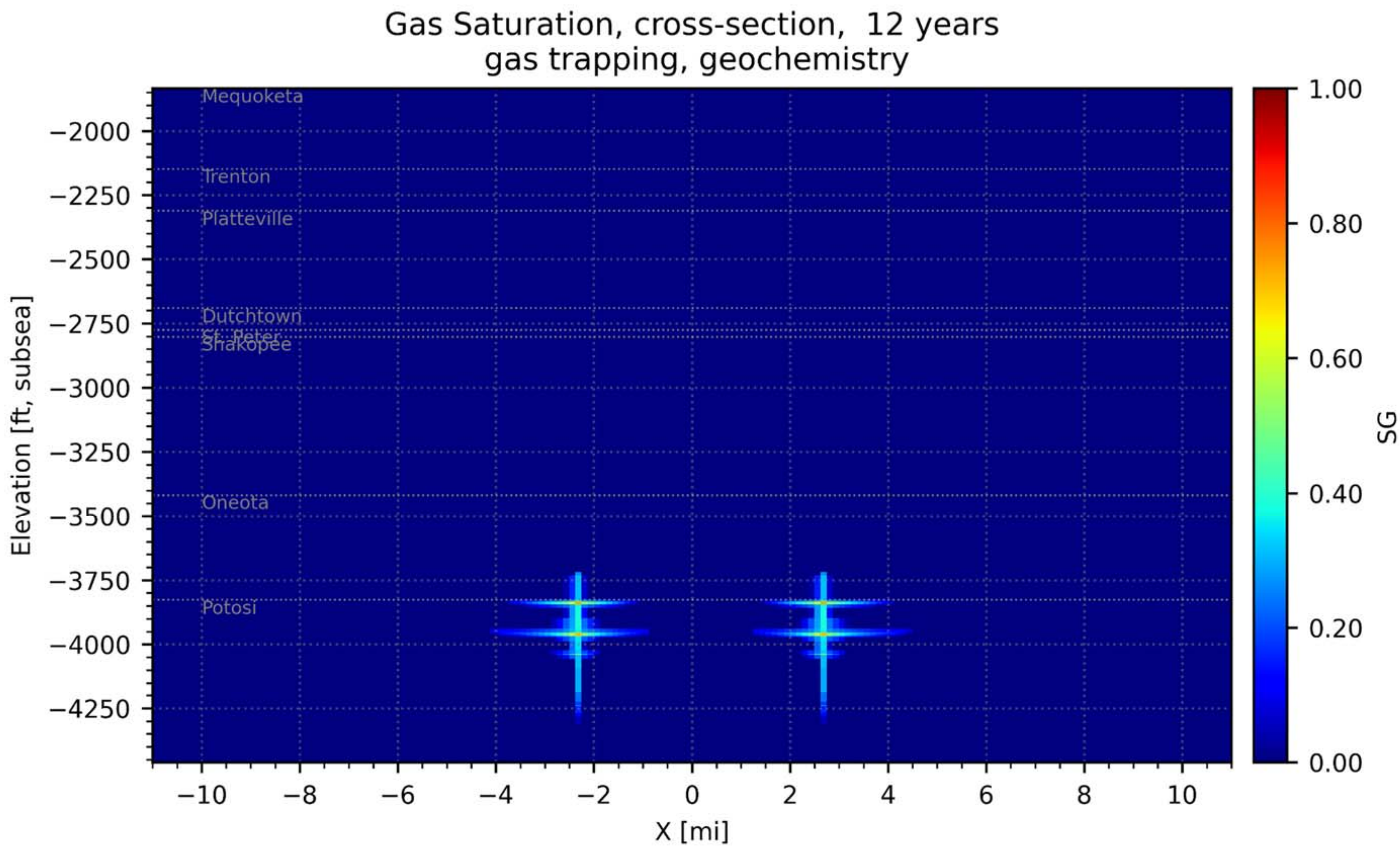


*Figure 11 CO2 Saturation Cross Section Year 12 (Cessation of Injection)*

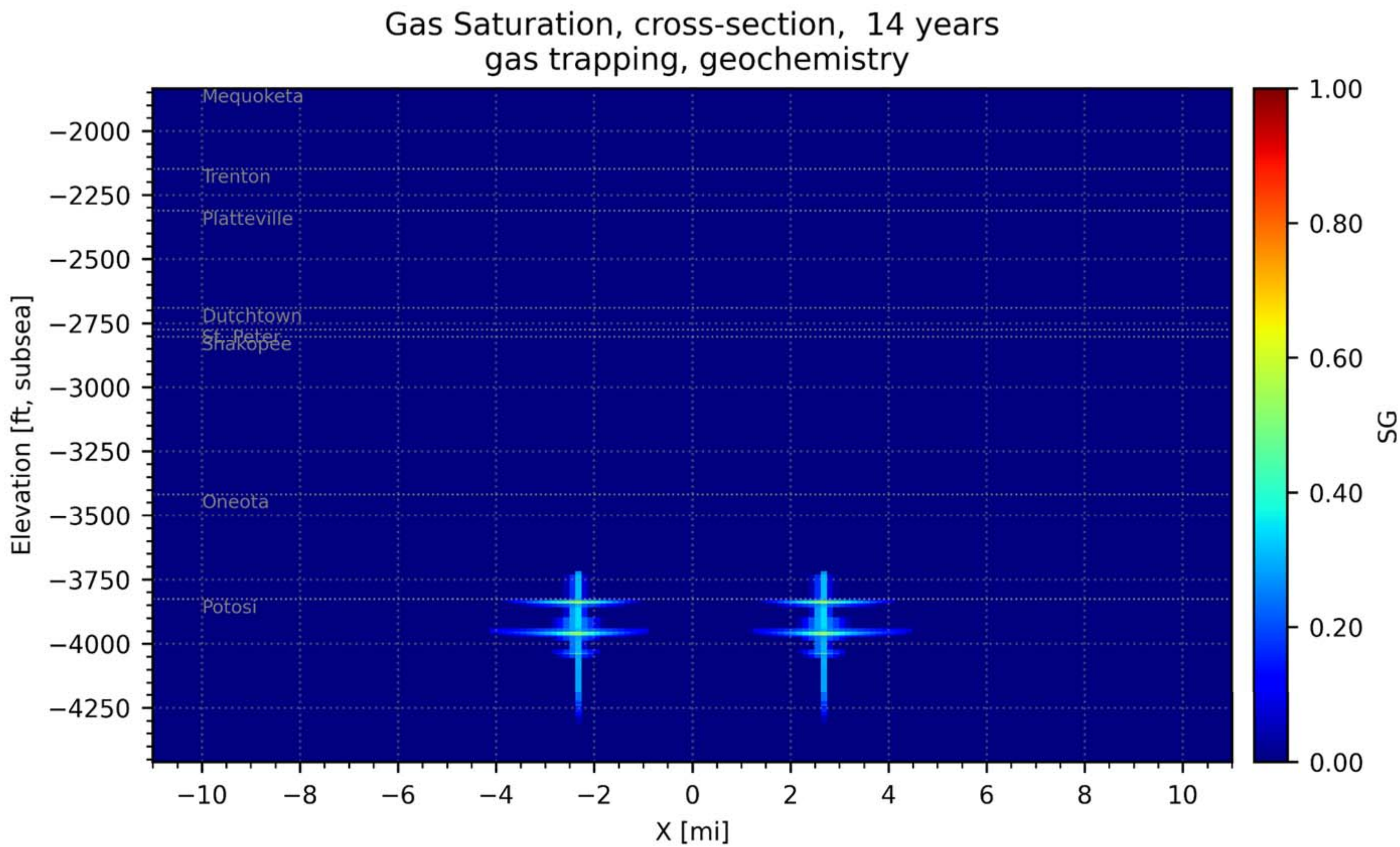


*Figure 12 CO2 Saturation Cross Section Year 14 (2 Years Post Injection)*

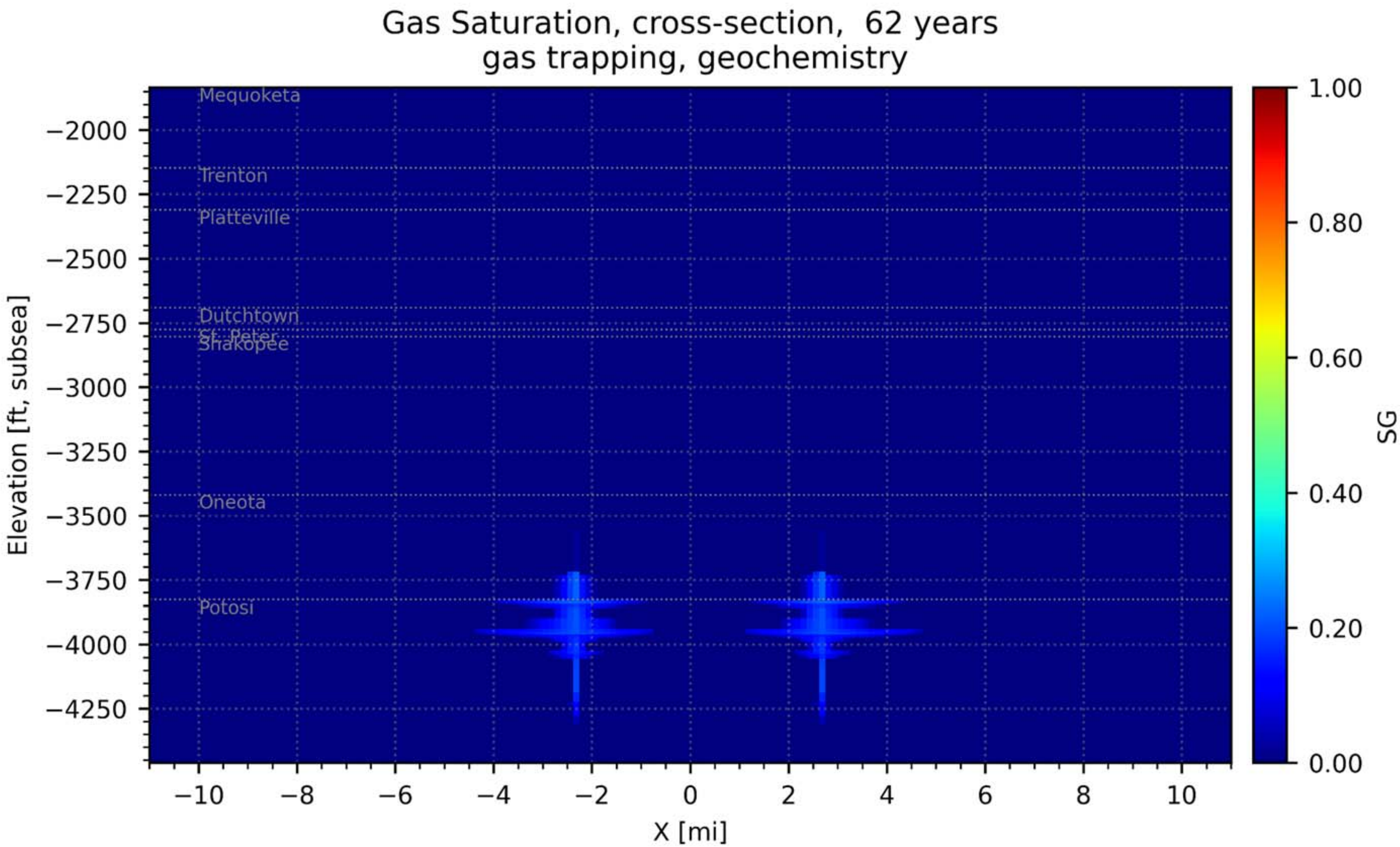


*Figure 13 CO2 Saturation Cross Section Year 62 (50 Years Post Injection)*

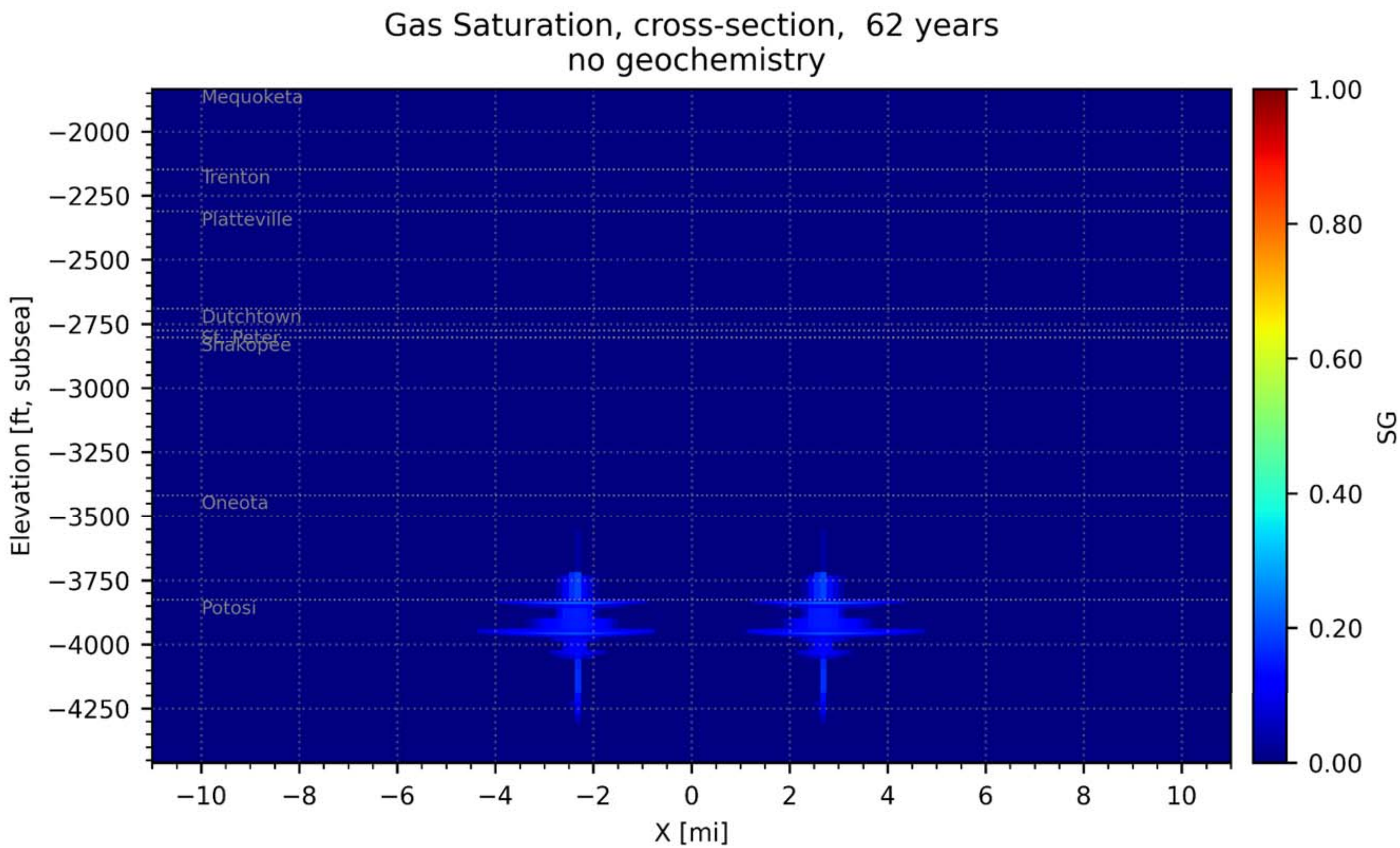


*Figure 14 CO2 Saturation Cross Section Year 62 (50 Years Post Injection) No GeoChemistry*

### *Predicted Timeframe for Pressure Decline – 40 CFR 146.93(c)(1)(ii)*

The maximum pressure is reached within the Potosi Dolomite at year 12 of injection (the final year). At the Trenton Limestone, layer directly below the Primary Seal, the differential pressure never exceeds 0.137 PSI, well below the calculated critical pressure of 70.4 PSI (*Figure 1*; *Figure 2*; *Figure* ***3***; *Figure 4*).

Within the AoR the pressure decline is homogenous within each modeled layer, however due to differing conditions between the vertical layers (porosity, permeability, starting differential pressure) the decay rates over time are heterogenous (*Figure 3*; *Figure 4*).

The Pressure Front within the Potosi Dolomite is expected to reach the formation monitoring wells after year 2 of injection. Figure 15 displays the pressure front at year 3 of injection. Pressure in the Potosi reaches its peak at year 12, the final year of injection (*Figure 16*). At the cessation of injection, the pressure rapidly declines (*Figure 17*). As discussed above the Pressure Decline was also calculated without the predicted effect of GeoChemistry. Figure 18 displays that there is a negligible impact on the pressure decline if no geochemical interaction occurs within the injection zone.

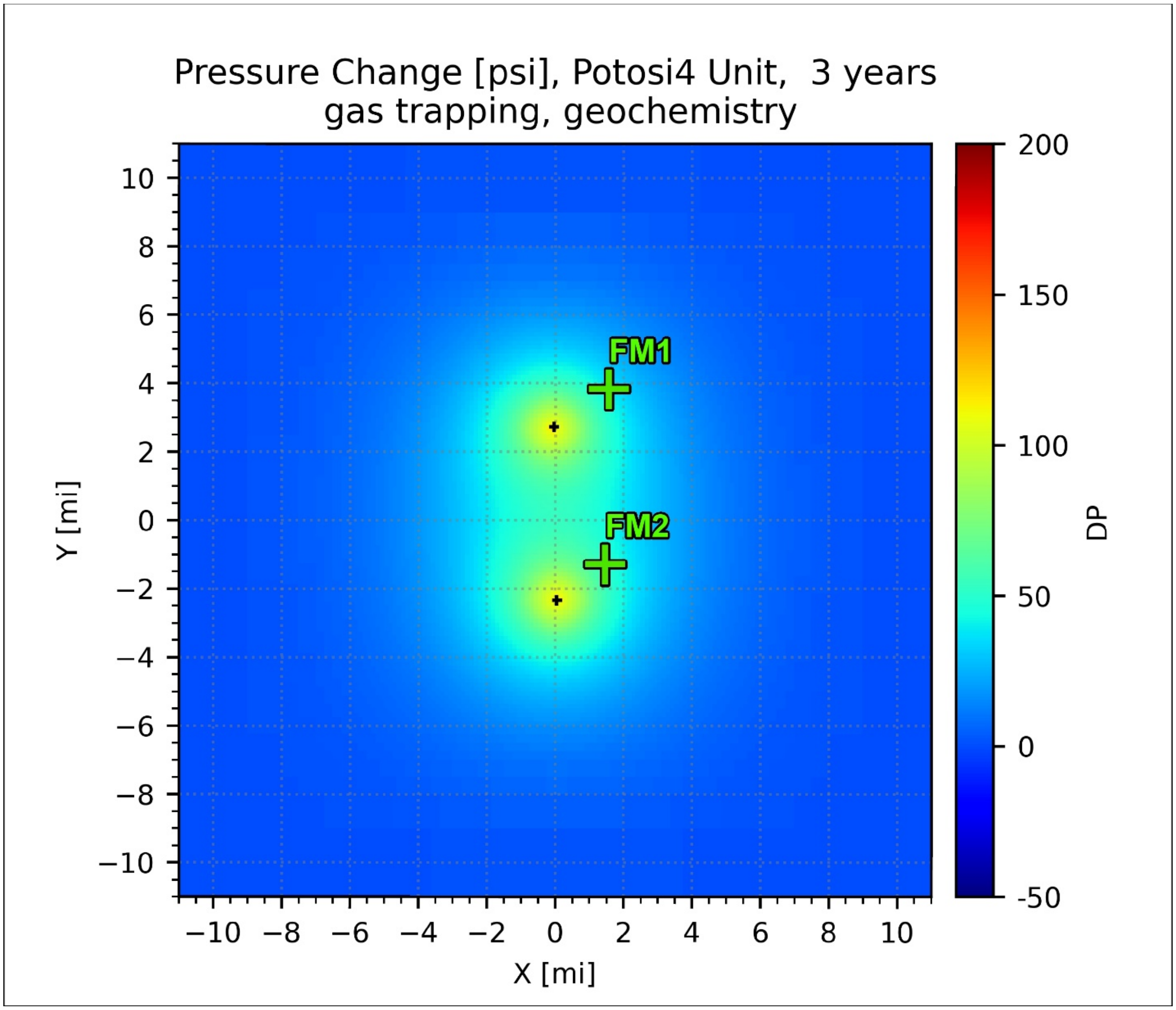


*Figure 15 Pressure Front at 3 Years in relation to monitoring wells.*

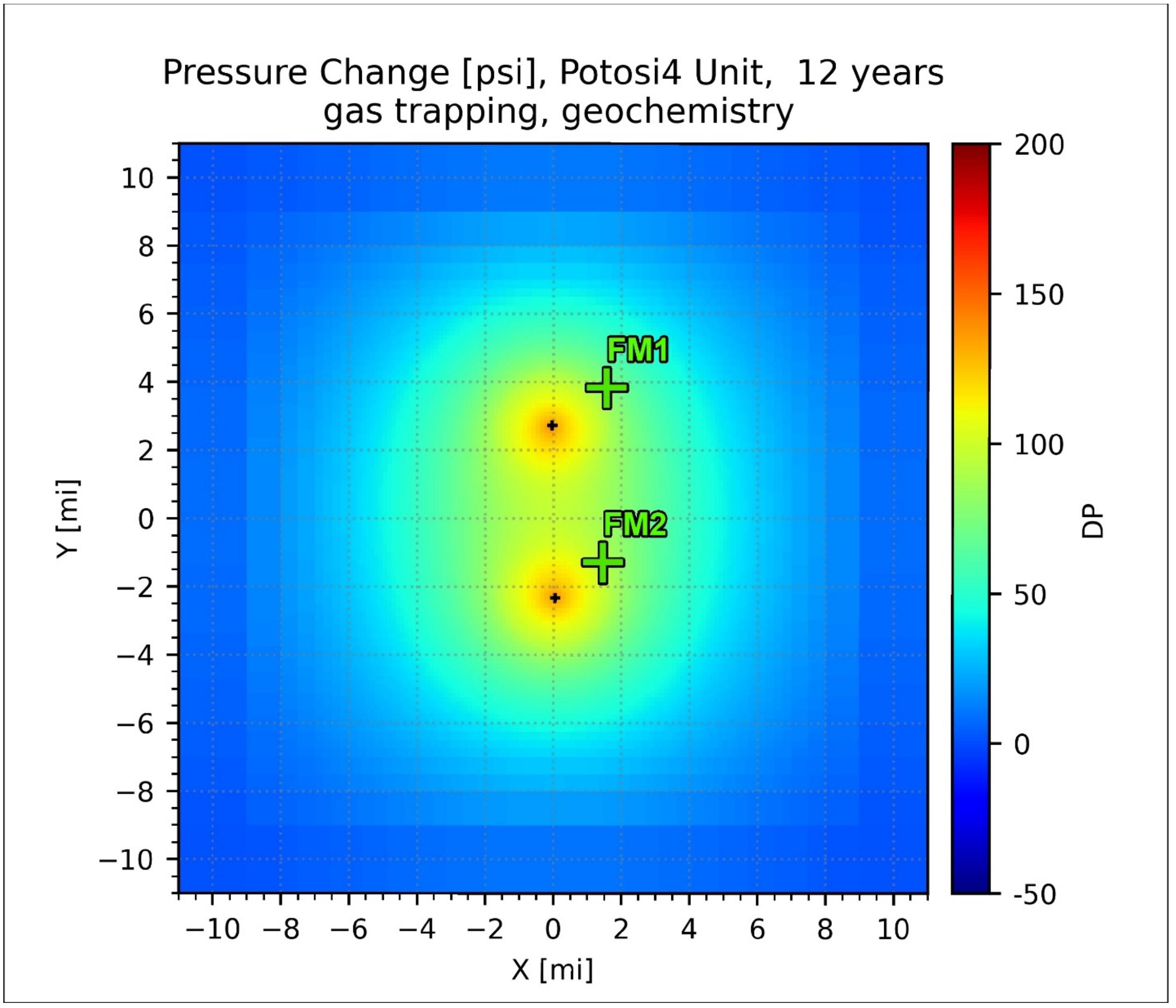


*Figure 16 Pressure Front at Year 12 in relation to monitoring wells.*

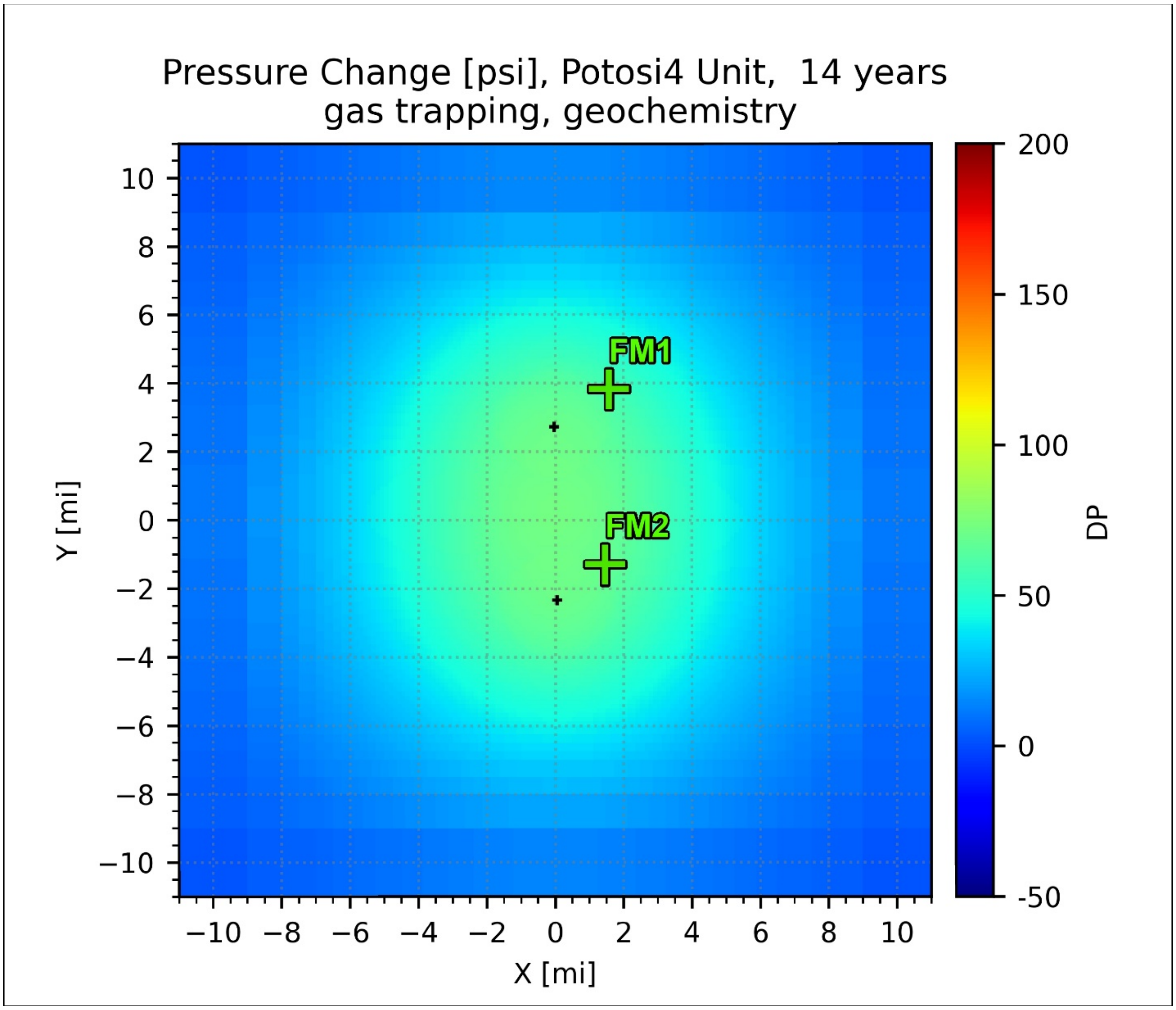


*Figure 17 Pressure Front at year 14 in relation to monitoring wells.*

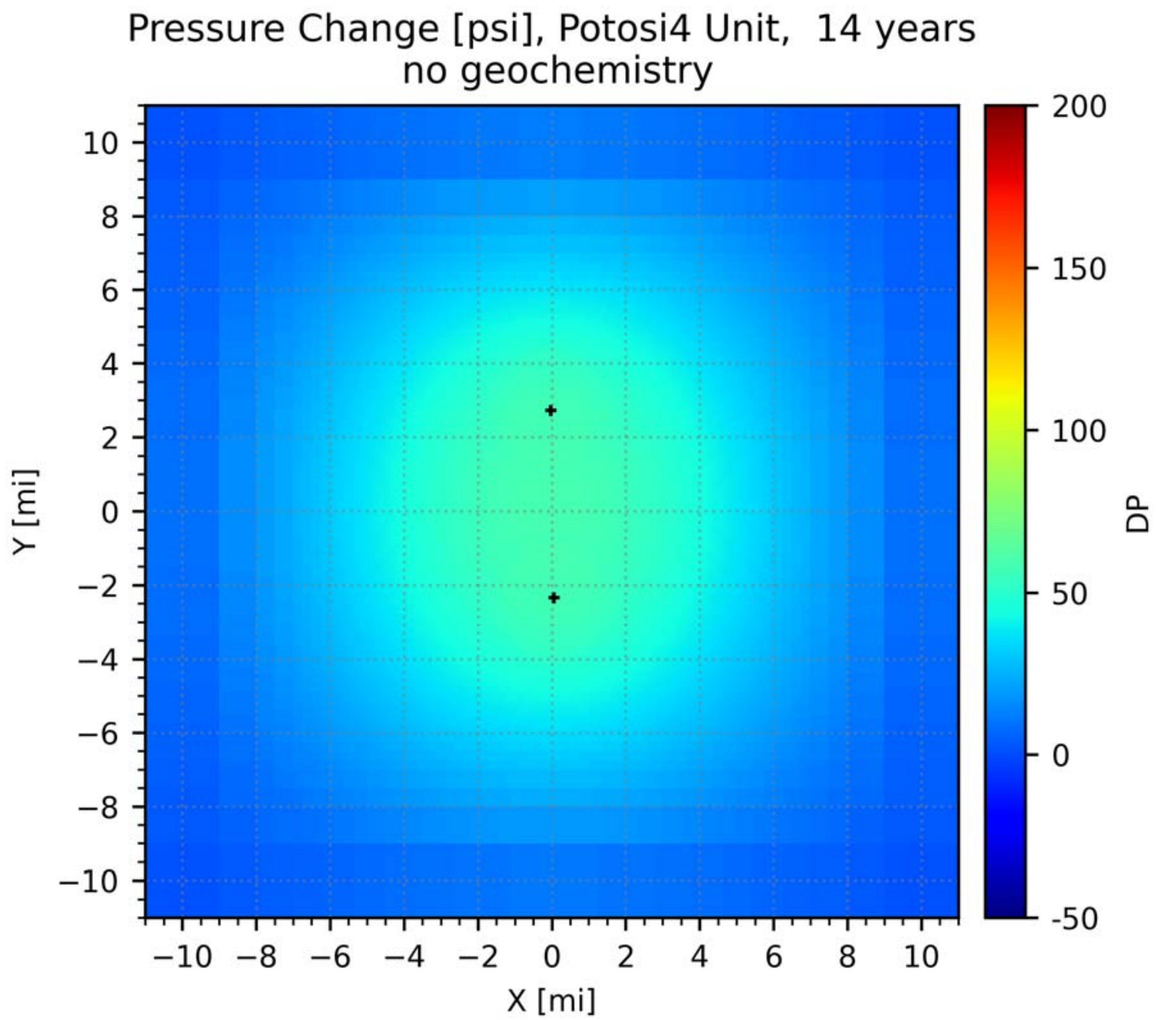


*Figure 18 Pressure Front at year 14 No GeoChemistry*

## *Predicted Rate of Plume Migration – 40 CFR 146.93(c)(1)(iii)*

As displayed in Figure 6 the $CO_2$ plumes reach their maximum spatial extent at year 14 (2 years post-injection). The plumes are essentially stable at this point, showing no horizontal migration through the remaining duration of the modeling period (*Figure 6*; *Figure 6*; *Figure 7*). During the modeling period the plumes do migrate vertically, resulting in a decrease in the total $CO_2$ saturation across the injection interval (*Figure 8; Figure 11; Figure 12; Figure 13*). The vertical movement of the $CO_2$ is limited to the Oneota formation, providing approximately 1,200 ft of vertical separation between the $CO_2$ plume and the base of the Primary Seal. Figure 19, Figure 20 and Figure 21 display the plume migration at years 3, 12, and 14 as it relates to the location of the monitoring wells.

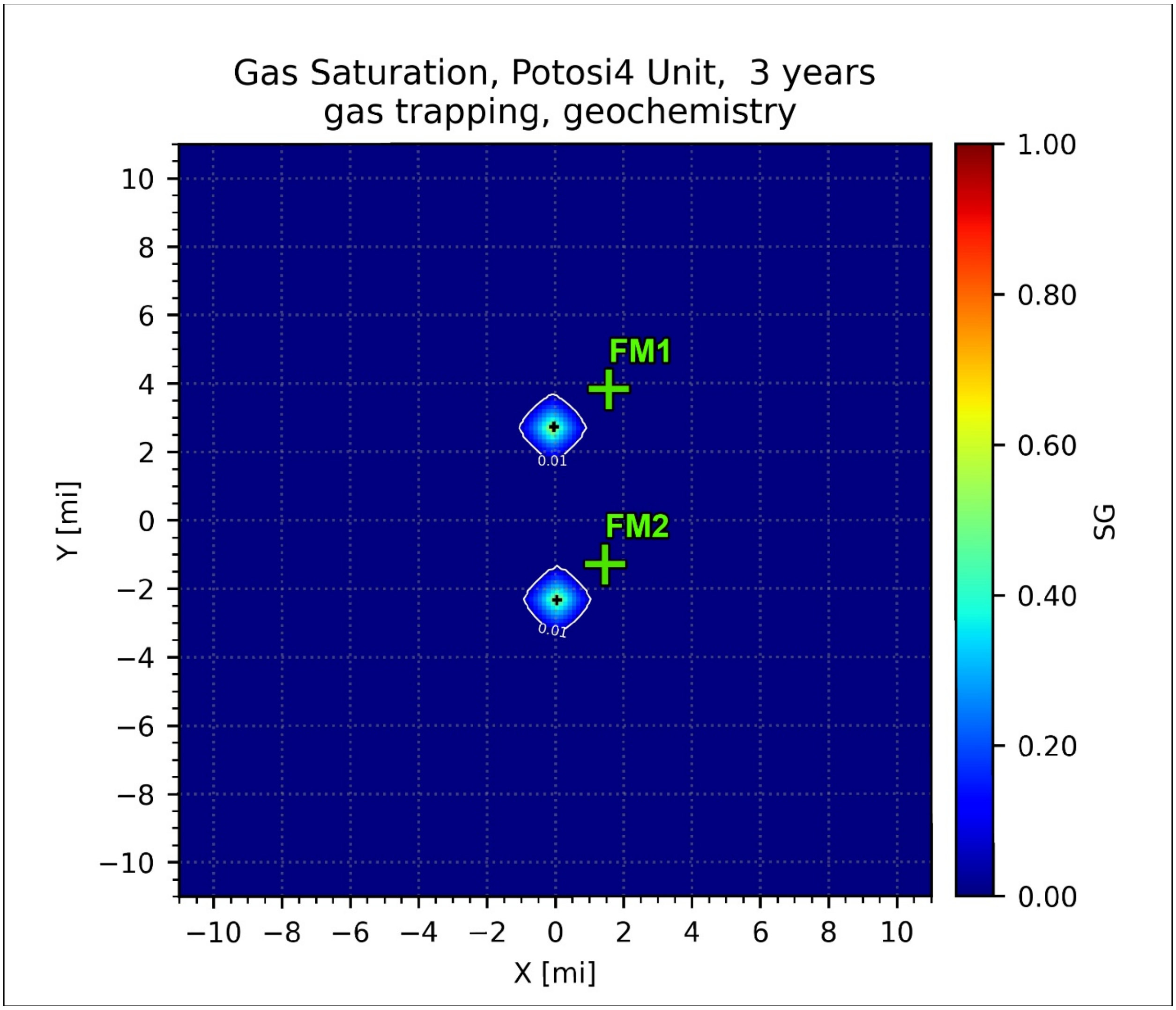


*Figure 19 $CO_2$ Plume Size Year 3 in relation to monitoring wells.*

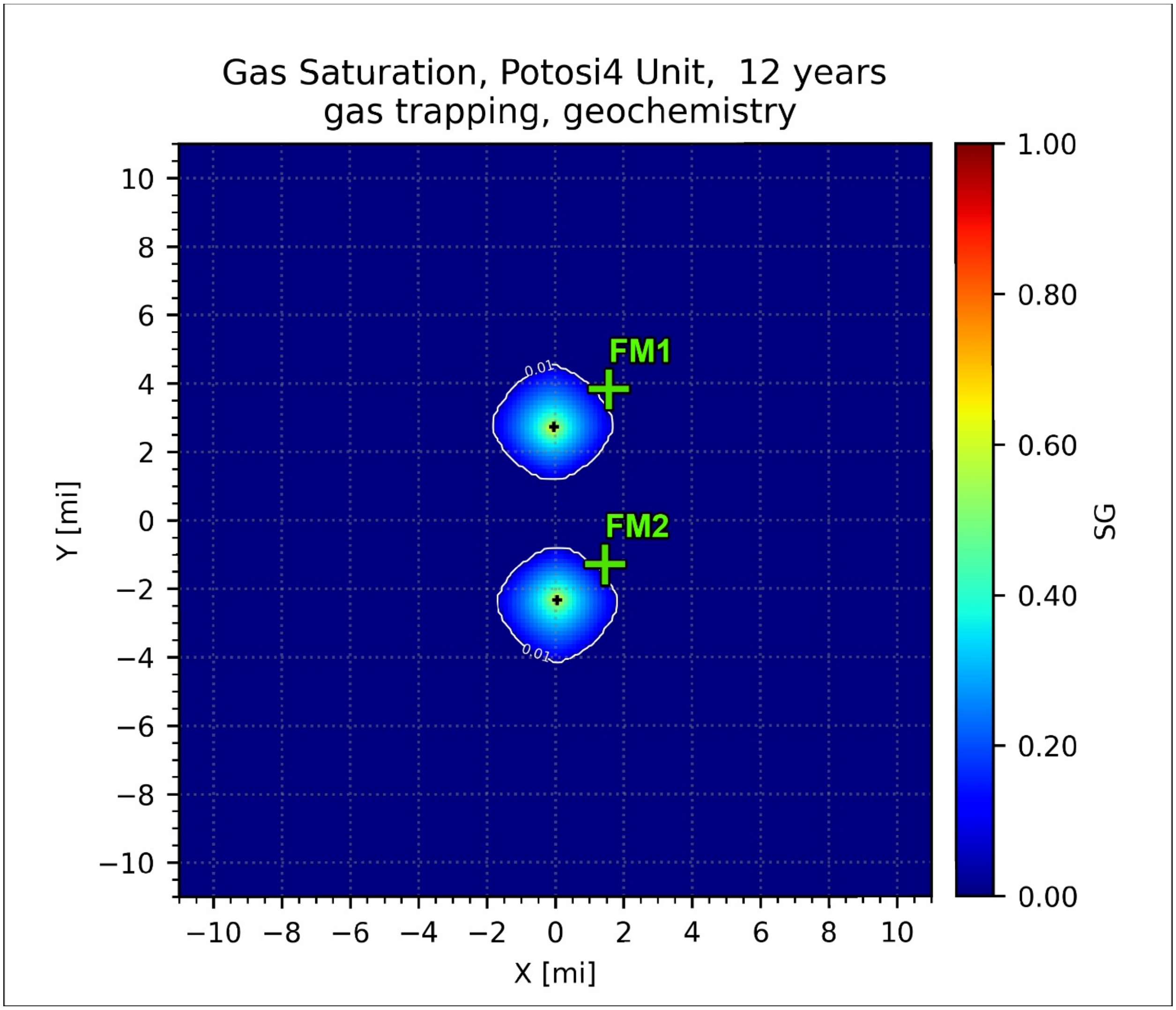


*Figure 20 $CO_2$ Plume Size Year 12 in relation to monitoring wells.*

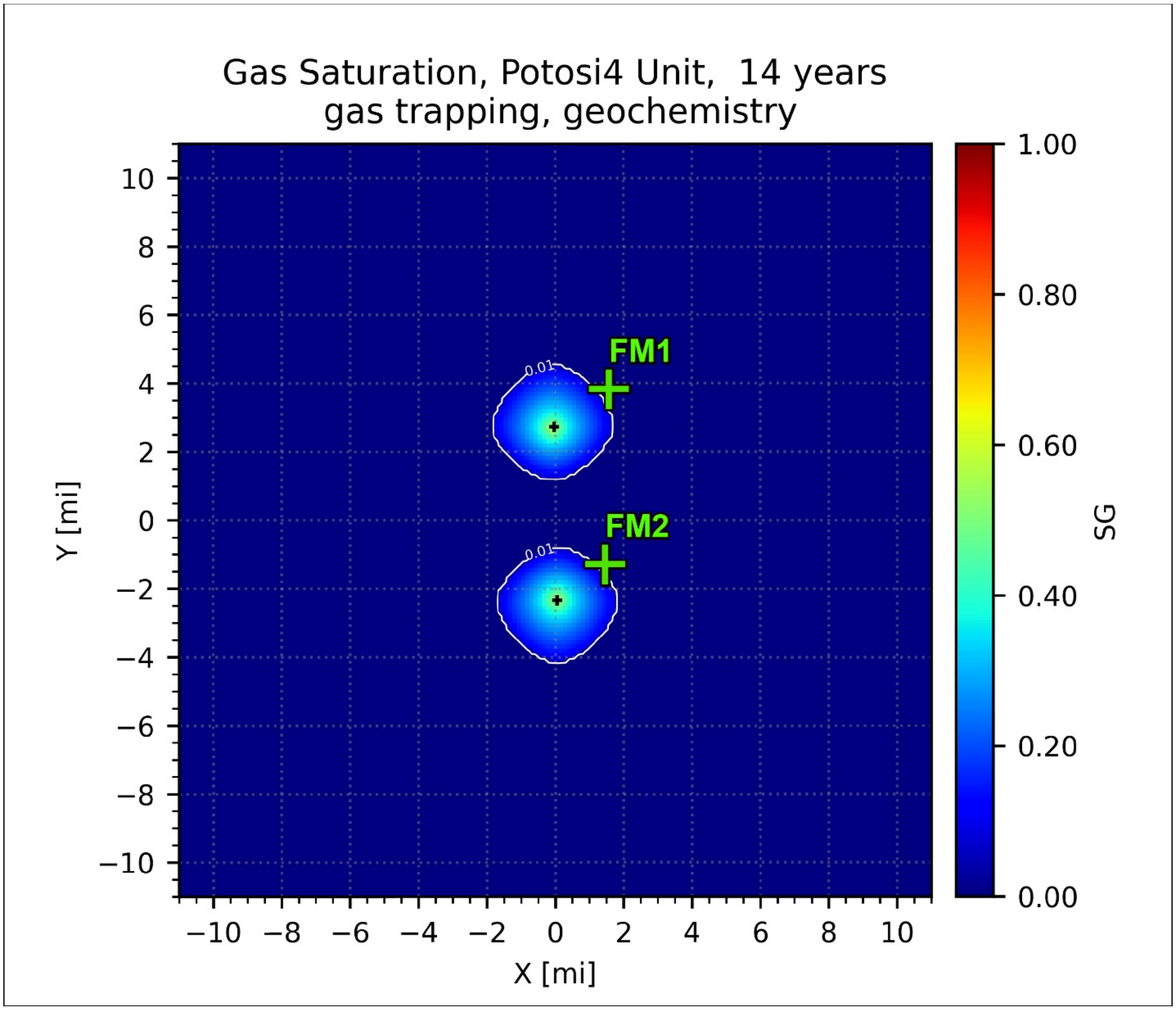


*Figure 21 $CO_2$ Plume Size Year 14 in relation to monitoring wells.*

### *Site-Specific Trapping Processes – 40 CFR 146.93(c)(1)(iv)-(vi)*

The development of the model used to determine the AoR included Site-Specific trapping processes. The Data Sources used to determine the Solid Phase Geochemistry, Geochemical Reactions and Mineral Trapping are discussed in the GEOCHEMISTRY section of the NARRATIVE TEMPLATE.

### *Confining Zone Characterization – 40 CFR 146.93(c)(1)(vii)*

The Confining Zone Characterization presented in the REGIONAL GEOLOGY, HYDROGEOLOGY, AND LOCAL STRUCTURAL GEOLOGY section of the NARRATIVE TEMPLATE supplied with the application provides all pertinent data around the compositions and extent of the different confining layers present above the injection zone. Based upon this information and the modeling results the $CO_2$ plume is limited in its vertical migration to the Oneota Section of the Knox Supergroup Dolomite. This limited upward mobility combined with the very low porosity and permeability present in the layers above the Oneota Dolomite result in the $CO_2$ being restricted to a depth of approximately 4,300 Ft MD (3,800 TVDss). This depth provides 2,000 ft of separation vertically between the $CO_2$ plume and the LUSDW.

The confining zone sections that are expected to come into contact with $CO_2$ and mobilized fluids are primarily dolomite formations with some interbedded shale layers. As described in the GEOCHEMISTRY section of the NARRATIVE TEMPLATE core flood experiments performed on samples from the Potosi Dolomite indicated the dissolution of the dolomite does occur, however equilibrium was reached before the end of the 4-month experimental period. Testing of the primary seal, the Maquoketa Group, and subsequent modeling of dissolution rates indicated a maximum decrease of mineral volume of 2.2% with actual rates forecasted to be less due to the lower water-to-mineral ratio being a limiting factor.

The determination of the AoR and subsequent behavior of the $CO_2$ plume took into account the porosity and permeability of the overlaying layers, thus accurately representing the rates of plume growth and expected stability.

### *Assessment of Fluid Movement Potential – 40 CFR 146.93(c)(1)(viii)-(ix)*

WCS performed a survey of all available well records that covered an area of approximately 50 sq/mi (4-mile radius) around each injection well. The results of the well survey have been loaded into the GSDT tool. Within the area reviewed only 1 well reached the depth of the primary seal. This well had a final depth of 2,500 ft, which does not fully penetrate the primary seal which has a measured depth of 2,700 ft. The only penetrations of the primary seal within the calculated AoR will be the injection wells and the formation monitoring wells that will be constructed as part of this project. No wells have been identified that could be considered as potential conduits of fluid movement that are not part of the WCS project and therefore will fall under the routine mechanical integrity protocols that are described in the TESTING AND MONITORING PLAN.

Modeling both injection wells and the resulting $CO_2$ plumes indicate that the at no point in the modeling timeframe (62 Years) does the $CO_2$ plume reach any known conduits that could result in the endangerment of USDW. Mobilized fluids (indicated by increases in formational pressure) were also investigated during the modeling phase. At no point in the modeling period do any mobilized fluids reach a potential conduit that could lead to an impact on the USDW.

The injection well design, as discussed in the PROJECT NARRATIVE, utilizes $CO_2$ resistant materials to ensure the integrity of the well bore during operations. At the cessation of injection activities, the injection wells will be plugged per the PLUGGING PLAN submitted with this application. $CO_2$ resistant cement will be used in the lower portion of the well bore, with a continuous cement plug being placed all the way to surface. This plugging technique provides an impermeable barrier to any potential fluid or $CO_2$ movement along the injection well.

### *Location of USDWs – 40 CFR 146.93(c)(1)(x)*

As per the HYDROLOGIC and HYDROGEOLOGIC section of the Project Narrative the LUSDW for the WCS project has been identified as the Silurian-Devonian bedrock aquifer. The LUSDW is present directly above the Maquoketa Group, the primary seal. The injection zone, the Potosi Dolomite, is approximately 2,100 feet below the LUSDW. The AoR modeling results show that the $CO_2$ plume is limited vertically to the Oneota Formation approximately 1,600 ft below the LUSDW. Any mobilized fluids, indicated by pressure rise within the formation, are limited vertically by the Dutchtown Limestone, approximately 700 ft below the LUSDW. Modeling of the Trenton Limestone, located directly below the primary seal, shows that at no point during the Alternate PISC timeframe does the pressure exceed 0.136 PSI indicating no risk to the LUSDW. During the entire modeling period, 62 years, neither the Pressure Front or $CO_2$ plume directly impinge upon the Primary Seal. The lack of challenge to the Primary Seal supports the Alternate PISC timeframe due to the very low risk to the LUSDW.

## Non-Endangerment Demonstration Criteria

Prior to approval of the end of the post-injection phase, WCS will submit a demonstration of non-endangerment of USDWs to the UIC Program Director, per 40 CFR 146.93(b)(2) and (3).

The owner or operator will issue a report to the UIC Program Director. This report will make a demonstration of USDW non-endangerment based on the evaluation of the site monitoring data used in conjunction with the project's computational model. The report will detail how the non-endangerment demonstration evaluation uses site-specific conditions to confirm and demonstrate non-endangerment. The report will include all relevant monitoring data and interpretations upon which the non-endangerment demonstration is based, model documentation and all supporting data, and any other information necessary for the UIC Program Director to review the analysis. The report will include the following sections:

### *Introduction and Overview*

A summary of relevant background information will be provided, including the operational history of the injection project, the date of the non-endangerment demonstration relative to the post-injection period outlined in this PISC and Site Closure Plan, and a general overview of how monitoring and modeling results will be used together to support a demonstration of USDW non-endangerment.

### *Summary of Existing Monitoring Data*

A summary of all previous monitoring data collected at the site, pursuant to the Testing and Monitoring Plan and this PISC and Site Closure Plan, including data collected during the injection and post-injection phases of the project, will be submitted to help demonstrate non-endangerment. Data submittals will be in a format acceptable to the UIC Program Director [40 CFR 146.91(e)], and will include a narrative explanation of monitoring activities, including the dates of all monitoring events, changes to the monitoring program over time, and an explanation of all monitoring infrastructure that has existed at the site. Data will be compared with baseline data collected during site characterization [40 CFR 146.82(a)(6) and 146.87(d)(3)].

### *Summary of Computational Modeling History*

The results of computational modeling used for AoR delineation and for demonstration of an alternative PISC timeframe will be compared to monitoring data collected during the operational and the PISC period. The data will include the results of time-lapse temperature and pressure monitoring, groundwater quality analysis, and geophysical surveys (i.e., logging and 3D surface seismic surveys) used to update the computational model and to monitor the site. Data generated during the PISC period will be used to help show that the computational model accurately represents the storage site and can be used as a proxy to determine the plume's properties and size. The operator will demonstrate this degree of accuracy by comparing the monitoring data obtained during the PISC period against the model's predicted properties (i.e., plume location, rate of movement, and pressure decay). Statistical methods will be employed to correlate the data and confirm the model's ability to accurately represent the storage site. The validation of the computational model with the large volume of available data will be a significant element to support the non-endangerment demonstration. Further, the validation of the complete model over the areas, and at the points, where direct data collection has taken place will help to ensure confidence in the model for those areas where surface infrastructure preclude geophysical data collection and where direct observation wells cannot be placed.

***Evaluation of Reservoir Pressure***

The operator will also support a demonstration of non-endangerment to USDWs by showing that, during the PISC period, the pressure within the injection zone rapidly decreases toward its pre-injection static reservoir pressure. Because the increased pressure during injection is the primary driving force for fluid movement that may endanger a USDW, the decay in the pressure differentials will provide strong justification that the injectate does not pose a risk to any USDWs.  In addition to the rapid decay rate of the pressure in the injection interval the lack of any measurable pressure increase in the Trenton Limestone, directly below the Primary Seal, indicates that endangerment of the LUSDW is highly unlikely. The operator will monitor the downhole reservoir pressure at various locations and intervals using a combination of surface and downhole pressure gauges. The measured pressure at a specific depth interval will be compared against the pressure predicted by the computational model. Agreement between the actual and the predicted values will help validate the accuracy of the model and further demonstrate non-endangerment.

***Evaluation of Carbon Dioxide Plume***

The operator will use a combination of RST logs and other seismic methods (2D or 3D surveys) to locate and track the extent of the $CO_2$ plume. The data gathered through the physical monitoring will be compared to the expected pressure front and plume data generated by the model.  A good correlation between the two data sets will help provide strong evidence in validating the model's ability to represent the storage system. 2D and 3D seismic surveys will be employed to determine the plume location at specific times. The data produced by these activities will be compared against the model using statistical methods to validate the model's ability to accurately represent the storage site.

Regarding the carbon dioxide plume, the PISC monitoring data will be used to support a demonstration of the stabilization of the $CO_2$ plume as the reservoir pressure returns toward its pre-injection state. The storage interval (Potosi Dolomite) is considered to be an open reservoir system.  Locally, the storage interval has thin stratigraphic bands of high permeability.

Modeling performed to delineate the plume and pressure front predicts that, during the PISC period, the $CO_2$ will gradually rise through the reservoir until it reaches the low permeability and porosity sections found in the Oneota Dolomite (2.5 mD). Based on the results of a 50-year post injection simulation, the top of the $CO_2$ plume is about 1,600 vertical feet below the primary seal formation (Maquoketa Group).

The stabilization of the site conditions combined with the site's characteristic of not having any local penetrations of the seal formation will be the central focus of the operator's demonstration of non-endangerment.

***Evaluation of Emergencies or Other Events***

*Evaluation of Mobilized Fluids*

In addition to carbon dioxide, mobilized fluids may pose a risk to USDWs. These include native fluids that are high in TDS and therefore may impair a USDW, and fluids containing mobilized drinking water contaminants (e.g., arsenic, mercury, hydrogen sulfide). The geochemical data collected from monitoring wells will be used to demonstrate that no mobilized fluids have moved above the seal formation and therefore after the PISC period would not pose a risk to USDWs. In order to demonstrate non-endangerment, the operator will compare the operational and PISC period samples from layers above the injection zone, including the lowermost USDW, against the pre-injection baseline samples. This comparison will support a demonstration that no significant changes in the fluid properties of the overlying formations have occurred and that no mobilized formation fluids have moved through the seal formation. This validation of seal integrity will help demonstrate that the injectate and or mobilized fluids would not represent an endangerment to any USDWs. Additionally, RST logs will be used to monitor the salinity of the reservoir fluids in the observation zone above the Maquoketa Group seal. By comparing the time lapse RST logs against the pre-injection baseline logs, the operator will be able to monitor any changes in reservoir fluid salinity. RST logs indicating steady salinity levels within each zone would indicate no movement of fluids out of the storage unit, confirming the integrity of the well and seal formation.

*Evaluation of Potential Conduits for Fluid Movement*

Other than the project wells, there are no identified potential conduits for fluid movement or leakage pathways within the AoR. WCS performed a survey of available well data for both water wells and oil and gas wells within a radius of 4 miles of each injection well. Within this research area no artificial penetrations of the primary seal were found. Based upon the computer modeling the $CO_2$ plume does not extend beyond the injection site more than 2.2 miles in any direction. Based on this information, the potential for fluid movement through artificial penetrations of the seal formation does not present a risk of endangerment to any USDWs.

## Site Closure Plan

WCS will conduct site closure activities to meet the requirements of 40 CFR 146.93(e) as described below. WCS will submit a final Site Closure Plan and notify the permitting agency at least 120 days prior of its intent to close the site. Once the permitting agency has approved closure of the site, WCS will plug the monitoring wells and submit a site closure report to EPA. The activities, as described below, represent the planned activities based on information provided to EPA. The actual site closure plan may employ different methods and procedures. A final Site Closure Plan will be submitted to the UIC Program Director for approval with the notification of the intent to close the site.

### *Plugging Monitoring Wells*

The well will be flushed with a kill weight brine fluid. A minimum of three tubing volumes will be injected without exceeding fracture pressure. A final external MIT will be conducted to ensure mechanical integrity. Detailed plugging procedures are provided below. All casing in this well will be cemented to surface and will not be retrievable at abandonment. After injection ceases and after the appropriate post-injection monitoring period is finished, the completion equipment will be removed from the well.

#### *Type and Quantity of Plugging Materials, Depth Intervals*

Well cementing software (e.g., Schlumberger's CemCade) will be used to model the plugging and aid in the plug design. The cements used for plugging will be tested in the lab prior to plug placement and both wet and dry samples will be collected during plugging for each plug to ensure quality of the plug.

All of the casing strings will be cut off at least 3 feet below the surface, below the plow line. A blanking plate with the required permit information will be welded to the top of the cutoff casing.

#### *Volume Calculations*

Volumes will be calculated for specific abandonment wellbore environments based on desired plug diameter and length required. Volume calculations are the same for plug and abandonment during construction and post-injection.

1. Choose the following:
    a. Length of the cement plug desired.
    b. Desired setting depth of base of plug.
    c. Amount of spacer to be pumped ahead of the slurry.
2. Determine the following:
    a. Number of sacks of cement required.
    b. Volume of spacer to be pumped behind the slurry to balance the plug.
    c. Plug length before the pipe is withdrawn.
    d. Length of mud freefall in drill pipe.
    e. Displacement volume required to spot the plug.
3. Field cementing and wellsite supervisor will both review calculations prior to spotting any plug.

*Plugging and Abandonment Procedure*

At the end of the serviceable life of the verification well, the well will be plugged and abandoned. In summary, the plugging procedure will consist of removing all components of the completion system and then placing cement plugs along the entire length of the well. Prior to placing the cement plugs, casing inspection and temperature logs will be run confirming external mechanical integrity. If a loss of integrity is discovered, then a plan to repair using the cement squeeze method will be prepared and submitted to the agency for review and approval. At the surface, the well head will be removed; and the casing will be cut off 3 feet below surface. A detailed procedure follows:

1. Notify Indiana EPA and/or U.S. EPA (as appropriate) 48 hours prior to commencing operations. Ensure proper notifications have been given to all regulatory agencies for rig move.
2. Make sure all permits to P&A have been duly executed by all local, State & Federal agencies and Wabash have written permission to proceed with planned ultimate P&A procedure.
3. Ensure in advance that a pre-site inspection has been performed and the rig company has visited the site and is capable of transporting rig, tanks & ancillary equipment to perform P&A operations. Notify all key third parties of expected work scope, and ensure third party contracts for work are in place prior to move in.
4. Have copies of all government permits prior to initiating operations and maintain on location at all times. Check to see if conditions of approval have been met.
5. Make sure partners (U.S. DOE, Indiana DEM (or Indiana DNR) and/or U.S. EPA, and Wabash) approvals have been obtained, as applicable.
6. Make sure all necessary safety forms are on the rig, i.e., NPDES, safety meetings, trip sheets, etc.

*Plugging Procedures*

1. Mobilize workover (WO) or Plugging Rig Equipment. Give appropriate notice before commencing operations.

2. Move in rig to well location. Notify the Project Coordinator before moving rig. Ensure all overhead restrictions (telephone, power lines, etc.) have been adequately previewed and managed prior to move in and rig up (MI & RU). All $CO_2$ pipelines will be marked and noted to Workover (WO) rig supervisor prior to moving in (MI) rig. Move rig onto location per operational procedures.

3. Conduct a safety meeting for the entire crew prior to operations, record date and time of all safety meetings and maintain records on location for review.

4. Make daily “Project Inspection” walks around the rig. Immediately correct deficiencies and report deficiencies during the regulatory discussion during morning meetings/calls. Maintain International Association of Drilling Contractors (IADC) or plugging reports daily at the WO rig logbook or doghouse.

5. MI rig package and finish rigging up hoses, hydraulic lines, etc.

6. Open up all valves on the vertical run of the tree. Check pressures.

7. Rig up pump and line and test same to 2,500 psi. Fill casing with kill weight brine (9.5 lbs/gallon - ppg). Bleeding off occasionally may be necessary to remove all air from the system. Keep track and record volume of fluid to fill annulus (Hole should be full). If there is pressure remaining on tubing, rig to pump down tubing and inject two tubing volumes of kill weight brine. Monitor tubing and casing pressure for 1 hour. If both casing and tubing are dead, then nipple up blowout preventers (NU BOP's). Monitor casing and tubing pressures.

8. If needed, if well is not dead nor pressure cannot be bled off of tubing, rig up (RU) slickline (SL) and set X-lock plug in X nipple located in X-Plug in tailpipe below packer. Circulate well with kill weight brine. Ensure well is dead. Nipple down (ND) tree. NU Blowout Prevention Equipment (BOP's) and function test same. BOP's should have 4 ½" single pipe rams on top and blind rams in the bottom ram for 4 ½". Test BOP's as per local, state or federal provisions or utilize higher standard, 30 CFR250.616. Test pipe rams and blind rams to 250 psi low, 3,000 psi high. Test annular preventer to 250 psi low and 3,000 psi high. Test all Texas Iron Works (TIW's), BOP's, choke and kill lines, choke manifold, etc. to 250 psi low and 3,000 psi high. **NOTE: Make sure casing valve is open during all BOP tests.** After testing BOPs pick up 4 ½" tubing string and unlatch seal assembly from seal bore. Rig slick line and lubricator back to well and remove X-plug from well. Rig to pump via lubricator and keep well dead.

9. RU 4 ½" rig hydraulic tubing tongs for handling of production tubing. Pick back up on tubing string and pull seal assembly from seal bore. Pull hanger to floor and remove same. Circulate bottoms up with packer fluid.

10. Pull out of hole (POOH) with tubing laying down same. **NOTE: Ensure well does not flow due to $CO_2$ "back flow"! Well condition is to be over-balanced at all times with at least 2 well control barriers in place at all times.**

11. Contingency: If unable to pull seal assembly, RU electric line and make cut on tubing string just above packer. Note: Cut must be made above packer at least 5-10 ft MD. Several different sizes of cutters and pipe recovery tools should be on location due to possible tight spots in tubing. If successful pulling seal assembly then pick up 3 ½ or 4 ½ inch workstring and Trip in Hole (TIH) with packer retrieving tools. If tubing was cut in previous step, then skip this step. Latch onto packer and pull out of hole laying down same. If unable to pull packer, pull work string out of hole and proceed to next step. Assuming tubing can be pulled with packer with no issues, run CBL cement bond log or USIT ultrasonic imager to determine that there is no leakage around the wellbore above the caprock. If leakage is noted, perform diagnostics to determine whether there is actual leakage or micro-annulus etc. Rerun CBL/USIT under pressure, if necessary, to eliminate micro-annulus effects. If leakage is confirmed, prepare cement remediation plan and execute during plugging operations. Set 7 5/8 inch cement retainer on wireline just in Oneota above the Potosi formation. Trip into hole with work string and sting into cement

retainer. Test backside to 750 psi for 30 minutes on chart. A successful casing test should have less than 10% bleed off over the 30-minute period. This will be considered a successful casing test. Establish injection with packer kill fluid at 0.5, 1, and 2 BPM not to exceed 2,000 psi injection pressure. Sting out of retainer.

12. With pipe stung out of retainer, mix and pump EverCRETE $CO_2$ resistant cement mixed at 12.7 ppg plus fluid loss additive as proposed by cementing company and actual downhole conditions (temperature, bottom hole pressure (BHP), etc.). Obtain fluid loss of less than 100 cc/30 min. Follow that with EverCRETE $CO_2$ resistant cement mixed at 12.7 ppg with dispersant. Circulate to within 5 bbls of end of work/tubing string, sting into retainer and finish mixing cement. Displace tubing and squeeze away 30 bbls of cement into the open perforations. Note: Do not squeeze at higher pressures than 2,000 psi. Sting out of retainer and reverse out a minimum of 2 pipe volumes. Note: Leave cement on top of retainer.

13. Pull out of hole (POOH) racking back work string. Shut down for 12 hours. Trip in Hole (TIH) open ended. Tag up on cement on top of retainer and note same.

14. Circulate well and ensure well is in balance. Place tubing just above cement top from previous day. Mix and spot 500 ft balanced plug of EverCRETE $CO_2$ resistant cement in the 7 5/8-inch casing. Pull out of plug and reverse circulate tubing. Repeat this operation and spot a second 500 ft balance plug.

15. POOH racking back work string. Shut down for 12 hours. Trip in Hole (TIH) open ended. Tag up on cement on top of retainer and note same.

16. Circulate well and ensure well is in balance. Place tubing just above cement top from previous day. Mix and spot 500 ft balanced plug in the 7 5/8-inch casing. Pull out of plug and reverse circulate tubing. Repeat this operation until a total of 9 (including previously set EverCRETE plugs) plugs have been set. If plugs are well balanced, then the reverse circulation step can be omitted until after each third plug. Lay down work string while pulling from well. If rig is working daylights only then pull 10 stands and rack back in derrick and reverse tubing before shutting down for night. The following morning, trip back in hole and tag plug and continue. After 9 plugs have been set pull tubing from well and shut in for 12 hours. Trip in hole with tubing and tag cement top. Calculate volume for final plug. Pull tubing back out of well. Nipple down BOPs and cut all casing strings below plow line (min 3 feet below ground level or per local policies/standards and Wabash requirements). Trip in well and set final cement plug. Lay down all work string, etc. Rig down all equipment and move out. Clean cellar to where a plate can be welded with well name onto lowest casing string at 3 ft or as per regulatory requirements. The steel plate/cap will have the well identification number, the UIC Class VI permit number, and the date of plug and abandonment inscribed on it. Soil will be backfilled around the well and the area planted with natural vegetation or as per regulatory requirements.

17. File all plugging forms to local state, federal and other agencies as required. After the completion of the plugging activities, a Plugging and Abandonment (P&A) Report as per

EPA Form 7520-14 will be submitted to the UIC EPA Region 5 Office describing the details regarding the P&A job within 60 days of completing the plugging activities.

Approximately five days are required from move in to move out, depending on the operations at hand and the physical constraints of the well, weather, and other conditions.

See Figure 22 below for a plugging schematic.

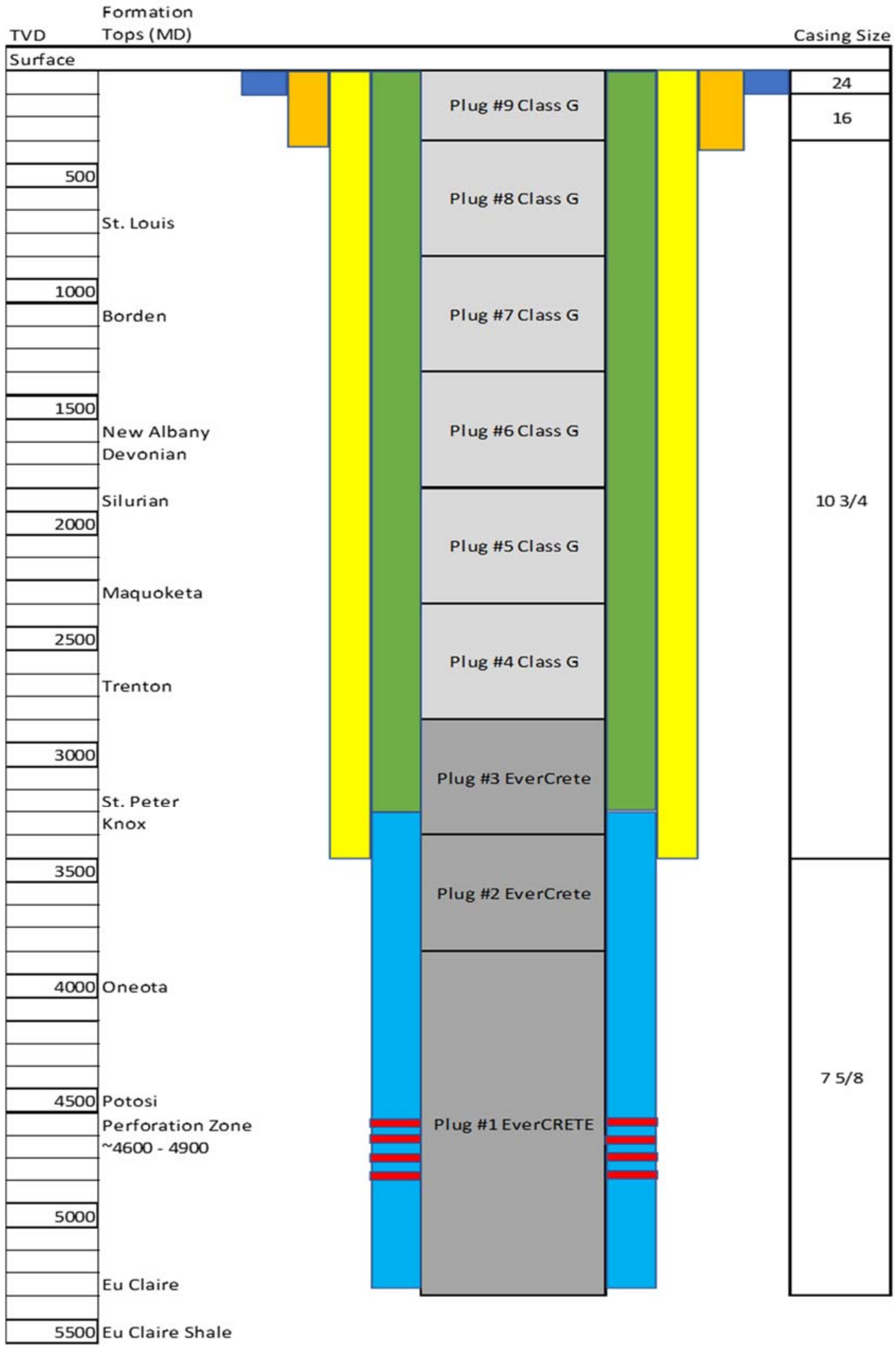


*Figure 22. Pugging Schematic*

*Plugging the Confinement Monitor Well(s)*

At the end of the serviceable life of the well, the well will be plugged and abandoned utilizing the following procedure:

1. Notify the permitting agency of abandonment at least 60 days prior to plugging the well.

2. Remove any monitoring equipment from well bore. Well will contain fresh water or a mixture of fresh water and native Silurian formation water.

3. Nipple down well head and connect cement pump truck to casing. Establish injection rate with fresh water. Mix and pump Class A cement (15.9 ppg). Slow injection rate to ½ bbl/min as cement starts to enter Silurian perforations. Continue squeezing cement into formation until a squeeze pressure of 500 psi is obtained. Monitor static cement level in casing for 12 hours and fill with cement if needed to top out. Plan to have 50 sacks additional cement above calculated volume on location to top out if needed. Cement volume requirements will be determined based upon actual well construction depths and final casing diameters used.

4. After cement cures, cut off all well head components and cut off all casings below the plow line.

5. Install permanent marker at surface, or as required by the permitting agency.

6. Reclaim surface to normal grade and reseed location.

*Planned Remedial/Site Restoration Activities*

To restore the site to its pre-injection condition following site closure, WCS will be guided by the state rules for plugging and abandonment of wells located on leased property.

The following steps will be taken:

1. The free liquid fraction of the plugging fluid waste, which may consist of produced water and/or crude oil, shall be removed from the pit and disposed of in accordance with state and federal regulations (e.g., injection or in above ground tanks or containers pending disposal) prior to restoration. The remaining plugging fluid wastes shall be disposed of by on-site burial.

2. All plugging pits shall be filled and leveled in a manner that allows the site to be returned to original use with no subsidence or leakage of fluids, and where applicable, with sufficient compaction to support farm machinery.

3. All drilling and production equipment, machinery, and equipment debris shall be removed from the site.

4. Casing shall be cut off at least three (3) feet below the surface of the ground, and a steel plate welded on the casing.

5. Any drilling rat holes shall be filled with cement to no lower than four (4) feet and no higher than three (3) feet below ground level.

6. The well site and all excavations, holes and pits shall be filled, and the surface leveled.

***Site Closure Report***

A site closure report will be prepared and submitted within 90 days following site closure, documenting the following:

- Plugging of the verification and geophysical wells (and the injection well if it has not previously been plugged),
- Location of sealed injection well on a plat of survey that has been submitted to the local zoning authority,
- Notifications to state and local authorities as required at 40 CFR 146.93(f)(2),
- Records regarding the nature, composition, and volume of the injected $CO_2$, and
- Post-injection monitoring records.

WCS will record a notation to the property's deed on which the injection well was located that will indicate the following:

- That the property was used for carbon dioxide sequestration,
- The name of the local agency to which a plat of survey with injection well location was submitted,
- The volume of fluid injected,
- The formation into which the fluid was injected, and
- The period over which the injection occurred.

The site closure report will be submitted to the permitting agency and maintained by the owner or operator for a period of 10 years following site closure. Additionally, the owner or operator will maintain the records collected during the post-injection period for a period of 10 years after which these records will be delivered to the UIC Program Director.

## Quality Assurance and Surveillance Plan (QASP)

The Quality Assurance and Surveillance Plan is presented in the Appendix of the Testing and Monitoring Plan.