5.0 Testing and Monitoring Plan

This chapter describes the testing and monitoring the Alliance will undertake in accordance with 40 CFR 146.89, 146.90, and 146.91 to verify that the Morgan County CO_2 storage site is operating as permitted and is not endangering any USDWs. The Testing and Monitoring Plan described in this chapter is part of the UIC Class VI Permit Application submitted by the Alliance for construction and operation of CO_2 injection wells in Morgan County, Illinois.

This plan describes components of the Monitoring, Verification, and Accounting (MVA) program, which includes hydraulic, geophysical, and geochemical components for characterizing the complex fate and transport processes associated with CO_2 injection. The injection and monitoring wells within the target injection zone will be monitored for the duration of the project to characterize pressure and CO_2 transport response and guide operational and regulatory decision-making. These monitoring results, along with those from a deep early-detection monitoring well installed to just above the primary confining zone, will likely provide the first indication of any unanticipated containment loss. If a containment loss is detected, a modeling evaluation of any observed CO^2 migration above the confining zone would be used to assess the magnitude of containment loss and make bounding predictions regarding the expected impacts on shallower intervals, and ultimately, the potential for adverse impacts on USDW aquifers and other ecological impacts. Comparison of observed and simulated arrival responses at the early-detection well and shallower monitoring locations would continue throughout the life of the project and would be used to calibrate and verify the model, and improve its predictive capability for assessing the long-term environmental impacts of any observed loss of CO_2 containment.

In addition to direct monitoring, the MVA program will also adopt indirect monitoring methodologies for assessing CO_2 fate and transport within the injection zone. Methods will be evaluated and screened throughout the design and initial injection testing phase of the project to identify the most promising monitoring technologies under site-specific conditions. Based on the results of this evaluation, one or more indirect monitoring methods will be selected for implementation. Screening criteria will include 1) data quality; 2) implementability; 3) cost effectiveness, including both capital cost and long-term monitoring costs; and 4) landowner/public impacts (e.g., noise, traffic congestion, property access). An example of factors affecting this screening process is provided by consideration of the electrical resistivity tomography (ERT) technology. Although implementation of ERT will require nonstandard well designs and construction (i.e., the use of non-conductive casing) and thus involve increased capital cost, once it is in place the long-term monitoring cost will be low and the technology will provide continuous real-time results. Two- and three-dimensional seismic methods, which have proved to be an effective monitoring approach at other GS sites, provide another example of screening process considerations. An initial 2D seismic-reflection survey was conducted at the Morgan County site, but the quality of the data obtained from the survey was poor and thus the efficacy of seismic methods for characterization and plume tracking under site conditions was called into question. A reinterpretation of site 2D seismic-reflection data that incorporates recently obtained information on local geologic structure is under way. These results will be used to further assess the effectiveness of seismic methods under site-specific conditions and determine whether they represent a viable monitoring technology for the Morgan County site.

Direct monitoring of the lowermost USDW aquifer is required by the EPA's UIC Class VI GS Rule (75 FR 77230) and is a primary objective of this monitoring program. Additional surface or near-surface-monitoring approaches that may be implemented include shallow groundwater monitoring, soil-gas monitoring, atmospheric monitoring, and ecological monitoring. If implemented, the associated networks of shallow monitoring locations will be designed to provide 1) a thorough assessment of baseline conditions at the site and 2) spatially distributed monitoring locations that can be routinely sampled throughout the life of the project. The need for surface-monitoring approaches will be continually evaluated throughout the design and operational phases of the project, and may be discontinued if deemed unnecessary for the MVA assessment. Given our current conceptual understanding of the subsurface environment, early and appreciable impacts on near-surface environments are not expected, and thus extensive networks of USDW aquifer, surface-water, soil-gas, and atmospheric monitoring stations are not warranted. Any implemented surface-monitoring networks would be optimized to provide good areal coverage while also focusing on areas of higher leak potential (e.g., near the injection wells or other abandoned well locations). If deep early-detection monitoring locations indicate that a primary confining zone containment loss has occurred, a comprehensive near-surface-monitoring program could be implemented to fully assess environmental impacts relative to baseline conditions.

Section 5.1 of this chapter describes the design of the monitoring network, Section 5.2 describes the planned monitoring activities, including the frequencies with which they will be conducted, and Section 5.3 discusses how the monitoring activities described in Section 5.2 will be used to verify effective sequestration and account for all injected CO_2 mass. A brief description of project schedule is presented in Section 5.4 and the data management plan for organizing and storing information collected or generated by the monitoring activities is described in Section 5.5. Section 5.6 describes the criteria for periodic review and updating of this Testing and Monitoring Plan. Finally, Section 5.7 describes the quality assurance program under which the planned testing and monitoring activities will be performed. References for sources cited in the chapter are listed in Section 5.8.

5.1 Conceptual Monitoring Network Design

The monitoring network design was developed based on the current conceptual understanding of the Morgan County CO_2 storage site and was used to guide development of the testing and monitoring approaches described in Section 5.2. Note that this conceptual design will be modified as required based on any additional site-specific characterization data collected at the Morgan County CO_2 storage site, and any significant changes in our conceptual understanding of the site may result in changes to the Testing and Monitoring Plan. The technical approaches described in Section 5.2 should be considered working versions that over time will be updated and modified as required in response to changes in the site conceptual model and/or operational parameters.

Previous CO_2 GS demonstration projects have used a variety of techniques to monitor the injection and migration of CO_2 within the injection zone, and to evaluate the potential for migration of CO_2 through confining zones and to near-surface environments. Techniques used at other sites include both direct (e.g., pressure and aqueous monitoring within and above the injection zone) and indirect measurements (e.g., surface/downhole/cross-borehole geophysical measurements, land surface elevation mapping). During development of the monitoring systems design for the Morgan County storage site, experience gained at other sites was considered, as were previously developed GS guidance documents. Guidance documents that were consulted during development of the project Testing and Monitoring Plan include those published by the EPA (2011) and DOE/National Energy Technology Laboratory (DOE/NETL 2009). The monitoring systems that will be considered for deployment at the Morgan County CO_2 storage site to meet MVA requirements are discussed in detail in Section 5.2.

5.1.1 Environmental Monitoring Considerations

Potential release pathways and the possibility for associated environmental impacts were both considered during development of the monitoring strategy and inform the design basis for the various monitoring system components.

5.1.1.1 Release Pathways

Potential pathways for release of CO_2 from the targeted injection zone include diffuse release across the confining zone; concentrated release through natural faults, fractures, and bedding planes; and release along existing active or abandoned well bores. A detailed discussion of these potential release pathways is provided in Chapter 2.0 (see summary in Section 2.9) and Chapter 3.0 (Section 3.2). A site-specific assessment of potential release pathways identified the following:

- Diffuse release: previous studies and site-specific information indicate a low likelihood of diffuse release from permeation of the primary confining zone.
- Geologic features: A 2D seismic-reflection survey conducted at the Morgan County CO_2 storage site provided no clear indication of major tectonic structures or faults. However, the quality of the seismic survey data was insufficient to rule out the presence of small-scale faults/fracture zones. Morgan County is not located in a seismically active part of the state and has no geologic faults or fracture zones shown on the structural geology map published by the ISGS. In addition, wireline logs obtained from the stratigraphic well showed no indication of significant fracturing within the injection or primary confining zones. A reinterpretation of the 2D seismic-reflection data that incorporates recently obtained information about the local geologic structure is underway. These results will be used to further assess the effectiveness of seismic methods under site-specific conditions and to better understand the presence/absence of localized geologic features of concern. These results will be provided to the EPA.
- Artificial penetrations: The closest preexisting, non-project-related well that penetrates the primary confining zone, and thus provides a potential preferential pathway between the injection zone and shallow USDW aquifers, is located at the Waverly Storage Field approximately 16 mi south-southeast of the Morgan County CO_2 storage site. This location is well outside the project AoR. Within the AoR, three abandoned oil and gas wells were identified that extend to depths of approximately 1,000 to 1,500 ft bgs. These wells do not penetrate the primary or secondary confining zones, but they do represent potential candidate locations for soil-gas monitoring because of their potential for providing a preferential pathway for CO_2 gas transport through shallow shale units (e.g., Maquoketa and New Albany shales). No wells were identified that require corrective action.

5.1.1.2 Potential Environmental Indicators

Migration of injected CO_2 from the injection zone into overlying formations via available (but currently unknown) pathways could result in the following CO_2 phases in overlying aquifers: 1) separate liquid phase CO_2, 2) miscible CO_2 partitioning into existing aqueous phase, and 3) CO_2 gas (i.e., at less than 1,070 psi). CO_2 injection might also result in displacement of hypersaline water from the injection zone that could adversely affect water quality in overlying permeable intervals. If release pathways are present and injected CO_2 migrates into an overlying aquifer, it would introduce increased carbonate concentration, cause some acidity (from the carbonate and/or minor components such as sulfur dioxide [SO_2]), and potentially introduce other trace metals present in the injected CO_2. Consequently, the monitoring program is designed to monitor the CO_2 injection process over the range of relevant locations, phases, and potential secondary chemical by-products that could result from CO_2 migration.

Some typical physical and geochemical indicators that can be used to monitoring CO_2 injection processes occurring within the injection zone include 1) change in the pressure gradients and flow patterns within the injection zone due to the pressurized injection of CO_2, 2) changes in injections zone permeability over time associated with precipitate formation, 3) long-term lateral movement of the CO_2 plume within the injection zone, and 3) minute land surface elevation changes (i.e., upward doming) above the injected CO_2 plume. In the event of a containment loss, partitioning of CO_2 (in and of itself, excluding trace co-contaminants) into overlying permeable zones will have generally minor water-quality impacts, because the Ironton Sandstone and Potosi Dolomite (permeable intervals above the primary confining zone) already have generally poor water quality. However, the potential does exist for decreases in water quality, including 1) increased TDS; 2) increased carbonate, sodium, and chloride concentration; 3) increased trace metals concentrations; and 4) decreased pH. Given that the Ironton Sandstone unit directly overlying the primary confining zone is not potable, these initial water-quality impacts are inconsequential. Secondary (i.e., longer-term) impacts of CO_2/hypersaline fluids migration into an overlying aquifer include 1) carbonate precipitation (calcite, dolomite, and dawsonite), 2) metals mobilization caused by the CO_2 acidification and dissolution of aquifer mineral phases, and 3) changes in aquifer redox state (from reduced to oxic) resulting from coinjecting of dissolved oxygen along with the CO_2, and the associated potential for mobilization of precipitated/reduced metals. Precipitation of carbonates may also decrease permeability in overlying formations, but this is unlikely to be significant (or may be highly localized) because any containment loss is likely to be small in volume relative to the water in an overlying aquifer.

The expected CO_2 injection stream composition is presented in Chapter 4.0, Table 4.1. The CO_2 source is expected to be at least 97 percent pure with the balance of the stream including oxygen, water vapor, and other trace constituents. The injection stream will be continuously monitored at the injection wells for verification and reporting. Although the major component being injected at the Morgan County storage site is CO_2, other minor components may also have some influence on the groundwater geochemistry (i.e., precipitation reactions or may simply be useful as tracers of the injected CO_2.

Experiments designed to assess the relative importance of the above water-quality impacts under site-specific conditions have been initiated and are planned to continue throughout the design phase of the project. However, preliminary bench-scale results, and a detailed discussion of the experimental plan, are beyond the scope of this UIC permit application and will not be included here.

5.1.2 Numerical Modeling

Numerical modeling of the CO_2 injection process will follow the approach described in the EPA guidance for GS modeling (EPA 2011, Section 3.2). Numerical modeling will progress through the following steps: 1) develop site conceptual model, 2) determine the physical processes to be included in the model, 3) implement the numerical model, and 4) execute the simulations. Initial development of the site conceptual model (see Section 3.1.3) is based on available data from the deep Morgan County stratigraphic well installed under this project, along with data from the literature and other wells located in the surrounding area. As additional characterization data are collected, the site conceptual model will be revised and the modeling steps described above will be updated to incorporate new knowledge about the site. The numerical simulations will include multi-fluid and density-dependent flow and transport of dissolved solutes (e.g., water, $scCO_2$, gas-phase CO_2, dissolved CO_2, co-injected tracers, brine), and thermal energy transport where appropriate. The numerical simulator STOMP-CO2 developed by Pacific Northwest National Laboratory (PNNL) will be the primary simulator for modeling multiphase flow conditions (White et al. 2012; White and Oostrom 2006; White and McGrail 2005).

In addition to the reservoir modeling described in Chapter 3.0 that is being performed to satisfy requirements of the UIC permit application, an additional modeling effort focused on evaluation of environmental release scenarios, may be performed. This environmental release model would be developed to support design, operation, and maintenance of the MVA program if significant technical and cost benefit, and/or improved public acceptance would be realized. Results from the reservoir modeling effort (Chapter 3.0) will be used to estimate the spatial extent and distribution of the CO_2 injection volume and the pressure buildup distribution within the reservoir under various operational scenarios, which in turn will be used to guide monitoring systems design (e.g., monitoring and geophysical well spacings, geophysical measurement configurations). The reservoir model will also be used to generate boundary conditions for the lower boundary of the environmental release model. This flow and transport model, which will encompass the overburden materials between the injection zone and ground surface, will be used to predict vertical migration of CO_2 and/or brine under various containment loss scenarios and to assess the potential for impacts on shallow USDW aquifers. Numerical models will be maintained throughout the life of the project and will be routinely updated to support reevaluation of the AoR delineation and any required amendments to this Testing and Monitoring Plan.

5.1.3 Defining the Area of Review

According to EPA guidance (EPA 2011), an AoR is “the region surrounding the GS project where USDWs may be endangered by the injection activity.” A detailed discussion of the AoR determination for the Morgan County CO_2 storage site is provided in Chapter 3.0. The resulting AoR is shown in Figure 5.1 as the 22-year CO_2 plume (defined as the area encompassing 99% of the CO_2 mass). The 22-year contour represents the predicted maximum lateral extent of the injected CO_2 volume during the injection and post-closure monitoring periods.

5.1.4 Monitoring Well Network

This section describes the conceptual monitoring well network that will be used to support collection of the various characterization and monitoring measurements needed to track development of the CO_2 plume within the injection zone and identify/quantify any potential release of CO_2 from containment that may occur. The monitoring well locations, shown in the figures below, are representative but approximate and subject to landowner approval. A detailed description of the various components of this monitoring network is provided in Section 5.2. The conceptual monitoring network design (Figure 5.1 and Figure 5.2) is based on the Alliance’s current understanding of the site conceptual model and predictive simulations of injected CO_2 fate and transport. A detailed description of the site conceptual model and AoR determination is provided in Chapters 2.0 and 3.0 of this supporting documentation, respectively. Chapter 4.0 of this supporting documentation provides a detailed description of operational parameters (e.g., injection rates, volumes, scheduling, etc.) and well construction details.

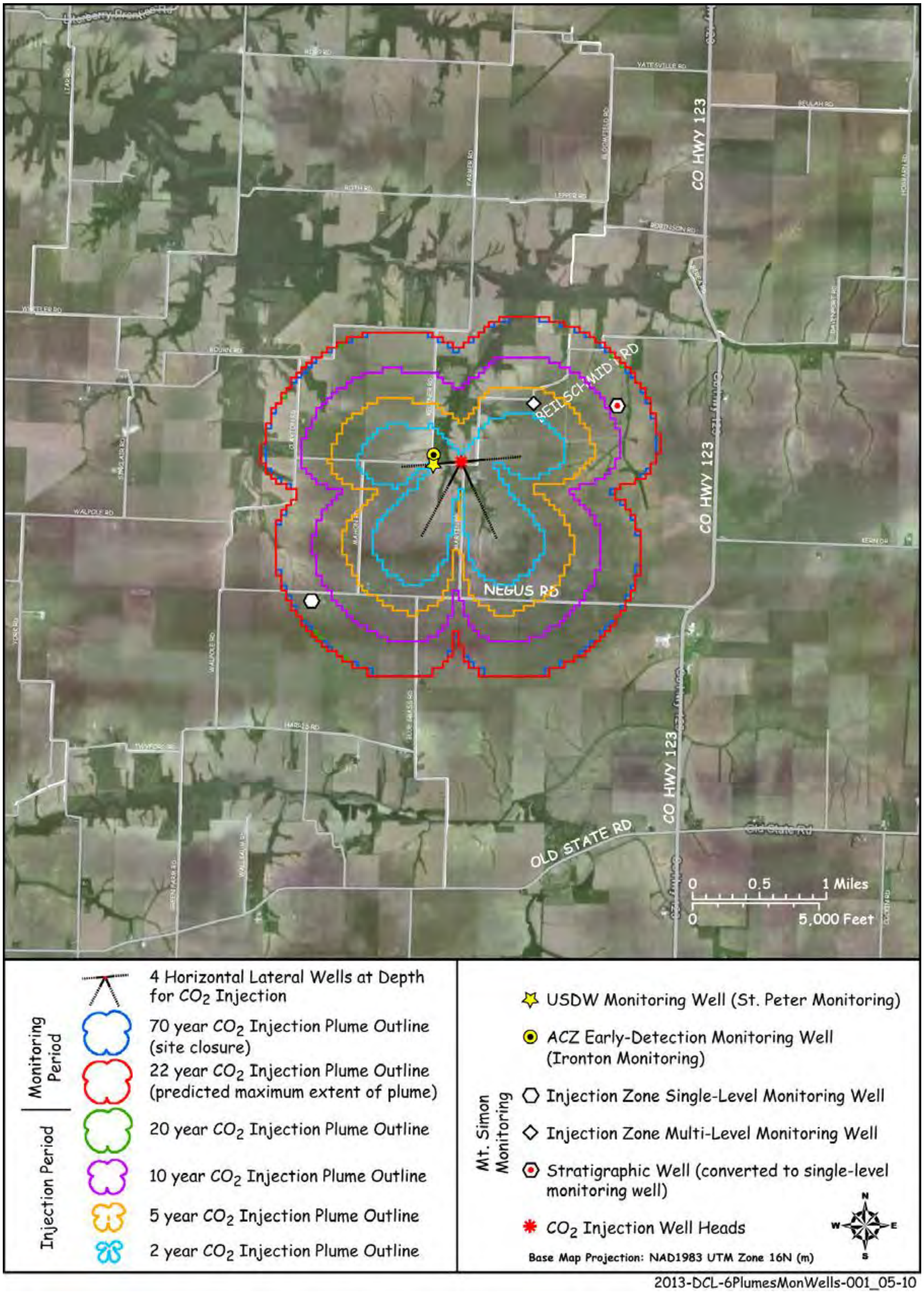

Figure 5.1. Conceptual Injection and Monitoring Well Network Layout with Predicted CO_2 Lateral Extent over Time

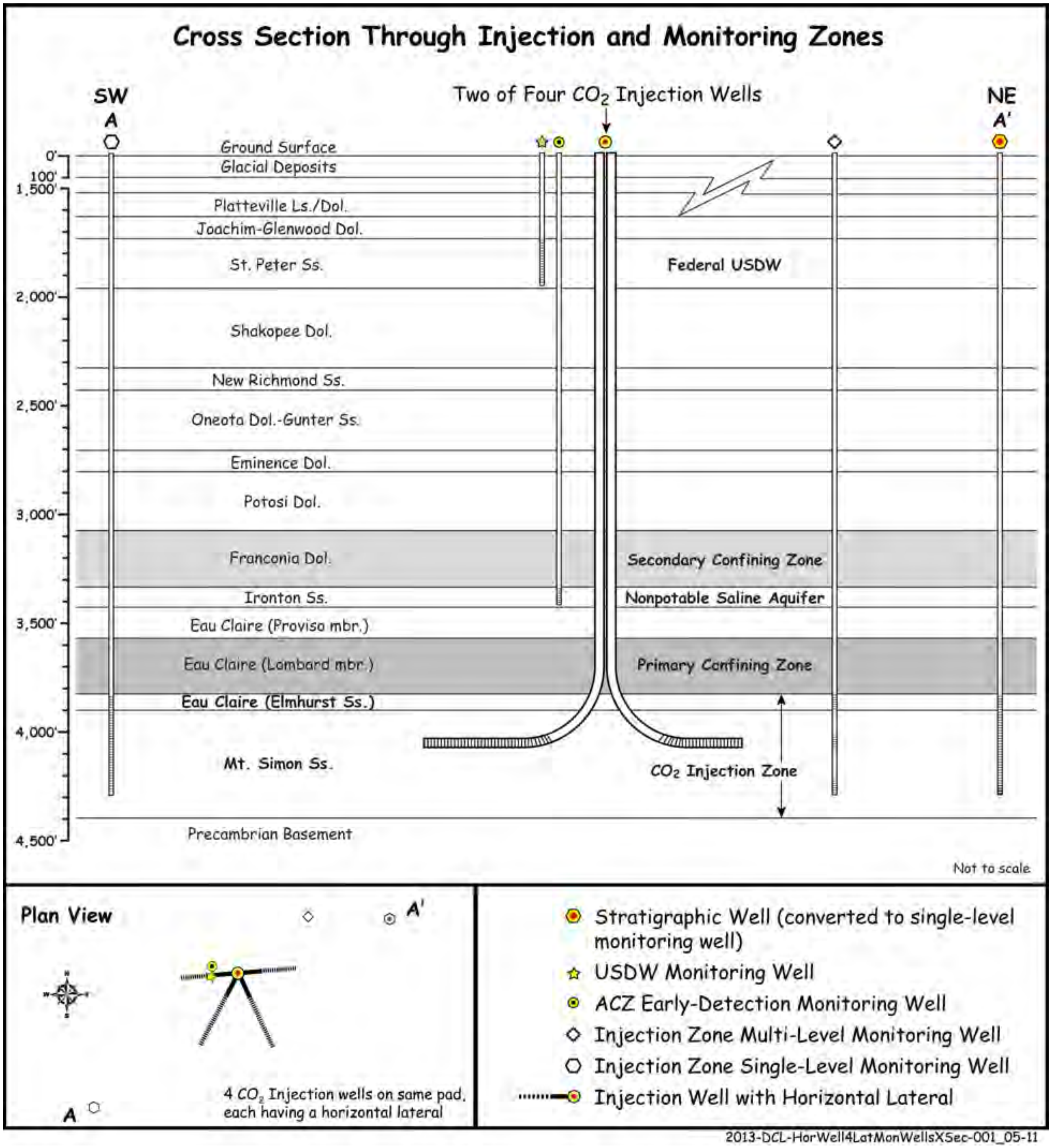

Figure 5.2. Cross-Sectional View of Injection and Monitoring Well Network

The selected monitoring network layout and well designs have been informed by site-specific characterization data collected from the stratigraphic well at the Morgan County CO_2 storage site, and consider structural dip, expected ambient flow conditions, and the potential for heterogeneities or horizontal/vertical anisotropy within the injection zone and overburden materials. The final design may be modified based on ongoing 3D reactive transport modeling that incorporates 1) additional site-specific characterization measurements from the stratigraphic well (e.g., additional hydraulic testing, vertical seismic profiling, etc.), 2) additional characterization data collected during injection well installation, and

3) practical constraints such as land access and the desire to minimize landowner impact. As such, well locations shown in Figure 5.1 could change but only to the extent that they retain their monitoring intent described in the following sections . The location of any wells required to support implementation of indirect monitoring approaches will be determined once candidate technologies have been evaluated and the selection process completed.

5.1.4.1 Injection Zone Monitoring Wells

As indicated in Figure 5.1, well installations within the target injection zone (Mount Simon Sandstone and Elmhurst Sandstone member of the Eau Claire Formation) include four horizontal injection wells and three monitoring wells. Two of the injection zone monitoring wells will be single-level completions located within the predicted lateral extent of the 5- to 25-year CO_2 plumes. The monitoring network will also include one injection zone monitoring well located within the predicted lateral extent of the 2- to 5-year CO_2 plume and ideally within the predicted lateral extent of the 2- to 3-year CO_2 plume. This well may be completed as a multi-level installation, using either 1) a dedicated multi-level monitoring system (e.g., Westbay System) within a single casing string completed with multiple sampling intervals, or 2) a multi-level piezometer installation. Multi-level monitoring is useful for assessing vertical anisotropy during site-specific characterization of the injection zone and for monitoring the vertical distribution of CO_2 within the injection zone during injection operations. All wells extending into the injection zone will be designed and installed to maintain an effective, long-term seal through the overlying primary confining zone. Injection well completion and construction details are discussed in Chapter 4.0 of this supporting documentation.

5.1.4.2 Monitoring Well Installed Immediately Above the Primary Confining Zone

A single above confining zone (ACZ) early-detection monitoring well will be installed within the first permeable interval above the primary confining zone, which most likely will be the Ironton Sandstone unit. The well will be located in the vicinity of the injection well drill pad, within the region of highest pressure buildup. This well might also be used for vertical seismic profiling (VSP) and/or microseismic (MS) monitoring. This multiuse approach will only be implemented if it can be shown that aqueous monitoring or other monitoring related activities will not interfere with the continuous microseismic monitoring at these locations. Construction detail for this well installation is still under development and thus not included in this supporting documentation.

5.1.4.3 Monitoring Well Installed in Lowermost USDW

One of the primary objectives of the monitoring program is to adequately characterize baseline water quality within the lowermost USDW aquifer at the site, including the degree of temporal variability in groundwater quality. These baseline data will be the basis of comparison for measurements collected during operational phases of the project and will be used to assess whether any adverse impacts are occurring as a direct result of CO_2 injection operations. As discussed in Chapter 2.0 (Section 2.6), the lowermost USDW aquifer at the Morgan County site, based on water-quality considerations, resides within the St. Peter Sandstone. A single regulatory compliance well will be installed within this lowermost USDW aquifer, proximal to the ACZ early-detection monitoring well and within the region of highest pressure buildup (Figure 5.1). Construction detail for this well installation is still under development and thus not included in this supporting documentation.

5.2 Monitoring Activities

The primary objective of the MVA program is to track the lateral extent of CO_2 within the target reservoir and determine whether it is effectively contained within the injection zone. Other monitoring objectives include characterizing any geochemical or geomechanical changes that occur within the injection zone and overlying confining zone and monitoring any change in land surface elevation associated with CO_2 injection. If the overlying confining zone (i.e., upper members of the Eau Clair Formation) is found to not act as a competent caprock material, another primary objective of the monitoring program will be to quantify the magnitude of the containment loss and assess the potential for it to adversely affect water quality in USDW aquifers.

5.2.1 Monitoring Program Summary

This section provides a brief overview of the MVA program. Details for the various components of this monitoring program are discussed in the sections below.

5.2.1.1 General Approach

The proposed monitoring program includes hydraulic, geophysical, and geochemical components for characterizing the complex fate and transport processes of a CO_2 injection. Injection into the Mount Simon Sandstone, which contains hypersaline waters at pressures greater than the critical pressure for maintaining CO_2 in the supercritical state, will effectively maintain the supercritical fluid conditions. Supercritical CO_2 is considered to be immiscible with water due to its hydrophobic nature, although some CO_2 will dissolve in water along the interface between the $scCO_2$ plume and the surrounding reservoir fluids. If any loss of containment from the confining zone occurs and the injected CO_2 is transported to shallower depths, where the hydrostatic pressure decreases below the critical value (1,070 psi at 31°C), the $scCO_2$ will change to the gas phase. Gas-phase CO_2 will partially dissolve into the water solution, and the remaining portion will exist as entrapped gas. Because of these multiple liquid/gas phases, leak detection above the primary confining zone involves monitoring changes in the aqueous phase (predominantly pH, carbonate, and trace metal changes in water), the $scCO_2$ phase, and the gas phase (CO_2 and other gases).

Carbon dioxide and other liquids/gases can potentially migrate through the primary confining zone and overlying formations by 1) slow permeation through porous intervals, 2) increased transport through existing or induced fractures in the formations, and 3) leakage along the injection well or other abandoned wells in the vicinity. Given the complexity of this system, a comprehensive monitoring program is needed to assess all potential migration pathways. Based on an evaluation of both regional and site-specific information (see Sections 2.1.2.3 and 2.1.3.2), migration of CO_2 and brine through the overlying primary confining zone is thought to be unlikely. In addition, simulation results from a previous study indicated <1 m of CO_2 transport into a shale after 100 years of CO_2 injection (Person et al. 2010). However, the integrity of this confining zone material will remain uncertain until site-specific characterization is completed. Natural and pressure-induced fractures in the Eau Claire Formation and/or limited thickness of the confining intervals could increase the likelihood of containment loss. There are no preexisting (i.e., not project-related) deep boreholes that penetrate the Mount Simon Sandstone in the immediate vicinity of the proposed injection well locations; the closest well is approximately 16 mi away, so preferential vertical migration related to project-installed injection and monitoring wells will be one of the most important pathways to monitor.

As discussed in the introduction to this chapter, the monitoring program will adopt 1) both direct and indirect monitoring methodologies for assessing CO_2 fate and transport within the injection zone, 2) early-detection monitoring immediately above the primary confining zone, 3) direct monitoring of the lowermost USDW aquifer, and 4) other near-surface-monitoring technologies (as needed to meet project or regulatory requirements), including shallow groundwater, soil-gas, atmospheric, and ecological monitoring. A summary of testing and monitoring activities is provided in Table 5.1 and Table 5.2. Table 5.1 specifies technologies that are a GS Rule requirement and/or considered by the Alliance to be critical monitoring activities. Table 5.2 includes additional indirect geophysical monitoring techniques and surface leak-detection monitoring methodologies that will be evaluated by the project and may or may not be implemented in the monitoring program. Methods will be evaluated and screened throughout the design and initial injection testing phase of the project to identify the most promising monitoring technologies under site-specific conditions. At a minimum, at least one indirect geophysical monitoring technique will be carried forward through the operational phases of the project.

Planned monitoring frequencies for each of these monitoring methodologies throughout the life of the project (i.e., for those selected for implementation) are provided in Table 5.3. As indicated, there will be five general phases of aqueous monitoring: baseline monitoring, DOE active injection monitoring, commercial injection monitoring, and commercial post-injection monitoring.

5.2.1.2 Monitoring Considerations and Supporting Studies

Injection of CO_2 above supercritical pressure (1,070 psi) into the targeted injection zone will result in both lateral advection and upward migration of the CO_2 plume. Upward migration results from buoyancy effects associated with $scCO_2$, which has a significantly lower density (0.47 to 0.83 g/cm^3 depending on pressure and temperature conditions) than the reservoir fluids. The $scCO_2$ will have limited solubility into water at the advection front, so near the injection well it should displace essentially all water and “dry out” the pore space. Emplacement of the CO_2 plume results in multiple CO_2 phases (liquid, gas, solid) that include 1) $scCO_2$ liquid (hydrophobic, will incorporate and mobilize organic phases, if present), 2) predominantly aqueous phase that incorporates some carbonate, 3) carbonate precipitates, and 4) CO_2 gas phase (in formations where pressure is <1,070 psi) and other minor gas phases present (i.e., oxygen, nitrogen, argon).

The complex geochemical changes that can occur within the injection zone have been partially characterized for the Mount Simon Sandstone in previous laboratory studies, but not under site-specific conditions or in other potential aquifer zones present in the overburden materials. To better understand these processes, a series of laboratory experiments will be performed using site-specific injection zone cores and representative $scCO_2$ fluids to evaluate geochemical, microbial, and physical changes that may occur within the injection zone as a result of CO_2 storage. Due to the spatial and temporal evolution of potential geochemical changes, trace metals in the CO_2 injection stream and those mobilized from aquifer solids can be of concern, so they are included in this monitoring plan.

Table 5.1. Summary of Planned Testing and Monitoring Activities

Monitoring Category	Monitoring Method	Description
CO_2 Injection Stream Monitoring	Sampling and analysis	Monitoring of the chemical and physical characteristics of the CO_2 injection stream.
CO_2 Injection Process Monitoring	Continuous monitoring of injection process	Continuous monitoring of injection mass flow rate, pressure, and temperature, annular pressure, and fluid volume.
Well Mechanical Integrity Testing (one or more methods selected for implementation)	Oxygen-activation tracer Logging	Geophysical tracer logging technique that uses a pulsed-neutron tool to quantify flow of water in or around a borehole.
	Radioactive tracer logging	A radioactive tracer survey (RTS) that uses a wireline tool to detect the location(s) (e.g., perforations, leaks through casing) where the injected tracer exits from or migrates along the well bore.
	Temperature logging	Identifies injection-related fluids that have moved along channels adjacent to the well bore.
	Pressure fall-off testing	A pressure transient test that involves shutting in the injection well after a period of prolonged injection and measuring pressure decline.
Corrosion Monitoring of Well Materials	Corrosion coupon method	Coupons consisting of the same material as the casing and tubing will be placed in the CO_2 injection line and periodically removed for corrosion inspection.
	Wireline monitoring of casing and tubing	Ultrasonic, electromagnetic, and/or mechanical logging tools used to evaluate the condition of the well casing and the CO_2 injection tubing.
	Cement-bond logging	Verifies the integrity of the cement bond to the well casing and formation in the presence of CO_2 and injection zone brine.
Groundwater Quality and Geochemistry Monitoring	Early leak-detection Monitoring	Fluid sampling and field parameter monitoring for early leak detection within the deepest permeable zone (e.g., Ironton Sandstone) located above the primary confining zone.
	USDW aquifer monitoring	Fluid sampling and field parameter monitoring for leak detection and assessment of water-quality impacts to the lowermost USDW aquifer (St. Peter Sandstone).
Injection Zone Monitoring	Single-level monitoring wells	Fluid sampling and field parameter monitoring for assessment of CO_2 fate and transport and leak detection.
	Multi-level monitoring wells	Fluid sampling and field parameter monitoring for assessment of CO_2 fate and transport and leak detection, injection zone heterogeneity, and anisotropy.
Indirect Geophysical Monitoring Techniques	Multiple technologies tested for efficacy and cost effectiveness, one or more selected for deployment	See Table 5.2 for details on technologies under consideration.

Table 5.2. Additional Monitoring Activities Under Consideration

Monitoring Category	Monitoring Method	Description
Indirect Geophysical Monitoring Techniques (surface)	Integrated deformation monitoring	Uses a combination of tools (e.g., satellite Interferometric Synthetic Aperture Radar, tiltmeter, and global positioning system) to measure the magnitude and geographical extent of deformation associated with CO_2 injection.
	3D multi-component surface seismic monitoring	Provides the basic framework for building the conceptual reservoir model and tracking subsurface distribution and migration of CO_2.
	Magnetotelluric (MT) sounding	Measures changes in electromagnetic field resulting from variations in electrical properties of CO_2 and formation fluids.
	Time-lapse gravity	Used to measure variations in density in the subsurface due to CO_2 injection.
Indirect Geophysical Monitoring Techniques (downhole)	Vertical seismic profile(ing) (VSP)	Downhole seismic survey performed in a well bore with multi-component processing. Provides high-resolution seismic data for identifying distribution and migration of CO_2. Can be used to calibrate 2D and 3D seismic-reflection surveys.
	Cross-well seismic imaging	Eliminates near-surface noise and provides high-resolution imaging of plume migration by placing both seismic sources and receivers in well bores.
	Passive seismic monitoring (microseismicity)	Observed microseismic activity induced by CO_2 injection. Provides accurate location and focal mechanism of seismic events allowing real-time monitoring of reservoir and caprock integrity during injection and addresses induced seismicity concerns.
	Real-time ERT	Permanent downhole installation that measures the resistivity changes caused by CO_2 injection and migration in geological reservoirs.
	Real-time distributed temperature sensing (DTS)	Fiber-optic sensor cables permanently installed behind the well casing of injection and/or monitoring wells to measure real-time temperatures with high temporal and spatial resolution.
Indirect Geophysical Monitoring Techniques (wireline logging)	Pulsed-neutron capture	Detects and helps quantify CO_2 saturations.
	Sonic (acoustic) logging	Determines location and azimuth of strike of natural and induced fractures, both in the reservoir and caprock, and changes in acoustic velocity due to changes in the CO_2 saturation.
	Gamma-ray logging	Detects changes in uranium, thorium, and radioactive potassium that can be related to rock properties and/or fluid movement behind the casing or in the reservoir.

Table 5.2. (contd)

Monitoring Category	Monitoring Method	Description
Surficial Aquifer Monitoring	Groundwater monitoring in local landowner wells	Fluid sampling and field parameter monitoring for assessment of surficial aquifer water quality
Soil-Gas Monitoring	Shallow soil-gas monitoring	Soil-gas collector chambers and/or standard soil-gas sampling points will be used to monitor the concentration of CO_2 and other noncondensable gases (e.g., N, O) in shallow soils.
	Tracer and isotopic signature monitoring	Soil-gas sampling for carbon and oxygen isotopic signature and/or tracer compounds injected along with the CO_2 to improve leak-detection capabilities.
Atmospheric Monitoring	Fixed-point CO_2 and tracer monitoring	Continuous CO_2 measurement at fixed location, with routine sampling for CO_2 and tracer gas concentrations. Tracer gases will provide improved leak-detection capability.
	Mobile CO_2 and tracer monitoring	Periodic measurements of CO_2 and tracer gas using a mobile, real-time instrument, near injection/monitoring wells and along transects spanning the AoR.
	Weather Station (at two fixed-point locations)	Measurements of air temperature, relative humidity, precipitation, barometric pressure, solar radiation, soil moisture, and soil temperature.
Ecological Monitoring	Baseline ecological survey	Pre-operational monitoring and characterization to establish baseline conditions for comparisons with operational monitoring results.
	Continuous surface-water monitoring	Continuous measurement of pH, temperature, electrical conductivity, and dissolved oxygen content of nearby surface waters.
	Remotely sensed data for vegetation condition assessment	Satellite imagery used to characterize vegetation conditions and detect subtle changes in normal plant growth processes and relative vegetation stress.

Table 5.3. Monitoring Frequencies by Method and Project Phase for both Planned and Considered Monitoring Activities

Monitoring Category	Monitoring Method	Baseline 3 yr	DOE Active Injection (startup) ~3 yr	DOE Active Injection ~2 yr	Commercial Injection ~15 yr	Post Injection 50 yr
Monitoring Plan Update	NA	As required	As Required	As Required	As Required	NA
CO_2 Injection Stream Monitoring	Grab sampling and analysis	Up to 6 events during commissioning	Quarterly	Quarterly	Quarterly	NA
CO_2 Injection Process Monitoring	Continuous monitoring of injection process (injection rate, pressure, and temperature; annulus pressure and volume)	NA	Continuous	Continuous	Continuous	NA
Well Mechanical Integrity Testing	Oxygen activation, radioactive tracer, and/or temperature logging	Once after well completion	Annual	Annual	Annual	NA (wells plugged)
	Injection well pressure fall-off testing	NA	Every 5 yr	Every 5 yr	Every 5 yr	NA
Corrosion Monitoring of Well Materials	Corrosion coupon monitoring	NA	Quarterly	Quarterly	Quarterly	NA
	Wireline monitoring of casing and/or tubing corrosion and cement	Once after well completion	During well workovers	During well workovers	During well workovers	NA
Groundwater Quality and Geochemistry Monitoring	Early leak-detection monitoring in above confinement zone monitoring wells	3 events	Quarterly	Semi-Annual	Annual	Every 5 yr
	USDW aquifer monitoring (continuous parameter monitoring, aqueous sample collection as indicated)	1 yr continuous monitoring, 3 sampling events	Quarterly	Annual	Annual	Every 5 yr
Injection Zone Monitoring	Single-level monitoring wells	3 events	Annual	Annual	Every 2 yr	Every 5 yr
	Multi-level monitoring wells	3 events	Quarterly	Semi-Annual	Annual	Every 5 yr
Indirect Geophysical Monitoring Techniques (surface)	Integrated deformation monitoring	2 yr min	Continuous	Continuous	Continuous	Continuous
	3D multi-component surface seismic monitoring	Once	NA	Once	Every 5 yr	NA
	Magnetotelluric (MT) sounding	3 events	Once	Once	Every 5 yr	Every 5 yr
	Time-lapse gravity	Once	Semi-Annual	Semi-Annual	Semi-Annual	Every 5 yr

Table 5.3. (contd)

Monitoring Category	Monitoring Method	Baseline 3 yr	DOE Active Injection (startup) ~3 yr	DOE Active Injection ~2 yr	Commercial Injection ~15 yr	Post Injection 50 yr
Indirect Geophysical Monitoring Techniques (downhole)	Vertical seismic profile(ing) (VSP)	Once	Once	Once	Every 5 yr	Every 10 yr
	Cross-well seismic imaging	Once	Once	Once	Every 5 yr	Every 10 yr
	Passive seismic monitoring (microseismicity)	1 yr min	Continuous	Continuous	Continuous	Continuous
	ERT	1 yr min	Continuous	Continuous	Continuous	Continuous
	Real-time distributed temperature sensing (DTS)	1 yr min	Continuous	Continuous	Continuous	Continuous
Indirect Geophysical Monitoring Techniques (wireline logging)	Pulsed-neutron capture, sonic (acoustic) logging, and gamma-ray logging	Once after well completion	Annual	Annual	Annual	NA
Surficial Aquifer Monitoring	Continuous parameter monitoring in 1 project-installed well, aqueous sample collection as indicated	1 yr continuous monitoring, 3 sampling events	Quarterly	Annual	Annual	Every 5 yr
Soil-Gas Monitoring	Samples collected for CO_2, other noncondensable gases and tracers	4 events	Quarterly	Annual	Annual to every 5 yr	Every 5 yr
Atmospheric Monitoring	Continuous CO_2 monitoring, tracer sampling and analysis	1-yr baseline monitoring	Quarterly	Semi-Annual	Annual to every 5 yr	Every 5 yr
Ecological Monitoring	Eco survey for baseline, continuous surface-water monitoring, remote sensing of vegetation conditions as indicated	Eco survey once, 1 yr baseline monitoring,	Annual	Annual	Annual to every 5 yr	Every 5 yr

To better understand the impacts that increased CO_2 concentrations might have on the USDW aquifer, and the resulting acidification that mineral-phase dissolution (and possible change in redox geochemistry) has on the mobilization of trace metals, a series of bench-scale laboratory studies will be performed using site-specific USDW aquifer sediments. These studies will evaluate the changes in aquifer geochemistry and water quality that would be expected to occur at various levels of CO_2 intrusion.

5.2.1.3 Tracer and Isotopic Monitoring

Previous studies have used two different classes of tracers (hydrophobic or "water-fearing" and hydrophilic or "water-loving") that have greater sensitivity and significantly lower detection limits compared with changes in major ion geochemistry or isotopic tracers. These compounds are highly resistant to natural breakdown, so they are persistent in the environment, even under extreme temperature and pressure. One class of hydrophobic tracers, which tend to stay in the $scCO_2$ phase or partition into oil or the gaseous phase, is generally referred to as perfluorinated tracers (PFTs). Three PFTs commonly used in groundwater and reservoir investigations include perfluoro-1,2-dimethylcyclohexane (PDCH), perfluorotrimethyl-cyclohexane (PTCH), and perfluorodimethylcyclobutane (PDCB). Each of these tracers has been previously injected with CO_2 (Wells et al. 2007; Eastoe et al. 2003). These tracers also can be monitored near the land surface to aid in leak-detection monitoring. Use of these types of tracers can result in early detection of the PFT in a shallow aquifer or at land surface (Wells et al. 2007) if that gas phase travels faster than the CO_2, as noted in previous studies (Dietz 1986; Spangler et al. 2009). However, if intervals within the overburden materials contain significant quantities of organic matter, the PFT may partition into that phase and never be transported to shallower monitoring depths. This potential scenario demonstrates the utility of including a hydrophilic component in the tracer suite, which provides an additional measure of leak-detection capability in deeper monitoring intervals.

There are several examples of hydrophilic tracers that partition into the aqueous phase. Naphthalene sulfonate tracers used in previous studies (Rose et al. 2001) include 2-naphthalene sulfonate, 2,7-naphthalene sulfonate, and 1,3,6-naphthalene trisulfonate. Fluorinated benzoic acids that have been used previously include pentafluorobenzoic acid (PFBA), 2,6-difluorobenzoic acid, and 2,3-difluorobenzoic acid (Flury and Wai 2003; Stetzenbach and Farnham 1995).

Direct measurement of CO_2 for leak detection, either in the dissolved or gaseous phase, can be difficult to separate from other carbonate sources in the overlying aquifers or soil zone. Measurement of $^{13/12}C$ isotopic change in the carbonate (or CO_2 soil-gas) has significantly lower detection limits, because the isotopic change is essentially a tracer. In one study, CO_2 gas with a different isotopic $^{13/12}C$ ratio was emitted into the air, and laser measurements in real time were used (Steele et al. 2008). This study demonstrated the effectiveness of isotopic $^{13/12}C$ measurements for characterizing soil-gas composition. Isotopic measurements of $^{13/12}C$ (and $^{18/16}O$ in water) in the past were expensive measurements, requiring a prep line and mass spectrometry. Newly developed off-axis laser absorption spectroscopy has the potential to reduce this cost considerably due to rapid, automated sample analysis on a relatively inexpensive instrument. ^{14}C has also been shown to be a powerful tool for distinguishing between modern biogenic sources of CO_2 (containing ^{14}C) and CO_2 derived from fossil fuel sources (^{14}C has decayed over time). Because injected CO_2 would be expected to be depleted in ^{14}C, this isotopic signature provides another useful tracer that can be used to discriminate between CO_2 released from the injection zone and that naturally present in the near-surface environment.

5.2.2 Groundwater Quality and Geochemistry Monitoring

Direct monitoring of aqueous chemistry and related field parameters will be used to identify and quantify any potential impacts on USDW aquifers from a release of hypersaline waters and/or CO_2 from the injection zone. Monitoring locations will include immediately above the primary confining zone for early leak-detection (i.e., ACZ monitoring wells) and USDW aquifer monitoring.

5.2.2.1 ACZ Early-Detection Monitoring

Direct monitoring of pressure and aqueous chemistry will be used to identify and quantify any potential release of injection zone fluids and/or CO_2 resulting from a loss of containment.

Objectives

Monitoring groundwater in one or more zones between the confining zone(s) overlying the injection zone and the USDW aquifers is required by 40 CFR 146.90 (d). The purpose of such monitoring is to detect CO_2 migration out of the injection zone before it can result in any impacts on USDW aquifer water quality.

Monitoring Approach

Candidate ACZ monitoring intervals that could be used for early leak detection of CO_2 from the injection zone, and thus protect the lowermost USDW from potential water-quality impacts, include permeable units within the upper Eau Claire unit and the Ironton Sandstone (see Figure 5.2). Information from the stratigraphic well at the Morgan County site indicates the Ironton Sandstone unit, which is located immediately above the primary confining zone and should be a viable monitoring interval, will likely provide the best early-detection monitoring capability. One ACZ, early-leak-detection monitoring well will be installed in the vicinity of the injection well pad (Figure 5.1). This well will be perforated in the Ironton Sandstone and completed to facilitate continuous field parameter monitoring and periodic aqueous sampling. This well may also be used to support VSP and passive seismic monitoring, and may be constructed using non-conductive casing so that an array of electrical resistivity electrodes attached to the outside of the casing can be used to provide a real-time, early-detection capability.

Pressure and aqueous monitoring requirements for the early-detection monitoring well, including the general monitoring approach, the list of target analytes, and the analytical and quality assurance requirements, are specified in Section 5.2.2.3, Sampling and Analysis. The planned monitoring frequencies during the various phases of the project are listed in Table 5.3. Once CO_2 injection begins, aqueous monitoring in the early-detection well will be conducted on a regular basis to monitor for potential upward migration of CO_2 out of the targeted injection zone. Additional interim sampling will be conducted if CO_2 containment loss is suspected based on pressure data from the well or other evidence, such as geophysical measurements or other aqueous monitoring results. Post-injection monitoring will nominally extend over a 50-year period, or as required to demonstrate that the injected CO_2 poses no threat to the USDW aquifers (see discussion in Section 7.2). Monitoring of the deep, ACZ early-leak-detection monitoring well for pressure, temperature, electrical conductivity, and aqueous chemistry will be conducted throughout the post-injection monitoring period to support this evaluation. Pressure and electrical conductivity (if ERT is implemented) will be continuously monitored and aqueous samples will be collected on a routine basis.

5.2.2.2 USDW Aquifer Monitoring

Direct monitoring of aqueous chemistry and related field parameters will be used to identify and quantify any potential impacts on USDW aquifers resulting from injection zone containment loss. Given the depth of the targeted injection interval (~4,000 ft bgs), the expected integrity of the overlying confining unit, the presence of the secondary confining units at shallower depths (e.g., the Franconia Dolomite unit), and the lack of any known preferential pathways between the injection zone and USDW aquifers (see Section 5.1.1.1 and Section 3.2.1), the likelihood of CO_2 coming into direct contact with the lowermost USDW aquifer (St. Peter Sandstone, see Figure 5.2), and the associated impacts on water quality, are relatively low. In addition, if a significant breach in the primary confining zone occurred during injection operations, ACZ early-leak-detection monitoring in the Ironton Sandstone should identify the leak and allow for the implementation of mitigation strategies well before any impacts on the overlying USDW aquifers can occur. However, to ensure that the local drinking water supply is adequately protected, a comprehensive USDW monitoring program will be instituted.

Objectives

Monitoring groundwater quality in USDW aquifers is required by 40 CFR 146.90. The intended purpose of this type of monitoring is to detect and quantify any potential impacts of CO_2 containment loss on the water quality of local drinking water aquifers.

Monitoring Approach

As discussed in Chapter 2.0 (Section 2.6.3.1), the lowermost USDW aquifer at the Morgan County site, based on water-quality considerations, resides within the St. Peter Formation. A single regulatory compliance well will be installed within this lowermost USDW aquifer (Figure 5.1 and Figure 5.2). In addition, the shallow surficial aquifer residing within the near-surface glacial deposits will be monitored using one project-installed groundwater monitoring well and a network of approximately 10 local landowner wells. Shallow USDW monitoring will be performed to directly assess groundwater quality at current USDW user locations, which reside exclusively within the shallow semiconsolidated glacial sediments beneath the study area and in surrounding communities.

A general description of this surficial USDW monitoring network and the results from an initial groundwater sampling campaign conducted by ISGS to support characterization of local-scale USDW water quality, is included in Chapter 2.0 (Section 2.6.1). A literature search and evaluation conducted by the ISGS (ISGS in prep) indicate that the upper Pennsylvanian bedrock aquifer is a potentially potable source of drinking water in the region. However, within the immediate vicinity of the Morgan County storage site (and anticipated AoR extent) usage is essentially precluded by 1) decreasing water quality with depth and 2) the difficulty associated with finding geologic material that has enough primary or secondary porosity to generate a well of sufficient yield to act as an economically viable source of drinking water. In addition, current residential/farm usage in the vicinity of the site is limited to wells completed within the shallow Quaternary, glacially derived sediments that compose the surficial aquifer system. All of the smaller towns and communities in the vicinity of the proposed CO_2 injection site obtain water supplies from surface-water sources, sometimes supplemented with shallow groundwater withdrawn from localized more-permeable lenses within the shallow Quaternary sediments. For these reasons, the surficial aquifer system is considered a USDW of interest at the Morgan County storage site, even though it is not the lowermost USDW aquifer.

Monitoring data will be continuously evaluated throughout the active injection phase, and if specific analytes are found to be of little benefit, they will be removed from the analyte list. The post-injection monitoring period will nominally extend over a 50-year period, or as required to demonstrate that the injected CO_2 does not pose a threat to any USDW aquifers. In addition to aqueous sample collection, continuous monitoring of pressure (water level) and other water-quality parameters (specific conductance and pH) will be conducted using dedicated downhole electrodes. Instrumentation will be installed to record these parameters using multiple submersible downhole sensors, all connected to a single above-ground automated data-logging system.

5.2.2.3 Sampling and Analysis

Specific field sampling protocols will be described in a project-specific sampling plan to be developed prior to initiation of field test operations, once the test design has been finalized. The work will comply with applicable EPA regulatory procedures and relevant American Society for Testing and Material, ISGS, and other procedural standards applicable for groundwater sampling and analysis. All sampling and analytical measurements will be performed in accordance with project quality assurance requirements (see Section 5.8), samples will be tracked using appropriately formatted chain-of-custody forms, and analytical results will be managed in accordance with a project-specific data management plan (see Section 5.6). Investigation-derived waste will be handled in accordance with site requirements.

During all groundwater sampling, field parameters (pH, specific conductance, and temperature) will be monitored for stability and used as an indicator of adequate well purging (i.e., parameter stabilization provides indication that a representative sample has been obtained). Calibration of field probes will follow the manufacturer's instructions using standard calibration solutions. A comprehensive list of target analytes under consideration and groundwater sample collection requirements is provided in Table 5.4. The relative benefit (and cost) of each analytical measurement will be evaluated throughout the design and initial injection testing phase of the project to identify the analytes best suited to meeting project monitoring objectives under site-specific conditions. If some analytical measurements are shown to be of limited use and/or cost prohibitive, they will be removed from the analyte list. All analyses will be performed in accordance with the analytical requirements listed in Table 5.5. Additional analytes may be included for the shallow USDW based on landowner requests (e.g., coliform bacteria). If implemented, monitoring for tracers will follow standard aqueous sampling protocols for the naphthalene sulfonate tracer, but a pressurized sample for the PFT tracer will be required because the PFT will be partitioned into the gas phase.

Table 5.4. Aqueous Sampling Requirements

Parameter	Monitoring Phase	Volume/ Container	Preservation	Holding Time
Major Cations: Al, Ba, Ca, Fe, K, Mg, Mn, Na, Si,	All phases	20-mL plastic vial	Filtered (0.45 µm), HNO_3 to pH <2	60 days
Trace Metals: Sb, As, Ba, Cd, Cr, Cu, Pb, Hg, Se, Tl	All phases	20-mL plastic vial	Filtered (0.45 µm), HNO_3 to pH <2	60 days
Anions: Cl^-, Br^-, F^-, SO_4^{2-}, NO_3^-,	All phases	20-mL plastic vial	Cool 4°C	45 days
Gravimetric Total Dissolved Solids (TDS), compare to TDS by calculation from major ions	All phases	250-mL plastic vial	Filtered (0.45 µm), no preservation Cool 4°C	
Water Density	Baseline, periodic during injection	100 mL plastic vial	Filtered (0.45 µm), no preservation Cool 4°C	60 days
Alkalinity	All phases	100 mL HDPE	Filtered (0.45 µm) Cool 4°C	5 days
Dissolved Inorganic Carbon (DIC)	All phases	20-mL plastic vial	Cool 4°C	45 days
Total Organic Carbon (TOC)	All phases	40 mL glass	unfiltered	14 days
Carbon Isotopes (^{14}C, $^{13/12}C$)	Baseline, other phases as indicated	5-L HDPE	pH >6	14 days
Water Isotopes ($^{2/1}H$, $^{18/16}O$)	Baseline only	20-mL glass vial	Cool 4°C	45 days
Radon (^{222}Rn)	All phases	1.25-L PETE	Pre-concentrate into 20-mL scintillation cocktail. Maintain groundwater temperature prior to pre-concentration	1 day
Naphthalene Sulfonate or Fluorinated Benzoic Acid Tracers (aqueous phase)	No baseline, all operational phases	500 mL HDPE	Filtered (0.45 µm), no preservation	60 days
Perfluorocarbon Tracer (PFT) ($scCO_2$ or gas phase)	No baseline, all operational phases	500 mL glass	unfiltered, Cool 4°C	60 days
pH	Monitored during each sampling event	Field parameter	None	<1 h
Specific Conductance	Monitored during each sampling event	Field parameter	None	<1 h
Temperature	Monitored during each sampling event	Field parameter	None	<1 h

HDPE = high-density polyethylene; PETE = polyethylene terephthalate.

Table 5.5. Analytical Requirements

Parameter	Analysis Method	Detection Limit or (Range)	Typical Precision/ Accuracy	QC Requirements
Major Cations: Al, Ba, Ca, Fe, K, Mg, Mn, Na, Si,	ICP-OES, PNNL-AGG-ICP-AES (similar to EPA Method 6010B)	0.1 to 1 mg/L (analyte dependent)	±10%	Daily calibration; blanks and duplicates and matrix spikes at 10% level per batch of 20
Trace Metals: Sb, As, Ba, Cd, Cr, Cu, Pb, Hg, Se, Tl	ICP-MS, PNNL-AGG-415 (similar to EPA Method 6020)	1 µg/L for trace elements	±10%	Daily calibration; blanks and duplicates and matrix spikes at 10% level per batch of 20
Anions: Cl^-, Br^-, F^-, SO_4^{2-}, NO_3^-, CO_3^{2-}	Ion Chromatography, AGG-IC-001 (based on EPA Method 300.0A)		±15%	Daily calibration; blanks and duplicates at 10% level per batch of 20
TDS	Gravimetric Method Standard Methods 2540C	12 mg/L	± 5%	Balance calibration, triplicate samples
Water Density	Standard Methods 227	0.0001 g/mL	±0.0`%	Triplicate measurements
Alkalinity	Titration, standard methods 102	4 mg/L	±3 mg/L	Triplicate titrations
Dissolved Inorganic Carbon (DIC)	Carbon analyzer, phosphoric acid digestion of DIC	0.002%	±10%	Triplicate analyses, daily calibration
Total Organic Carbon (TOC)	Carbon analyzer; total carbon by 900°C pyrolysis minus DIC = TOC	0.002%	±10%	Triplicate analyses, daily calibration
Carbon Isotopes ($^{14/12}C$, $^{13/12}C$)	Accelerator MS	10^{-15}	±4‰ for ^{14}C; ±0.2‰ for ^{13}C;	Triplicate analyses
Water Isotopes ($^2H/^1H$, $^{18/16}O$)	Water equilibration coupled with IRMS ; Alternatively, consider WS-CRDS	10^{-9}	IRMS: ±1.0‰ for ^2H; ±0.15‰ for ^{18}O; WS-CRDS: ±0.10‰ for ^2H; ±0.025‰ for ^{18}O	Triplicate analyses
Radon (^{222}Rn)	Liquid scintillation after pre-concentration	5 mBq/L	±10%	Triplicate analyses
Naphthalene Sulfonate **or** Benzoic Acid Tracer (aqueous phase)	Liquid chromatography-mass spectrometry (LC-MS) **or** gas chromatography with electron capture detector (ECD)	5 parts per trillion (5×10^{12}) **or** 10 parts per quadrillion (10×10^{15})	Varies with conc., ±30% at detection limit	Duplicates 10% of samples, significant number of blanks for cross-contamination
Perfluorocarbon Tracer (PFT) ($scCO_2$ or gas phase)	gas chromatography with electron capture detector (ECD)	10 parts per quadrillion (10×10^{15})	varies with conc., ±30% at detection limit	duplicates 10% of samples, significant number of blanks for cross-contamination

Table 5.5. (contd)

Parameter	Analysis Method	Detection Limit or (Range)	Typical Precision/ Accuracy	QC Requirements
pH	pH electrode	2 to 12 pH units	±0.2 pH unit For indication only	User calibrate, follow manufacturer recommendations
Specific conductance	Electrode	0 to 100 mS/cm	±1% of reading For indication only	User calibrate, follow manufacturer recommendations
Temperature	Thermocouple	5 to 50°C	±0.2°C For indication only	Factory calibration

ICP = inductively coupled plasma; IRMS = isotope ratio mass spectrometry; MS = mass spectrometry; OES = optical emission spectrometry; WS-CRDS = wavelength scanned cavity ring-down spectroscopy.

5.2.3 Injection Zone Monitoring

Direct monitoring of pressure and aqueous chemistry will be used to assess the lateral extent of injected CO_2 and the pressure front within the injection zone. In addition, surface and downhole geophysical methods will be used to provide an indirect measure of CO_2 plume development and spatial distribution. This section describes the proposed injection zone monitoring program.

5.2.3.1 Objectives

The primary objective of monitoring injection zone pressure is to provide the information needed to assess the lateral extent of injected CO_2 and the pressure front over time. Specific objectives for monitoring injection zone pressure include the following:

- Calibrate the numerical models that will be used to help track CO_2 and pressure in the injection zone.
- Guard against over-pressuring, which could induce unwanted fracturing of the injection zone or the overlying confining zone(s).
- Determine the need for well rehabilitation.
- Assess injection zone properties (e.g., permeability, porosity, reservoir size) within progressively larger areas of the reservoir as the pressure front advances.

Data collection will be accomplished by monitoring pressure in wells completed in the injection zone, including injection wells, single-level (i.e., single discrete depth interval) monitoring wells, and possibly a multi-level monitoring well. Temperature and electrical conductivity will also be monitored at all well locations with a downhole combined pressure/temperature/electrical conductivity sensor. Temperature monitoring provides an additional benefit when the temperature of the injected CO_2 is sufficiently different from ambient reservoir temperatures, providing another indication of CO_2 plume arrival at monitoring well locations.

Specific objectives for aqueous monitoring of mixed hypersaline/CO_2 fluids in injection zone wells include the following:

- Aid in assessing the lateral and vertical extent of injected CO_2 over time within the injection zone.
- Characterize geochemical changes caused by interaction between the injected CO_2 and the host formation/fluids within the injection zone (i.e., pH, Eh, metal mobility, precipitation/dissolution).
- Characterize the fraction of aqueous solution and scCO_2 at selected locations in the injection zone within/near the CO_2 plume (as identified by cross-borehole geophysical surveys).

Fluid samples will be collected from monitoring wells completed in the injection zone before, during, and after CO_2 injection. The samples will be analyzed for chemical parameter changes that are indicators of the presence of CO_2 and/or reactions caused by the presence of CO_2.

5.2.3.2 Monitoring Approach

The post-injection monitoring period will nominally extend over at least a 50-year period, or as required to demonstrate that the injected CO_2 does not pose a threat to USDW aquifers (see Section 7.2).

Baseline pressure monitoring will involve the installation and testing of pressure sensors in the injection well and monitoring wells and collection of pressure data for approximately 1 year prior to the start of injection. Thus, baseline injection zone pressure monitoring cannot be initiated until the wells have been installed. Baseline aqueous monitoring is required to characterize the background injection zone fluid chemistry and provide a measure for comparison during and after injection operations. Baseline monitoring will involve collection and analysis of a minimum of three rounds of aqueous samples from each well completed in the target injection zone prior to initiation of CO_2 injection. If time allows, additional samples may be collected to aid in assessing the variability in the analytical parameters.

During the 20-year active injection phase, continuous (i.e., uninterrupted) monitoring of pressure will be conducted in injection zone monitoring wells and the CO_2 injection wells. The pressure gauges will be removed from the monitoring wells only when they require maintenance or when necessitated by other activities (e.g., well maintenance). In addition, all injection zone monitoring wells will be sampled on a regular basis to quantify CO_2 arrival times and transport processes. Injection wells will not be sampled during the operational phase because this would interfere with injection operations. However, the CO_2 injection stream will be monitored/sampled during this phase and the injection wells will be sampled after the conclusion of the injection period. Aqueous samples will be analyzed for the same parameters (see Section 5.2.2.3) that are measured during the baseline monitoring period. Monitoring data will be continuously evaluated throughout the active injection phase and if specific analytes are found to be of little benefit, they will be removed from the analyte list.

Post-injection monitoring data will be evaluated to determine when the injected CO_2 can no longer affect the USDW aquifers. This demonstration requires knowledge of pressure data for the injection reservoir; therefore, pressure monitoring in wells in the injection reservoir will continue throughout the post-injection monitoring period. At least two wells in the injection zone will be retained for this purpose. Monitoring of the injection zone fluids is not required during this phase of the project, but periodic samples may be collected to characterize longer-term geochemical changes occurring within the injection zone. Aqueous monitoring of injection zone fluids during this phase, if performed, will be performed at a reduced frequency (i.e., every 5 years).

5.2.3.3 Pressure Monitoring

Injection of CO_2 into a saline aquifer generates pressure perturbations that diffuse through the fluid-filled pores of the geologic system. The objective of pressure monitoring is to record the pressure signal at the source (i.e., injection well) and one or more monitoring wells in order to infer important rock and fluid characteristics such as permeability and total compressibility from the analysis of the pressure data. Pressure monitoring information also provides input for the calibration of numerical models, where injection zone properties are adjusted to match the observed pressure data with corresponding simulator predictions. This provides confirmation of predictions regarding the extent of the CO_2 plume, pressure buildup, and the occurrence of fluid displacement into overlying formations.

Pressure in the injection zone will be monitored at several well locations (see the conceptual monitoring network design shown in Figure 5.1), including the injection wells, one single- or multi-level injection zone monitoring well located inside the projected 5-year plume extent, and two single-level Mount Simon monitoring wells located within the projected 5- to 22-year CO_2 plume extent.

Pressure monitoring as a component of the overall MVA program provides multiple benefits. Inferences about formation permeability at scales comparable to that of CO_2 plume migration can be made (as opposed to that from small centimeter-scale core samples). Permeability values estimated for different regions of the injection zone may indicate the presence of anisotropy and hence, suggest potential asymmetry in the plume trajectory. Such information can be useful in adapting the monitoring strategy.

Continuous monitoring of injection zone pressure and temperature will be performed with sensors installed in wells that are completed in the injection zone. Pressure and temperature monitoring in the injection well and all monitoring wells will be performed using a real-time monitoring system with surface readout capabilities so that pressure gauges do not have to be removed from the well to retrieve data. The injection zone multi-level monitoring well is designed to monitor multiple discrete depth intervals within the Mount Simon and Elmhurst sandstones. Similar to the injection wells, this well will be instrumented to provide real-time pressure data with surface readout capabilities. Power for the injection well will be provided by a dedicated line power supply. Power for all monitoring wells will be provided by a stand-alone solar array with battery backup so that a dedicated power supply to these more distal locations is not required.

The following measures will be taken to ensure that the pressure gauges are providing accurate information on an ongoing basis:

- High-quality (high-accuracy, high-resolution) gauges with low drift characteristics will be used.
- Gauge components (gauge, cable head, cable) will be manufactured of materials designed to provide a long life expectancy for the anticipated downhole conditions.
- Upon acquisition, a calibration certificate will be obtained for every pressure gauge. The calibration certificate will provide the manufacturer's specifications for range, accuracy (% full scale), resolution (% full scale), and drift (< psi per year) and calibration results for each parameter. The calibration certificate will also provide the date that the gauge was calibrated and the methods and standards used.
- Gauges will be installed above any packers so they can be removed if necessary for recalibration by removing the tubing string. Redundant gauges may be run on the same cable to provide confirmation of downhole pressure and temperature.
- Upon installation, all gauges will be tested to verify they are functioning (reading/transmitting) correctly.
- Gauges will be pulled and recalibrated whenever a workover occurs that involves removal of tubing. A new calibration certificate will be obtained whenever a gauge is recalibrated.

5.2.3.4 Aqueous Monitoring

Periodically, fluid samples will be collected from the monitoring wells completed in the injection zone (see sampling and analysis requirements in Section 5.2.2.3). Because of their proximity to the injection wells, a higher sampling frequency is warranted for the near-field single- or multi-level monitoring well, which will be located within the predicted 2- to 5-year plume, than for the single-level monitoring wells, which will be located within the 5- to 22-year plume. The sampling frequency for all wells may need to be adjusted as the CO_2 plume approaches the outer wells. Fluid samples will be collected using an appropriate method to preserve the fluid sample at injection zone temperature and pressure conditions. Examples of appropriate methods include using a bomb-type sampler (e.g., Kuster sampler) after pumped or swabbed purging of the sampling interval, using a Westbay sampler, or using a pressurized U-tube sampler (Freifeld et al. 2005). These types of pressurized sampling methods are needed to collect the two-phase fluids (i.e., aqueous and $scCO_2$ solutions) for measurement of the percent water and CO_2 present at the monitoring location.

Fluid samples will be analyzed for parameters that are indicators of CO_2 dissolution (Table 5.4), including major cations and anions, selected metals, general water-quality parameters (pH, alkalinity, TDS, specific gravity), and any tracers added to the CO_2 stream. Changes in major ion and trace element geochemistry are expected in the injection zone, but the arrival of proposed fluorocarbon or sulfonate tracers (co-injected with the CO_2) should provide an improved early-detection capability, because these compounds can be detected at 3 to 5 orders of magnitude lower relative concentration. Analysis of carbon and oxygen isotopes in injection zone fluids and the injection stream ($^{13/12}C$, $^{18/16}O$) provides another potential supplemental measure of CO_2 migration. Where stable isotopes are included as an analyte, data quality and detectability will be reviewed throughout the active injection phase and discontinued if these analyses provide limited benefit.

5.2.3.5 Geophysical Monitoring

A suite of indirect geophysical monitoring methods will be evaluated and tested to assess their efficacy and cost effectiveness for monitoring the spatial extent, evolution, and fate and transport of the injected CO_2 plume. Indirect monitoring methodologies under consideration are listed in Table 5.2 and measurement frequencies (if selected for deployment) are provided in Table 5.3. All methods will be evaluated during the design, construction, and initial operational phase (Phase IV) of the project and the most promising and cost-effective method(s) will be selected to carry forward through the operational phases.

5.2.4 CO_2 Injection Process Monitoring

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

5.2.4.1 Continuous Monitoring of the CO_2 Injection Process

Continuous Recording of Injection Mass Flow Rate

The mass flow rate of CO_2 injected into the well field will be measured by a flow meter skid with a Coriolis mass flow transmitter for each well. Each meter will have analog output (Micro Motion Coriolis Flow and Density Meter Elite Series or similar). A total of six flow meters will be supplied, providing for two spare flow meters to allow for flow meter servicing and calibration. Valving will be installed to select flow meters for measurement and for calibration. A single flow prover will be installed to calibrate the flow meters, and piping and valving will be configured to permit the calibration of each flow meter. The flow transmitters will each be connected to a remote terminal unit (RTU) on the flow meter skid. The RTU will communicate with the Control Center through the well annular pressure maintenance and monitoring system (WAPMMS) programmable logic controller (PLC) located at the injection well site. The flow rate into each well will be controlled using a flow-control valve located in the CO_2 pipeline associated with each well. The control system will be programmed to provide the desired flow rate into three of the four injection wells, with the one remaining well receiving the balance of the total flow rate.

Continuous Recording of Injection Pressure

The pressure of the injected CO_2 will be continuously measured for each well at a regular frequency by an electronic pressure transmitter with analog output mounted on the CO_2 line associated with each injection well at a location near the wellhead. The transmitter will be connected to the WAPMMS PLC at the injection well site.

Continuous Recording of Injection Temperature

The temperature of the injected CO_2 will be continuously measured for each well at a regular frequency by an electronic temperature transmitter. The temperature transmitter will be mounted in a temperature well in the CO_2 line at a location close to the pressure transmitter near the wellhead. The transmitter will be connected to the WAPMMS PLC located at the injection well site.

5.2.4.2 Injection Stream Analysis Parameters

According to the requirements of 40 CFR 146.90 (Testing and Monitoring Requirements) of the Class VI UIC Regulation, analysis of the CO_2 stream is required with sufficient frequency to provide data representative of its chemical and physical characteristics. Based on the anticipated composition of the CO_2 stream, a list of parameters was identified for analysis (Chapter 4.0, Table 4.1). Samples of the CO_2 stream will be collected regularly (e.g., quarterly) for chemical analysis.

5.2.4.3 Sampling Method

Grab samples of the CO_2 stream will be obtained for analysis of gases, including CO_2, O_2, H_2S, Ar, and water moisture. Samples of the CO_2 stream will be collected from the CO_2 pipeline at a location where the material is representative of injection conditions. A sampling station will be installed in the ground or on a structure close to the pipeline and connected to the pipeline via small-diameter stainless steel tubing to accommodate sampling cylinders that will be used to collect the samples. A pressure regulator will be used to reduce the pressure of the CO_2 to approximately 250 psi so that the CO_2 is in the gas state when collected rather than a supercritical liquid. Cylinders will be purged with sample gas (i.e., CO_2) prior to sample collection to remove laboratory-added helium gas and ensure a representative sample.

5.3 Injection Well Testing and Monitoring

This section describes the testing and monitoring activities that will be performed during the service life of the injection wells to routinely assess their mechanical integrity. Initial (i.e., baseline) mechanical integrity testing that will be performed on the injection wells prior to the start of CO_2 injection is discussed in the Construction and Operations Plan (Chapter 4.0).

5.3.1 Pressure Fall-Off Testing

Pressure fall-off testing is required upon completion of the injection wells prior to their operation (i.e., injection) to characterize reservoir hydrogeologic properties (40 CFR 146.87(e)(1)) and at least once every 5 years once injection operations begin (40 CFR 146.90(f)) to confirm site-characterization information, assess reservoir and well conditions, and inform AoR reevaluations. Pressure fall-off tests conducted after the start of CO_2 injection operations will provide the following information:

- confirmation of hydrogeologic reservoir properties
- long-term pressure buildup in the injection reservoir(s) due to CO_2 injection over time
- average reservoir pressure, which can be compared to modeled predictions of reservoir pressure to verify that the operation is responding as modeled/predicted and identify the need for recalibration of the AoR model in the event that the monitoring results do not match expectations
- formation damage (skin) near the well bore, which can be used to diagnose the need for well remediation/rehabilitation.

The EPA has not issued guidance for conducting pressure fall-off testing at GS sites; however, guidance is available for conducting these tests for Class I UIC wells (see for example EPA 2002, 1998). These guidelines will be followed when conducting pressure fall-off tests for the FutureGen 2.0 Project.

In the pressure fall-off test, flow is maintained at a steady rate for a period of time, then injection is stopped, the well is shut-in, and bottom-hole pressure is monitored and recorded for a period of time sufficient to make a valid observation of the pressure fall-off curve. Downhole or surface pressure gauges will be used to record bottom-hole pressures during the injection period and the fall-off period. Pressures will be measured at a frequency that is sufficient to measure the changes in bottom-hole pressure throughout the test period, including rapidly changing pressures immediately following cessation of injection. The fall-off period will continue until radial flow conditions are observed, as indicated by stabilization of pressure and leveling off of the pressure derivative curve. The fall-off test may also be truncated if boundary effects are encountered, which would be indicated as a change in the slope of the derivative curve, or if radial flow conditions are not observed. In addition to the radial flow regime, other flow regimes may be observed from the fall-off test, including spherical flow, linear flow, and fracture flow. Analysis of pressure fall-off test data will be done using transient-pressure analysis techniques that are consistent with EPA guidance for conducting pressure fall-off tests (EPA 1998, 2002).

5.3.2 Mechanical Integrity Testing During Service Life of Well

This section describes the mechanical integrity tests that will be conducted during the period of active CO_2 injection. Initial (i.e., baseline) mechanical integrity testing (MIT) that will be performed on the injection wells prior to the start of CO_2 injection as discussed in the Construction and Operations Plan (Chapter 4.0, Section 4.3). Regular MIT will be conducted after CO_2 injection commences to ensure that the well has adequate internal and external mechanical integrity as injection continues.

Internal Mechanical Integrity Testing

Internal mechanical integrity will be continuously monitored by monitoring the annular pressure in the well. This will be accomplished automatically by the WAPMMS, as described in the Construction and Operations Plan (Section 4.3). In addition to continuous monitoring of the annular pressure, an APT (annular pressure test) will be performed whenever the tubing or packer is removed from the well (e.g., during well workovers) and prior to resuming injection operations.

External Mechanical Integrity Testing

As discussed in the Construction and Operations Plan (Section 4.3, an initial (baseline) temperature log and/or oxygen-activation log will be run on the well after well construction but prior to commencing CO_2 injection. These baseline log(s) will serve as a reference for comparing future temperature and/or oxygen-activation logs for evaluating external mechanical integrity. The following sections describe temperature logging and oxygen-activation logging during the service life of the well. A third type of mechanical integrity test—a RTS—is also described. This method may be used instead of or in addition to temperature logging or oxygen-activation logging, if needed, to help explain results.

Temperature Logging

Temperature logs can be used to identify fluid movement along channels adjacent to the well bore. In addition to identifying injection-related flows behind casing, temperature logs can often locate small casing leaks.

Injection of CO_2 will have a cooling or heating effect on the natural temperature in the storage reservoirs, depending on the temperature of the injected CO_2 and other factors. Once injection starts, the flowing temperature will stabilize quickly (assuming conditions remain steady). When an injection well is shut-in for temperature logging, the well bore fluid begins to revert toward ambient conditions. Zones that have taken injectate, either by design or not, will exhibit a “storage” signature on shut-in temperature surveys (storage signatures are normally cold anomalies in deeper wells, but may be cool or hot depending on the temperature contrast between the injectate and the reservoir). Losses behind pipe from the injection zone can be detected on both flowing and shut-in temperature surveys and exhibit a “loss” signature.

For temperature logging to be effective for detecting fluid leaks, there should be a contrast in the temperature of the injected CO_2 and the reservoir temperature. The greater the contrast in the CO_2 when it reaches the injection zone and the ambient reservoir temperature, the easier it will be to detect temperature anomalies due to leakage behind casing. Based on data from the stratigraphic well, ambient bottom-hole temperatures in the Mount Simon Sandstone are expected to be approximately 100°F; the temperature of the injected CO_2 is anticipated to be on the order of 72°F to 90°at the surface (depending on time of year) but will undergo some additional heating as it travels down the well. After the baseline (i.e., prior to injection) temperature log has been run to determine ambient reservoir temperature in each well, it will be possible to determine whether there will be sufficient temperature contrast to make the temperature log an effective method for evaluating external mechanical integrity. Temperature logging would be conducted through the tubing and therefore would not require removal of the tubing and packer from the well.

The Alliance will consult the EPA Region 5 guidance for conducting temperature logging (EPA 2008) when performing this test.

Oxygen-Activation Logging

Oxygen activation is a geophysical logging technique that uses a pulsed-neutron capture tool to quantify the flow of water in or around a borehole. For purposes of demonstrating external mechanical integrity, a baseline oxygen activation will be run prior to the start of CO_2 injection and compared to later runs to determine changing fluid flow conditions adjacent to the well bore (i.e., formation of channels or other fluid isolation concerns related to the well).

The pulsed-neutron tool emits high-energy neutrons that interact with water molecules present in the casing-formation annular space, among others. This temporarily activates oxygen (^{16}O) to produce an isotope of nitrogen (^{16}N) that decays back to oxygen with a half-life of 7.1 seconds and emits an easily detected gamma ray. Typical pulsed-neutron capture tools have two or three gamma-ray detectors (above and below the neutron source) to detect the movement of the activated molecules, from which water velocity can then be calculated. The depth of investigation for oxygen-activation logging is typically less than 1 ft; therefore, this log type provides information immediately adjacent to the well bore.

Repeat runs will be made under conditions that mimic baseline conditions (e.g., similar logging speeds and tool coefficients) as closely as possible to ensure comparability between baseline and repeat data.

The Alliance will consult the EPA Region 5 guidance for conducting the oxygen-activation logging (EPA 2008) when performing this test.

5.3.2.2 Corrosion Monitoring

This section discusses the measures that will be taken to monitor corrosion of well materials, including tubulars (i.e., casing, tubing) and cement; planned monitoring frequencies are provided in Table 5.3. Note that cement evaluation beyond the preliminary cement-bond log is not required for Class VI wells under MIT or corrosion monitoring (40 CFR 146.89 and 146.90). However, it is recognized that cement integrity over time can influence the mechanical integrity of an injection well. Therefore, cement-evaluation logs will be run when tubing is removed from the well (i.e., during well workovers). In addition, while they are not required for corrosion monitoring, casing inspection logs will also be run when tubing is removed from the well (i.e., during well workovers).

Casing and Tubing

Corrosion of well materials will be monitored using the corrosion coupon method. Corrosion monitoring of well casing and tubing materials will be conducted using coupons placed in the CO_2 pipeline. The coupons will be made of the same material as the long string of casing and the injection tubing. The coupons will be removed quarterly and assessed for corrosion using the American Society for Testing and Materials (ASTM) G1-03, Standard Practice for Preparing, Cleaning, and Evaluating Corrosion Test Specimens (ASTM 2011). Upon removal, coupons will be inspected visually for evidence of corrosion (e.g., pitting). The weight and size (thickness, width, length) of the coupons will also be measured and recorded each time they are removed. Corrosion rate will be calculated as the weight loss during the exposure period divided by the duration (i.e., weight loss method).

Casing and tubing will also be evaluated periodically for corrosion throughout the life of the injection well by running casing inspection (wireline) logs. The frequency of running these tubing and casing inspection logs will be determined based on site-specific parameters and well performance. Wireline tools are lowered into the well to directly measure properties of the well tubulars that indicate corrosion. Four types of wireline tools are available for assessing corrosion of well materials—mechanical, electromagnetic, ultrasonic, and videographic. Mechanical, electromagnetic, and/or ultrasonic tools will be used primarily to monitor well corrosion (Table 5.6). These tools, or comparable tools from alternate vendors, will be used to monitor the condition of well tubing and casing.

Table 5.6. Examples of Wireline Tools for Monitoring Corrosion of Casing and Tubing

	Mechanical	Ultrasonic	Electromagnetic
Tool Name	Multifinger Imaging Tool[(a)]	Ultrasonic Imager Tool[(a)]	High-Resolution Vertilog[(b)]
Type	Mechanical	Ultrasonic	Electromagnetic
Parameter(s) Measured	Internal radius; does not measure wall thickness	Inner diameter, wall thickness, acoustic impedance, cement bonding to casing Up to 180 measurements per revolution	Magnetic flux leakage (internal and external) Full 360 degree borehole coverage
Tool O.D. (in.)	1.6875, 2.75, 4 (multiple versions of available)	3.41 to 8.625	2.2 to 8.25
Tubular Size That Can Be Measured Min/Max (in.)	2/4.5, 3/7, 5/10 (multiple versions of available	4.5/13.375	4.5/9.625
Comments, limitations, special requirements, etc.	Typically run on memory using slickline. Can also be run in surface real-time mode.	Can detect evidence of defects/corrosion on casing walls (internal/external), quality of cement bond to pipe, and channels in cement. Moderate logging speed (30 ft/min) is possible.	Can distinguish between general corrosion, pitting, and perforations. Can measure pipe thickness. High logging speed (200 ft/min) is possible. Cannot evaluate multiple strings of tubular simultaneously.

(a) Schlumberger Limited
(b) Baker Hughes, Inc.

Mechanical casing evaluation tools, referred to as calipers, have multiple “fingers” that measure the inner diameter of the tubular as the tool is raised or lowered through the well. Modern-day calipers have several fingers and are capable of recording information measured by each finger so that the data can be used to produce highly detailed 3D images of the well. An example caliper tools is Schlumberger’s Multifinger Imaging Tool (Table 5.6). This tool is available in multiple sizes to accommodate various sizes of well tubing and casing.

Ultrasonic tools are capable of measuring wall thickness in addition to the inner diameter (radius) of the well tubular. Consequently, these tools can also provide information about the outer surface of the casing or tubing. Examples of ultrasonic tools include Schlumberger’s Ultrasonic Casing Imager (UCI) and Ultrasonic Imager (USI). The USI can also be used for cement evaluation, as discussed below. Specifications for the USI tool are listed in Table 5.6.

Electromagnetic tools are able to distinguish between internal and external corrosion effects using variances in the magnetic flux of the tubular being investigated. These tools are able to provide mapped (circumferential) images with high resolution such that pitting depths, due to corrosion, can often be accurately measured. An example electromagnetic tool is Baker Hughes’ High-Resolution Vertilog (Table 5.6).

Mechanical caliper tools are excellent casing/tubing evaluation tools for internal macro-scale features of the casing/tubing string. Ultrasonic tools, such as the USI, are able to further refine the scale of feature detection and can evaluate cement condition. However, electromagnetic tools offer the most sensitive means for casing/tubing corrosion detection. When conducting casing inspection logging, both an ultrasonic and an electromagnetic tool will be run to assess casing corrosion conditions (the ultrasonic tool will also be run to provide information on cement corrosion).

Well Cement

The cement associated with the long-string casing may be susceptible to corrosion where it is exposed to injected CO_2. Several measures will be taken during the construction and operation of the injection well to monitor the condition of the cement. As described in the Construction and Operations Plan (Chapter 4.0, Section 4.2.3), a corrosion-resistant cement will be used in this casing section to mitigate corrosion that could lead to the formation of channels that could transmit fluid. Furthermore, the condition of the cement will be determined initially when the casing string is cemented using cement-bond logging, and external mechanical integrity tests will be conducted periodically using temperature surveys or other means to look for evidence of fluid movement behind casing that could be caused by cement corrosion. In addition to these measures, cement-evaluation logging will be conducted whenever the tubing is removed from the injection well (i.e., during well workovers).

Types of cement-bond logging tools include conventional CBL (e.g., Baker Hughes' acoustic cement-bond log, CBL), acoustic pad-based (e.g., Baker Hughes' segmented bond tool [SBT]), and ultrasonic (e.g., Schlumberger's USI). Table 5.7 summarizes information for example acoustic and ultrasonic casing evaluation tools. These tools, or similar tools, from alternate vendors may be used to monitor the condition of well tubing and casing.

Table 5.7. Examples of Wireline Tools for Evaluating Cement Behind Casing

	Acoustic Tool	Acoustic Pad Tool	Ultrasonic Tool
Tool Name	Slim Cement Mapping Tool[a]	Segmented Bond Tool [b]	Ultrasonic Imager Tool[a]
Type	Acoustic	Acoustic	Ultrasonic
Parameter(s) measured	Acoustic signal attenuation VDL	Acoustic signal attenuation 360 degree borehole coverage VDL	Inner diameter, wall thickness, acoustic impedance, cement bonding to casing Up to 180 measurements per revolution
Tool O.D. (in.)	11.0625 and 2.0625	3.625	3.41 to 8.625
Tubular Size That Can Be Measured Minimum/ Maximum (in.)	2.375/8.875	4.5/13.375	4.5/13.375
Comments, limitations, special requirements, etc.	Can be run through tubing. Gives a radial map image of cement sheath	Not affected by borehole fluid type presence of gas. Can detect channeling and gives VDL output.	Can detect evidence of defects/corrosion on casing walls (internal/external), quality of cement bond to pipe, and channels in cement. Moderate logging speed (30 ft/min) is possible.

(a) Schlumberger Limited
(b) Baker Hughes, Inc.
NA = not available.

A traditional, acoustic bond logging tool is a simple arrangement that requires an acoustic signal transmitter and one or more receivers. The transmitted signal strength is compared to the strength of the received signal to qualitatively infer the quality/amount of cement present behind the casing string (where a more attenuated return signal indicates a better cement bond). The received signal's wave train is often represented in a variable-density log (VDL) display where various signal arrivals can be inferred (e.g., mud, casing, cement, formation). However, these traditional acoustic tools often require an omni-directional averaging method, which results in a limited ability to detect channeling in the cement sheath. Therefore, some tools offer multiple receivers, which reduces the radial averaging requirement and allows for a presentation of a radial image (e.g., Schlumberger's slim cement mapping tool).

Baker Hughes' pad-based SBT uses an acoustic transmitter/receiver setup similar to a traditional acoustic logging tool but instead uses six pads that make contact with the inner casing walls. This technology boosts the signal-to-noise ratio resulting in higher data quality and interpretability. In addition, each pad is able to measure a 60-degree swath of the cross-sectional well-bore area, which allows for enhanced channel detection in the cemented annular space. Data collected using the SBT can also be presented as a VDL.

An ultrasonic casing evaluation tool, specifically Schlumberger's USI, is an example of a wireline logging tool that is capable of assessing the condition of the cement behind casing at the same time that the casing integrity is being evaluated. One limitation of the USI, specifically, is that only the casing-to-cement bond is evaluated. That is, no direct information is collected on the cement-to-formation contact. In addition, a VDL presentation with any ultrasonic tool is not possible. For this reason, two bond logs are often collected, one ultrasonic and one acoustic, where the interpretation from each can be verified using the other.

For cement evaluation, both an ultrasonic and an acoustic logging tool will be run when conducting casing inspection logging because information provided by ultrasonic tools is limited to the cement-to-casing bond; whereas, the condition of the cement beyond the casing-cement contact will be provided by the acoustic logging tool. The cement associated with the section of long-string casing that spans the confining layers will be the primary focus of the cement-evaluation logging.

5.3.3 Well Annulus Pressure Maintenance and Monitoring System

The injection wells will be constructed with an annulus pressure control system to maintain annular fluid in each well at a prescribed pressure. A comprehensive automated WAPMMS will be designed and implemented. The preliminary WAPMMS design specifications presented in this section may be revised before the system is constructed.

The WAPMMS includes piping, instrumentation valves, controls, and other equipment to accomplish several functions, including the following:

- Maintain a prescribed pressure on the annular fluid in the well and a downward pressure differential across the packer. If annular (surface) pressure must be maintained at a value greater than the injection pressure, the maximum annulus pressure will not exceed a value that is more than ~200 psi greater than injection pressure at the surface. Otherwise, the maximum annulus (surface) pressure will not exceed a value that would result in a pressure at the top of the packer that is greater than the pressure inside the tubing when the bottom-hole injection pressure is at the maximum allowable pressure

- Automatically deliver annular fluid to the well when the fluid volume in the well decreases because of temperature and/or pressure changes or leaks in the well.
- Automatically remove annular fluid from the wells when the fluid volume in the well increases because of temperature and/or pressure changes.
- Continuously monitor injection well parameters including annular pressure, wellhead pressure and temperature, and bottom-hole pressure and temperature.
- Monitor parameters (e.g., pressure, temperature, fluid levels, air pressure) associated with the pressure-maintenance system.
- Automatically cease CO_2 injection to the wells when injection pressure or annulus pressure fall outside of prescribed limits.

During operation, the annular fluid pressurization system will be monitored and important parameters will be electronically recorded for documentation and review. The system will be equipped with alarms to warn of impending noncompliance or out-of-operating-parameter excursions.

5.3.4 Injection Well Control and Alarm System

The injection process will be monitored by the WAPMMS, an integrated system of equipment (tanks, lines, pumps, valves) and instrumentation (pressure and temperature transmitters) that will be capable of detecting when injection conditions are out of acceptable limits and responding by either adjusting conditions or halting injection. The system is designed to operate automatically with minimal operator intervention. The proposed control system for the WAPMMS consists of a local PLC interfaced with the control room (located at the power plant) distributed control system via a communications network. The WAPMMS PLC will provide control and monitoring of the injection pressure, annular pressure, and related parameters associated with the WAPMMS.

5.4 Monitoring, Verification, and Accounting

The testing and monitoring activities described in Section 5.2 are designed to collect the data necessary to verify that CO_2 is effectively sequestered within the targeted deep geologic formation and track the total mass of CO_2, including any potential injection zone containment loss and migration into overlying formations. The monitoring network design includes one ACZ monitoring well installed to just above the primary confining zone for enhanced early-detection capability. Such monitoring, along with direct and indirect (i.e., geophysical) measurements made within the injection zone, will facilitate timely and effective indications of CO_2 migration beyond the injection zone. The monitoring design will also consider inclusion of other surface or near-surface-monitoring approaches that provide for supplemental, broad-area indicators of CO_2 leakage along unidentified preferential transport pathways. As discussed in Section 3.2, no preferential pathways are known to exist within the defined AoR for the Morgan County storage site. These proposed secondary near-surface-monitoring systems will ensure that any potential impacts on near-surface environments, including impacts on shallow USDW aquifers, are quantitatively assessed relative to baseline conditions. This multi-component “lines of evidence” approach to monitoring and detection will increase the likelihood that any significant release of CO_2 from the injection zone is identified and mitigated in a timely manner.

Throughout the operational and post-operational phases of the project, collected monitoring data and numerical simulation will be used to evaluate the CO_2 mass balance for the injection zone. The mass balance will be based on the mass of CO_2 injected, the estimated mass present within the injection zone (based on direct and indirect monitoring techniques), and any identified containment loss. The model will be used to evaluate observed tracer and/or CO_2 arrival responses and predict when arrival will occur at more distal locations and later times. If significant discrepancies exist between the mass injected and the predicted/observed spatial extent of the CO_2 plume, this will provide additional evidence that injection zone containment loss may be occurring. If a release is confirmed through mass balance analysis and/or direct measurement of impacts occurring above the primary confining zone, the environmental release model will be used to estimate the magnitude of the leak and assess potential migration rates and pathways for CO_2 transport to shallower depths. Numerical models will be routinely validated and recalibrated to observed responses and will be used to guide modification of the monitoring program if required.

5.5 Schedule

There will be three general phases of aqueous monitoring: baseline monitoring, active injection monitoring, and post-injection monitoring. The approximate duration of these defined phases is 3 years, 20 years, and 50 years, respectively.

5.6 Data Management

The Project Data Management Plan[1] identifies how the information and data collected or generated for the storage facility task will be stored and organized to support all phases of the project. It describes the institutional responsibilities and requirements for managing relevant data, including the types of data to be managed and how the data will be managed and made available to prospective users. There are various needs/uses for data and information throughout the life of the project. These needs include site selection and evaluation, characterization, regulatory permitting, storage facility design, operation and monitoring, and post-closure monitoring. Data and information management needs will also change over the life of the project, and, given the long-term nature of the project life cycle, there will be many organizational and personnel changes, as well as major changes in the technologies used to acquire, record, and manage data and information. As these changes take place the data management strategies and tools will be revised and updated, as needed.

The primary objectives of the monitoring program are to track the lateral extent of the CO_2 plume and the pressure front within the target reservoir, characterize any geochemical or geomechanical changes that occur within the reservoir and overlying caprock, determine whether the injected CO_2 is effectively contained within the injection zone, and, if any release is indicated, quantify the size of the leak and the potential impacts on USDW aquifer water quality. The monitoring program will also be designed to identify and assess any impacts on near-surface soil-gas composition, atmospheric CO_2 concentrations, or ecological receptors. The data management plan is designed to facilitate compliance with EPA-specified requirements in 40 CFR 146.91. Particular care will be taken to provide secure and easily retrievable

[1] Last GV, MA Chamness, MT Schmick, and DC Lanigan. June 2011. *FutureGen Support Project Data Management Plan*. (Accessed at FUTUREGEN 2.0 > Site Characterization > Storage Facility Task > 1.0 Task Management > Project Data Management > Data Management Plan)

storage of all forms of data throughout the life of the GS project and for 10 years after site closure consistent with 40 CFR 146.91 (f). All required reports, submittals, and notifications will be issued to the EPA in an electronic format approved by the EPA.

The monitoring program is broken down into several tasks: reservoir monitoring (including continuous, quarterly, and periodic measurements/sampling), deep-leak-detection monitoring, USDW aquifer monitoring, soil-gas monitoring, atmospheric monitoring, and ecological monitoring. Each of these monitoring tasks produces different types of data and has different data management needs (input, storage, manipulation, querying, access/output). Thus, the data management program will develop and maintain a number of "semi-autonomous" databases under individual tasks, subject to their compatibility with an overarching distributed data management system. These individual heterogeneous databases will eventually all be linked to a centralized database and file archival system, eventually housed at a local visitor/training center.

A wide variety of monitoring data will be collected specifically for this project, under appropriate quality assurance protocols (e.g., screening data might have less stringent requirements than compliance monitoring data). These data will come in many different forms including hard copy, electronic image files, digitally collected, telemetered and recorded data, acquired digital data (e.g., remote sensing), and even physical samples. Each data form will require different data management protocols and storage/management tools from simple file management to relational databases to geographic information systems

Subject matter experts will screen, validate, and/or pre-process raw data (e.g., average high-frequency continuous data over various time intervals, or deconvolve composite analyses) to produce "science-ready" and/or "interpreted" data sets. Data with different levels of quality assurance documentation (e.g., legacy data vs compliance-driven data) and at different levels of processing/verification should all be managed separately. To this end, the following data classifications/groupings are defined:

- Level 0 – Legacy data with little or no substantial documentation or quality.
- Level 1 – Raw data (resulting from some procedure or technology).
- Level 1.5 – Cleaned raw data (raw data that has been scrubbed for duplicates, gaps, corrupted data, qualification flags, etc.). Need to capture the verification/validation/scrubbing procedures.
- Level 2 – Processed data (the cleaned or raw data that has been processed, normalized, or otherwise transformed using some model, code, algorithms, etc.). Need to capture the pedigree of how the data was processed—what code or algorithms were used (input and output files).
- Level 3 – Interpreted/subjective data sets (e.g., geologists' visual descriptions of cuttings and core, stratigraphic contacts, assumed/estimated parameter values). Need to capture assumptions, criteria, data sets, etc. forming the basis for interpretation.
- Level 4 – Averaged, upscaled, or statistically summarized or otherwise reconfigured parameter data sets destined for use as model/simulation input parameters. Need to capture methods, data sets, etc. used to generate input data.

The data management approach will consist of a number of different database/file management systems, each with its own data management protocols/procedures, etc. A detailed description of this relational database structure will be documented in the Project Data Management Plan.

5.7 Testing and Monitoring Plan Maintenance

This Testing and Monitoring Plan will be reviewed, at a minimum, after each reevaluation of the AoR, and amended as necessary. This reevaluation process will occur at least every 5 years. Results from the AoR reevaluation, which will include a comprehensive interpretation of the monitoring data, operational data, and any newly collected site-characterization data, will be used to assess the need for a Testing and Monitoring Plan amendment. Other conditions that would trigger a review of the Testing and Monitoring Plan include, but are not limited to 1) changes to (or the addition of) a Class VI injection well and/or significant changes to the monitoring network design, 2) changes to the AoR determination, 3) evidence of CO_2 migration through the caprock or other release-related changes in water quality, 4) well construction or mechanical integrity concerns, and 5) adverse events that require implementation of the Emergency Response Plan (Chapter 8.0 of this supporting documentation). Prior to amending the Testing and Monitoring Plan, findings will be discussed with the UIC Program Director to determine whether it is required.

5.8 Quality Assurance and Surveillance Plan

Data quality assurance and surveillance protocols adopted by the project will be designed to facilitate compliance with the requirements specified in 40 CFR 146.90(k). Quality Assurance (QA) requirements for direct measurements within the injection zone, above the confining zone, and within the shallow USDW aquifer that are critical to the MVA program (e.g., pressure and aqueous concentration measurements) are covered in Sections 5.2.2 and 5.2.3 above. QA requirements for selected geophysical methods, which provide indirect measurements of CO_2 nature and extent and are being tested for their applicability under site conditions, are not addressed in this plan. These measurements will be performed based on best industry practices and the QA protocols recommended by the geophysical services contractors selected to perform the work.

5.9 References

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9.0 Financial Responsibility

This chapter describes financial responsibilities related to the construction and operation of four horizontal wells for the injection of CO_2 in Morgan County, Illinois. The chapter first describes the Alliance's approach to demonstrating and maintaining financial responsibility for the construction, operation, closure, and monitoring of the proposed injection wells (Section 9.1). It then provides an overview of the cost of hiring a third party to perform corrective actions, if needed, on wells in the AoR after injection begins,[1] injection well plugging, post-injection site care and site closure, and emergency and remedial response actions if needed (Section 9.2). Section 9.3 describes the Alliance's proposed CO_2 Storage Trust Fund that will be available for corrective actions required after injection begins, injection well plugging, and post-injection site care, and site closure. Section 9.4 describes the Alliance's proposed third-party insurance policy that would be available for conducting any necessary emergency or remedial response actions. References are provided in Section 9.5.

9.1 Alliance Financial Requirements Compliance Approach

The Alliance plans to use a trust fund and third-party insurance to provide sufficient funding for actions that will or may need to be taken to protect USDWs within the AoR, which is defined in Chapter 3.0 of this supporting documentation. Together, these instruments will be sufficient to address endangerment of USDWs. Table 9.1 summarizes the approach the Alliance proposes to use to meet the financial responsibility requirements. Each of these instruments is described in full in subsequent sections of this chapter. Information related to the financial instruments will be updated on an annual basis and submitted to the U.S. EPA Director for review.

[1] With the exception of the FutureGen stratigraphic well, no wells located within the AoR extend to the confining zone (see Section 2.7.3). In fact, the closest penetration of the confining zone is approximately 16 mi (26 km) from the proposed injection wells (see Section 3.2.1). The modeling described in Chapter 3.0, Area of Review and Corrective Action Plan, shows that the projected CO_2 plume will not extend to this distance. Thus, there are no active or abandoned wells or underground mines that penetrate the confining zone in the AoR. For this reason, the Alliance does not expect to need to undertake any corrective actions before the start of CO_2 injection at the Morgan County CO_2 storage site or during the planned injection of up to 22 MMT over approximately 20 years. However, for purposes of the third-party cost estimate, the Alliance assumed that during the injection or post-injection period one previously unidentified well penetrating the confining zone would need to undergo corrective action to protect USDWs.

Table 9.1. Approach to Meeting Financial Responsibility Requirements

Required Activity	Qualifying Financial Instrument	Description
Corrective Actions (as necessary following periodic reevaluation of AoR)	CO_2 Storage Trust Fund	• Established pursuant to the U.S. Environmental Protection Agency (EPA) Geologic Sequestration (GS) Financial Responsibility regulation (40 CFR 146.85) • Created prior to injection • Held in trust by U.S. Bank National Association, as trustee
Injection Well Plugging	CO_2 Storage Trust Fund	• Same as above
Post-Injection Site Care and Site Closure	CO_2 Storage Trust Fund	• Same as above
Emergency and Remedial Response Actions	Third-Party Insurance	• Established pursuant to EPA GS Financial Responsibility regulation (40 CFR 146.85) • Pollution Legal Liability policy, with carbon capture and sequestration endorsement, placed prior to injection

9.2 Detailed Cost Estimate

To demonstrate that the financial instruments used by the Alliance will be sufficient to protect USDWs within the AoR, the Alliance asked Patrick Engineering, Inc., a nationwide engineering, design, and project management firm, to prepare a detailed estimate of the costs (in 2012 dollars) associated with corrective action on wells within the AoR after the start of injection, injection well plugging, post-injection site care, site closure, and emergency and remedial response actions that would or could be needed to protect USDWs. The cost estimate, which is contained in Appendix C, assumes that these costs would be incurred if the Alliance was no longer involved in the FutureGen 2.0 Project and a third party was asked to conclude the project. For that reason, the estimate includes costs such as project management and oversight, general and administrative costs, overhead, and profit.

The cost estimate is based upon historic price data from other projects managed by Patrick Engineering, Inc., cost quotes from third-party companies, EPA guidance documents, and professional judgment about the level of effort required to complete an activity. The estimated costs for each planned activity are listed in Table 9.2. Although the probability of such events occurring is extremely low, the types of events that could require emergency and remedial response actions and the cost of such actions are listed in Table 9.3. This information is consistent with Chapter 8.0, Emergency and Remedial Response Plan.

Table 9.2. FutureGen 2.0 Third-Party Cost Estimate for Planned Activities

Required Activity	Cost Estimate ($ millions)
AoR and Corrective Action	0.623
Injection & Monitoring Well Plugging (including site reclamation)	2.723
Post-Injection Site Care	18.32
Site Closure	3.402
Total	25.068

Table 9.3. FutureGen 2.0 Third-Party Cost Estimate for Emergency and Remedial Response Actions

	Required Activity	Cost Estimate ($ millions)
1.	**Post-injection USDW contamination**	
	Acidification due to migration of CO_2	0.305
	Toxic metal dissolution and mobilization	5.865
	Displacement of groundwater with brine due to CO_2 injection	0.270
2.	**Post-injection failure scenarios (acute)**	
	Upward migration through CO_2 injection well	3.343
	Upward migration through deep oil and gas wells	2.111
	Upward migration through undocumented, abandoned, or poorly constructed wells	2.111
3.	**Post-injection failure scenarios (chronic)**	
	Upward migration as a result of the gradual failure of the confining zone(s)	5.865
	Release through existing faults due to effects of increased pressure	5.865
	Release through induced faults due to effects of increased pressure	6.10
	Upward migration through CO_2 injection well	0.821
	Upward migration through deep oil and gas wells	0.411
	Upward migration through undocumented, abandoned, or poorly constructed deep wells	0.411
4.	**Other**	
	Catastrophic failure of confining zone(s)	6.10
	Failure of confining zone(s) or well integrity due to seismic event	6.10

9.3 CO_2 Storage Trust Fund

This section describes the selection of a trustee for the CO_2 Storage Trust Fund, the Trust Agreement, and the financial strength of the trustee. The trust fund will be established prior to injection and will be designed to meet the requirements of 40 CFR 146.85.

The Alliance expects that DOE will share the cost of the initial funding of the trust in a manner similar to the cost-sharing for other project-related expenses. The initial funding level has not yet been determined. The trust fund will be available for corrective action on wells within the AoR after the start of injection and, after injection ceases, for injection well plugging, post-injection site care, and site closure. The trust funds will be available to the Alliance or to a third party if the Alliance were no longer involved in the FutureGen 2.0 Project.

9.3.1 Trustee Selection

On October 27, 2011, the Alliance sent requests to eight local, regional, and national banks seeking a statement of qualifications for the management of an irrevocable trust to meet the Alliance’s obligations for injection well plugging and post-injection site care and site closure. The Alliance provided the trustee requirements and specifications that prospective trustees must meet and provided the draft Trust Agreement included in *Underground Injection Control (UIC) Program Class VI Financial Responsibility Guidance, Appendix B* (EPA 2011). Expressions of interest were due to the Alliance by November 15, 2011.

On December 19, 2011, the Alliance sent a formal Request for Proposal to the four banks that had expressed interest in serving as the trustee for the CO_2 Storage Trust Fund; clarifications were issued on January 10, 2012. On January 13, 2012, the four banks submitted their proposals.

Each proposal was reviewed and evaluated by a four-member review committee that assigned scores to price and non-price proposal responses. The price portion of the proposal was worth 33.3 percent of the total score and was based on five different categories such as setup fees, transaction fees, and other costs and fees. The non-price portion was worth 67.7 percent of the total score and was based on 14 different categories including the type, size, and location of assets held; the banks' ratings; and their experience working with federal agencies.

Based on the scoring summarized above, the review team unanimously recommended that the Alliance enter into negotiations with U.S. Bank as the prospective trustee in support of the financial assurance requirements associated with the UIC permit application.

9.3.2 Trust Agreement

U.S. Bank stated that it is able to accept a form of trust agreement that largely conforms to the Sample Trust Agreement provided by the Alliance, which includes the terms recommended by the EPA.

9.3.3 Financial Strength of the Trustee

U.S. Bank has been providing trust services for more than 100 years and currently administers more than 120,000 client matters in its Corporate Trust Division with $4 trillion in assets under its administration. U.S. Bank has trusts in Morgan County, Illinois, that have assets of between $200 million and $300 million. U.S. Bank has a credit rating in the top categories from all of Standard & Poor's or Moody's Investor Service and Fitch Ratings. Importantly, U.S. Bank serves as trustee on more than 200 environmental protection or remediation trusts, including trust estates of hundreds of millions of dollars. The bank is involved in environmental trusts involving multiple beneficiaries including EPA and state environmental protection agencies.

9.4 Third-Party Insurance

This section describes the manner in which the Alliance will select a third-party insurer, develop an insurance estimate, obtain proof of insurance, and confirm the financial strength of the insurer.

9.4.1 Selection of Third-Party Insurer

The Alliance has procured the services of McGriff, Siebels & Williams (McGriff), an insurance broker operating as a separate, wholly owned subsidiary of BB&T Insurance Services. As the largest independent energy broker in the United States, McGriff serves as the broker to electric generation, natural gas, water and wastewater treatment, and energy services companies, among others. McGriff developed and placed the first insurance policy for CCS liability, representing American Electric Power on the Mountaineer Project. The company is currently engaged with multiple CCS projects on their insurance program development and management.

McGriff prepared a memorandum for the Alliance that describes the applicable insurance products, expected policy terms and conditions, exclusions, and costs and deductibles. That memorandum and a specimen policy form with a sample CCS endorsement are contained in Appendix D. A summary of the information provided by McGriff is provided in the following sections.

9.4.2 Insurance Estimate and Application

The Alliance intends to secure third-party insurance to cover the potential need to undertake emergency and remedial response actions to protect USDWs in the AoR. Although the Alliance has been able to obtain information about the possible terms, conditions, and cost of such a policy, the Alliance has not yet applied for such a policy. This section describes the type of coverage that the Alliance expects to obtain from a third-party insurer, including protective conditions of coverage (cancellation, renewal, and continuation provisions). Additional information about deductions, exceptions, and the premium to be paid is also provided.

9.4.2.1 Type of Coverage

After surveying the insurance marketplace, it is McGriff's understanding and opinion that the purchase of a Pollution Legal Liability (PLL) policy will provide insurance coverage for cleanup costs if the Alliance were to become legally obligated to remediate contamination of USDWs. The Alliance expects to obtain a PLL insurance policy, which will include a specifically crafted endorsement designed to address the environmental risk exposures for CCS injection and storage operations. PLL insurance can generally be obtained for bodily injury, property damage, and remediation costs arising from pollution-related exposures and would include coverage for defense costs. PLL policies contain an aggregate limit of liability for the term of the policy. To protect other aspects of the Alliance's FutureGen 2.0 activities, a PLL policy would cover costs in excess of those needed to carry out any possible emergency and remedial response actions.

A PLL policy would cover the following identified events affecting a USDW and requiring emergency and remedial response actions:

- acidification due to migration of CO_2
- toxic metal dissolution and mobilization
- displacement of groundwater with brine due to CO_2 injection
- acute and chronic upward migration through the CO_2 injection well
- acute and chronic upward migration through deep oil and gas wells
- acute and chronic upward migration through undocumented, abandoned, or poorly constructed wells
- upward migration as a result of the gradual failure of the confining zone(s)
- release through existing or induced faults due to effects of increased pressure
- catastrophic failure of the confining zone(s)
- failure of the confining zone(s) or well integrity due to seismic events.

In order for the policy to respond to the events listed above, the action must fall within the definition of "cleanup costs" and be required by "environmental law." The specimen policy definition of "cleanup costs" is as follows:

Clean-Up Costs means reasonable and necessary expenses, including legal expenses incurred with the Company's written consent which consent shall not be unreasonably withheld or delayed, for the investigation, removal, treatment including in situ treatment, remediation including associated monitoring, or disposal of soil, surface water, groundwater, microbial matter, Legionella pneumophila, or other contamination:

1. *To the extent required by environmental laws or required to satisfy a Voluntary Cleanup Program;*
2. *With respect to Microbial Matter, in the absence of any applicable Environmental Laws, to the extent recommended in writing by a Certified Industrial Hygienist; or*
3. *With respect to Legionella pneumophila, in the absence of any applicable Environmental Laws, to the extent required in writing by the Center for Disease Control or local health department; or*
4. *That have been actually incurred by the government or any political subdivision of the U.S. or any state thereof or Canada or any province thereof, or by third parties.*

Clean-Up Costs also include Restoration Costs.

The specimen policy definition of "environmental law" is as follows:

Environmental Law means any federal, state, provincial or local laws (including, but not limited to, statutes, rules, regulations, ordinances, guidance documents, and governmental, judicial or administrative orders and directives) that are applicable to the pollution condition.

Other specific information regarding expected coverage is contained in the specimen policy form in Appendix D (Section I).

9.4.2.2 Coverage Limits

McGriff believes that the greatest exposure would be a catastrophic failure of the confining zone, which would have an estimated cost of $6.1 million for emergency and remedial response actions to protect USDWs (see Third-Party Cost Estimate in Appendix C). Because the actual claim amount could be much higher, McGriff recommends that the Alliance purchase $100 million in insurance coverage. The limits of liability are discussed in more detail in the specimen policy form in Appendix D (Section V).

9.4.2.3 Deductible

Based on its experience in placing other CCS policies, McGriff indicates that the deductible would be $250,000. The deductible is discussed in more detail in the specimen policy form in Appendix D (Section V(F)).

9.4.2.4 Exclusions

The common exclusions applicable to all coverages are contained in the specimen policy form in Appendix D (Section II).

9.4.2.5 Renewal

McGriff indicates that the insurance market currently offers PLL policy terms of 3 to 5 years, depending on the required limit of liability. The market, at this time, will not guarantee renewal of such a policy because market conditions at expiration, loss of reinsurance capacity, or risk appetite for CCS exposures may limit the ability of the insurers to offer renewal terms.

9.4.2.6 Cancellation

The terms under which the policy may be cancelled are contained in the specimen policy form in Appendix D (Section VI(G)). In general, the policy may be cancelled by the Alliance by surrender of the policy. It may be cancelled by the insurance company only for nonpayment of the premium, misrepresentation by the Alliance, failure of the Alliance to comply with material terms, or a change in use or operation.

9.4.2.7 Premium

McGriff estimates that a $100 million insurance policy with a deductible of $250,000 would cost between $625,000 and $825,000 annually. This is only an estimate; the premium will be determined based on information provided to the underwriter prior to a cost quotation.

9.4.3 Proof of Insurance

Proof of insurance will be provided when the insurance policy is obtained, prior to injection.

9.4.4 Financial Strength of Insurer

The financial strength of the insurer will be an important component of the Alliance's selection of an insurer. Information regarding the insurer's financial strength will be provided to the EPA when the insurer is selected.

9.5 References

40 CFR 146.85. Code of Federal Regulations, Title 40, *Protection of the Environment*, Part 146, "Underground Injection Control Program: Criteria and Standards," Section 85, "Financial responsibility."

Clean Coal FutureGen for Illinois Act. Illinois Public Act 097-0618, effective October 26, 2011

EPA (U.S. Environmental Protection Agency). 2011. *UIC Program Class VI Financial Responsibility Guidance,* Appendix B (Recommended Financial Responsibility Instruments). EPA 816-R-11-005, Washington, D.C.

Appendix A

Requirements Matrices

Appendix A

Requirements Matrices

The following tables specify where in this supporting documentation the applicable regulatory provisions in the Geologic Sequestration Rule are addressed. Table A.1 addresses the required information in 40 CFR 146.82(a), Table A.2 addresses the minimum criteria for siting in 40 CFR 146.83, and Table A.3 addresses the criteria and standards in 40 CFR 146.84 through 146.95.

Table A.1. Required Class VI Permit Information

40 CFR §146.82(a) - Required Class VI permit information		FutureGen Alliance UIC Permit Application
(a) Prior to the issuance of a permit for the construction of a new Class VI well or the conversion of an existing Class I, Class II, or Class V well to a Class VI well, the owner or operator shall submit, pursuant to §146.91(e), and the Director shall consider the following:		
(1) Information required in §144.31 (e)(1) through (6) of this Section;	§144.31 (e)(1) - (6) Information Requirements	Section 1
	(1) The activities conducted by the applicant which require it to obtain permits under RCRA, UIC, the National Pollution Discharge Elimination System (NPDES) program under the Clean Water Act, or the Prevention of Significant Deterioration (PSD) program under the Clean Air Act.	Section 1
	(2) Name, mailing address, and location of the facility for which the application is submitted.	Section 1, Table 1.2
	(3) Up to four SIC codes which best reflect the principal products or services provided by the facility.	Section 1, Table 1.2
	(4) The operator's name, address, telephone number, ownership status, and status as Federal, State, private, public, or other entity.	Section 1, Table 1.2
	(5) Whether the facility is located on Indian lands.	Section 1, Table 1.2
	(6) A listing of all permits or construction approvals received or applied for under any of the following programs:	
	(i) Hazardous Waste Management program under RCRA.	Section 1, Table 1.3
	(ii) UIC program under SDWA.	Section 1, Table 1.3
	(iii) NPDES program under CWA.	Section 1, Table 1.3
	(iv) Prevention of Significant Deterioration (PSD) program under the Clean Air Act.	Section 1, Table 1.3
	(v) Nonattainment program under the Clean Air Act.	Section 1, Table 1.3
	(vi) National Emission Standards for Hazardous Pollutants (NESHAPS) preconstruction approval under the Clean Air Act.	Section 1, Table 1.3
	(vii) Ocean dumping permits under the Marine Protection Research and Sanctuaries Act.	Section 1, Table 1.3
	(viii) Dredge and fill permits under section 404 of CWA	Section 1, Table 1.3
	(ix) Other relevant environmental permits, including State permits.	Section 1, Table 1.3

Table A.1. (contd)

40 CFR §146.82(a) - Required Class VI permit information	FutureGen Alliance UIC Permit Application
(2) A map showing the injection well for which a permit is sought and the applicable area of review consistent with §146.84. Within the area of review, the map must show the number or name, and location of all injection wells, producing wells, abandoned wells, plugged wells or dry holes, deep stratigraphic boreholes, State- or EPA-approved subsurface cleanup sites, surface bodies of water, springs, mines (surface and subsurface), quarries, water wells, other pertinent surface features including structures intended for human occupancy, State, Tribal, and Territory boundaries, and roads. The map should also show faults, if known or suspected. Only information of public record is required to be included on this map;	Section 2, Figure 2.33
(3) Information on the geologic structure and hydrogeologic properties of the proposed storage site and overlying formations, including:	Section 2
(i) Maps and cross sections of the area of review;	Section 2, various
(ii) The location, orientation, and properties of known or suspected faults and fractures that may transect the confining zone(s) in the area of review and a determination that they would not interfere with containment;	Section 2
(iii) Data on the depth, areal extent, thickness, mineralogy, porosity, permeability, and capillary pressure of the injection and confining zone(s); including geology/facies changes based on field data which may include geologic cores, outcrop data, seismic surveys, well logs, and names and lithologic descriptions;	Section 2
(iv) Geomechanical information on fractures, stress, ductility, rock strength, and in situ fluid pressures within the confining zone(s);	Section 2.4
(v) Information on the seismic history including the presence and depth of seismic sources and a determination that the seismicity would not interfere with containment; and	Section 2.5
(vi) Geologic and topographic maps and cross sections illustrating regional geology, hydrogeology, and the geologic structure of the local area.	Section 2
(4) A tabulation of all wells within the area of review which penetrate the injection or confining zone(s). Such data must include a description of each well's type, construction, date drilled, location, depth, record of plugging and/or completion, and any additional information the Director may require;	Section 2.8
(5) Maps and stratigraphic cross sections indicating the general vertical and lateral limits of all USDWs, water wells and springs within the area of review, their positions relative to the injection zone(s), and the direction of water movement, where known;	Section 2.6, 2.8
(6) Baseline geochemical data on subsurface formations, including all USDWs in the area of review;	Section 2.2, Section 2.6
(7) Proposed operating data for the proposed geologic sequestration site:	Section 4
(i) Average and maximum daily rate and volume and/or mass and total anticipated volume and/or mass of the carbon dioxide stream;	Section 4.1.3
(ii) Average and maximum injection pressure;	Section 4.2.1

Table A.1. (contd)

40 CFR §146.82(a) - Required Class VI permit information	FutureGen Alliance UIC Permit Application
(iii) The source(s) of the carbon dioxide stream; and	Section 4.1.1
(iv) An analysis of the chemical and physical characteristics of the carbon dioxide stream.	Section 4.1.2
(8) Proposed pre-operational formation testing program to obtain an analysis of the chemical and physical characteristics of the injection zone(s) and confining zone(s) and that meets the requirements at §146.87;	Section 4.3, 5.2.3.1
(9) Proposed stimulation program, a description of stimulation fluids to be used and a determination that stimulation will not interfere with containment;	Section 4.4
(10) Proposed procedure to outline steps necessary to conduct injection operation;	Section 4.0
(11) Schematics or other appropriate drawings of the surface and subsurface construction details of the well;	Section 4.2.6
(12) Injection well construction procedures that meet the requirements of §146.86;	Section 4.2
(13) Proposed area of review and corrective action plan that meets the requirements under §146.84;	Section 3
(14) A demonstration, satisfactory to the Director, that the applicant has met the financial responsibility requirements under §146.85;	Section 9
(15) Proposed testing and monitoring plan required by §146.90;	Section 5
(16) Proposed injection well plugging plan required by §146.92(b);	Section 6
(17) Proposed post-injection site care and site closure plan required by §146.93(a);	Section 7
(18) At the Director's discretion, a demonstration of an alternative post-injection site care timeframe required by §146.93(c);	The Alliance is not proposing an alternative timeframe at this time.
(19) Proposed emergency and remedial response plan required by §146.94(a);	Section 8
(20) A list of contacts, submitted to the Director, for those States, Tribes, and Territories identified to be within the area of review of the Class VI project based on information provided in paragraph (a)(2) of this section; and	Section 8.5, Table 8.3, Table 8.4
(21) Any other information requested by the Director.	No additional information has been requested by the Director at this time.

Table A.2. Minimum Criteria for Siting

40 CFR §146.83 - Minimum Criteria for Siting	FutureGen Alliance UIC Permit Application
(a) Owners or operators of Class VI wells must demonstrate to the satisfaction of the Director that the wells will be sited in areas with a suitable geologic system. The owners or operators must demonstrate that the geologic system comprises:	Section 2
(1) An injection zone(s) of sufficient areal extent, thickness, porosity, and permeability to receive the total anticipated volume of the carbon dioxide stream;	Section 2.9
(2) Confining zone(s) free of transmissive faults or fractures and of sufficient areal extent and integrity to contain the injected carbon dioxide stream and displaced formation fluids and allow injection at proposed maximum pressures and volumes without initiating or propagating fractures in the confining zone(s).	Section 2.9, Conclusion of 2Summary
(b) The Director may require owners or operators of Class VI wells to identify and characterize additional zones that will impede vertical fluid movement, are free of faults and fractures that may interfere with containment, allow for pressure dissipation, and provide additional opportunities for monitoring, mitigation, and remediation.	No additional requirements have been imposed at this time.

Table A.3. Criteria and Standards Applicable to Class VI Wells

40 CFR Part 146, Subpart H - Criteria and Standards Applicable to Class VI Wells	FutureGen Alliance UIC Permit Application
§146.84 Area of review and corrective action.	
(a) The area of review is the region surrounding the geologic sequestration project where USDWs may be endangered by the injection activity. The area of review is delineated using computational modeling that accounts for the physical and chemical properties of all phases of the injected carbon dioxide stream and is based on available site characterization, monitoring, and operational data.	Section 3.1.8
(b) The owner or operator of a Class VI well must prepare, maintain, and comply with a plan to delineate the area of review for a proposed geologic sequestration project, periodically reevaluate the delineation, and perform corrective action that meets the requirements of this section and is acceptable to the Director. The requirement to maintain and implement an approved plan is directly enforceable regardless of whether the requirement is a condition of the permit. As a part of the permit application for approval by the Director, the owner or operator must submit an area of review and corrective action plan that includes the following information:	
(1) The method for delineating the area of review that meets the requirements of paragraph (c) of this section, including the model to be used, assumptions that will be made, and the site characterization data on which the model will be based;	Section 3.0
(2) A description of:	
(i) The minimum fixed frequency, not to exceed five years, at which the owner or operator proposes to reevaluate the area of review;	Section 3.1.9.1
(ii) The monitoring and operational conditions that would warrant a reevaluation of the area of review prior to the next scheduled reevaluation as determined by the minimum fixed frequency established in paragraph (b)(2)(i) of this section.	Section 3.1.9.2
(iii) How monitoring and operational data (e.g., injection rate and pressure) will be used to inform an area of review reevaluation; and	Section 3.1.9.2
(iv) How corrective action will be conducted to meet the requirements of paragraph (d) of this section, including what corrective action will be performed prior to injection and what, if any, portions of the area of review will have corrective action addressed on a phased basis and how the phasing will be determined; how corrective action will be adjusted if there are changes in the area of review; and how site access will be guaranteed for future corrective action.	Section 3.2.2
(c) Owners or operators of Class VI wells must perform the following actions to delineate the area of review and identify all wells that require corrective action:	
(1) Predict, using existing site characterization, monitoring and operational data, and computational modeling, the projected lateral and vertical migration of the carbon dioxide plume and formation fluids in the subsurface from the commencement of injection activities until the plume movement ceases, until pressure differentials sufficient to cause the movement of injected fluids or formation fluids into a USDW are no longer present, or until the end of a fixed time period as determined by the Director. The model must:	Section 3.0
(i) Be based on detailed geologic data collected to characterize the injection zone(s), confining zone(s) and any additional zones; and anticipated operating data, including injection pressures, rates, and total volumes over the proposed life of the geologic sequestration project;	Section 3.1.3

Table A.3. (contd)

40 CFR Part 146, Subpart H - Criteria and Standards Applicable to Class VI Wells	FutureGen Alliance UIC Permit Application
(ii) Take into account any geologic heterogeneities, other discontinuities, data quality, and their possible impact on model predictions; and	Section 3.1.3
(iii) Consider potential migration through faults, fractures, and artificial penetrations.	Section 3.2.1
(2) Using methods approved by the Director, identify all penetrations, including active and abandoned wells and underground mines, in the area of review that may penetrate the confining zone(s). Provide a description of each well's type, construction, date drilled, location, depth, record of plugging and/or completion, and any additional information the Director may require; and	Section 3.2.1
(3) Determine which abandoned wells in the area of review have been plugged in a manner that prevents the movement of carbon dioxide or other fluids that may endanger USDWs, including use of materials compatible with the carbon dioxide stream.	Section 3.2.1
(d) Owners or operators of Class VI wells must perform corrective action on all wells in the area of review that are determined to need corrective action, using methods designed to prevent the movement of fluid into or between USDWs, including use of materials compatible with the carbon dioxide stream, where appropriate.	Section 3.2
(e) At the minimum fixed frequency, not to exceed five years, as specified in the area of review and corrective action plan, or when monitoring and operational conditions warrant, owners or operators must:	
(1) Reevaluate the area of review in the same manner specified in paragraph (c)(1) of this section;	Section 3.1.9.1
(2) Identify all wells in the reevaluated area of review that require corrective action in the same manner specified in paragraph (c) of this section;	Section 3.2.2
(3) Perform corrective action on wells requiring corrective action in the reevaluated area of review in the same manner specified in paragraph (d) of this section; and	Section 3.2.2
(4) Submit an amended area of review and corrective action plan or demonstrate to the Director through monitoring data and modeling results that no amendment to the area of review and corrective action plan is needed. Any amendments to the area of review and corrective action plan must be approved by the Director, must be incorporated into the permit, and are subject to the permit modification requirements at §§144.39 or 144.41 of this Section, as appropriate.	Section 3.1.9.1
(f) The emergency and remedial response plan (as required by §146.94) and the demonstration of financial responsibility (as described by §146.85) must account for the area of review delineated as specified in paragraph (c)(1) of this section or the most recently evaluated area of review delineated under paragraph (e) of this section, regardless of whether or not corrective action in the area of review is phased.	Section 3.1.9.3
(g) All modeling inputs and data used to support area of review reevaluations under paragraph (e) of this section shall be retained for 10 years.	Section 3.1.9.3
§146.85 Financial responsibility.	
(a) The owner or operator must demonstrate and maintain financial responsibility as determined by the Director that meets the following conditions:	Section 9.0
(1) The financial responsibility instrument(s) used must be from the following list of qualifying instruments: (i) Trust Funds, (ii) Surety Bonds, (iii) Letter of Credit, (iv) Insurance, (v) Self Insurance (i.e., Financial Test and Corporate Guarantee), (vi) Escrow Account, (vii) Any other instrument(s) satisfactory to the Director	Section 9.1

Table A.3. (contd)

40 CFR Part 146, Subpart H - Criteria and Standards Applicable to Class VI Wells	FutureGen Alliance UIC Permit Application
(2) The qualifying instrument(s) must be sufficient to cover the cost of:	
(i) Corrective action (that meets the requirements of §146.84);	Section 9.1, Table 9.1
(ii) Injection well plugging (that meets the requirements of §146.92);	Section 9.1, Table 9.1
(iii) Post injection site care and site closure (that meets the requirements of §146.93); and	Section 9.1, Table 9.1
(iv) Emergency and remedial response (that meets the requirements of §146.94).	Section 9.1, Table 9.1 Section 9.4.2
(3) The financial responsibility instrument(s) must be sufficient to address endangerment of underground sources of drinking water.	Section 9.2
(4) The qualifying financial responsibility instrument(s) must comprise protective conditions of coverage.	
(i) Protective conditions of coverage must include at a minimum cancellation, renewal, and continuation provisions, specifications on when the provider becomes liable following a notice of cancellation if there is a failure to renew with a new qualifying financial instrument, and requirements for the provider to meet a minimum rating, minimum capitalization, and ability to pass the bond rating when applicable.	Appendix D
(A) Cancellation – for purposes of this part, an owner or operator must provide that their financial mechanism may not cancel, terminate or fail to renew except for failure to pay such financial instrument. If there is a failure to pay the financial instrument, the financial institution may elect to cancel, terminate, or fail to renew the instrument by sending notice by certified mail to the owner or operator and the Director. The cancellation must not be final for 120 days after receipt of cancellation notice.	Section 9.4.2.6
(B) Renewal – for purposes of this part, owners or operators must renew all financial instruments, if an instrument expires, for the entire term of the geologic sequestration project. The instrument may be automatically renewed as long as the owner or operator has the option of renewal at the face amount of the expiring instrument. The automatic renewal of the instrument must, at a minimum, provide the holder with the option of renewal at the face amount of the expiring financial instrument.	Section 9.4.2.5
(C) Cancellation, termination, or failure to renew may not occur and the financial instrument will remain in full force and effect in the event that on or before the date of expiration: the Director deems the facility abandoned; or the permit is terminated or revoked or a new permit is denied; or closure is ordered by the Director or a U.S. district court or other court of competent jurisdiction; or the owner or operator is named as debtor in a voluntary or involuntary proceeding under Title 11 (Bankruptcy), U.S. Code; or the amount due is paid.	Section 9.5
(5) The qualifying financial responsibility instrument(s) must be approved by the Director.	
(i) The Director shall consider and approve the financial responsibility demonstration for all the phases of the geologic sequestration project prior to issue a Class VI permit (§146.82).	
(ii) The owner or operator must provide any updated information related to their financial responsibility instrument(s) on an annual basis and if there are any changes, the Director must evaluate, within a reasonable time, the financial responsibility demonstration to confirm that the instrument(s) used remain adequate for use. The owner or operator must maintain financial responsibility requirements regardless of the status of the Director's review of the financial responsibility demonstration.	Section 9.1

Table A.3. (contd)

40 CFR Part 146, Subpart H - Criteria and Standards Applicable to Class VI Wells	FutureGen Alliance UIC Permit Application
(iii) The Director may disapprove the use of a financial instrument if he determines that it is not sufficient to meet the requirements of this section.	
(6) The owner or operator may demonstrate financial responsibility by using one or multiple qualifying financial instruments for specific phases of the geologic sequestration project.	Section 9.1
(i) In the event that the owner or operator combines more than one instrument for a specific geologic sequestration phase (e.g., well plugging), such combination must be limited to instruments that are not based on financial strength or performance (i.e., self insurance or performance bond), for example trust funds, surety bonds guaranteeing payment into a trust fund, letters of credit, escrow account, and insurance. In this case, it is the combination of mechanisms, rather than the single mechanism, which must provide financial responsibility for an amount at least equal to the current cost estimate.	Section 9.1, Table 9.1
(ii) When using a third-party instrument to demonstrate financial responsibility, the owner or operator must provide a proof that the third-party providers either have passed financial strength requirements based on credit ratings; or has met a minimum rating, minimum capitalization, and ability to pass the bond rating when applicable.	Section 9.3.3
(iii) An owner or operator using certain types of third party instruments must establish a standby trust to enable EPA to be party to the financial responsibility agreement without EPA being the beneficiary of any funds. The standby trust fund must be used along with other financial responsibility instruments (e.g., surety bonds, letters of credit, or escrow accounts) to provide a location to place funds if needed.	Section 9.3.2
(iv) An owner or operator may deposit money to an escrow account to cover financial responsibility requirements; this account must segregate funds sufficient to cover estimated costs for Class VI (geologic sequestration) financial responsibility from other accounts and uses.	Section 9.3
(v) An owner or operator or its guarantor may use self insurance to demonstrate financial responsibility for geologic sequestration projects. In order to satisfy this requirement the owner or operator must meet a Tangible Net Worth of an amount approved by the Director, have a Net working capital and tangible net worth each at least six times the sum of the current well plugging, post injection site care and site closure cost, have assets located in the United States amounting to at least 90 percent of total assets or at least six times the sum of the current well plugging, post injection site care and site closure cost, and must submit a report of its bond rating and financial information annually. In addition the owner or operator must either: have a bond rating test of AAA, AA, A, or BBB as issued by Standard & Poor's or Aaa, Aa, A, or Baa as issued by Moody's; or meet all of the following five financial ratio thresholds: a ratio of total liabilities to net worth less than 2.0; a ratio of current assets to current liabilities greater than 1.5; a ratio of the sum of net income plus depreciation, depletion, and amortization to total liabilities greater than 0.1; a ratio of current assets minus current liabilities to total assets greater than -0.1; and a net profit (revenues minus expenses) greater than 0.	Self-Insurance not invoked
(vi) An owner or operator who is not able to meet corporate financial test criteria may arrange a corporate guarantee by demonstrating that its corporate parent meets the financial test requirements on its behalf. The parent's demonstration that it meets the financial test requirement is insufficient if it has not also guaranteed to fulfill the obligations for the owner or operator.	Corporate guarantee not invoked.
(vii) An owner or operator may obtain an insurance policy to cover the estimated costs of geologic sequestration activities requiring financial responsibility. This insurance policy must be obtained from a third party provider.	Section 9.4

Table A.3. (contd)

40 CFR Part 146, Subpart H - Criteria and Standards Applicable to Class VI Wells	FutureGen Alliance UIC Permit Application
(b) The requirement to maintain adequate financial responsibility and resources is directly enforceable regardless of whether the requirement is a condition of the permit.	
(1) The owner or operator must maintain financial responsibility and resources until:	
(i) The Director receives and approves the completed post-injection site care and site closure plan; and	
(ii) The Director approves site closure.	
(2) The owner or operator may be released from a financial instrument in the following circumstances:	
(i) The owner or operator has completed the phase of the geologic sequestration project for which the financial instrument was required and has fulfilled all its financial obligations as determined by the Director, including obtaining financial responsibility for the next phase of the GS project, if required; or	
(ii) The owner or operator has submitted a replacement financial instrument and received written approval from the Director accepting the new financial instrument and releasing the owner or operator from the previous financial instrument.	
(c) The owner or operator must have a detailed written estimate, in current dollars, of the cost of performing corrective action on wells in the area of review, plugging the injection well(s), post-injection site care and site closure, and emergency and remedial response.	
(1) The cost estimate must be performed for each phase separately and must be based on the costs to the regulatory agency of hiring a third party to perform the required activities. A third party is a party who is not within the corporate structure of the owner or operator.	
(2) During the active life of the geologic sequestration project, the owner or operator must adjust the cost estimate for inflation within 60 days prior to the anniversary date of the establishment of the financial instrument(s) used to comply with paragraph (a) of this section and provide this adjustment to the Director. The owner or operator must also provide to the Director written updates of adjustments to the cost estimate within 60 days of any amendments to the area of review and corrective action plan (§146.84), the injection well plugging plan (§146.92), the post-injection site care and site closure plan (§146.93), and the emergency and remedial response plan (§146.94).	
(3) The Director must approve any decrease or increase to the initial cost estimate. During the active life of the geologic sequestration project, the owner or operator must revise the cost estimate no later than 60 days after the Director has approved the request to modify the area of review and corrective action plan (§146.84), the injection well plugging plan (§146.92), the post-injection site care and site closure plan (§146.93), and the emergency and response plan (§146.94), if the change in the plan increases the cost. If the change to the plans decreases the cost, any withdrawal of funds must be approved by the Director. Any decrease to the value of the financial assurance instrument must first be approved by the Director. The revised cost estimate must be adjusted for inflation as specified at paragraph (c)(2) of this section.	
(4) Whenever the current cost estimate increases to an amount greater than the face amount of a financial instrument currently in use, the owner or operator, within 60 days after the increase, must either cause the face amount to be increased to an amount at least equal to the current cost estimate and submit evidence of such increase to the Director, or obtain other financial responsibility instruments to cover the increase. Whenever the current cost estimate decreases, the face amount of the financial assurance instrument may be reduced to the amount of the current cost estimate only after the owner or operator has received written approval from the Director.	

Table A.3. (contd)

40 CFR Part 146, Subpart H - Criteria and Standards Applicable to Class VI Wells	FutureGen Alliance UIC Permit Application
(d) The owner or operator must notify the Director by certified mail of adverse financial conditions such as bankruptcy that may affect the ability to carry out injection well plugging and post-injection site care and site closure.	
(1) In the event that the owner or operator or the third party provider of a financial responsibility instrument is going through a bankruptcy, the owner or operator must notify the Director by certified mail of the commencement of a voluntary or involuntary proceeding under Title 11 (Bankruptcy), U.S. Code, naming the owner or operator as debtor, within 10 days after commencement of the proceeding.	
(2) A guarantor of a corporate guarantee must make such a notification to the Director if he/she is named as debtor, as required under the terms of the corporate guarantee.	
(3) An owner or operator who fulfills the requirements of paragraph (a) of this section by obtaining a trust fund, surety bond, letter of credit, escrow account, or insurance policy will be deemed to be without the required financial assurance in the event of bankruptcy of the trustee or issuing institution, or a suspension or revocation of the authority of the trustee institution to act as trustee of the institution issuing the trust fund, surety bond, letter of credit, escrow account, or insurance policy. The owner or operator must establish other financial assurance within 60 days after such an event.	
(e) The owner or operator must provide an adjustment of the cost estimate to the Director within 60 days of notification by the Director, if the Director determines during the annual evaluation of the qualifying financial responsibility instrument(s) that the most recent demonstration is no longer adequate to cover the cost of corrective action (as required by §146.84), injection well plugging (as required by §146.92), post-injection site care and site closure (as required by §146.93), and emergency and remedial response (as required by §146.94).	
(f) The Director must approve the use and length of pay-in-periods for trust funds or escrow accounts.	
§146.86 Injection well construction requirements.	
(a) General. The owner or operator must ensure that all Class VI wells are constructed and completed to:	
(1) Prevent the movement of fluids into or between USDWs or into any unauthorized zones;	Section 4.2
(2) Permit the use of appropriate testing devices and workover tools; and	Section 4.2.4
(3) Permit continuous monitoring of the annulus space between the injection tubing and long string casing.	Section 4.2.4
(b) Casing and Cementing of Class VI Wells.	
(1) Casing and cement or other materials used in the construction of each Class VI well must have sufficient structural strength and be designed for the life of the geologic sequestration project. All well materials must be compatible with fluids with which the materials may be expected to come into contact and must meet or exceed standards developed for such materials by the American Petroleum Institute, ASTM International, or comparable standards acceptable to the Director. The casing and cementing program must be designed to prevent the movement of fluids into or between USDWs. In order to allow the Director to determine and specify casing and cementing requirements, the owner or operator must provide the following information:	Section 4.2.3
(i) Depth to the injection zone(s);	Table 4.12
(ii) Injection pressure, external pressure, internal pressure, and axial loading;	Section 4.2; 4.2.1

Table A.3. (contd)

40 CFR Part 146, Subpart H - Criteria and Standards Applicable to Class VI Wells	FutureGen Alliance UIC Permit Application
(iii) Hole size;	Table 4.10
(iv) Size and grade of all casing strings (wall thickness, external diameter, nominal weight, length, joint specification, and construction material);	Tables 4.10, 4.11
(v) Corrosiveness of the carbon dioxide stream and formation fluids;	Table 5.1 (corrosion coupons)
(vi) Down-hole temperatures;	Section 4.3
(vii) Lithology of injection and confining zone(s);	Figures 4.4, 4.5
(viii) Type or grade of cement and cement additives; and	Table 4.12
(ix) Quantity, chemical composition, and temperature of the carbon dioxide stream.	Section 4.1.3, 4.1.4, 4.2.1
(2) Surface casing must extend through the base of the lowermost USDW and be cemented to the surface through the use of a single or multiple strings of casing and cement.	Figures 4.4, 4.5
(3) At least one long string casing, using a sufficient number of centralizers, must extend to the injection zone and must be cemented by circulating cement to the surface in one or more stages.	Figures 4.4, 4.5
(4) Circulation of cement may be accomplished by staging. The Director may approve an alternative method of cementing in cases where the cement cannot be recirculated to the surface, provided the owner or operator can demonstrate by using logs that the cement does not allow fluid movement behind the well bore.	Section 4.2.3
(5) Cement and cement additives must be compatible with the carbon dioxide stream and formation fluids and of sufficient quality and quantity to maintain integrity over the design life of the geologic sequestration project. The integrity and location of the cement shall be verified using technology capable of evaluating cement quality radially and identifying the location of channels to ensure that USDWs are not endangered.	Section 4.2.3
(c) Tubing and packer.	
(1) Tubing and packer materials used in the construction of each Class VI well must be compatible with fluids with which the materials may be expected to come into contact and must meet or exceed standards developed for such materials by the American Petroleum Institute, ASTM International, or comparable standards acceptable to the Director.	Section 4.2.6
(2) All owners or operators of Class VI wells must inject fluids through tubing with a packer set at a depth opposite a cemented interval at the location approved by the Director.	Section 4.2
(3) In order for the Director to determine and specify requirements for tubing and packer, the owner or operator must submit the following information:	
(i) Depth of setting;	Figures 4.4, 4.5
(ii) Characteristics of the carbon dioxide stream (chemical content, corrosiveness, temperature, and density) and formation fluids;	Table 4.1

Table A.3. (contd)

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(iii) Maximum proposed injection pressure;	Section 4.2.1
(iv) Maximum proposed annular pressure;	Section 4.2.5
(v) Proposed injection rate (intermittent or continuous) and volume and/or mass of the carbon dioxide stream;	Section 4.1.3
(vi) Size of tubing and casing; and	Table 4.10
(vii) Tubing tensile, burst, and collapse strengths.	Table 4.11
§146.87 Logging, sampling, and testing prior to injection well operation.	
(a) During the drilling and construction of a Class VI injection well, the owner or operator must run appropriate logs, surveys and tests to determine or verify the depth, thickness, porosity, permeability, and lithology of, and the salinity of any formation fluids in all relevant geologic formations to ensure conformance with the injection well construction requirements under §146.86 and to establish accurate baseline data against which future measurements may be compared. The owner or operator must submit to the Director a descriptive report prepared by a knowledgeable log analyst that includes an interpretation of the results of such logs and tests. At a minimum, such logs and tests must include:	Section 4.2.9
(1) Deviation checks during drilling on all holes constructed by drilling a pilot hole which is enlarged by reaming or another method. Such checks must be at sufficiently frequent intervals to determine the location of the borehole and to ensure that vertical avenues for fluid movement in the form of diverging holes are not created during drilling; and	Section 4.2.9
(2) Before and upon installation of the surface casing:	Section 4.2.10
(i) Resistivity, spontaneous potential, and caliper logs before the casing is installed; and	Section 4.2.10
(ii) A cement bond and variable density log to evaluate cement quality radially, and a temperature log after the casing is set and cemented.	Table 4.14
(3) Before and upon installation of the long string casing:	
(i) Resistivity, spontaneous potential, porosity, caliper, gamma ray, fracture finder logs, and any other logs the Director requires for the given geology before the casing is installed; and	Table 4.14
(ii) A cement bond and variable density log, and a temperature log after the casing is set and cemented.	Table 4.14
(4) A series of tests designed to demonstrate the internal and external mechanical integrity of injection wells, which may include:	
(i) A pressure test with liquid or gas;	Section 4.3
(ii) A tracer survey such as oxygen-activation logging;	Section 4.3
(iii) A temperature or noise log;	Section 4.3
(iv) A casing inspection log; and	Table 5.3
(5) Any alternative methods that provide equivalent or better information and that are required by and/or approved of by the Director.	

Table A.3. (contd)

40 CFR Part 146, Subpart H - Criteria and Standards Applicable to Class VI Wells	FutureGen Alliance UIC Permit Application
(b) The owner or operator must take whole cores or sidewall cores of the injection zone and confining system and formation fluid samples from the injection zone(s), and must submit to the Director a detailed report prepared by a log analyst that includes: well log analyses (including well logs), core analyses, and formation fluid sample information. The Director may accept information on cores from nearby wells if the owner or operator can demonstrate that core retrieval is not possible and that such cores are representative of conditions at the well. The Director may require the owner or operator to core other formations in the borehole.	Section 4.2.11
(c) The owner or operator must record the fluid temperature, pH, conductivity, reservoir pressure, and static fluid level of the injection zone(s).	Section 4.2.11
(d) At a minimum, the owner or operator must determine or calculate the following information concerning the injection and confining zone(s):	
(1) Fracture pressure;	Section 4.2.1
(2) Other physical and chemical characteristics of the injection and confining zone(s); and	Sections 2.1.3, 2.2
(3) Physical and chemical characteristics of the formation fluids in the injection zone(s).	Section 2.2
(e) Upon completion, but prior to operation, the owner or operator must conduct the following tests to verify hydrogeologic characteristics of the injection zone(s):	
(1) A pressure fall-off test; and,	Section 5.3.1
(2) A pump test; or	Section 4.2.9
(3) Injectivity tests.	Section 4.2.9
(f) The owner or operator must provide the Director with the opportunity to witness all logging and testing by this subpart. The owner or operator must submit a schedule of such activities to the Director 30 days prior to conducting the first test and submit any changes to the schedule 30 days prior to the next scheduled test.	Section 4.8.7
§146.88 Injection well operating requirements.	
(a) Except during stimulation, the owner or operator must ensure that injection pressure does not exceed 90 percent of the fracture pressure of the injection zone(s) so as to ensure that the injection does not initiate new fractures or propagate existing fractures in the injection zone(s). In no case may injection pressure initiate fractures in the confining zone(s) or cause the movement of injection or formation fluids that endangers a USDW. Pursuant to requirements at § 146.82(a)(9), all stimulation programs must be approved by the Director as part of the permit application and incorporated into the permit.	Section 4.2.1
(b) Injection between the outermost casing protecting USDWs and the well bore is prohibited.	Section 4.2.5
(c) The owner or operator must fill the annulus between the tubing and the long string casing with a non-corrosive fluid approved by the Director. The owner or operator must maintain on the annulus a pressure that exceeds the operating injection pressure, unless the Director determines that such requirement might harm the integrity of the well or endanger USDWs.	Section 4.2.5
(d) Other than during periods of well workover (maintenance) approved by the Director in which the sealed tubing casing annulus is disassembled for maintenance or corrective procedures, the owner or operator must maintain mechanical integrity of the injection well at all times.	Section 4.2.6

Table A.3. (contd)

40 CFR Part 146, Subpart H - Criteria and Standards Applicable to Class VI Wells	FutureGen Alliance UIC Permit Application
(e) The owner or operator must install and use:	
(1) Continuous recording devices to monitor: The injection pressure; the rate, volume and/or mass, and temperature of the carbon dioxide stream; and the pressure on the annulus between the tubing and the long string casing and annulus fluid volume; and	Table 5.3
(2) Alarms and automatic surface shut-off systems or, at the discretion of the Director, down-hole shut-off systems (e.g., automatic shut-off, check valves) for onshore wells or, other mechanical devices that provide equivalent protection; and	Section 5.3.4
(3) Alarms and automatic down-hole shut-off systems for wells located offshore but within State territorial waters, designed to alert the operator and shut-in the well when operating injection rate, or other parameters diverge beyond permitted ranges and/or gradients specified in the permit.	Not Applicable
(f) If a shutdown (i.e., down-hole or at the surface) is triggered or a loss of mechanical integrity is discovered, the owner or operator must immediately investigate and identify as expeditiously as possible the cause of the shutoff. If, upon such investigation, the well appears to be lacking mechanical integrity, or if monitoring required under paragraph (e) of this section otherwise indicates that the well may be lacking mechanical integrity, the owner or operator must:	
(1) Immediately cease injection;	Section 8.1.3
(2) Take all steps reasonably necessary to determine whether there may have been a release of the injected carbon dioxide stream or formation fluids into any unauthorized zone;	Table 8.2
(3) Notify the Director within 24 hours;	Section 8.5
(4) Restore and demonstrate mechanical integrity to the satisfaction of the Director prior to resuming injection; and	Section 8.2
(5) Notify the Director when injection can be expected to resume.	Section 8.2
§146.89 Mechanical Integrity.	
(a) A Class VI well has mechanical integrity if:	
(1) There is no significant leak in the casing, tubing, or packer; and	
(2) There is no significant fluid movement into a USDW through channels adjacent to the injection well bore.	
(b) To evaluate the absence of significant leaks under paragraph (a)(1) of this section, owners or operators must, following an initial annulus pressure test, continuously monitor injection pressure, rate, injected volumes; pressure on the annulus between tubing and long-string casing; and annulus fluid volume as specified in § 146.88 (e);	Section 4.3
(c) At least once per year, the owner or operator must use one of the following methods to determine the absence of significant fluid movement under paragraph (a)(2) of this section:	Table 5.3
(1) An approved tracer survey such as an oxygen-activation log; or	Table 5.3
(2) A temperature or noise log.	Table 5.3

Table A.3. (contd)

40 CFR Part 146, Subpart H - Criteria and Standards Applicable to Class VI Wells	FutureGen Alliance UIC Permit Application
(d) If required by the Director, at a frequency specified in the testing and monitoring plan required at § 146.90, the owner or operator must run a casing inspection log to determine the presence or absence of corrosion in the long string casing.	Table 5.1
(e) The Director may require any other test to evaluate mechanical integrity under paragraphs (a)(1) or (a)(2) of this section. Also, the Director may allow the use of a test to demonstrate mechanical integrity other than those listed above with the written approval of the Administrator. To obtain approval for a new mechanical integrity test, the Director must submit a written request to the Administrator setting forth the proposed test and all technical data supporting its use. The Administrator may approve the request if he or she determines that it will reliably demonstrate the mechanical integrity of wells for which its use is proposed. Any alternate method approved by the Administrator will be published in the Federal Register and may be used in all States in accordance with applicable State law unless its use is restricted at the time of approval by the Administrator.	Section 5.7
(f) In conducting and evaluating the tests enumerated in this section or others to be allowed by the Director, the owner or operator and the Director must apply methods and standards generally accepted in the industry. When the owner or operator reports the results of mechanical integrity tests to the Director, he/she shall include a description of the test(s) and the method(s) used. In making his/her evaluation, the Director must review monitoring and other test data submitted since the previous evaluation.	Section 5.7
(g) The Director may require additional or alternative tests if the results presented by the owner or operator under paragraphs (a) through (d) of this section are not satisfactory to the Director to demonstrate that there is no significant leak in the casing, tubing, or packer, or to demonstrate that there is no significant movement of fluid into a USDW resulting from the injection activity as stated in paragraphs (a)(1) and (2) of this section.	Section 5.7
§146.90 Testing and monitoring requirements. The owner or operator of a Class VI well must prepare, maintain, and comply with a testing and monitoring plan to verify that the geologic sequestration project is operating as permitted and is not endangering USDWs. The requirement to maintain and implement an approved plan is directly enforceable regardless of whether the requirement is a condition of the permit. The testing and monitoring plan must be submitted with the permit application, for Director approval, and must include a description of how the owner or operator will meet the requirements of this section, including accessing sites for all necessary monitoring and testing during the life of the project. Testing and monitoring associated with geologic sequestration projects must, at a minimum, include:	Section 5.0
(a) Analysis of the carbon dioxide stream with sufficient frequency to yield data representative of its chemical and physical characteristics;	Table 5.3
(b) Installation and use, except during well workovers as defined in §146.88(d), of continuous recording devices to monitor injection pressure, rate, and volume; the pressure on the annulus between the tubing and the long string casing; and the annulus fluid volume added;	Table 5.1
(c) Corrosion monitoring of the well materials for loss of mass, thickness, cracking, pitting, and other signs of corrosion, which must be performed on a quarterly basis to ensure that the well components meet the minimum standards for material strength and performance set forth in §146.86(b), by:	Table 5.1
(1) Analyzing coupons of the well construction materials placed in contact with the carbon dioxide stream; or	Table 5.1
(2) Routing the carbon dioxide stream through a loop constructed with the material used in the well and inspecting the materials in the loop; or	Not applicable
(3) Using an alternative method approved by the Director;	Not Applicable
(d) Periodic monitoring of the ground water quality and geochemical changes above the confining zone(s) that may be a result of carbon dioxide movement through the confining zone(s) or additional identified zones including:	Section 5.2.2.2

Table A.3. (contd)

40 CFR Part 146, Subpart H - Criteria and Standards Applicable to Class VI Wells	FutureGen Alliance UIC Permit Application
(1) The location and number of monitoring wells based on specific information about the geologic sequestration project, including injection rate and volume, geology, the presence of artificial penetrations, and other factors; and	Section 5.1.4
(2) The monitoring frequency and spatial distribution of monitoring wells based on baseline geochemical data that has been collected under §146.82(a)(6) and on any modeling results in the area of review evaluation required by §146.84(c).	Table 5.3, Figure 5.1
(e) A demonstration of external mechanical integrity pursuant to §146.89(c) at least once per year until the injection well is plugged; and, if required by the Director, a casing inspection log pursuant to requirements at §146.89(d) at a frequency established in the testing and monitoring plan;	Table 5.3
(f) A pressure fall-off test at least once every five years unless more frequent testing is required by the Director based on site-specific information;	Table 5.3
(g) Testing and monitoring to track the extent of the carbon dioxide plume and the presence or absence of elevated pressure (e.g., the pressure front) by using:	Section 5.2
(1) Direct methods in the injection zone(s); and,	Table 5.3
(2) Indirect methods (e.g., seismic, electrical, gravity, or electromagnetic surveys and/or down-hole carbon dioxide detection tools), unless the Director determines, based on site-specific geology, that such methods are not appropriate;	Table 5.3
(h) The Director may require surface air monitoring and/or soil gas monitoring to detect movement of carbon dioxide that could endanger a USDW.	Section 5.2.1.3
(i) Any additional monitoring, as required by the Director, necessary to support, upgrade, and improve computational modeling of the area of review evaluation required under §146.84(c) and to determine compliance with standards under §144.12 of this Section;	
(j) The owner or operator shall periodically review the testing and monitoring plan to incorporate monitoring data collected under this subpart, operational data collected under §146.88, and the most recent area of review reevaluation performed under §146.84(e). In no case shall the owner or operator review the testing and monitoring plan less often than once every five years. Based on this review, the owner or operator shall submit an amended testing and monitoring plan or demonstrate to the Director that no amendment to the testing and monitoring plan is needed. Any amendments to the testing and monitoring plan must be approved by the Director, must be incorporated into the permit, and are subject to the permit modification requirements at §§144.39 or 144.41 of this Section, as appropriate. Amended plans or demonstrations shall be submitted to the Director as follows:	Section 5.7
(1) Within one year of an area of review reevaluation;	
(2) Following any significant changes to the facility, such as addition of injection or monitoring wells, on a schedule determined by the Director; or	
(3) When required by the Director.	
(k) A quality assurance and surveillance plan for all testing and monitoring requirements.	Section 5.8
§149.91 Reporting Requirements. The owner or operator must, at a minimum, provide, as specified in paragraph (e) of this section, the following reports to the Director, for each permitted Class VI well:	Section 5.6

Table A.3. (contd)

40 CFR Part 146, Subpart H - Criteria and Standards Applicable to Class VI Wells	FutureGen Alliance UIC Permit Application
(a) Semi-annual reports containing:	Section 5.6
(1) Any changes to the physical, chemical, and other relevant characteristics of the carbon dioxide stream from the proposed operating data;	
(2) Monthly average, maximum, and minimum values for injection pressure, flow rate and volume, and annular pressure;	
(3) A description of any event that exceeds operating parameters for annulus pressure or injection pressure specified in the permit;	
(4) A description of any event which triggers a shut-off device required pursuant to § 146.88(e) and the response taken;	
(5) The monthly volume and/or mass of the carbon dioxide stream injected over the reporting period and the volume injected cumulatively over the life of the project;	
(6) Monthly annulus fluid volume added; and	
(7) The results of monitoring prescribed under § 146.90.	
(b) Report, within 30 days, the results of:	Section 5.6
(1) Periodic tests of mechanical integrity;	
(2) Any well workover; and,	
(3) Any other test of the injection well conducted by the permittee if required by the Director.	
(c) Report, within 24 hours:	Section 5.6
(1) Any evidence that the injected carbon dioxide stream or associated pressure front may cause an endangerment to a USDW;	
(2) Any noncompliance with a permit condition, or malfunction of the injection system, which may cause fluid migration into or between USDWs;	
(3) Any triggering of a shut-off system (i.e., down-hole or at the surface);	
(4) Any failure to maintain mechanical integrity; or.	
(5) Pursuant to compliance with the requirement at ¤ 146.90(h) for surface air/soil gas monitoring or other monitoring technologies, if required by the Director, any release of carbon dioxide to the atmosphere or biosphere.	
(d) Owners or operators must notify the Director in writing 30 days in advance of:	Section 5.6
(1) Any planned well workover;	
(2) Any planned stimulation activities, other than stimulation for formation testing conducted under § 146.82; and	
(3) Any other planned test of the injection well conducted by the permittee.	
(e) Regardless of whether a State has primary enforcement responsibility, owners or operators must submit all required reports, submittals, and notifications under subpart H of this part to EPA in an electronic format approved by EPA.	Section 5.6

Table A.3. (contd)

40 CFR Part 146, Subpart H - Criteria and Standards Applicable to Class VI Wells	FutureGen Alliance UIC Permit Application
(f) Records shall be retained by the owner or operator as follows:	
(1) All data collected under ¤ 146.82 for Class VI permit applications shall be retained throughout the life of the geologic sequestration project and for 10 years following site closure.	Section 5.6
(2) Data on the nature and composition of all injected fluids collected pursuant to ¤ 146.90(a) shall be retained until 10 years after site closure. The Director may require the owner or operator to deliver the records to the Director at the conclusion of the retention period.	Section 5.6
(3) Monitoring data collected pursuant to § 146.90(b) through (i) shall be retained for 10 years after it is collected.	Section 5.6
(4) Well plugging reports, post-injection site care data, including, if appropriate, data and information used to develop the demonstration of the alternative post-injection site care timeframe, and the site closure report collected pursuant to requirements at ¤¤ 146.93(f) and (h) shall be retained for 10 years following site closure.	Section 5.6, Section 7.3.4
(5) The Director has authority to require the owner or operator to retain any records required in this subpart for longer than 10 years after site closure.	
§146.92 Injection well plugging.	Section 6.0
(a) Prior to the well plugging, the owner or operator must flush each Class VI injection well with a buffer fluid, determine bottomhole reservoir pressure, and perform a final external mechanical integrity test.	Sections 6.1, 6.2
(b) *Well Plugging Plan*. The owner or operator of a Class VI well must prepare, maintain, and comply with a plan that is acceptable to the Director. The requirement to maintain and implement an approved plan is directly enforceable regardless of whether the requirement is a condition of the permit. The well plugging plan must be submitted as part of the permit application and must include the following information:	Section 6.3
(1) Appropriate tests or measures for determining bottomhole reservoir pressure;	Section 6.1.1
(2) Appropriate testing methods to ensure external mechanical integrity as specified in §146.89;	Section 6.2
(3) The type and number of plugs to be used;	Section 6.3
(4) The placement of each plug, including the elevation of the top and bottom of each plug;	Table 6.1
(5) The type, grade, and quantity of material to be used in plugging. The material must be compatible with the carbon dioxide stream; and	Table 6.1
(6) The method of placement of the plugs.	Section 6.3
(c) Notice of intent to plug.	Section 6.3
(d) Plugging report.	Section 6.3
§146.93 Post-injection site care and site closure.	Section 7.0
(a) The owner or operator of a Class VI well must prepare, maintain, and comply with a plan for post-injection site care and site closure that meets the requirements of paragraph (a)(2) of this section and is acceptable to the Director.	Section 7.0

Table A.3. (contd)

40 CFR Part 146, Subpart H - Criteria and Standards Applicable to Class VI Wells	FutureGen Alliance UIC Permit Application
(1) The owner or operator must submit the post-injection site care and site closure plan as a part of the permit application to be approved by the Director.	Section 7.0
(2) The post-injection site care and site closure plan must include the following information:	
(i) The pressure differential between pre-injection and predicted post-injection pressures in the injection zone(s);	Table 7.1, Section 7.1.1
(ii) The predicted position of the carbon dioxide plume and associated pressure front at site closure as demonstrated in the area of review evaluation required under §146.84(c)(1);	Figure 7.2
(iii) A description of post-injection monitoring location, methods, and proposed frequency;	Section 7.2
(iv) A proposed schedule for submitting post-injection site care monitoring results to the Director pursuant to §146.91(e); and,	Section 7.2.4, Table 7.2.4
(v) The duration of the post-injection site care timeframe and, if approved by the Director, the demonstration of the alternative post-injection site care timeframe that ensures non-endangerment of USDWs.	Section 7.2
(b) The owner or operator shall monitor the site following the cessation of injection to show the position of the carbon dioxide plume and pressure front and demonstrate that USDWs are not being endangered.	Section 7.2
(1) Following the cessation of injection, the owner or operator shall continue to conduct monitoring as specified in the Director-approved post-injection site care and site closure plan for at least 50 years or for the duration of the alternative timeframe approved by the Director pursuant to requirements in paragraph (c) of this section, unless he/she makes a demonstration under (b)(2) of this section. The monitoring must continue until the geologic sequestration project no longer poses an endangerment to USDWs and the demonstration under (b)(2) of this section is submitted and approved by the Director.	Section 7.2
(2) If the owner or operator can demonstrate to the satisfaction of the Director before 50 years or prior to the end of the approved alternative timeframe based on monitoring and other site-specific data, that the geologic sequestration project no longer poses an endangerment to USDWs, the Director may approve an amendment to the post-injection site care and site closure plan to reduce the frequency of monitoring or may authorize site closure before the end of the 50-year period or prior to the end of the approved alternative timeframe, where he or she has substantial evidence that the geologic sequestration project no longer poses a risk of endangerment to USDWs.	
(3) Prior to authorization for site closure, the owner or operator must submit to the Director for review and approval a demonstration, based on monitoring and other site-specific data, that no additional monitoring is needed to ensure that the geologic sequestration project does not pose an endangerment to USDWs.	Section 7.2.6
(4) If the demonstration in paragraph (b)(3) of this section cannot be made (i.e., additional monitoring is needed to ensure that the geologic sequestration project does not pose an endangerment to USDWs) at the end of the 50-year period or at the end of the approved alternative timeframe, or if the Director does not approve the demonstration, the owner or operator must submit to the Director a plan to continue post-injection site care until a demonstration can be made and approved by the Director.	

Table A.3. (contd)

40 CFR Part 146, Subpart H - Criteria and Standards Applicable to Class VI Wells	FutureGen Alliance UIC Permit Application
(c) *Demonstration of alternative post-injection site care timeframe*. At the Director's discretion, the Director may approve, in consultation with EPA, an alternative post injection site care timeframe other than the 50 year default, if an owner or operator can demonstrate during the permitting process that an alternative post-injection site care timeframe is appropriate and ensures non-endangerment of USDWs. The demonstration must be based on significant, site-specific data and information including all data and information collected pursuant to §§146.82 and 146.83, and must contain substantial evidence that the geologic sequestration project will no longer pose a risk of endangerment to USDWs at the end of the alternative post-injection site care timeframe.	A default period is not being proposed at this time.
(1) A demonstration of an alternative post-injection site care timeframe must include consideration and documentation of:	
(i) The results of computational modeling performed pursuant to delineation of the area of review under §146.84;	
(ii) The predicted timeframe for pressure decline within the injection zone, and any other zones, such that formation fluids may not be forced into any USDWs; and/or the timeframe for pressure decline to pre-injection pressures;	
(iii) The predicted rate of carbon dioxide plume migration within the injection zone, and the predicted timeframe for the cessation of migration;	
(iv) A description of the site-specific processes that will result in carbon dioxide trapping including immobilization by capillary trapping, dissolution, and mineralization at the site;	
(v) The predicted rate of carbon dioxide trapping in the immobile capillary phase, dissolved phase, and/or mineral phase;	
(vi) The results of laboratory analyses, research studies, and/or field or site specific studies to verify the information required in paragraphs (iv) and (v) of this section;	
(vii) A characterization of the confining zone(s) including a demonstration that it is free of transmissive faults, fractures, and micro-fractures and of appropriate thickness, permeability, and integrity to impede fluid (e.g., carbon dioxide, formation fluids) movement;	
(viii) The presence of potential conduits for fluid movement including planned injection wells and project monitoring wells associated with the proposed geologic sequestration project or any other projects in proximity to the predicted/modeled, final extent of the carbon dioxide plume and area of elevated pressure;	
(ix) A description of the well construction and an assessment of the quality of plugs of all abandoned wells within the area of review;	
(x) The distance between the injection zone and the nearest USDWs above and/or below the injection zone; and	
(xi) Any additional site-specific factors required by the Director.	
(2) Information submitted to support the demonstration in paragraph (c)(1) of this section must meet the following criteria:	
(i) All analyses and tests performed to support the demonstration must be accurate, reproducible, and performed in accordance with the established quality assurance standards;	
(ii) Estimation techniques must be appropriate and EPA-certified test protocols must be used where available;	

Table A.3. (contd)

40 CFR Part 146, Subpart H - Criteria and Standards Applicable to Class VI Wells	FutureGen Alliance UIC Permit Application
(iii) Predictive models must be appropriate and tailored to the site conditions, composition of the carbon dioxide stream and injection and site conditions over the life of the geologic sequestration project;	
(iv) Predictive models must be calibrated using existing information (e.g., at Class I, Class II, or Class V experimental technology well sites) where sufficient data are available;	
(v) Reasonably conservative values and modeling assumptions must be used and disclosed to the Director whenever values are estimated on the basis of known, historical information instead of site-specific measurements;	
(vi) An analysis must be performed to identify and assess aspects of the alternative post-injection site care timeframe demonstration that contribute significantly to uncertainty. The owner or operator must conduct sensitivity analyses to determine the effect that significant uncertainty may contribute to the modeling demonstration.	
(vii) An approved quality assurance and quality control plan must address all aspects of the demonstration; and,	
(viii) Any additional criteria required by the Director.	
§146.94 Emergency and remedial response.	Section 8.0
(a) As part of the permit application, the owner or operator must provide the Director with an emergency and remedial response plan that describes actions the owner or operator must take to address movement of the injection or formation fluids that may cause an endangerment to a USDW during construction, operation, and post-injection site care periods. The requirement to maintain and implement an approved plan is directly enforceable regardless of whether the requirement is a condition of the permit.	Section 8.0
(b) If the owner or operator obtains evidence that the injected carbon dioxide stream and associated pressure front may cause an endangerment to a USDW, the owner or operator must:	Section 8.1, Table 8.2
(1) Immediately cease injection;	Table 8.2
(2) Take all steps reasonably necessary to identify and characterize any release;	Table 8.2
(3) Notify the Director within 24 hours; and	Section 8.5
(4) Implement the emergency and remedial response plan approved by the Director.	Section 8.0
(c) The Director may allow the operator to resume injection prior to remediation if the owner or operator demonstrates that the injection operation will not endanger USDWs.	
(d) The owner or operator shall periodically review the emergency and remedial response plan developed under paragraph (a) of this section. In no case shall the owner or operator review the emergency and remedial response plan less often than once every five years. Based on this review, the owner or operator shall submit an amended emergency and remedial response plan or demonstrate to the Director that no amendment to the emergency and remedial response plan is needed. Any amendments to the emergency and remedial response plan must be approved by the Director, must be incorporated into the permit, and are subject to the permit modification requirements at §§ 144.39 or 144.41 of this Section, as appropriate. Amended plans or demonstrations shall be submitted to the Director as follows:	Section 8.3

Table A.3. (contd)

40 CFR Part 146, Subpart H - Criteria and Standards Applicable to Class VI Wells	FutureGen Alliance UIC Permit Application
(1) Within one year of an area of review evaluation;	Section 8.3
(2) Following any significant changes to the facility, such as addition of injection or monitoring wells, on a schedule determined by the Director; or	Section 8.3
(3) When required by the Director.	Section 8.3
§146.95 Class VI injection depth waiver requirements.	No waiver is requested.

Appendix B

Known Wells Within the Survey Area

Appendix B

Known Wells Within the Survey Area

Table B.1. List of Wells Located Within the Survey Area and Outside the AoR

Map ID	API Number	ISWS ID	Latitude (NAD 83)	Longitude (NAD 83)	Public Land Survey System (PLSS)	Total Depth (ft)	Elevation (ft)	Completion Date	Owner	Well #	Well Type	Status	Confining Zone Penetration Well
2	121372155200	237387	39.815638	-90.084967	T16N,R9W,Sec 23	41		19920313	Nickel, Gerald	1	Water	Private Water Well	No
3	121372182100	300966	39.815638	-90.084967	T16N,R9W,Sec 23	46		19971104	Nickel, Gerald & Diane	1	Water	Private Water Well	No
13	121372173400	297871	39.811987	-90.07805	T16N,R9W,Sec 26	37		19960213	Keltner, Dale		Water	Private Water Well	No
23	121370024000		39.780186	-90.094859	T15N,R9W,Sec 3	402	642	19230101	Trotter, L.B.	1	Oil & Gas	Dry and Abandoned, No Shows	No
24	121372097800		39.776078	-90.080727	T15N,R9W,Sec 3	327	632	0	Harris		Unknown / other	Unknown, Plugged	No
28		115642	39.82166	-90.041238	T16N,R8W,Sec 19	25		1870	W W Robertson		Water		No
38		116456	39.776761	-90.107843	T15N,R9W,Sec 4	30			Rayburn		Water		No
39		116457	39.776761	-90.107843	T15N,R9W,Sec 4	32			Greene		Water		No
40		115725	39.821959	-90.097446	T16N,R9W,Sec 22	18			K Brown		Water		No
41		115726	39.821959	-90.097446	T16N,R9W,Sec 22	30			E C Trotter		Water		No
52		115640	39.836203	-90.022343	T16N,R8W,Sec 17	25			J H Hubbs		Water		No
53		115641	39.83617	-90.041154	T16N,R8W,Sec 18	32		1850	H Robinson		Water		No
54		115643	39.821671	-90.022214	T16N,R8W,Sec 20	26		1900	S Weinfeldt		Water		No
55		115644	39.821671	-90.022214	T16N,R8W,Sec 20	30		1904	Robinson		Water		No
56		115649	39.807149	-90.022402	T16N,R8W,Sec 29	26			M Walbaum		Water		No
57		115653	39.793	-90.022	T16N,R8W,Sec 32	18			Beggs		Water		No
58	121372070800	116522	39.77156	-90.0878	T15N,R9W,Sec 3	50		19770320	Linebarger, David		Water		No
59	121372118300	116520	39.769673	-90.080523	T15N,R9W,Sec 3	42			Harris, Frank R.		Water	Private Water Well	No
60	121372070700	116521	39.769673	-90.080523	T15N,R9W,Sec 3	40			harris F R		Water		No
61		116458	39.777	-90.126	T15N,R9W,Sec 5	30			Gary S. B.		Water		No
62		116464	39.761	-90.126	T15N,R9W,Sec 8	30			Cleray W		Water		No
63		116465	39.761	-90.126	T15N,R9W,Sec 8	40			Coons A		Water		No
64		116466	39.761	-90.107	T15N,R9W,Sec 9	30			Wallbaum W M		Water		No
65		116467	39.761	-90.107	T15N,R9W,Sec 9	35			Trotter l B		Water		No
66		227314	39.761	-90.107	T15N,R9W,Sec 9	40			Carl Shinnall #1		Water		No
67		116468	39.761	-90.089	T15N,R9W,Sec 10	30			Orear R		Water		No
68	121372070900	116525	39.765755	-90.080645	T15N,R9W,Sec 10	40			Linebarger D		Water		No
69		116469	39.761	-90.07	T15N,R9W,Sec 11	30			Collins W		Water		No
70		116470	39.761	-90.07	T15N,R9W,Sec 11	32			Lockhart G		Water		No
71		116393	39.776799	-90.032936	T15N,R8W,Sec 6	25		1923			Water		No
72		116394	39.776799	-90.032936	T15N,R8W,Sec 6	28			C Smith		Water		No
73	121372116800	116436	39.784526	-90.041604	T15N,R8W,Sec 6	54		19770226	Becker, Carl J.	1	Water	Livestock Watering Well	No
74	121372116900	116435	39.784526	-90.041604	T15N,R8W,Sec 6	43		19781010	Becker, Carl J.	1	Water	Private Water Well	No
75	121372117000	116434	39.782453	-90.041567	T15N,R8W,Sec 6	27		19761213	Smith, Lloyd E.	1	Water	Livestock Watering Well	No
76	121372161900		39.766277	-90.041266	T15N,R8W,Sec 7	26			Walpole, Ron		Water		No
77		116395	39.763	-90.033	T15N,R8W,Sec 7	30					Water		No
78		115696	39.836221	-90.059875	T16N,R9W,Sec 13	25			V R Mc Clure		Water		No

Table B.1. (contd)

Map ID	API Number	ISWS ID	Latitude (NAD 83)	Longitude (NAD 83)	Public Land Survey System (PLSS)	Total Depth (ft)	Elevation (ft)	Completion Date	Owner	Well #	Well Type	Status	Confining Zone Penetration Well
79		115697	39.836221	-90.059875	T16N,R9W,Sec 13	27			U B Fox		Water		No
80		115698	39.836221	-90.059875	T16N,R9W,Sec 13	27			G W Lewis		Water		No
81		115699	39.836362	-90.078662	T16N,R9W,Sec 14	30			J Parrat		Water		No
82		115700	39.836362	-90.078662	T16N,R9W,Sec 14	28			C W Lewis		Water		No
83		115701	39.836362	-90.078662	T16N,R9W,Sec 14	28			J W Parrat		Water		No
84		115702	39.836362	-90.078662	T16N,R9W,Sec 14	32			J Hodgeson		Water		No
85	121372203900	356742	39.830101	-90.102984	T16N,R9W,Sec 15	47		20030910	Lomar Hager Construction		Water	Private Water Well	No
86		115703	39.836486	-90.097369	T16N,R9W,Sec 15	24			G Noulty		Water		No
87		115704	39.836486	-90.097369	T16N,R9W,Sec 15	30			L Lamkaular		Water		No
88		115705	39.836486	-90.097369	T16N,R9W,Sec 15	35			E E Hart		Water		No
89		115706	39.8365	-90.116151	T16N,R9W,Sec 16	23			S Jumper		Water		No
90		115707	39.8365	-90.116151	T16N,R9W,Sec 16	25			H Wester		Water		No
91		115722	39.821967	-90.116263	T16N,R9W,Sec 21	30			T J Ward		Water		No
92		115724	39.821967	-90.116263	T16N,R9W,Sec 21	30			C Trotter		Water		No
93		216249	39.821967	-90.116263	T16N,R9W,Sec 21	28		1934	Wm Noulty		Water		No
94	121370028400		39.822767	-90.073164	T16N,R9W,Sec 23	405		19540301	Keltner	1	Water		No
95	121372155100	237377	39.820978	-90.077895	T16N,R9W,Sec 23	42		19920414	Allen, John D.	1	Water	Private Water Well	No
96	121372207600	365042	39.822764	-90.075515	T16N,R9W,Sec 23	46		20040715	Burton, Larry		Water	Private Water Well	No
97	121372128400	115776	39.826288	-90.058992	T16N,R9W,Sec 24	40		19760220	Robinson, Leroy A.	1	Water	Private Water Well	No
98	121372128500	115777	39.828869	-90.059535	T16N,R9W,Sec 24	37		19781214	Romine, Buddy	1	Water	Private Water Well	No
99	121372211600	420169	39.813876	-90.103667	T16N,R9W,Sec 27	35		20060809	Donnan, Jeff		Water	Private Water Well	No
100		115744	39.807541	-90.116512	T16N,R9W,Sec 28	110			Noah B Fox		Water		No
101		115745	39.807541	-90.116512	T16N,R9W,Sec 28	28			Noah B Fox		Water		No
102		115746	39.807541	-90.116512	T16N,R9W,Sec 28	30			C Holdbrook		Water		No
103		115723	39.807541	-90.116512	T16N,R9W,Sec 28	28			W Noulty		Water		No
104	121372203000	348692	39.806645	-90.122622	T16N,R9W,Sec 28	42			Kendra Swain		Water		No
105		115759	39.792956	-90.116724	T16N,R9W,Sec 33	30			H Swain		Water		No
106		115760	39.792956	-90.116724	T16N,R9W,Sec 33	28			L L Hart		Water		No
107	121372155000		39.822856	-90.119949	T16N,R9W,Sec 21				Spradlin, Jack		Water		No
108	121370011400		39.833775	-90.10777	T16N,R9W,Sec 16	385	616	19551101	Wolfe, Eliz	1	Oil & Gas	Dry and Abandoned, No Shows, Plugged	No
109	121370011500		39.80091	-90.040421	T16N,R8W,Sec 30	420	635	19560101	Beilschmidt	1	Oil & Gas	Dry and Abandoned, No Shows, Plugged	No
110	121370011600		39.815108	-90.028322	T16N,R8W,Sec 20	365	610	19551201	Robinson, Howard	1	Oil & Gas	Dry and Abandoned, No Shows, Plugged	No
111	121370018900		39.825408	-90.062536	T16N,R9W,Sec 24	200		19440101	Lewis, E. C.		Oil & Gas	Dry Hole	No
112	121370024100		39.769077	-90.111454	T15N,R9W,Sec 4	580			Rayborn	1	Oil & Gas	Gas Producer	No
113	121370044200		39.770193	-90.110273	T15N,R9W,Sec 4	350			Rayburn	1	Oil & Gas	Gas Producer	No
114	121372086900		39.769679	-90.098565	T15N,R9W,Sec 4	301					Coal Test		No
115	121370024200		39.778927	-90.119618	T15N,R9W,Sec 5	423			Green, Laura & Effie	1	Oil & Gas	Gas Producer	No
116	121370024600		39.764523	-90.098492	T15N,R9W,Sec 9	293			Baxter	2	Oil & Gas	Dry and Abandoned, Gas Shows	No
117	121372094800		39.767065	-90.11144	T15N,R9W,Sec 9	325			Beilschmidt	1	Oil&Gas	Temporarily Abandoned	No
118	121372105200		39.763524	-90.104346	T15N,R9W,Sec 9				Leinberger	2	Oil&Gas	Permit to Drill Issued	No
119	121370007900		39.766464	-90.091366	T15N,R9W,Sec 10	295			Dunlap	8	Oil & Gas	Gas Producer	No
120	121372084800		39.766422	-90.065678	T15N,R9W,Sec 11	243					Coal Test		No
121	121370030900		39.806625	-90.105838	T16N,R9W,Sec 27	324	610	19591001	Fox, Lyman	1	Oil & Gas	Dry and Abandoned, No Shows, Plugged	No
122	121370033200		39.788212	-90.03349	T16N,R8W,Sec 31	323	641	19271001	Corrington	1	Oil & Gas	Dry and Abandoned, No Shows	No

Table B.1. (contd)

Map ID	API Number	ISWS ID	Latitude (NAD 83)	Longitude (NAD 83)	Public Land Survey System (PLSS)	Total Depth (ft)	Elevation (ft)	Completion Date	Owner	Well #	Well Type	Status	Confining Zone Penetration Well
123	121370062300		39.828772	-90.06935	T16N,R9W,Sec 24	814	624	19700701	#MA-3		Stratigraphic or Structure Test	Structure Test, Plugged	No
124	121372068000		39.792709	-90.039363	T16N,R8W,Sec 31	142	641	19700518	Flynn, Robert		Coal Test		No
125	121372088400		39.829096	-90.098826	T16N,R9W,Sec 22	318	621	0			Coal Test		No
126	121372088600		39.801122	-90.108499	T16N,R9W,Sec 28	301	621	0			Coal Test		No
127	121372067800		39.814431	-90.023514	T16N,R8W,Sec 20	130	610	19700507	Newberry, Lucille		Coal Test		No
128	121372086000		39.83138	-90.055009	T16N,R9W,Sec 13	301	619	0			Coal Test		No

Appendix C

Cost Estimate to Demonstrate Financial Responsibility for Class VI UIC Permit

Cost Estimate to Demonstrate Financial Responsibility for Class VI UIC Permit

March 8, 2013

Prepared by:

PATRICK ENGINEERING

Confidential/Business Sensitive

I. Introduction

The U.S. Environmental Protection Agency (EPA) has published federal regulations for Underground Injection Control (UIC) Class VI wells that inject carbon dioxide (CO_2) for the purpose of geologic sequestration. The regulations require that owners or operators of Class VI wells must demonstrate and maintain financial responsibility for taking corrective action on wells in the Area of Review (AoR), plugging the injection wells once injection ceases, undertaking post-injection site care (PISC) and site closure, and conducting any necessary emergency and remedial response actions to ensure that owners or operators have the resources to allow a third party to carry out any activities that may be needed to protect Underground Sources of Drinking Water (USDW) as required by the regulation. The FutureGen Industrial Alliance, Inc. (Alliance) is submitting applications for Class VI permits for the proposed construction and operation of CO_2 injection wells at a site in Morgan County, IL. This third-party cost estimate was prepared in support of those applications.

II. Company qualifications

Patrick Engineering Inc. is a nationwide engineering, design, and project management firm with a long history of success on a variety of complex infrastructure projects. Their client list includes key government agencies, private and public utilities, and FORTUNE 500 companies in a broad range of industries. They provide pre-construction services, procurement, and construction management of heavy civil infrastructure projects. Patrick has technical experts in the fields of civil, structural, hydraulic, environmental, geotechnical, and electrical engineering, geology, surveying, construction management, process control, and geographic information systems. Engineering News Record (ENR) has included Patrick in its ENR Top 500 for 17 consecutive years and the company has been ranked as one of the Midwest's Top 10 Design Firms for the past five years.

III. Project description

FutureGen 2.0 is a first-of-its-kind, near-zero emissions coal-fueled power plant with carbon capture and storage. In cooperation with the U.S. Department of Energy (DOE), the FutureGen 2.0 project partners would upgrade a power plant in Meredosia, Illinois with oxy-combustion technology to capture approximately 1.1 million metric tons of CO_2 each year—more than 90 percent of the plant's carbon emissions. Other emissions would be reduced to near-zero levels. The captured CO_2 would be compressed to a super-critical fluid and, using safe and proven pipeline technology, the CO_2 would be transported approximately 30 miles and stored underground at a site in northeastern Morgan County, Illinois.

Four horizontal injection wells would penetrate approximately 4,030 feet vertically and 2,000 feet horizontally into the Mt. Simon formation – a porous, saline-saturated sandstone – where the CO_2 would be sequestered. Surface facilities at the injection site would consist of a site control building and a well maintenance and monitoring system building. The Alliance is evaluating locating the site control and pumping functions at the power plant facility in Meredosia. If that proves to be functionally and economically preferable, the injection wells site would only have a well maintenance and monitoring system building.

In addition to the injection wells, the Alliance would use its existing stratigraphic well that was drilled into the Mt. Simon formation as a monitoring well and would drill two additional monitoring wells into the Mt. Simon formation. The Alliance would also install up to three monitoring wells above the Eau Claire caprock formation at approximately 3,400 feet, and one monitoring well into the St. Peter formation (considered the lowest USDW [LUSDW]) at 1,900 feet.

IV. Description of activities considered to demonstrate financial responsibility

In estimating the costs to demonstrate financial responsibility for the geologic sequestration of carbon dioxide by the FutureGen Alliance at the Morgan County site, Patrick Engineering has considered the costs associated with: 1) corrective action on wells, 2) plugging of the four injection wells and the three monitoring wells, 3) post-injection site care, 4) site closure, and 5) emergency and remedial response, as detailed below:

1. Corrective action on wells in the AoR
    a. Review existing plume model
    b. Remodel plume
    c. Review of state databases of known wells and abandoned mines
    d. Well integrity testing
    e. Plug deficient wells
    f. Perform remedial cementing of defective wells
2. Injection wells and monitoring wells plugging and site reclamation
    a. Injection wells plugging
        i. Casing evaluation
        ii. Repair problems & cleanup of any impacted groundwater
        iii. Cement materials used to plug the well
        iv. Labor, engineering, rig time, equipment
        v. Decontamination of equipment
        vi. Disposal of any equipment
    b. Land reclamation
        i. Phase I demolition of surface site buildings at injection well site
        ii. Removal of gravel well pads and land restoration at injection well site
    c. Well remediation
        i. Sample analysis (Fluid or Soil)
        ii. Site assessment/hydrogeologic study
        iii. System removal
        iv. Disposal system modification
        v. Installation of monitoring well
3. Post-injection site care
    a. Monitoring wells for geochemical and geophysical analyses
        i. LUSDW monitoring well
        ii. Injection zone monitoring well
        iii. Above confining zone monitoring well
    b. Operation and maintenance of monitoring wells
        i. LUSDW monitoring well
        ii. Injection zone monitoring well
        iii. Above confining zone monitoring well
    c. Site management and EPA reporting
4. Site closure
    a. Non-endangerment demonstration
    b. LUSDW monitoring well plugging and site reclamation

i. Casing evaluation
ii. Evaluation of any problems discovered by the casing evaluation
iii. Cost for repairing problems & cleanup of any groundwater or soil contamination
iv. Cost for cementing or other materials used to plug the wells
v. Cost for labor, engineering, rig time, equipment and consultants
vi. Cost for decontamination of equipment
vii. Cost for disposal of any equipment
viii. Gravel pad removal

c. Injection zone monitoring well plugging and site reclamation
    i. Casing evaluation
    ii. Evaluation of any problems discovered by the casing evaluation
    iii. Cost for repairing problems & cleanup of any groundwater or soil contamination
    iv. Cost for cementing or other materials used to plug the well
    v. Cost for labor, engineering, rig time, equipment and consultants
    vi. Cost for decontamination of equipment
    vii. Cost for disposal of any equipment
    viii. Gravel pad removal
d. Above confining zone monitoring well plugging and site reclamation
    i. Casing evaluation
    ii. Evaluation of any problems discovered by the casing evaluation
    iii. Cost for repairing problems & cleanup of any groundwater or soil contamination
    iv. Cost for cementing or other materials used to plug the well
    v. Cost for labor, engineering, rig time, equipment and consultants
    vi. Cost for decontamination of equipment
    vii. Cost for disposal of any equipment
    viii. Gravel pad removal
e. Land reclamation
    i. Phase II demolition
    ii. Remove access roads
f. Document plugging and closure process

5. Emergency and remedial response
    a. Post-injection USDW contamination
        i. Acidification due to migration of CO_2
        ii. Toxic metal dissolution and mobilization
        iii. Displacement of groundwater with brine due to CO_2 injection
    b. Post-Injection Failure Scenarios (acute)
        i. Upward leakage through CO_2 injection well
        ii. Upward leakage through deep oil and gas wells
        iii. Upward leakage through undocumented, abandoned, or substandard wells
    c. Post-injection failure scenarios (chronic)
        i. Upward leakage through caprock through gradual failure
        ii. Release through existing faults due to effects of increased pressure
        iii. Release through induced faults due to effects of increased pressure
        iv. Upward leakage through CO_2 injection well
        v. Upward leakage through deep oil and gas wells
        vi. Upward leakage through undocumented, abandoned, or substandard deep wells
    d. Other

i. Catastrophic failure of caprock
ii. Failure of caprock/seals or well integrity due to seismic event

V. Basis used to develop cost estimates

The FutureGen Alliance contracted with Patrick Engineering to provide a third-party cost estimate to meet the required financial responsibility activities: corrective action on wells in the AoR; injection well plugging; post-injection site care and site closure; and emergency and remedial response. Patrick used the EPA's UIC Program Class VI Financial Responsibility Guidance[1] as the basis to define the activities required to be included in the cost estimate. The costs of the required activities were then estimated from 1) historic price data from other projects the company has managed, 2) cost quotes from third-party companies, 3) EPA's Geologic CO_2 Sequestration Technology and Cost Analysis document[2], and 4) professional judgment on the level of effort required to complete an activity. The estimated costs are in current (2012) dollars and reflect the costs of a third party to complete the work. The unit costs are fully loaded with general and administrative costs; overhead and profit are also included.

In developing the estimate, Patrick assumed the costs would be incurred if the FutureGen Alliance was no longer involved in the project and a third party was asked to conclude the project in a manner to protect USDWs. Thus, the costs included in this estimate would cover the efforts required to ensure the protection of USDWs at no cost to the public. The cost estimate includes the assumption that the third party would not take over and complete the full vision of FutureGen's research project and thus that CO_2 injection would cease immediately.

VI. Area of Review and Corrective Action Cost Estimate

The estimated costs in this section cover the periodic reevaluation of the AoR and the identification and remediation of newly identified deficient wells. For the purposes of this cost estimate, the initial study area was defined as an area of approximately 5,000 acres surrounding the injection well pad for the four injection wells. This area was based on a computational model that assumed injection of 1.1 million metric tons of CO_2 annually for 20 years (total of 22 million metric tons). Based on the model, the area covered by CO_2 plume after plume movement ceased would be contained within the 5,000-acre area. All deficient wells found in the initial AoR would be remediated before injection begins. Therefore, no cost is included to remediate deficient wells within the initial AoR.

As noted above, this cost estimate assumes CO_2 injection would cease at, or would have ceased by, the time a third party was needed to take over responsibility for the injection well and storage site. For purposes of the cost estimate, a reevaluation of the AoR would occur at the time a third party took responsibility and then would occur once every five years during the 50-year post-injection period – the default frequency required by the Class VI regulations. Should the injection reservoir tracking data obtained over the five-year period deviate significantly from the predictions of the original (or updated) computational model, the model would be updated to reflect the actual measured shape and extent of the CO_2 plume and improve the accuracy of the

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[1] *Underground Injection Control (UIC) Class VI Program. Financial Responsibility Guidance.* USEPA

[2] *Geologic CO2 Sequestration Technology and Cost Analysis.* USEPA Office of Water (4606-M). EPA 816-D-10-008, November 2010.

predicted AoR. It is assumed this would only be necessary once during the post-injection period as the model would have been regularly verified and updated during the injection period.

Any newly identified wells are assumed to be either deficient wells within the initial AoR which were not discovered before injection, or deficient wells added because of adjustments to the AoR due to ongoing monitoring of the plume during injection. Based on current investigations by Patrick and the Alliance, the closest well in any direction that penetrates the confining zone (the Eau Claire Formation) is approximately 16 miles away from the proposed injection site. For this reason, Patrick believes that the likelihood of encountering additional wells within an adjusted AoR is small and, for purposes of the cost estimate, has assumed that there would be one newly identified well.

Remediation costs were estimated based on Patrick's experience and costs incurred or estimated for other projects.

Table 1: Corrective Action on Wells in Area of Review

Activity	Unit			Unit Cost ($)			Total Costs ($)
a. Review existing plume model (every five years)	1,600	hrs	@	153	per hour	=	245,000
b. Remodel plume (once)	1,500	hrs	@	153	per hour	=	230,000
c. Review of state databases of known wells and abandoned mines (every five years)	200	hrs	@	153	per hour	=	31,000
d. Well integrity testing	1	well	@	26,000	per well	=	26,000
e. Plug deficient wells	1	well	@	15,000	per well	=	15,000
f. Perform remedial cementing of defective wells	1	well	@	15,000	per well	=	15,000
g. Project management and oversight (every five years)	400	hrs	@	153	per hour	=	61,000
Total Corrective Action on Wells in AoR over 50-year Post-injection Period							**623,000**

VII. Injection Wells Plugging and Site Reclamation Cost Estimate

The estimated costs in this section cover the plugging of the four injection wells after injection had ceased. Site reclamation for the plugged sites is included in the cost as well.

The costs are broken into three areas: 1) plugging and abandoning the four injection wells, 2) land reclamation including removal of injection site buildings and appurtenances, and 3) remediation cost in the unlikely event that the plugging activity causes the need to remediate local shallow wells. The costs are one-time costs that would be paid at the end of the anticipated 30-year injection period or when injection ceased, whichever came first.

The plugging of all wells would include mechanical integrity testing, plugging the hole with cement for the entire depth of the well, and cutting the well off below the ground. All structures and appurtenances at the sites of the first and second injection wells would be removed except for those directly necessary to the continued monitoring of the plume. The surface facilities remaining for post-injection monitoring would be removed during site closure.

Well plugging and site remediation costs were estimated based on Patrick's experience and costs incurred or estimated for other projects. Four previous UIC applications for CO_2 sequestration wells were reviewed and average costs for mobilization and plugging costs per inch-foot of bore were developed.

Table 2: Injection Wells & Monitoring Wells Plugging & Site Reclamation Summary

Activity	Total Cost ($)
a. Injection wells plugging	1,633,000
b. Land reclamation	1,037,000
c. Well remediation	53,000
Total Injection Wells & Monitoring Wells Plugging & Site Reclamation	**2,723,000**

Table 2a: Injection Wells Plugging & Site Reclamation Detail

Activity	Unit			Unit Cost ($)		Total Costs ($)	
a. Injection wells plugging							
i. Casing evaluation	4	wells	@	62,000	per well	=	248,000
ii. Repair problem & groundwater cleanup	4	wells	@	31,000	per well	=	124,000
iii. Cement materials used to plug the well	4	wells	@	140,000	per well	=	560,000
iv. Labor, engineering, rig time, equipment	4	wells	@	114,000	per well	=	456,000
v. Decontamination of equipment	4	wells	@	4,000	per well	=	16,000
vi. Disposal of any equipment	4	wells	@	3,000	per well	=	12,000
Miscellaneous and minor contingencies (10%)	4	wells	@	36,000	per well	=	144,000
Project Management and Oversight (480 hours @ $153/hour)							73,000
Total injection wells plugging							**1,633,000**

b. Land reclamation							
i. Phase I demolition of site control building at injection well site	1	site	@	836,000	per site	=	836,000
ii. Removal of gravel well pads and land restoration at injection well site	1	pad	@	186,000	per pad	=	186,000
Project Management and Oversight (100 hours @ $153/hour)							15,000
Total land reclamation							**1,037,000**

c. Well remediation						
i. Sample analysis (fluid or soil)	1	@	1,000	each	=	1,000
ii. Site assessment/ hydrogeological study	1	@	15,300	each	=	15,300
iii. System removal	1	@	7,600	each	=	7,600
iv. Disposal system modification	1	@	1,500	each	=	1,500
v. Installation of monitoring well	1	@	15,300	each	=	15,300
Project management and oversight (80 hours @ $153/hour)						12,000
				Total remediation		**53,000**

VIII. Post-Injection Site Care Cost Estimate

The estimated costs in this section cover the tracking and modeling of the plume during the 50-year post-injection period.

The PISC activities would include collecting geochemical and geophysical monitoring data from three injection zone monitoring wells, up to three above-caprock monitoring wells, and one LUSDW (St. Peter formation) monitoring well. The data collected would include continuous formation temperature and pressure readings and annual well samples. The geochemical and geophysical data from the deep well would be used to verify and, if necessary, recalibrate the computational model. PISC costs would also include record keeping and reporting the information to the proper governmental agency.

The PISC costs were estimated based on Patrick's experience, costs incurred or estimated for other projects, and EPA guidance[3].

Table 3: Post-injection Site Care Summary

Activity	Total Cost ($)
a. Monitoring wells for geochemical and geophysical analyses	10,870,000
b. Monitoring well mechanical integrity testing	3,650,000
c. Site management and EPA reporting	3,800,000
Total post-injection site care	**$18,320,000**

[3] *Ibid.*

Table 3a: Post-injection Site Care Detail

a. Monitoring wells for geochemical and geophysical analyses				
Activity	**Number of Wells**	**Base Cost ($)**	**Unit Cost ($)**	**Annual Cost ($)**
LUSDW well (geochemical analyses)	1	7,000	4,000	11,000
Injection zone monitoring well (pressure, temperature, electrical resistivity tomography (ERT)	3	80,000	16,000	128,000
Above confining zone monitoring well (pressure, temperature, ERT)	3	27,000	12,000	63,000
Project management and oversight (100 hours @ $153/hour)				15,300
Annual well monitoring cost				217,300
Total well monitoring cost for 50 years post-injection				**10,870,000**

b. Monitoring well mechanical integrity testing					
Activity	**Number of Wells**	**Base Cost ($)**	**Unit Cost ($/ft)**	**Well Depth (ft)**	**Annualized Cost ($)**
LUSDW well, monitoring sensors O&M (every five years - annualized)	1	2,000	4.25	1,900	2,000
Injection zone monitoring well (annually)	3	2,000	4.25	4,300	56,800
Above confining zone well monitoring sensors O&M (every five years - annualized)	3	2,000	4.25	3,400	9,100
Project management and oversight (160 hours @ $153/hour every five years)					5,000
Annualized monitoring well operation and maintenance					72,900
Total monitoring well operation and maintenance for 50 years post-injection					**3,650,000**

c. Site management and EPA reporting					
Activity	**Annual hours**		**Unit Cost ($)**		**Total Costs ($)**
Record keeping and reporting	250	@	153	per hour	38,000
Project management and oversight	250	@	153	per hour	38,000
Annual site management and EPA reporting					76,000
Total site management and EPA reporting over 50 years					**3,800,000**

IX. Site Closure Cost Estimate

The estimated costs in this section cover the final closure of the site. After the default 50-year, post-injection and site care period, and when it could be demonstrated that the project would no longer pose a risk of endangerment to any USDWs, the site would be permanently closed.

The costs are broken into four functional areas; 1) preparing the non-endangerment report, 2) plugging and abandoning all monitoring wells, 3) reclaiming land including removal of remaining surface site buildings and appurtenances, and 4) documenting the site closure process. The costs would be one-time costs that would be paid at the final project termination.

The plugging of the monitoring wells would include mechanical integrity testing, plugging the hole with cement the entire depth of the well, and cutting the well off below the ground. All structures and appurtenances at the sites of the monitoring wells would be completely removed and the sites would be restored to pre-project condition.

Well plugging and site remediation costs were estimated based on Patrick's experience and costs incurred or estimated for other projects. Four previous UIC applications for CO_2 sequestration wells were reviewed and average costs for mobilization and plugging costs per inch-foot of bore were developed.

Table 4: Site Closure Summary

Activity	Total Cost ($)
a. Non-endangerment demonstration	26,000
b. LUSDW monitoring well plugging	319,000
c. Injection-zone monitoring well plugging	1,609,800
d. Above-confining zone monitoring well plugging	1,288,500
e. Remove surface features and reclaim land	140,000
f. Document plugging and closure process	17,000
Total site closure	**3,402,000**

Table 4a: Site Closure Detail

a. Non-endangerment demonstration			
Activity	**Cost per Well ($)**	**Number of Wells**	**Total Cost ($)**
Prepare non-endangerment demonstration report			26,000
Total cost non-endangerment demonstration			**26,000**

b. LUSDW monitoring well plugging (1900 feet deep)			
Activity	**Cost per Well ($)**	**Number of Wells**	**Total Cost ($)**
Casing evaluation	21,000	1	21,000
Evaluation of any problems discovered by the casing evaluation	7,000	1	7,000
Cost for repairing problems & cleanup of any groundwater or soil contamination	14,000	1	14,000
Cost for cementing or other materials used to plug the well	62,000	1	62,000
Cost for labor, engineering, rig time, equipment and consultants	52,000	1	52,000
Cost for decontamination of equipment	4,000	1	4,000
Cost for disposal of any equipment	2,000	1	2,000
Gravel pad removal (175' x 175')	143,000	1	143,000
Project management and oversight (90 hours @ $153/hour)			14,000
Total cost plug LUSDW monitoring well			**319,000**

c. Injection zone monitoring wells plugging (Assumes 3 wells 4300 feet deep)			
Activity	**Cost per Well ($)**	**Number of Wells**	**Total Cost ($)**
Casing evaluation	51,000	3	153,000
Evaluation of any problems discovered by the casing evaluation	20,000	3	60,000
Cost for repairing problems & cleanup of any groundwater or soil contamination	31,000	3	93,000
Cost for cementing or other materials used to plug the well	140,000	3	420,000
Cost for labor, engineering, rig time, equipment and consultants	114,000	3	342,000
Cost for decontamination of equipment	4,000	3	12,000
Cost for disposal of any equipment	3,000	3	9,000
Gravel pad removal (175' x 175')	143,000	3	429,000
Project management and oversight (600 hours @ $153/hour)			91,800
Total injection zone monitoring wells plugging			**1,609,800**

d. Above confining zone monitoring well plugging (3,400 feet deep)			
Activity	**Cost per Well ($)**	**Number of Wells**	**Total Cost ($)**
Casing evaluation	34,000	3	102,000
Evaluation of any problems discovered by the casing evaluation	11,000	3	33,000
Cost for repairing problems & cleanup of any groundwater or soil contamination	23,000	3	69,000
Cost for cementing or other materials used to plug the well	102,000	3	306,000
Cost for labor, engineering, rig time, equipment and consultants	86,000	3	258,000
Cost for decontamination of equipment	4,000	3	12,000
Cost for disposal of any equipment	2,000	3	6,000
Gravel pad removal (175' x 175')	143,000	3	429,000
Project management and oversight (480 hours @ $153/hour)			73,500
Total cost plug above confining zone monitoring wells			**1,288,500**

e. Land reclamation			
Activity	**Unit Cost ($)**	**Number**	**Total Cost ($)**
Phase II demolition (@ 50 years following cessation of injection) - injection well site 1 well maintenance and monitoring building, and appurtenances	112,000	1	112,000
Remove access roads (miles)	11,000	2.5	28,000
Total remove surface features and reclaim land			**140,000**

f. Documentation			
Activity	**Hours**	**Rate ($/hr)**	**Total Cost ($)**
Document plugging and closure process (well plugging, post-injection plans, notification of intent to close, and post-closure report).	110	153	17,000
Total documentation			**17,000**

X. Emergency and Remedial Response Cost Estimate

It was assumed the response to discovered CO_2 leaks, both acute/high volume and chronic/low volume, would be to plug leaks where possible, assess any impact to USDWs, and remediate any contamination of USDWs. Potential consequences and response actions were taken from Esposito 2010[4]. The cost estimate assumes a maximum affected area of about 4 square miles. The costs include installation and sampling of 10 monitoring wells, installation and operation of 4 extraction wells, extraction, treatment of 10 to 20 gallons per minute of groundwater for 2 years using absorption, and removal of system. The extent and costs of treatment were adapted from Federal Remediation Technologies Roundtable website[5]. The cost of study and well installation were derived from previous experience. Costs for municipal water hook-up are not included as this scenario is deemed to be extremely unlikely, although the cost of remediation may make municipal water hook-up preferable. Also note that treatment costs can vary significantly depending on specific metal and concentration.

The costs of responding to catastrophic events assumed wide areas with groundwater impacted from CO_2 seeps which would require groundwater remediation and providing alternative water supplies to affected residents.

Table 5: Emergency and Remedial Response Events

Event	Consequences	Response Actions
<u>1. Post-injection USDW contamination</u>		
Acidification due to migration of CO_2	Decrease in pH by 1 to 2 units, mobilization of trace and alkali metals, other geochemical changes to groundwater that result in USDW exceeding applicable standards	Hydrogeological study to delineate 3-D extent and nature of impact to USDW. Groundwater extraction with treatment of groundwater or extraction coupled with injection of 'clean' water, if possible. Significant impact to USDW could require supplying municipal water to affected properties.
Toxic metal dissolution and mobilization	Concentrations of toxic metals in USDW greater than applicable standards	Hydrogeological study to delineate 3-D extent and nature of impact to USDW. Groundwater extraction with treatment of groundwater or extraction coupled with injection of 'clean' water, if possible. Significant impact to USDW could require supplying municipal water to affected properties.

[4] Exposito, Ariel M.M. *'Remediation of Possible Leakage from Geologic CO_2 Storage Reservoirs into Groundwater Aquifers.* Stanford University Department of Energy Resources Engineering. June 2010.

[5] Environmental Cost Estimating Tools. In *Federal Remediation Technologies Roundtable*. Retrieved June 9, 2011. From www.frtr.gov.

Table 5 (continued)

Event	Consequences	Response Actions
Displacement of groundwater with brine due to CO_2 injection	Concentrations of anions/cations in USDW greater than applicable drinking water standards.	Hydrogeological study to delineate 3-D extent and nature of impact to USDW. Groundwater extraction with treatment of groundwater or extraction coupled with injection of 'clean' water, if possible. Significant impact to USDW could require supplying municipal water to affected properties.
2. Post-injection failure scenarios (acute)		
Upward leakage through CO_2 injection well	Groundwater contamination	1) Pull and replace the tubing or the packer, 2) Repair the well by plugging it with cement, 3) Create a hydraulic barrier by increasing reservoir pressure upstream of the leak, 4) Install chemical sealant barrier to block leaks, and 5) Remediate groundwater (see 1. above).
Upward leakage through deep oil and gas wells	Groundwater contamination	1) Pull and replace the tubing or the packer, 2) Repair the well by plugging it with cement, 3) Create a hydraulic barrier by increasing reservoir pressure upstream of the leak, 4) Install chemical sealant barrier to block leaks, and 5) Remediate groundwater (see 1. above).
Upward leakage through undocumented, abandoned, or poorly constructed wells	Groundwater contamination	1) Pull and replace the tubing or the packer, 2) Repair the well by plugging it with cement, 3) Create a hydraulic barrier by increasing reservoir pressure upstream of the leak, 4) Install chemical sealant barrier to block leaks, and 5) Remediate groundwater (see 1. above).
3. Post-injection failure scenarios (chronic)		
Upward leakage through caprock through gradual failure	Groundwater contamination	Remediate groundwater (see 1. above)
Release through existing faults due to effects of increased pressure	Groundwater contamination	Remediate groundwater (see 1. above)
Release through induced faults due to effects of increased pressure	Groundwater contamination	Remediate groundwater (see 1. above)

Table 5 (continued)

Event	Consequences	Response Actions
Upward leakage through CO_2 injection well	Groundwater contamination	1) Repair the well by plugging it with cement, 2) Create a hydraulic barrier by increasing reservoir pressure upstream of the leak, 3) Install chemical sealant barrier to block leaks, and 4) Remediate groundwater (see 1. above)
Upward leakage through deep oil and gas wells	Groundwater contamination	1) Pull and replace the tubing or the packer, 2) Repair the well by plugging it with cement, 3) Create a hydraulic barrier by increasing reservoir pressure upstream of the leak, 4) Install chemical sealant barrier to block leaks, and 5) Remediate groundwater (see 1. above).
Upward leakage through undocumented, abandoned, or poorly constructed deep wells	Groundwater contamination	1) Pull and replace the tubing or the packer, 2) Repair the well by plugging it with cement, 3) Create a hydraulic barrier by increasing reservoir pressure upstream of the leak, 4) Install chemical sealant barrier to block leaks, and 5) Remediate groundwater (see 1. above).
4. Other		
Catastrophic failure of caprock	Groundwater contamination	Remediate groundwater (see 1. above)
Failure of caprock or well integrity due to seismic event	Groundwater contamination	Remediate groundwater (see 1. above)

Table 5a: Emergency and Remedial Response Estimated Costs

Event	Estimated Cost ($)
<u>1. Post-injection USDW contamination</u>	
Acidification due to migration of CO_2	305,000
Toxic metal dissolution and mobilization	5,865,000
Displacement of groundwater with brine due to CO_2 injection	270,000
<u>2. Post-injection failure scenarios (acute)</u>	
Upward leakage through CO_2 injection well	3,343,000
Upward leakage through deep oil and gas wells	2,111,000
Upward leakage through undocumented, abandoned, or poorly constructed wells	2,111,000
<u>3. Post-injection failure scenarios (chronic)</u>	
Upward leakage through caprock through gradual failure	5,865,000
Release through existing faults due to effects of increased pressure	5,865,000
Release through induced faults due to effects of increased pressure	6,100,000
Upward leakage through CO_2 injection well	821,000
Upward leakage through deep oil and gas wells	411,000
Upward leakage through undocumented, abandoned, or poorly constructed deep wells	411,000
4. Other	
Catastrophic failure of caprock	6,100,000
Failure of caprock/seals or well integrity due to seismic event	6,100,000

XI. Cost Summary

For the Morgan County CO_2 injection site, the total cost for a third party to take corrective actions on wells within the AoR, plug the injection wells, conduct post-injection site care and site closure actions necessary to protect USDWs if the Alliance were unable to do so is estimated to be $17,785,000 as shown in Table 6. Possible emergency and remedial response actions as necessary to protect USDWs could possibly amount to as much as $6,100,000 for a single event.

Table 6: Total Financial Responsibility Cost by Category

Activity	Total Cost ($)
Corrective action on wells in AoR	623,000
Injection wells & monitoring wells plugging & site reclamation	2,723,000
Post-injection site care	18,320,000
Site closure	3,402,000
Total Financial Responsibility	**25,068,000**

The costs, assuming a 20-year injection period, are shown by category projected over time in Table 7 on the following page

Table 7: Total Financial Responsibility Cost by Category and Year (in 2012 dollars)

Year After Injection Stops	Corrective action on wells in AoR Cost ($)	Injection wells & monitoring wells plugging & site reclamation Cost ($)	Post-injection Site Care Cost ($)	Site Closure Cost ($)
1	33,700	2,723,000	430,800	-
2	-	-	350,200	-
3	-	-	350,200	-
4	-	-	350,200	-
5	-	-	350,200	-
6	33,700	-	430,800	-
7	-	-	350,200	-
8	-	-	350,200	-
9	-	-	350,200	-
10	-	-	350,200	-
11	33700	-	430,800	-
12	-	-	350,200	-
13	-	-	350,200	-
14	-	-	350,200	-
15	-	-	350,200	-
16	263,700	-	430,800	-
17	-	-	350,200	-
18	-	-	350,200	-
19	-	-	350,200	-
20	-	-	350,200	-
21	33700	-	430,800	-
22	-	-	350,200	-
23	-	-	350,200	-
24	-	-	350,200	-
25	-	-	350,200	-
26	89,700	-	430,800	-
27	-	-	350,200	-
28	-	-	350,200	-
29	-	-	350,200	-
30	-	-	350,200	-
31	33,700	-	430,800	-
32	-	-	350,200	-
33	-	-	350,200	-
34	-	-	350,200	-
35	-	-	350,200	-

Table 7 (continued)

36	33,700	-	430,800	-
37	-	-	350,200	-
38	-	-	350,200	-
39	-	-	350,200	-
40	-	-	350,200	-
41	33,700	-	430,800	-
42	-	-	350,200	-
43	-	-	350,200	-
44	-	-	350,200	-
45	-	-	350,200	-
46	33,700	-	430,800	-
47	-	-	350,200	-
48	-	-	350,200	-
49	-	-	350,200	-
50	-	-	350,200	-
51	-	-	-	3,402,000
TOTAL	**623,000**	**2,723,000**	**18,320,000**	**3,402,000**

Appendix D

Insurance Review to Support Futuregen Alliance's UIC Permit Application

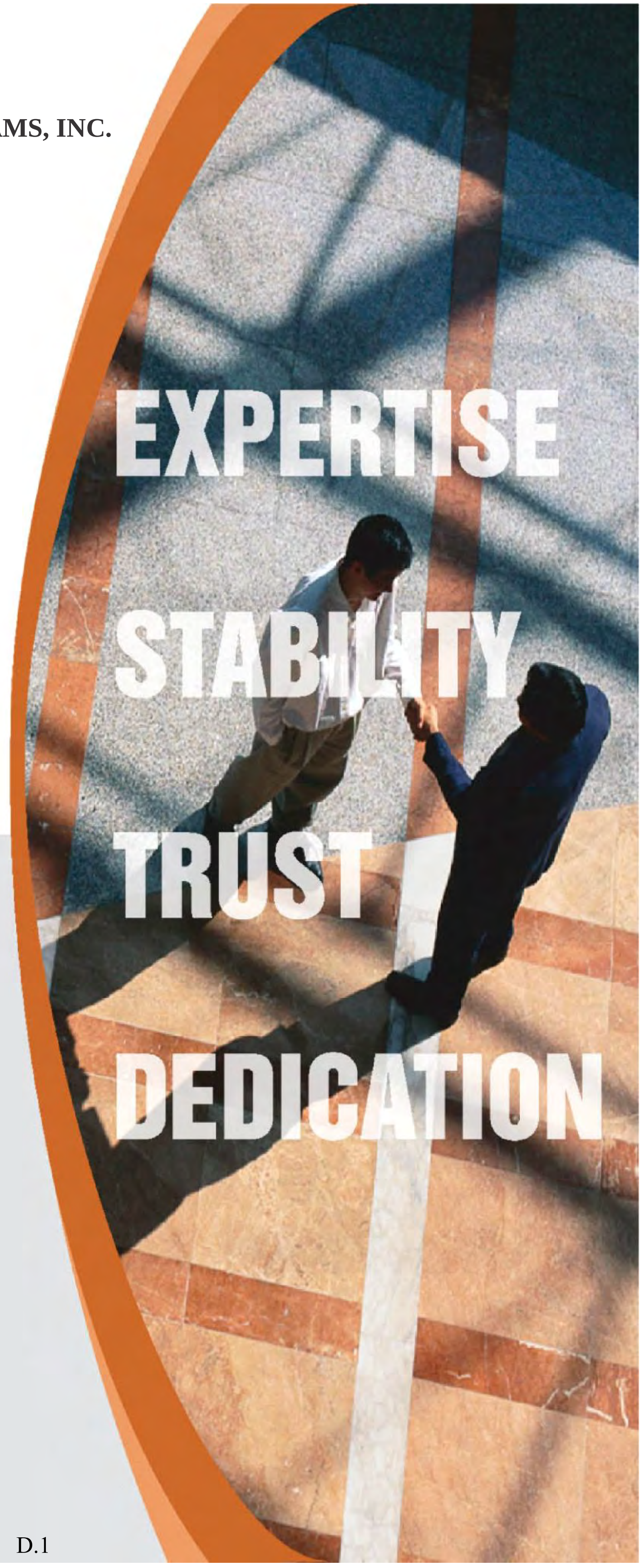
McGRIFF, SEIBELS & WILLIAMS, INC.

Insurance Review to support FutureGen Alliance's UIC Permit Application

FutureGen™ ALLIANCE

CONFIDENTIAL

September, 2012



Financial and Confidential Information

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Financial and Confidential Information

MEMORANDUM DISCUSSING EMERGENCY AND REMEDIAL RESPONSE ACTIVITIES AND AVAILABLE INSURANCE

SEPTEMBER, 2012

1. INTRODUCTION

We have been asked to prepare for the Alliance a plan and memorandum outlining the applicable environmental insurance products, expected policy terms and conditions, exclusions, costs and deductibles to support the Alliance's application to US EPA Region 5 for the necessary UIC Class VI well injection permit financial responsibility requirements. The analysis presented in this memo was focused and based on the **Emergency and Remedial Response activities** for the FutureGen 2.0 geological sequestration project identified in the Patrick Engineering report dated September, 2012.

2. COMPANY EXPERIENCE

McGriff has extensive experience with power generation and emissions exposures. As part of the 6th largest insurance brokerage firm in the U.S., we represent companies with over 300,000 megawatts of installed power generation. As part of our service to the energy industry, we developed and placed the first insurance policy for Carbon Capture and Sequestration (CCS) liability, representing American Electric Power on their Mountaineer Project. Additionally, we are currently engaged with multiple CCS projects on their insurance program development and management. Please see the Appendix for additional information on our firm.

3. US EPA REGION 5 PERMIT APPLICATION AND INSURABILITY OF EMERGENCY AND REMEDIAL RESPONSE EVENTS

According to the EPA Guidelines, owners/operators must demonstrate **financial responsibility** for four activities:

1. Performing corrective action on wells
2. Well plugging
3. Post injection site care and site closure
4. Emergency and Remedial Response

This is to ensure that owners/operators have the financial resources to carry out activities related to operating, closing and remediating well sites if needed during injection or after wells are plugged, so that they do not endanger Underground Sources of Drinking Water (USDW), and will also ensure that the costs of abandoned projects are not borne by the general public.

There are two approved ways of demonstrating financial responsibility:

1. Independent third-party instruments (such as Trust, LOC, Surety Bond, Escrow or insurance)
2. Self insurance

The Alliance is planning to utilize a Trust to fulfill the financial responsibility requirements for performing corrective action on wells, well plugging and post injection site care and site closure, and purchase insurance for the Emergency and Remedial Response activities.

4. Pollution Legal Liability Coverage for Emergency and Remedial Response Activities

It is McGriff's understanding and opinion after surveying the insurance marketplace that there are no insurance products currently available that meet all of the financial responsibility requirements outlined in the Regulatory Language for Financial Responsibility for Class VI Wells – 40 CFR 146.85. However, the purchase of a Pollution Legal Liability (PLL) policy will provide insurance coverage for clean-up costs if the Alliance becomes legally obligated to remediate contamination of Underground Sources of Drinking Water.

The PLL policy also provides coverage for legal liability arising out of third party bodily injury and property damage caused by a pollution condition, and includes coverage for defense costs. The policy would include a specifically crafted endorsement designed to address the environmental risk exposures for CCS injection and storage operations. We have included a specimen PLL policy and CCS endorsement in the Appendix as an example of the insurance coverage currently available in the marketplace.

Currently the markets offer PLL policy terms of three (3) to five (5) years, depending on the required limit of liability. The market, at this time, will not guarantee renewal of such a policy, as market conditions at expiration, loss of reinsurance capacity, or risk appetite for CCS exposures may limit the ability of the insurers to offer renewal terms.

The policy will contain an aggregate limit of liability for the policy term. It is important to note that if the limit of liability is exhausted, the Alliance will need to purchase another policy or elect to reinstate policy limits, subject to an additional premium. There is no guarantee that the Alliance would be able to purchase another policy because the available market capacity for CCS projects is relatively limited and could erode if a significant loss were to occur.

Typically a PPL policy may be cancelled by the insurer for the following reasons: material misrepresentation, failure to comply with policy terms, non-payment of premium, or change in use or operation. Generally, the insurer will give 90 days written notice of cancellation to the Named Insured (10 days for non-payment).

5. EVENTS OUTLINED IN THE PATRICK ENGINEERING REPORT

In order to trigger the PLL policy, there must be an event that is caused by a "POLLUTION CONDITION." A Pollution Condition is defined in the Carbon Capture and Storage Covered Operations Endorsement as:

Pollution Condition *means the discharge, dispersal, release or escape of Carbon Dioxide and all other components captured in accordance with the Permit for Injection into or upon land not considered the Injection Zone, or any structure on land, the atmosphere or any watercourse or body of water, including ground water.*

Listed in the following table we have noted which PLL coverage sections should be purchased in order to respond to the Emergency and Remedial Response events indentified in the Patrick Engineering report:

Event	Consequences	Response Actions	Insurance Coverage Availability *
1. Post Injection USDW Contamination			
Acidification due to migration of CO_2	Decrease in pH by 1 to 2 units, mobilization of trace and alkali metals, other geochemical changes to groundwater that result in USDW exceeding applicable standards	1) Hydrogeological study to delineate 3-D extent and nature of impact to USDW. 2) Groundwater extraction with treatment of groundwater or extraction coupled with injection of 'clean' water, if possible. 3) Significant impact to USDW could require supplying municipal water to affected properties.	Coverage B, D, E, F
Toxic metal dissolution and mobilization	Concentrations of toxic metals in USDW greater than applicable standards	1) Hydrogeological study to delineate 3-D extent and nature of impact to USDW. 2) Groundwater extraction with treatment of groundwater or extraction coupled with injection of 'clean' water, if possible. 3) Significant impact to USDW could require supplying municipal water to affected properties.	Coverage B, D, E, F
Displacement of groundwater with brine due to CO_2 injection	Concentrations of anions/cations in USDW greater than applicable drinking water standards.	1) Hydrogeological study to delineate 3-D extent and nature of impact to USDW. 2) Groundwater extraction with treatment of groundwater or extraction coupled with injection of 'clean' water, if possible. 3) Significant impact to USDW could require supplying municipal water to affected properties.	Coverage B, D, E, F

Event	Consequences	Response Actions	Insurance Coverage Availability *
2. Post-Injection Failure Scenarios (Acute)			
Upward leakage through CO_2 injection well	Groundwater contamination	1) Stop injection, 2) Pull and replace the tubing or the packer, 3) Repair the well by plugging it with cement, 4) Create a hydraulic barrier by increasing reservoir pressure upstream of the leak, 5) Install chemical sealant barrier to block leaks, and 6) Remediate groundwater.	Coverage B, D, E, F
Upward leakage through deep oil and gas wells	Groundwater contamination	1) Stop injection, 2) Pull and replace the tubing or the packer, 3) Repair the well by plugging it with cement, 4) Create a hydraulic barrier by increasing reservoir pressure upstream of the leak, 5) Install chemical sealant barrier to block leaks, and 6) Remediate groundwater.	Coverage B, D, E, F
Upward leakage through undocumented, abandoned, or poorly constructed wells	Groundwater contamination	1) Stop injection, 2) Pull and replace the tubing or the packer, 3) Repair the well by plugging it with cement, 4) Create a hydraulic barrier by increasing reservoir pressure upstream of the leak, 5) Install chemical sealant barrier to block leaks, and 6) Remediate groundwater.	Coverage B, D, E, F
3. Post-Injection Failure Scenarios (Chronic)			
Upward leakage through caprock and seals through gradual failure	Groundwater contamination	1) Stop injection, 2) Remediate groundwater.	Coverage B, D, E, F
Release through existing faults due to effects of increased pressure	Groundwater contamination	1) Stop injection, 2) Remediate groundwater.	Coverage B, D, E, F
Release through induced faults due to effects of increased pressure	Groundwater contamination	1) Stop injection, 2) Remediate groundwater.	Coverage B, D, E, F
Upward leakage through CO_2 injection well	Groundwater contamination	1) Stop injection, 2) Repair the well by plugging it with cement, 3) Create a hydraulic barrier by increasing reservoir pressure upstream of the leak, 4) Install chemical sealant barrier to block leaks, and 5) Remediate groundwater.	Coverage B, D, E, F

Event	Consequences	Response Actions	Insurance Coverage Availability *
Upward leakage through deep oil and gas wells		1) Stop injection, 2) Pull and replace the tubing or the packer, 3) Repair the well by plugging it with cement, 4) Create a hydraulic barrier by increasing reservoir pressure upstream of the leak, 5) Install chemical sealant barrier to block leaks, and 6) Remediate groundwater.	Coverage B, D, E, F
Upward leakage through undocumented, abandoned, or poorly constructed deep wells		1) Stop injection, 2) Pull and replace the tubing or the packer, 3) Repair the well by plugging it with cement, 4) Create a hydraulic barrier by increasing reservoir pressure upstream of the leak, 5) Install chemical sealant barrier to block leaks, and 6) Remediate groundwater.	Coverage B, D, E, F
4. Other			
Catastrophic failure of caprock and seals	Groundwater contamination	1) Stop injection, 2) Remediate groundwater.	Coverage B, D, E, F
Failure of caprock/seals or well integrity due to seismic event	Groundwater contamination	1) Stop injection, 2) Remediate groundwater.	Coverage B, D, E, F

PLL Coverage Sections:

Coverage B - On-Site Clean-Up of New Conditions

Coverage D - Third-Party Claims for Off-Site Clean-Up Resulting from New Conditions

Coverage E - Third-Party Claims for Bodily Injury and Property Damage

Coverage F - Emergency Response Costs

Notes:

* In order for the policy to respond to the first party Response Actions listed above, the action must fall within the definition of **Clean-Up Costs** and be required by **Environmental Law**. The policy definition of **Clean-Up Costs** is:

Clean-Up Costs *means reasonable and necessary expenses, including legal expenses incurred with the Company's written consent which consent shall not be unreasonably withheld or delayed, for the investigation, removal, treatment including in-situ treatment, remediation including associated monitoring, or disposal of soil, surface water, groundwater,* ***Microbial Matter,*** *Legionella pneumophila, or other contamination:*

1. *To the extent required by* ***Environmental Laws*** *or required to satisfy a* ***Voluntary Cleanup Program;***

2. *With respect to* ***Microbial Matter****, in the absence of any applicable* ***Environmental Laws,*** *to the extent recommended in writing by a* ***Certified Industrial Hygienist;*** *or*

3. *With respect to Legionella pneumophila, in the absence of any applicable* ***Environmental Laws,*** *to the extent required in writing by the Center for Disease Control or local health department; or*

4. *That have been actually incurred by the government or any political subdivision of the United States of America or any state thereof or Canada or any province thereof, or by third parties.*

Clean-up Costs *also include* ***Restoration Costs.***

The definition of **Environmental Law** is:

Environmental Law *means any federal, state, provincial or local laws (including, but not limited to, statutes, rules, regulations, ordinances, guidance documents, and governmental, judicial or administrative orders and directives) that are applicable to the Pollution Condition.*

Ongoing maintenance and other non-fortuitous events are not covered by a PLL insurance policy, so it would not respond to all potential activities.

Please refer to the specimen policy in the Appendix for additional Definitions and Exclusions.

6. RECOMMENDED LIMITS

We have reviewed the Patrick Engineering report with a focus on the Emergency and Remedial Response events listed and the related expected costs. The greatest exposure identified by Patrick Engineering is a catastrophic failure of the caprock. This event has an estimated cost of $6,100,000 for remediation of USDWs. While that cost is not disputed, we believe the actual claim amount could be significantly higher. The Patrick Engineering cost estimate is an engineering estimate which does not take into account other costs such as third party bodily injury or property damage, expenses associated with defending third party liability claims, or potential subsequent lawsuits. Legal defense costs, which could be one of the most significant expenses related to a third party liability claim, were not included in the report.

Determining limits is a balance between purchasing adequate coverage for the project and weighing premium costs and deductible requirements. While there have been relatively few policies placed, other peer CCS projects purchase or plan to purchase between $25MM and $200MM in total PLL policy limits. The difference in purchased limits is related to the size of the projects, and the balance sheet of the owner/operator. Small test projects injecting 100,000 to 200,000 tons of CO_2 annually have purchased limits on the lower side, whereas large commercial projects have purchased or plan to purchase much higher limits. Based on the size and scope of the FutureGen project which is expected to inject approximately 1.1 million metric tons of CO_2 annually, we recommend that the Alliance consider purchasing PLL coverage with limits of $50,000,000 to $100,000,000.

Premium and deductible cost estimates for PLL coverage (Sections B, D, E, and F) with a CCS endorsement are provided in the following table. These are estimates only and actual premiums will be determined based on the underwriting information provided by the Alliance at the time, prior to quoting.

Limit	Deductible	Annual Premium
$ 25,000,000	$250,000	$225,000-$350,000
$ 50,000,000	$250,000	$375,000-$575,000
$100,000,000	$250,000	$625,000-$825,000

APPENDIX

- Specimen Policy Form
- Sample CCS Endorsement
- McGriff Overview

SPECIMEN POLICY FORM

CHARTIS SPECIALTY INSURANCE COMPANY

POLLUTION LEGAL LIABILITY SELECT® POLICY

MANY OF THE COVERAGES CONTAIN CLAIMS-MADE AND REPORTED REQUIREMENTS. PLEASE READ CAREFULLY. ADDITIONALLY, THIS POLICY HAS CERTAIN PROVISIONS AND REQUIREMENTS UNIQUE TO IT AND MAY BE DIFFERENT FROM OTHER POLICIES THE INSURED MAY HAVE PURCHASED. DEFINED TERMS, OTHER THAN HEADINGS, APPEAR IN BOLD FACE TYPE.

NOTICE: THE DESCRIPTIONS IN ANY HEADINGS OR SUB-HEADINGS OF THIS POLICY ARE INSERTED SOLELY FOR CONVENIENCE AND DO NOT CONSTITUTE ANY PART OF THE TERMS OR CONDITIONS HEREOF.

Various provisions in this Policy restrict coverage. Read the entire Policy carefully to determine the rights and duties hereunder and what is and is not covered. This Policy is issued in reliance upon the statements in the Application, deemed to be annexed hereto. In consideration of the payment of the premium and pursuant to all of the terms of this Policy, the Company agrees with the **Named Insured** as follows:

I. INSURING AGREEMENTS

1. COVERAGES:

THE FOLLOWING COVERAGES ARE IN EFFECT ONLY IF SCHEDULED IN THE DECLARATIONS.

COVERAGE A - ON-SITE CLEAN-UP OF PRE-EXISTING CONDITIONS

1. To pay on behalf of the **Insured**, **Clean-Up Costs** resulting from a **Pollution Condition** on or under the **Insured Property** that first commenced prior to the **Continuity Date** provided:

   (a) A **Responsible Insured** first becomes aware of such **Pollution Condition** during the **Policy Period** and such **Pollution Condition** is reported to the Company in writing as soon as possible after such discovery and in any event during the **Policy Period** in accordance with Section III. of the Policy.

   (b) Where required, such **Pollution Condition** has been reported to the appropriate governmental agency in substantial compliance with applicable **Environmental Laws** in effect as of the date of discovery.

2. To pay on behalf of the **Insured**, **Loss** that the **Insured** is legally obligated to pay as a result of a **Claim** for **Clean-Up Costs** resulting from a **Pollution Condition** on or under the **Insured Property**, which **Pollution Condition** first commenced prior to the **Continuity Date**, provided such **Claim** is first made against the **Insured** and reported to the Company in writing during the **Policy Period** in accordance with Section III. of the Policy, or during the **Extended Reporting Period** if applicable.

COVERAGE B - ON-SITE CLEAN-UP OF NEW CONDITIONS

1. To pay on behalf of the **Insured**, **Clean-Up Costs** resulting from a **Pollution Condition** on or under the **Insured Property** that first commenced on or after the **Continuity Date**, provided:

   (a) A **Responsible Insured** first becomes aware of such **Pollution Condition** during the **Policy Period** and such **Pollution Condition** is reported to the Company in writing as soon as possible after such discovery and in any event during the **Policy Period** in accordance with Section III. of the Policy.

   (b) Where required, such **Pollution Condition** has been reported to the appropriate governmental agency in substantial compliance with applicable **Environmental Laws** in effect as of the date of discovery.

2. To pay on behalf of the **Insured**, **Loss** that the **Insured** is legally obligated to pay as a result of a **Claim** for **Clean-Up Costs** resulting from a **Pollution Condition** on or under the **Insured Property**, which **Pollution Condition** first commenced on or after the **Continuity Date**, provided such **Claim** is first made against the **Insured** and reported to the Company in writing during the **Policy Period** in accordance with Section III. of the Policy, or during the **Extended Reporting Period** if applicable.

NOTICE: THIS INSURER IS NOT LICENSED IN THE STATE OF NEW YORK AND IS NOT SUBJECT TO ITS SUPERVISION

COVERAGE C – THIRD-PARTY CLAIMS FOR OFF-SITE CLEAN-UP RESULTING FROM PRE-EXISTING CONDITIONS

To pay on behalf of the **Insured**, **Loss** that the **Insured** becomes legally obligated to pay as a result of a **Claim** for **Clean-Up Costs** resulting from a **Pollution Condition**, beyond the boundaries of the **Insured Property**, that first commenced prior to the **Continuity Date**, and migrated from or through the **Insured Property**, provided such **Claim** is first made against the **Insured** and reported to the Company in writing during the **Policy Period** in accordance with Section III. of the Policy, or during the **Extended Reporting Period** if applicable.

COVERAGE D – THIRD-PARTY CLAIMS FOR OFF-SITE CLEAN-UP RESULTING FROM NEW CONDITIONS

To pay on behalf of the **Insured**, **Loss** that the **Insured** becomes legally obligated to pay as a result of a **Claim** for **Clean-Up Costs** resulting from a **Pollution Condition**, beyond the boundaries of the **Insured Property**, that first commenced on or after the **Continuity Date**, and migrated from or through the **Insured Property**, provided such **Claim** is first made against the **Insured** and reported to the Company in writing during the **Policy Period** in accordance with Section III. of the Policy, or during the **Extended Reporting Period** if applicable.

COVERAGE E – THIRD-PARTY CLAIMS FOR BODILY INJURY AND PROPERTY DAMAGE

To pay on behalf of the **Insured**, **Loss** that the **Insured** becomes legally obligated to pay as a result of a **Claim** for **Bodily Injury** or **Property Damage** resulting from a **Pollution Condition** on, under or migrating from or through the **Insured Property**, provided such **Claim** is first made against the **Insured** and reported to the Company in writing during the **Policy Period** in accordance with Section III. of the Policy, or during the **Extended Reporting Period** if applicable.

COVERAGE F – EMERGENCY RESPONSE COSTS

1. The Company will pay **Emergency Response Costs** resulting from a **Pollution Condition** on, under or migrating from the **Insured Property**. **Emergency Response Costs** must be first incurred by the **Insured** and reported to the Company during the **Policy Period**.

   For this Coverage to apply, all of the following conditions must be satisfied:

   (a) The **Insured** must report the **Emergency Response Costs** to the Company in accordance with Section III. of the Policy.

   (b) **COVERAGE B – ON-SITE CLEAN UP OF NEW CONDITIONS** is purchased.

2. The Company will pay **Emergency Response Costs** resulting from a **Pollution Condition** caused by **Transportation** or **Covered Operations**. **Emergency Response Costs** must be first incurred by the **Insured** and reported to the Company during the **Policy Period**.

   For this Coverage to apply, all of the following conditions must be satisfied:

   (a) The **Insured** must report the **Emergency Response Costs** to the Company in accordance with Section III. of the Policy.

   (b) With respect to **Covered Operations**, **COVERAGE H – THIRD-PARTY CLAIMS FOR COVERED OPERATIONS** is purchased and with respect to **Transportation**, **COVERAGE I – THIRD-PARTY CLAIMS RESULTING FROM THE TRANSPORTATION OF CARGO** is purchased.

COVERAGE G – THIRD-PARTY CLAIMS FOR NON-OWNED LOCATIONS

To pay on behalf of the **Insured**, **Loss** that the **Insured** becomes legally obligated to pay as a result of a **Claim** for **Bodily Injury** or **Property Damage** of parties other than the owners, operators or contractors of the **Non-Owned Location**, or their employees, or **Clean-Up Costs** resulting from a **Pollution Condition** on, under or migrating from the **Non-Owned Location**, provided such **Claim** is first made against the **Insured** and reported to the Company in writing during the **Policy Period** in accordance with Section III. of the Policy, or during the **Extended Reporting Period** if applicable.

COVERAGE H – THIRD-PARTY CLAIMS FOR COVERED OPERATIONS

To pay on behalf of the **Insured**, **Loss** that the **Insured** becomes legally obligated to pay as a result of a **Claim** for **Bodily Injury**, **Property Damage** or **Clean-Up Costs** resulting from a **Pollution Condition** caused by **Covered Operations**, provided such **Claim** is first made against the **Insured** and reported to the Company in writing during the **Policy Period** in accordance with Section III. of the Policy, or during the **Extended Reporting Period** if applicable.

For this Coverage to apply, the **Covered Operations** which result in a **Claim** must be performed on or after the **Continuity Date** shown in Item 8. of the Declarations.

COVERAGE I – THIRD-PARTY CLAIMS RESULTING FROM THE TRANSPORTATION OF CARGO

To pay on behalf of the **Insured**, **Loss** that the **Insured** becomes legally obligated to pay as a result of a **Claim** for **Bodily Injury**, **Property Damage** or **Clean-Up Costs** resulting from a **Pollution Condition** caused by **Transportation of Cargo,** provided such **Claim** is first made against the **Insured** and reported to the Company in writing during the **Policy Period** in accordance with Section III. of the Policy, or during the **Extended Reporting Period** if applicable. Provided, however, this Coverage shall not be utilized to evidence financial responsibility of any **Insured** under any federal, state, provincial or local law.

COVERAGE J – BUSINESS INTERRUPTION EXPENSES

To pay the **Named Insured's Interruption Expenses**, resulting from an **Interruption** caused directly by a **Pollution Condition** on or under the **Insured Property** that results in on-site **Clean-Up Costs** covered by this Policy. If the **Interruption** is caused by such **Pollution Condition** and any other cause, the Company shall pay only for that portion of **Interruption Expenses** caused solely and directly by such **Pollution Condition**. An **Interruption** must be reported to the Company in accordance with Section III. of the Policy and the **Named Insured** shall resume normal operation of the business and dispense with **Extra Expense** as soon as practicable.

2. LEGAL EXPENSE AND DEFENSE

When a **Claim** is made against the **Insured** to which Section **I. INSURING AGREEMENTS, 1. COVERAGES, COVERAGES A, B, C, D, E, G, H** or **I** applies, and provided the **Named Insured** has purchased such Coverage(s), the Company has the right to defend, including but not limited to the right to appoint counsel, and the duty to defend such **Claim**, even if groundless, false, or fraudulent. With respect to any such **Claim** being defended by the Company, the Company shall pay all reasonable expenses incurred by the **Insured** at the Company's request to assist it in the investigation or defense of the **Claim**, including actual loss of earnings up to $500 a day because of time off from work; provided, however, that the Company's aggregate liability for all such expenses under this Policy shall not exceed $5,000.

Upon the **Insured's** satisfaction of any applicable deductible amount for the Coverage Section that applies and is shown in Item 3. of the Declarations, defense costs, charges and expenses shall be paid by the Company and such payments shall be included as **Loss** and reduce the available limits of liability (except for the expenses incurred by the **Insured** as described and limited above). The Company shall not be obligated to defend or continue to defend any **Claim** after the applicable limit of liability has been exhausted by payment of **Loss**.

3. SETTLEMENT

The Company will present any monetary settlement offers to the **Insured**, and if the **Insured** refuses to consent to any monetary settlement within the applicable limits of liability of this Policy recommended by the Company and acceptable to the claimant, the Company's duty to defend the **Insured** shall then cease and the **Insured** shall thereafter negotiate or defend such **Claim** independently of the Company and the Company's liability shall not exceed the amount, less the Deductible or any outstanding Deductible balance, for which the **Claim** could have been settled if such recommendation was consented to by the **Insured**.

4. DISCOVERY OF A POLLUTION CONDITION OR CLAIMS ARISING FROM EACH INCIDENT

1. If the **Insured** first discovers a **Pollution Condition** during this **Policy Period** and reports it to the Company in accordance with Section III. of the Policy, such **Pollution Condition** arising from **Each Incident** and reported to the Company under a subsequent Pollution Legal Liability Policy issued by the Company or its affiliate providing substantially the same coverage as this Policy shall be deemed to have been first discovered and reported during this **Policy Period**.

2. If the **Insured** first notifies the Company of a **Claim** or **Emergency Response Costs** during this **Policy Period** in accordance with Section III. or during the **Extended Reporting Period**, if applicable, then all **Claims** or **Emergency Response Costs** arising from **Each Incident** that are reported to the Company under a subsequent Pollution Legal Liability Policy issued by the Company or its affiliate providing substantially the same coverage as this Policy, shall be deemed to have been first made and reported during this **Policy Period**.

3. Coverage under this Policy for such **Pollution Condition**, **Claim** or **Emergency Response Costs** shall not apply

unless, at the time such **Pollution Condition**, **Claim** or **Emergency Response Costs** are first discovered or made and reported, the **Insured** has maintained with the Company or its affiliate Pollution Legal Liability coverage substantially the same as this coverage on a continuous, uninterrupted basis since the first **Pollution Condition** was discovered and reported to the Company, or such **Claim** was made against the **Insured** and reported to the Company or such **Emergency Response Costs** were reported to the Company.

II. EXCLUSIONS

1. COMMON EXCLUSIONS - APPLICABLE TO ALL COVERAGES

The following Exclusions apply to all Coverages:

This Policy does not apply to **Claims** or **Loss**:

A. ASBESTOS AND LEAD:

Arising from asbestos or any asbestos-containing materials or lead-based paint installed or applied in, on or to any building or other structure. However, this Exclusion does not apply to:

1. **Claims** for **Bodily Injury** or **Property Damage**; or
2. **Clean-Up Costs** for the remediation of soil, surfacewater or groundwater.

B. CHANGE IN INTENDED USE OR OPERATIONS:

Based upon or arising from a change in use or a change in operations which is different from the uses or operations identified in writing by the **Insured** to the Company during the underwriting process or in the application and which materially increases a risk covered hereunder.

C. CONTRACTUAL LIABILITY:

Arising from liability of others assumed by the **Insured** under any contract or agreement, unless the liability of the **Insured** would have attached in the absence of such contract or agreement or the contract or agreement is an **Insured Contract**.

D. CRIMINAL FINES, PENALTIES, OR ASSESSMENTS:

Due to any criminal fines, criminal penalties or criminal assessments.

E. EMPLOYER LIABILITY:

For **Bodily Injury** sustained by any employee while engaged in employment by any **Named Insured**, or by any person whose right to assert a **Claim** against any **Named Insured** arises by reason of any employment, blood, marital, or any other relationship with such employee. This Exclusion applies:

1. Whether any **Named Insured** may be responsible as an employer or in any other capacity; or
2. To any obligation to share damages with or repay someone else who must pay damages because of **Bodily Injury**.

F. IDENTIFIED UNDERGROUND STORAGE TANK:

Arising from a **Pollution Condition** resulting from an **Underground Storage Tank** whose existence is known by a **Responsible Insured** as of the **Inception Date** and which is located on the **Insured Property** unless such **Underground Storage Tank** is scheduled on the Policy by an Underground Storage Tank Endorsement attached to this Policy. However, this Exclusion shall not apply to an **Underground Storage Tank(s)** which was removed prior to the **Inception Date**.

G. INTENTIONAL NONCOMPLIANCE:

Arising from a **Pollution Condition** based upon, due to or attributable to any **Responsible Insured's** intentional, willful or deliberate noncompliance with any statute, regulation, ordinance, administrative complaint, notice of violation, notice letter, executive order, or instruction of any governmental agency or body. However, this Exclusion does not apply to such non-compliance based upon:

1. The **Insured's** good faith reliance upon the written advice of qualified outside counsel received in advance of such non-compliance or upon the Company's written consent; or

2. The **Insured's** reasonable response to emergency circumstances in order to mitigate such **Pollution Condition** or **Loss**, provided such emergency circumstances are reported in writing to the Company within seventy-two (72) hours of the discovery of such emergency circumstances.

H. INTERNAL EXPENSES:

For costs, charges or expenses incurred by the **Insured** for goods supplied or services performed by the staff or salaried employees of the **Insured**, or its parent, subsidiary or affiliate. However, this Exclusion does not apply to such costs, charges or expenses if incurred:

1. In response to an emergency including **Emergency Response Costs**; or
2. Pursuant to **Environmental Laws** that require immediate remediation of a **Pollution Condition**; or
3. With the prior written approval of the Company, in its sole discretion.

I. INSURED vs. INSURED:

By any **Insured** against any other person or entity who is also an **Insured** under this Policy. However, this Exclusion does not apply to:

1. **Claims** initiated by third parties including cross-claims, counterclaims, or claims for contribution; or
2. **Claims** that arise out of an indemnification provided by one **Named Insured** to another **Named Insured** in an **Insured Contract**.

J. PRIOR KNOWLEDGE/NON-DISCLOSURE:

Arising from a **Pollution Condition** existing prior to the **Inception Date** and known by a **Responsible Insured** and not disclosed in the application for this Policy, or any previous policy for which this Policy is a renewal thereof.

K. WAR:

Based upon or arising out of any consequence, whether direct or indirect, of war, invasion, act of foreign enemy, hostilities, whether war be declared or not, civil war, rebellion, revolution, insurrection or military or usurped power, strike, riot or civil commotion.

2. COVERAGE H EXCLUSIONS

The following Exclusions apply to Coverage H.

This Policy does not apply to **Claims** or **Loss**:

A. DAMAGE TO INSURED'S PRODUCTS AND WORK:

For **Property Damage** to the **Insured's Products** or for **Property Damage** to work performed by, or on behalf of, the **Insured** arising out of the work or any portion thereof.

B. INSURED'S PROFESSIONAL SERVICES:

Arising out of professional services performed or rendered by the **Named Insured**, including but not limited to, recommendations, opinions or strategies rendered for architectural, consulting or engineering work, such as drawings, designs, maps, reports, surveys, change orders, plan specifications, assessment work, remedy selections, site maintenance equipment selection, and supervisory, inspection or engineering service.

C. PRODUCTS LIABILITY:

Arising from the **Insured's Products** after possession of such **Insured's Products** have been relinquished to others by the **Insured** or others trading under its name. However, this Exclusion shall not apply solely for the period during which such **Insured's Products** are being stored or transported by others on behalf of the **Named Insured**.

3. COVERAGE I EXCLUSION

The following Exclusion applies to Coverage I.

This Policy does not apply to **Claims** or **Loss**:

A. PROPERTY DAMAGE TO CONVEYANCES:

For **Property Damage** to any conveyance utilized during the **Transportation** of **Cargo**. However, this Exclusion does not apply to **Claims** arising from the **Insured's** negligence.

III. NOTICE REQUIREMENTS AND CLAIM PROVISIONS

A. NOTICE OF A POLLUTION CONDITION, EMERGENCY RESPONSE COSTS, CLAIM OR AN INTERRUPTION

1. The **Insured** shall provide written notice to the Company of a **Pollution Condition**, **Claim**, **Emergency Response Costs** or an **Interruption** to the following:

   Manager, Pollution Insurance Products Dept.
   Chartis Claims, Inc.
   Attn.: CID
   101 Hudson Street, 31st Floor
   Jersey City, NJ 07302
   Fax: 866-260-0104
   Email: SeverityFNOL@Chartisinsurance.com

   or other address(es) as substituted by the Company in writing.

2. The **Insured** shall give written notice of a **Pollution Condition** or **Interruption** as soon as possible. Notice under all coverages shall include, at a minimum, information sufficient to identify the **Named Insured**, the **Insured Property**, the names of persons with knowledge of the **Pollution Condition** or **Interruption** and all known and reasonably obtainable information regarding the time, place, cause, nature of and other circumstances of the **Pollution Condition** or **Interruption**. With respect to an **Interruption**, the **Insured** must supply the Company with relevant historical revenue and rental data as reasonably requested by the Company.

3. When **Emergency Response Costs** have been incurred, the **Insured** shall forward to the Company within ten (10) days of the first commencement of the **Pollution Condition** for which the **Emergency Response Costs** have been incurred, all information pertaining to the **Emergency Response Costs** that has become available during the ten (10) day period. At a minimum such information shall include the cause and location of the **Pollution Condition**, costs incurred and associated invoices. Additional information including but not limited to: technical reports, laboratory data, field notes, expert reports, investigations, data collected, additional invoices, regulatory correspondence or any other documents relating to such **Emergency Response Costs** must be forwarded to the Company immediately upon receipt.

4. The **Insured** shall give notice of all **Claims** as soon as possible, but in any event during the **Policy Period** or during the **Extended Reporting Period**, if applicable. The **Insured** shall furnish information at the request of the Company. When a **Claim** has been made, the **Insured** shall, in addition to furnishing other information as requested by the Company, forward the following to the Company as soon as possible:

   (a) All reasonably obtainable information with respect to the time, place and circumstances thereof, and the names and addresses of the claimant(s) and available witnesses; and

   (b) All demands, summonses, notices or other process or papers filed with a court of law, administrative agency or an investigative body; and

(c) Other information in the possession of the **Insured** or its hired experts which the Company reasonably deems necessary.

B. NOTICE OF POSSIBLE CLAIM

1. If during the **Policy Period**, the **Insured** first becomes aware of a **Possible Claim**, the **Insured** may provide written notice to the Company during the **Policy Period** containing all the information required under Paragraph 2. below. If the **Insured** provides such notice, any **Possible Claim** which subsequently becomes a **Claim** made against the **Insured** and reported to the Company within five (5) years after the end of the **Policy Period** of this Policy or any continuous, uninterrupted renewal thereof, shall be deemed to have been first made and reported during the **Policy Period** of this Policy. Such **Claim** shall be subject to the terms, conditions and limits of coverage and liability of the policy under which the **Possible Claim** was reported.

2. It is a condition precedent to the coverage afforded by this Section III.B. that written notice under Paragraph 1. above contain all of the following information:

(a) The cause of the **Pollution Condition**; and

(b) The address of the **Insured Property** or other location where the **Pollution Condition** took place; and

(c) The **Bodily Injury**, **Property Damage** or **Clean-Up Costs** which has resulted or may result from such **Pollution Condition**; and

(d) The name(s) of the **Insured(s)** which may be subject to the **Claim** and any potential claimant(s); and

(e) All engineering information available on the **Pollution Condition**; and

(f) Any other information that the Company deems reasonably necessary; and

(g) The circumstances by which and the date the **Insured** first became aware of the **Possible Claim**.

C. MEDIATION

If the **Named Insured** and the Company jointly agree to utilize **Mediation** as a means to resolve a **Claim** made against the **Insured**, and if such **Claim** is resolved as a direct result of the **Mediation**, the **Named Insured's** deductible obligation shall be reduced by 50% subject to a maximum reduction of $25,000. The Company shall reimburse the **Named Insured** for any such reimbursable deductible payment made prior to the **Mediation** as soon as practicable after the conclusion of the **Mediation**.

IV. RIGHTS OF THE COMPANY AND DUTIES OF THE INSURED IN THE EVENT OF A POLLUTION CONDITION

A. The Company's Rights

The Company shall have the right but not the duty to clean up or mitigate a **Pollution Condition** upon receiving notice as provided in Section III. of this Policy. Any sums expended in taking such action by the Company will be deemed incurred or expended by the **Insured** and shall be applied against the limits of liability and deductible under this Policy. The Company shall have the right but not the duty to participate in decisions regarding **Clean-Up Costs** and to assume direct control over all aspects of the cleanup and the adjustment of any **Claim** or **Emergency Response Costs** up to the applicable limits of liability. In case of the exercise of this right, the **Insured**, on demand of the Company, shall promptly reimburse the Company for any element of **Loss** falling within the **Insured's** deductible.

B. Duties of the Insured

The **Named Insured** shall have the duty to mitigate a **Pollution Condition**, and it shall have the duty to clean up a **Pollution Condition** to the extent required by **Environmental Laws**, by retaining competent professional(s) or contractor(s) mutually acceptable to the Company and the **Named Insured**. The Company may also exercise the right to require that such professional(s) or contractors(s) have certain qualifications with respect to their competency, including experience with a similar **Pollution Condition** and clean-up, mitigation or methodologies. The Company shall have the right but not the duty to review and approve all aspects of any such clean-up. The **Named Insured** shall notify the Company of actions and measures taken pursuant to this Paragraph.

V. LIMITS OF LIABILITY AND DEDUCTIBLE

Regardless of the number of **Claims**, claimants, **Insureds**, **Pollution Condition(s)**, **Emergency Response Costs** or **Interruption(s)** under this Policy, the following limits of liability apply:

A. Policy Aggregate Limit

The Company's total liability for all **Loss** shall not exceed the "Policy Aggregate Limit" stated in Item 4. of the Declarations. The Company's internal expenses do not erode the limit of liability available for any **Loss**.

B. Coverage Section Aggregate Limit

Subject to Paragraph V.A. above, the Company's total liability for all **Loss** under each Coverage in Coverages A through I, shall not exceed the "Coverage Section Aggregate" limit of liability for that particular coverage stated in Item 3. of the Declarations.

C. Each Incident Limit - Coverages A Through I

Subject to Paragraphs V.A. and V.B. above, the most the Company will pay for all **Loss** arising from **Each Incident** under each Coverage in Coverages A through I is the "Each Incident" limit of coverage for that particular coverage stated in Item 3. of the Declarations.

D. Maximum for All Business Interruption Expenses

Subject to Paragraph V.A. above, the maximum amount for which the Company is liable for all **Interruption Expenses** under Coverage J is 90% of the amount stated in Item 3. of the Declarations.

It is a condition of Coverage J that the remaining 10% of such amount be borne by the **Insured** at its own risk and remain uninsured.

E. Multiple Coverages – Each Incident Aggregate Limit

Subject to Paragraphs V.A. through V.D. above, if **Each Incident** results in coverage under more than one Coverage under Coverages A through J, every applicable "Each Incident" limit of coverage among such coverage sections shall apply to the **Loss**; however, the most the Company will pay for all **Loss** arising from **Each Incident** shall not exceed the highest "Each Incident" limit of Coverage stated in Item 3. of the Declarations among all the coverage sections applicable to the **Loss**.

F. Deductible

1. Coverages A through I

Subject to Paragraphs V.A. through V.E. above, this Policy is to pay covered **Loss** for **Each Incident** in excess of the Deductible amount stated in Item 3. of the Declarations for the applicable coverage, up to but not exceeding the applicable "Each Incident" limit of coverage.

If **Each Incident** results in coverage under more than one coverage section in Coverages A through I, only the highest Deductible amount stated in Item 3. of the Declarations among all the coverage sections applicable to the **Loss** will apply.

The **Insured** shall promptly reimburse the Company for advancing any element of **Loss** falling within the Deductible.

2. Coverage J

Subject to Paragraphs V.A. through V.E. above, this Policy is to pay **Interruption Expenses** under Coverage J in excess of the **Interruption Expenses** sustained during the first three (3) days of an **Interruption** during the **Period of Restoration**. The three (3) day period applies to all **Interruption Expenses** arising out of **Each Incident**.

VI. CONDITIONS

A. Access to Information – The **Named Insured** agrees to provide the Company with access to any information developed or discovered by an **Insured** concerning a **Claim**, **Loss** or a **Pollution Condition** covered under this Policy, whether or not deemed by an **Insured** to be relevant to such **Loss** and to provide the Company access to interview any **Insured** and review any documents of an **Insured**.

B. Acknowledgment of Shared Limits – By acceptance of this Policy, the **Named Insureds** and all other **Insureds** understand, agree and acknowledge that the Policy contains a "Policy Aggregate Limit" as set forth in Item 4. of the Declarations that is applicable to, and will be shared by, all **Named Insureds** and all other **Insureds** who are or may become insured hereunder. In view of the operation and nature of such shared "Policy Aggregate Limit", the **Named Insureds** and all other **Insureds** understand and agree that prior to filing a **Claim** or giving notice of a **Pollution Condition**, **Interruption** or incurring **Emergency Response Costs** under the Policy, the Policy Aggregate Limit may be exhausted or reduced by prior payments for other **Loss** under the Policy.

C. Action Against Company – No third-party action shall lie against the Company, unless as a condition precedent thereto there shall have been full compliance with all of the terms of this Policy, nor until the amount of the **Insured's** obligation to pay shall have been finally determined either by judgment against the **Insured** after actual trial or by written agreement of the **Insured**, the claimant and the Company.

Any person or organization or the legal representative thereof who has secured such judgment or written agreement shall thereafter be entitled to recover under this Policy to the extent of the insurance afforded by the Policy. No person or organization shall have any right under this Policy to join the Company as a party to any action against the **Insured** to determine the **Insured's** liability, nor shall the Company be impleaded by the **Insured** or its legal representative. Bankruptcy or insolvency of the **Insured** or of the **Insured's** estate shall not relieve the Company of any of its obligations hereunder.

D. Addition of Named Insureds – The Company agrees that upon the written request of the **Named Insured** first listed in Item 1. of the Declarations, the Company shall add to the Policy as a **Named Insured** any subsequent purchaser of an **Insured Property(ies)** if such purchase is finalized during the **Policy Period** and provided:

1. There is not a proposed change in use or operations at an **Insured Property(ies)** that is different than the use or operations at the **Insured Property(ies)** at the **Inception Date** or those otherwise consented to by the Company in writing; and
2. The purchaser has no actual, alleged or potential legal liability prior to the time of purchase for a **Pollution Condition** on, under or migrating from or through the **Insured Property**; and
3. The purchaser has no prior affiliation of any kind with the **Insured Property**; and
4. Notice of the finalization of the purchase of the **Insured Property** is given to the Company prior to a **Claim** or **Loss** involving the such subsequent purchaser; and
5. The purchaser of an **Insured Property** added as a **Named Insured** shall only be covered as a **Named Insured** for liability arising out of the ownership, operation, maintenance or use of such **Insured Property**; and
6. The addition of any purchaser as a **Named Insured** shall not affect the rights and duties of the **Named Insured** first listed in Item 1. of the Declarations and shall not be effective until endorsed onto the Policy.

E. Arbitration – It is hereby understood and agreed that all disputes or differences that may arise under or in connection with this Policy, whether arising before or after termination of this Policy, including any determination of the amount of **Loss**, may be submitted to the American Arbitration Association under and in accordance with its then prevailing commercial arbitration rules. The arbitrators shall be chosen in the manner and within the time frames provided by such rules. If permitted under such rules, the arbitrators shall be three disinterested individuals having knowledge of the legal, corporate management, or insurance issues relevant to the matters in dispute.

Any party may commence such arbitration proceeding and the arbitration shall be conducted in the **Insured's** state of domicile. The arbitrators shall give due consideration to the general principles of the law of the **Insured's** state of domicile in the construction and interpretation of the provisions of this Policy; provided, however, that the terms, conditions, provisions and exclusions of this Policy are to be construed in an evenhanded fashion as between the parties. Where the language of this Policy is alleged to be ambiguous or otherwise unclear, the issue shall be resolved in the manner most consistent with the relevant terms, conditions, provisions or exclusions of the Policy (without regard to the authorship of the language, the doctrine of reasonable expectation of the parties and without any presumption or arbitrary interpretation or construction in favor of either party or parties, and in accordance with the intent of the parties).

The written decision of the arbitrators shall set forth its reasoning, shall be provided simultaneously to both parties and shall be binding on them. The arbitrators' award shall not include attorney fees or other costs. Judgment on the award may be entered in any court of competent jurisdiction. Each party shall bear equally the expenses of the arbitration.

F. **Assignment** – This Policy may be assigned with the prior written consent of the Company, which consent shall not be unreasonably withheld or delayed. Assignment of interest under this Policy shall not bind the Company until its consent is endorsed thereon.

G. **Cancellation** – This Policy may be cancelled by the **Named Insured** by surrender thereof to the Company or any of its authorized agents or by mailing to the Company written notice stating when thereafter the cancellation shall be effective. This Policy may be cancelled by the Company only for the reasons stated below by mailing to the **Named Insured** at the address shown in the Policy, written notice stating when not less than ninety (90) days (ten (10) days for nonpayment of premium) thereafter such cancellation shall be effective. Proof of mailing of such notice shall be sufficient proof of notice.

1. Material misrepresentation by the **Insured**.

2. The **Insured's** failure to comply with the material terms, conditions or contractual obligations under this Policy, including failure to pay any premium or Deductible when due. However, the **Insured** shall have the ability, within the first thirty (30) days (ten (10) days for non-payment of premium) of the ninety (90) day notice period stated above, to cure such failure to comply with the material terms, conditions or contractual obligations. The determination of whether or not the **Insured** has cured any such failure is within the sole discretion of the Company.

3. A change in use or a change in operations which is different from the uses or operations identified in writing by the **Insured** to the Company during the underwriting process or in the application and which materially increases a risk covered hereunder. Solely with respect to this Paragraph 3. and solely with respect to such change in use or change in operations on or under a particular **Insured Property(ies)**, the Company shall have the right to cancel coverage only with respect to that **Insured Property(ies)** where such change in use or operations has taken place.

The time of surrender or the effective date and hour of cancellation stated in the notice shall become the end of the **Policy Period**. Delivery of such written notice either by the **Named Insured** or by the Company shall be equivalent to mailing. If the **Named Insured** cancels, earned premium shall be computed in accordance with the customary short rate table and procedure. If the Company cancels, earned premium shall be computed pro-rata. Premium adjustment may be either at the time cancellation is effected or as soon as practicable after cancellation becomes effective, but payment or tender of unearned premium is not a condition of cancellation.

H. **Changes** – Notice to any agent or knowledge possessed by any agent or by any other person shall not effect a waiver or a change in any part of this Policy or estop the Company from asserting any rights under the terms of this Policy; nor shall the terms of this Policy be waived or changed, except by endorsement issued by the Company to form a part of this Policy.

I. **Concealment or Fraud** – This entire Policy shall be void if, whether before or after **Loss** is incurred or a **Claim** is first made, the **Named Insured** has willfully concealed or misrepresented: (i) any fact or circumstance material to the granting of coverage under this Policy; (ii) the description of the **Insured Property(ies)** or the interest of the **Insured** therein; or (iii) any of the **Insured's** operations.

J. **Condition of Payment** – It is hereby agreed that any payment under this Policy shall only be made in full compliance with all United States of America economic and trade sanction laws or regulations, including, but not limited to, sanctions, laws and regulations administered and enforced by the U.S. Treasury Department's Office of Foreign Assets Control ("OFAC").

K. **Cooperation** – The **Insured** shall cooperate with the Company and offer all reasonable assistance in the investigation and defense of **Claims** and the clean up and mitigation of a **Pollution Condition**. The Company may require that the **Insured** submit to examination under oath, and attend hearings, depositions and trials. In the course of investigation or defense, the Company may require written statements or the **Insured's** attendance at meetings with the Company. The **Insured** must assist the Company in effecting settlement, securing and providing evidence and obtaining the attendance of witnesses.

L. Independent Counsel – In the event the **Insured** is entitled by law to select independent counsel to oversee the Company's defense of a **Claim** at the Company's expense, the attorney fees and all other expenses the Company must pay to that counsel are limited to the rates the Company would actually pay to counsel that the Company retains in the ordinary course of business in the defense of similar **Claims** in the community where the **Claim** arose or is being defended.

Additionally, the Company may exercise the right to require that such counsel have certain minimum qualifications with respect to their competency, including experience in defending **Claims** similar to the one pending against the **Insured**, and to require such counsel to have errors and omissions insurance coverage. As respects any such counsel, the **Insured** agrees that counsel will timely respond to the Company's request for information regarding the **Claim**.

Furthermore, the **Insured** may at any time, by the **Insured's** signed consent, freely and fully waive these rights to select independent counsel.

M. Other Insurance – Where other insurance may be available for **Loss** covered under this Policy, the **Insured** shall promptly upon request of the Company provide the Company with copies of all such policies. If other valid and collectible insurance is available to the **Insured** for **Loss** covered by this Policy, the Company's obligations are limited as follows:

1. Except as set forth in Paragraph 3. below, this insurance is primary, and the Company's obligations are not affected unless any of the other insurance is also primary. In that case, the Company will share with all such other insurance by the method described in Paragraph 2. below.

2. If all of the other insurance permits contribution by equal shares, the Company will follow this method also. Under this approach each insurer contributes equal amounts until it has paid its applicable limit of insurance or none of the loss remains, whichever comes first. If any of the other insurance does not permit contribution by equal shares, the Company will contribute by limits. Under this method, each insurer's share is based on the ratio of its applicable limit of insurance to the total applicable limits of insurance of all insurers.

3. Solely with respect to **Clean-Up Costs**, **Claims** or **Loss** arising in whole or in part from a **Pollution Condition** due to **Microbial Matter** and/or Legionella pneumophila, this insurance is excess of any other valid and collectible insurance. Where this insurance is excess insurance, the Company will pay only its share of the amount of **Loss**, if any, that exceeds the total amount of such other insurance.

N. Reduction of Interruption Expenses – If the **Insured** could reduce the **Interruption Expenses** resulting from an **Interruption**:

1. By complete or partial resumption of operations; or

2. By making use of other property at the **Insured Property**, or elsewhere,

such reductions shall be taken into account in arriving at **Interruption Expenses**. In determining the amount of **Interruption Expenses** payable under Section **I. INSURING AGREEMENTS, 1 COVERAGES, COVERAGE J – BUSINESS INTERRUPTION EXPENSES**, due consideration shall be given to the financial performance of the business before the **Interruption** and the financial performance thereafter had no **Interruption** occurred.

O. Representations – By acceptance of this Policy, the **Named Insured** agrees that the statements in the Declarations and the Application are their agreements and representations, that this Policy is issued in reliance upon the truth of such representations and that this Policy embodies all agreements existing between the **Insured** and the Company or any of its agents relating to this insurance.

P. Right of Access and Inspection – To the extent an **Insured** has such rights, any of the Company's authorized representatives shall have the right and opportunity but not the obligation to interview persons employed by the **Insured** and to inspect at any reasonable time, during the **Policy Period** or thereafter, an **Insured Property** or any other location, facility or item associated with a **Claim**, **Loss** or **Pollution Condition**. Neither the Company nor its representatives shall assume any responsibility or duty to the **Insured** or to any other party, person or entity, by reason of such right or inspection. Neither the

Company's right to make inspections, sample and monitor, nor the actual undertaking thereof nor any report thereon shall constitute an undertaking on behalf of the **Insured** or others, to determine or warrant that the property or operations are safe, healthful or conform to acceptable engineering practices or are in compliance with any law, rule or regulation. The **Named Insured** agrees to provide appropriate personnel to assist the Company's representatives during any inspection.

Q. Separation of Insureds – It is hereby agreed that except with respect to the Limit of Liability, Section II. 1.I. (Insured vs. Insured exclusion), and any rights and duties specifically assigned to the first **Named Insured,** this insurance applies: 1. As if each **Named Insured** were the only **Named Insured**; and 2. Separately to each **Named Insured** against whom a **Claim** is made. Misrepresentation, concealment, breach of a term or condition, or violation of any duty under this Policy by one **Named Insured** shall not prejudice the interest of coverage for another **Named Insured** under this Policy. Provided, however, that this Condition shall not apply to any entity or person who is a parent, subsidiary, affiliate, director, officer, partner, member or employee of the **Named Insured** that misrepresented, concealed or breached a term or condition, or violated a duty under this Policy. For the purposes of this Condition, an "affiliate" means an entity that directly or indirectly is controlled by or is under common control with the **Named Insured** that committed such misrepresentation, concealment or breach.

R. Subrogation – In the event of any payment under this Policy, the Company shall be subrogated to all the **Insured's** rights of recovery therefor against any third party and the **Insured** shall execute and deliver instruments and papers and do whatever else is necessary to secure such rights including without limitation, assignment of the **Insured's** rights against any person or organization who caused the **Pollution Condition** on account of which the Company made any payment under this Policy. The **Insured** shall do nothing to prejudice the Company's rights under this paragraph subsequent to **Loss**. Any recovery as a result of subrogation proceedings arising out of the payment of **Loss** covered under this Policy shall accrue first to the **Insured** to the extent of any payments in excess of the limit of liability; then to the Company to the extent of its payment under the Policy; and then to the **Insured** to the extent of its Deductible. Expenses incurred in such subrogation proceedings shall be apportioned among the interested parties in the recovery in the proportion that each interested party's share in the recovery bears to the total recovery. Notwithstanding anything to the contrary in this Condition R., the Company hereby expressly waives any rights of subrogation against an entity where such right has been waived in writing by the **Insured** prior to **Loss** or **Claim**.

S. Voluntary Payments – No **Insured** shall voluntarily enter into any settlement, or make any payment or assume any obligation, without the Company's consent which shall not be unreasonably withheld, except at the **Insured's** own cost. This Condition shall not apply if such payment or obligation is an **Emergency Response Costs** or is pursuant to **Environmental Laws** that require immediate remediation of a **Pollution Condition**.

T. Service Of Suit – Subject to Section **VI. CONDITIONS**, Paragraph E. above, it is agreed that in the event of failure of the Company to pay any amount claimed to be due hereunder, the Company, at the request of the **Insured**, will submit to the jurisdiction of a court of competent jurisdiction within the United States. Nothing in this condition constitutes or should be understood to constitute a waiver of the Company's rights to commence an action in any court of competent jurisdiction in the United States, to remove an action to a United States District Court, or to seek a transfer of a case to another court as permitted by the laws of the United States or of any state in the United States. It is further agreed that service of process in such suit may be made upon General Counsel, Law Department, Chartis Specialty Insurance Company, 175 Water Street, New York, New York 10038, or his or her representative, and that in any suit instituted against the Company upon this contract, the Company will abide by the final decision of such court or of any appellate court in the event of any appeal.

Further, pursuant to any statute of any state, territory, or district of the United States which makes provision therefor, the Company hereby designates the Superintendent, Commissioner, Director of Insurance, or other officer specified for that purpose in the statute, or his or her successor or successors in office as its true and lawful attorney upon whom may be served any lawful process in any action, suit or proceeding instituted by or on behalf of the **Insured** or any beneficiary hereunder arising out of this contract of insurance, and hereby designates the above named Counsel as the person to whom the said officer is authorized to mail such process or a true copy thereof.

VII. EXTENDED REPORTING PERIOD FOR CLAIMS - COVERAGES A THROUGH I

The **Named Insured** shall be entitled to an Automatic **Extended Reporting Period**, and (with certain exceptions as described in Paragraph B. of this Section) be entitled to purchase an Optional **Extended Reporting Period** for Coverages A through I collectively, upon termination of coverage as defined in Paragraph B.3. of this Section. If the **Named Insured** renews this Policy, the **Named Insured** shall be entitled to an Automatic Renewal **Extended Reporting Period** (as described in Paragraph C. below). Neither the Automatic, the Optional or the Automatic Renewal **Extended Reporting Period** shall reinstate or increase any of the limits of liability of this Policy.

A. Automatic Extended Reporting Period

Provided (i) that the **Named Insured** has not renewed this policy or purchased any other insurance to replace this insurance which applies to a **Claim** otherwise covered hereunder and (ii) the **Named Insured** has not purchased the Optional **Extended Reporting Period** available under Paragraph B. of this Section, the **Named Insured** shall have the right to the following: a period of ninety (90) days following the effective date of such termination of coverage in which to provide written notice to the Company of **Claims** first made against the **Insured** during the **Policy Period**.

A **Claim** first made against the **Insured** and reported to the Company within the Automatic **Extended Reporting Period** will be deemed to have been made and reported on the last day of the **Policy Period**, provided that the **Claim** arises from a **Pollution Condition** that commenced before the end of the **Policy Period** and is otherwise covered by this Policy. No part of the Automatic **Extended Reporting Period** shall apply if the Optional **Extended Reporting Period** is purchased.

B. Optional Extended Reporting Period

The **Named Insured** shall be entitled to purchase an Optional **Extended Reporting Period** upon termination of coverage as defined herein (except in the event of nonpayment of premium), as follows:

1. A **Claim** first made against the **Insured** and reported to the Company within the Optional **Extended Reporting Period**, if purchased in accordance with the provisions contained in Paragraph 2. below, will be deemed to have been made and reported on the last day of the **Policy Period**, provided that the **Claim** arises from a **Pollution Condition** that commenced before the end of the **Policy Period** and is otherwise covered by this Policy.

2. The Company shall issue an endorsement providing an Optional **Extended Reporting Period** of up to forty (40) months from termination of coverage hereunder for all **Insured Property(ies)** and **Non-Owned Locations**, if applicable, or any specific **Insured Property** or **Non-Owned Location**, provided that the **Named Insured**:

   (a) makes a written request for such endorsement which the Company receives within thirty (30) days after termination of coverage as defined herein; and

   (b) pays the additional premium when due. If that additional premium is paid when due, the **Extended Reporting Period** may not be cancelled, provided that all other terms and conditions of the Policy are met.

3. Termination of coverage occurs at the time of cancellation or nonrenewal of this Policy by the **Named Insured** or by the Company, or at the time of the Company's deletion of a location which previously was an **Insured Property** or **Non-Owned Location**.

4. The Optional **Extended Reporting Period** is available to the **Named Insured** for not more than 200% of the full Policy premium stated in the Declarations.

C. Automatic Renewal Extended Reporting Period

Provided that the **Named Insured** has renewed this Policy with the Company or an affiliate of the Company, the **Named Insured** shall have the right to the following: a period of ninety (90) days following the expiration of the **Policy Period** in which to provide written notice to the Company of **Claims** first made against the **Insured** within ninety (90) days prior to the expiration of the **Policy Period**.

A **Claim** first made against the **Insured** within ninety (90) days prior to the expiration of the **Policy Period** and reported to the Company within the Renewal **Extended Reporting Period** will be deemed to have been made and reported on the last day of the **Policy Period** of this Policy.

VIII. DEFINITIONS

A. Actual Loss means the:

1. Net profit or loss before income taxes the **Insured** would have earned or incurred had there been no **Interruption**; and

2. Continuing normal operating expenses incurred during the **Period of Restoration**, including payroll expense for all employees of the **Insured**, except officers, executives, department managers and employees under contract.

B. Bodily Injury means:

1. Physical injury, sickness or disease sustained by any person, including death resulting therefrom and solely with respect to this item B.1, any accompanying medical monitoring; or

2. Mental anguish, emotional distress, or shock.

C. Cargo means goods, products, or waste transported for delivery by the **Named Insured** or by a carrier on behalf of the **Named Insured** provided the **Named Insured** or carrier is properly licensed to transport such goods, products, or waste.

D. Certified Industrial Hygienist means a licensed professional as established by the American Board of Industrial Hygiene, mutually agreed upon by the Company and the **Named Insured**. The Company may also exercise the right to require that such **Certified Industrial Hygienist** have certain minimum qualifications with respect to his or her competency, including experience with similar **Microbial Matter** remediation.

E. Claim means a written demand received by the **Insured** alleging liability or responsibility and seeking a remedy on the part of the **Insured** for **Loss** under Coverages A through I. For purposes of this Policy, a **Claim** does not include a **Possible Claim** that was reported under a prior policy but which has become a **Claim** during the **Policy Period** of this Policy as described in Section III. B.

F. Clean-Up Costs means reasonable and necessary expenses, including legal expenses incurred with the Company's written consent which consent shall not be unreasonably withheld or delayed, for the investigation, removal, treatment including in-situ treatment, remediation including associated monitoring, or disposal of soil, surfacewater, groundwater, **Microbial Matter**, Legionella pneumophila, or other contamination:

1. To the extent required by **Environmental Laws** or required to satisfy a **Voluntary Cleanup Program**; or

2. With respect to **Microbial Matter**, in the absence of any applicable **Environmental Laws**, to the extent recommended in writing by a **Certified Industrial Hygienist**; or

3. With respect to Legionella pneumophila, in the absence of any applicable **Environmental Laws**, to the extent required in writing by the Center for Disease Control or local health department; or

4. That have been actually incurred by the government or any political subdivision of the United States of America or any state thereof or Canada or any province thereof, or by third parties.

Clean-Up Costs also include **Restoration Costs**.

G. Continuity Date means the date stated in Item 8. of the Declarations.

H. Covered Operations means those activities performed for a third party for a fee by or on behalf of the **Named Insured** at a job site. **Covered Operations** does not include: (i) **Transportation** or the movement of any material by a conveyance beyond the boundaries of a job site; or (ii) those activities performed at any real property which is owned, leased, rented or managed by the **Insured**.

I. Each Incident means the same, related, or continuous **Pollution Condition**.

J. Emergency Response Costs means reasonable and necessary expenses, including legal expenses incurred with the Company's written consent which consent shall not be unreasonably withheld or delayed, incurred in the remediation of soil, surfacewater, groundwater or other contamination that must be incurred:

1. In response to a **Pollution Condition** that necessitates immediate action; and

2. Within ninety-six (96) hours of the first commencement of such **Pollution Condition**; or as approved by the Company in writing.

K. **Environmental Laws** means any federal, state, provincial or local laws (including, but not limited to, statutes, rules, regulations, ordinances, guidance documents, and governmental, judicial or administrative orders and directives) that are applicable to the **Pollution Condition**.

L. **Extended Reporting Period** means either the automatic additional period of time, the optional additional period of time or the automatic renewal additional period of time, whichever is applicable, in which to report **Claims** following termination or renewal of coverage, as described in Section VII. of this Policy.

M. **Extra Expense** means necessary expenses the **Insured** incurs during the **Period of Restoration**:

1. That would not have been incurred if there had not been an **Interruption**; and

2. That avoid or minimize an **Interruption**;

but only to the extent such expenses reduce **Actual Loss** or loss of **Rental Value**, whichever is applicable, otherwise covered under this Policy.

Extra Expense will be reduced by any salvage value of property obtained for temporary use during the **Period of Restoration** that remains after the resumption of normal operations.

N. **Inception Date** means the first date set forth in Item 2. of the Declarations.

O. **Insured** means the **Named Insured**, and any past or present director, officer, partner, member, manager or employee thereof, including a temporary or leased employee, while acting within the scope of his or her duties as such.

P. **Insured Contract** means a contract or agreement submitted to and approved by the Company, and scheduled on an Insured Contract Endorsement attached to this Policy.

Q. **Insured's Products** means goods or products manufactured, sold, handled or distributed by the **Insured** or others trading under the **Insured's** name, and includes containers (other than automobiles, rolling stock, vessels or aircraft), materials, parts or equipment furnished in connection therewith, and includes warranties or representations made at any time with respect to the fitness, quality, durability, performance or use thereof, or the failure to provide warnings or instructions.

R. **Insured Property** means each of the locations identified in Item 5. of the Declarations.

S. **Interruption** means the necessary suspension of the **Named Insured's** business operations at an **Insured Property** during the **Period of Restoration**.

T. **Interruption Expenses** means **Actual Loss** or loss of **Rental Value**, and **Extra Expense**.

U. **Loss** means, under the applicable Coverages:

1. Monetary awards or settlements of compensatory damages; where allowable by law, punitive, exemplary, or multiple damages; and civil fines, penalties, or assessments for **Bodily Injury** or **Property Damage**;

2. Costs, charges and expenses incurred in the defense, investigation or adjustment of **Claims** for such compensatory damages or punitive, exemplary or multiple damages, and civil fines, penalties or assessments, or for **Clean-Up Costs**;

3. **Clean-Up Costs**;

4. **Interruption Expenses**; or

5. **Emergency Response Costs**.

V. **Mediation** means an alternative non-binding dispute resolution process involving a neutral third party.

W. Microbial Matter means fungi, mold or mildew.

X. Named Insured means: (i) the entity named in Item 1. of the Declarations; and (ii) any and all corporations, partnerships, companies or other entities as have existed at any time, or as now or may hereafter exist during the **Policy Period** and in which the entity named in Item 1. of the Declarations did or does have more than a 50% ownership interest but, with respect to such corporations, partnerships, companies or other entities, solely with respect to liability arising out of the ownership, operation, maintenance or use of an **Insured Property(ies)**.

The first **Named Insured** designated in Item 1. of the Declarations will act on behalf of all other **Insureds**, if any, for the payment or return of any premium, payment of any deductible, receipt and acceptance of any endorsement issued to form a part of this Policy, giving and receiving notice of cancellation or nonrenewal, and the exercise of the rights provided in the **Extended Reporting Period** clause.

Y. Natural Resource Damage means physical injury to or destruction of, including the resulting loss of value of, land, fish, wildlife, biota, air, water, groundwater, drinking water supplies, and other such resources belonging to, managed by, held in trust by, appertaining to, or otherwise controlled by the United States (including the resources of the fishery conservation zone established by the Magnuson-Stevens Fishery Conservation and Management Act (16 U.S.C. 1801 et seq.)), any state or local government, any foreign government, any Indian tribe, or, if such resources are subject to a trust restriction on alienation, any member of an Indian tribe.

Z. Non-Owned Location means:

1. A site that is not owned or operated by the **Insured** and that is scheduled on a Non-Owned Covered Locations Schedule Endorsement attached to this Policy; or

2. All waste treatment, waste storage or waste disposal facilities utilized by or on behalf of the **Named Insured** for waste generated from an **Insured Property**, provided that (i) the **Pollution Condition** first commenced on or after the **Continuity Date** shown in Item 8. of the Declarations; and (ii) as of the date that the waste was delivered to the treatment, storage or disposal facility, such facilities:

   (a) Are located within the United States, its territories or possessions;

   (b) Are not owned, operated or managed by the **Named Insured**;

   (c) Are properly licensed to accept and dispose of such waste;

   (d) Are not listed, are not proposed for listing and have never been listed on the federal National Priorities List (Superfund), State equivalent list, or local equivalent list;

   (e) Are not subject to, and have not been subject to in the prior five years, a Federal information request under Section 104(e) of the Comprehensive Environmental Response, Compensation, and Liability Act or Section 3007(a) of the Resource Conservation and Recovery Act, or a State or local equivalent request; and

   (f) Are not owned or operated by a bankrupt or financial insolvent entity.

AA. Period of Restoration means the length of time as would be required with the exercise of due diligence and dispatch to restore the **Insured Property** to a condition that allows the resumption of normal business operations, commencing with the date operations are interrupted by a **Pollution Condition** and not limited by the date of expiration of the **Policy Period**. The **Period of Restoration** does not include any time caused by the interference by an **Insured** with restoring the property, or with the resumption or continuation of operations.

BB. Policy Period means the period set forth in Item 2. of the Declarations, or any shorter period arising as a result of:

1. Cancellation of this Policy; or

2. With respect to particular **Insured Property(s)** or **Non-Owned Location(s)** designated in the Declarations, the deletion of such location(s) from this Policy.

CC. **Pollution Condition** means:

1. The discharge, dispersal, release or escape; or

2. The illicit abandonment on or after the **Inception Date** by a third party without the **Insured's** consent,

of any solid, liquid, gaseous or thermal irritant or contaminant, including, but not limited to, smoke, vapors, soot, fumes, acids, alkalis, toxic chemicals, hazardous substances, low-level radioactive material, electromagnetic fields, medical waste including infectious and pathological waste and waste materials into or upon land, or any structure on land, the atmosphere or any watercourse or body of water, including groundwater, provided such conditions are not naturally present in the environment in the amounts or concentrations discovered. **Pollution Condition** also means Legionella pneumophila or **Microbial Matter** in any structure on land and the atmosphere contained within that structure, provided that such **Pollution Condition** commences on or after the Indoor Air Quality Retroactive Date shown in Item 7. of the Declarations Page.

DD. **Possible Claim** means a **Pollution Condition** that first commenced on or after the **Inception Date** that the **Insured** reasonably expects may result in a **Claim**; provided, however, that **Possible Claim** shall not include a **Pollution Condition** that results in a **Claim** during the **Policy Period** or that is discovered and reported to the Company during the **Policy Period** under Coverage A., Paragraph 1. or Coverage B., Paragraph 1. and results in **Clean-Up Costs** covered by this Policy.

EE. **Property Damage** means:

1. Physical injury to or destruction of tangible property of parties other than an **Insured**, including the resulting loss of use and, except with respect to tangible property located on an **Insured Property**, diminution in value thereof;

2. Loss of use, but not diminution in value, of tangible property of parties other than an **Insured** that has not been physically injured or destroyed; or

3. **Natural Resource Damage**.

Property Damage does not include **Clean-Up Costs**.

FF. **Rental Value** means the:

1. Total anticipated rental income from tenant occupancy of the **Insured Property** as furnished and equipped by the **Insured**;

2. Amount of all charges that are the legal obligation of the tenant(s) pursuant to a lease and that would otherwise be the **Insured**'s obligations; and

3. Fair rental value of any portion of the **Insured Property** that is occupied by the **Insured** during the **Period of Restoration**, less any rental income the **Insured** could earn:

(a) By complete or partial rental of the **Insured Property**; or

(b) By making use of other property on the **Insured Property** or elsewhere.

GG. **Responsible Insured** means (i) the manager or supervisor of the **Named Insured** responsible for environmental affairs, control or compliance; or (ii) any manager of the **Insured Property**; or (iii) any manager or supervisor responsible for the **Named Insured's Covered Operations**; or (iv) any officer, director, partner or member of the **Named Insured**.

HH. **Restoration Costs** means reasonable and necessary costs incurred by the **Insured** with the Company's written consent, which consent shall not be unreasonably withheld or delayed, to repair, replace or restore real or personal property, that is damaged during work performed in the course of incurring **Clean-Up Costs** whether or not such property is also damaged by the **Pollution Condition**, to substantially the same condition it was in prior to being damaged during work performed in the course of incurring **Clean-Up Costs**.

Restoration Costs shall not include costs associated with improvements or betterments, except to the extent that such improvements or betterments of the damaged property entail the use of materials which are environmentally preferable to those materials which comprised the damaged property. Such environmentally preferable material must be certified as such by an applicable independent certifying body, where such certification is available, or, in the absence of such certification, based on the judgment of the Company in its sole discretion.

II. **Transportation** means the movement of **Cargo** by a conveyance, from the place where it is accepted for transport until it is moved:

1. To the place where the carrier finally delivers it; or
2. In the case of waste, to a waste disposal facility to which the carrier delivers such waste.

Transportation includes the carrier's loading or unloading of **Cargo** onto or from a conveyance, provided that the loading or unloading is performed by or on behalf of the **Named Insured**.

Transportation does not include **Cargo** in storage off-loaded from the conveyance transporting it.

JJ. **Underground Storage Tank** means any one or combination of tanks, including underground pipes connected thereto, that has at least ten (10) percent of its volume beneath the surface of the ground. **Underground Storage Tank** does not include:

1. Septic tanks, sump pumps or oil/water separators;
2. A tank that is enclosed within a basement, cellar, shaft or tunnel, if the tank is upon or above the surface of the floor; or
3. Storm-water or wastewater collection systems.

KK. **Voluntary Cleanup Program** means a program of the United States or a state of the United States enacted pursuant to **Environmental Laws** which provides for a mechanism for the written approval of, or authorization to conduct, voluntary remedial action for the cleanup, removal or remediation of a **Pollution Condition** that exceeds actionable levels established pursuant to **Environmental Laws**.

The remainder of this page has been intentionally left blank. Policy Signature Page shall immediately follow.

SAMPLE CCS ENDORSEMENT

ENDORSEMENT NO.

This endorsement, effective 12:01AM,

Forms a part of Policy No:

Issued to:

By:

THIS ENDORSEMENT CHANGES THE POLICY. PLEASE READ IT CAREFULLY.

CARBON STORAGE COVERED OPERATIONS ENDORSEMENT

It is hereby agreed that:

1. Section **I. INSURING AGREEMENTS, 1 COVERAGES, COVERAGE B - ON-SITE CLEAN-UP OF NEW CONDITIONS, COVERAGE D – THIRD - PARTY CLAIMS FOR OFF-SITE CLEAN-UP RESULTING FROM NEW CONDITIONS, COVERAGE E – THIRD - PARTY CLAIMS FOR BODILY INJURY AND PROPERTY DAMAGE** and **COVERAGE F – EMERGENCY RESPONSE COSTS** are deleted in their entirety and replaced with the following:

COVERAGE B - ON-SITE CLEAN-UP OF NEW CONDITIONS

1. To pay on behalf of the **Insured**, **Clean-Up Costs** resulting from a **Pollution Condition** arising from **Covered Operations** on or under the **Insured Property** that first commenced on or after the **Continuity Date**, provided:

   (a) A **Responsible Insured** first becomes aware of such **Pollution Condition** during the **Policy Period** and such **Pollution Condition** is reported to the Company in writing as soon as possible after such discovery and in any event during the **Policy Period** in accordance with Section III. of the Policy.

   (b) Where required, such **Pollution Condition** has been reported to the appropriate governmental agency in substantial compliance with applicable **Environmental Laws** in effect as of the date of discovery.

2. To pay on behalf of the **Insured, Loss** that the **Insured** is legally obligated to pay as a result of a **Claim** for **Clean-Up Costs** resulting from a **Pollution Condition** arising from **Covered Operations** on or under the **Insured Property**, which **Pollution Condition** first commenced on or after the **Continuity Date**, provided such **Claim** is first made against the **Insured** and reported to the Company in writing during the **Policy Period** in accordance with Section III. of the Policy, or during the **Extended Reporting Period** if applicable.

COVERAGE D – THIRD - PARTY CLAIMS FOR OFF-SITE CLEAN-UP RESULTING FROM NEW CONDITIONS

To pay on behalf of the **Insured, Loss** that the **Insured** becomes legally obligated to pay as a result of a **Claim** for **Clean-Up Costs** resulting from a **Pollution Condition** arising from **Covered Operations**, beyond the boundaries of the **Insured Property,** that commenced on or after the **Continuity Date** shown below**,** and migrated from or through the **Insured Property,** provided such **Claims** are first made against the **Insured** and reported to the Company in writing during the **Policy Period**, or during the **Extended Reporting Period** if applicable.

COVERAGE E – THIRD - PARTY CLAIMS FOR BODILY INJURY AND PROPERTY DAMAGE

To pay on behalf of the **Insured, Loss** that the **Insured** becomes legally obligated to pay as a result of a **Claim** for **Bodily Injury** or **Property Damage** resulting from a **Pollution Condition** arising from **Covered Operations,** beyond the boundaries of the **Insured Property** that commenced on or after the **Continuity Date** shown below**,** and migrated from the **Insured Property,** provided such **Claims** are first made against the **Insured** and reported to the Company in writing during the **Policy Period**, or during the **Extended Reporting Period** if applicable.

COVERAGE F – EMERGENCY RESPONSE COSTS

1. The Company will pay **Emergency Response Costs** resulting from a **Pollution Condition** arising from **Covered Operations** on, under or migrating from the **Insured Property**. **Emergency Response Costs** must be first incurred by the **Insured** and reported to the Company during the **Policy Period**.

   For this Coverage to apply, all of the following conditions must be satisfied:

   (a) The **Insured** must report the **Emergency Response Costs** to the Company in accordance with Section III. of the Policy.

ENDORSEMENT NO. CONTINUED

(b) **COVERAGE B – ON-SITE CLEAN UP OF NEW CONDITIONS** is purchased.

2. The Company will pay **Emergency Response Costs** resulting from a **Pollution Condition** caused by **Transportation**. **Emergency Response Costs** must be first incurred by the **Insured** and reported to the Company during the **Policy Period**.

   For this Coverage to apply, all of the following conditions must be satisfied:

   (a) The **Insured** must report the **Emergency Response Costs** to the Company in accordance with Section III. of the Policy.

   (b) With respect to **Transportation**, **COVERAGE I – THIRD-PARTY CLAIMS RESULTING FROM THE TRANSPORTATION OF CARGO** is purchased.

Continuity Date: (**Inception Date**)

2. It is hereby agreed that Section **VIII. DEFINITIONS**, Paragraph **H. Covered Operations** is deleted in its entirety and replaced with the following:

   H. Covered Operations means the injection and storage of Carbon Dioxide and all other components captured into the **Injection Zone** through the permitted underground injection control (UIC) wells at the **Insured Property**. **Covered Operations** shall also include the capture, scrubbing, compression, and dehydration of Carbon Dioxide in preparation for such injection.

3. Except with respect to Coverage F. Paragraph 2, Coverage G. and Coverage I., Section **VIII. DEFINITIONS,** Paragraph **CC. Pollution Condition** is deleted in its entirety and replaced with the following:

   CC. **Pollution Condition** means the discharge, dispersal, release or escape of Carbon Dioxide and all other components captured in accordance with the **Permit for Injection** into or upon land not considered the **Injection Zone**, or any structure on land, the atmosphere or any watercourse or body of water, including groundwater.

4. Section **VII. EXTENDED REPORTING PERIOD FOR CLAIMS - COVERAGES A THROUGH I**, Paragraph **B. Optional Extended Reporting Period** is deleted in its entirety.

5. Section **III. NOTICE REQUIREMENTS AND CLAIM PROVISIONS**, Paragraph **B. NOTICE OF POSSIBLE CLAIM** is deleted in its entirety.

6. Section **II. EXCLUSIONS, 1. COMMON EXCLUSIONS – APPLICABLE TO ALL COVERAGES** is amended by the addition of the following:

NON-COMPLIANCE WITH PERMIT

Arising from any **Insured's** material violation of or non-compliance with the **Permit for Injection.**

GLOBAL WARMING AND CLIMATE CHANGE

Arising from, due to or in any way associated with global warming or global climate change.

MONITORING COSTS:

Due to or arising from monitoring costs associated with the **Covered Operations** as specified in the **Permit for Injection**.

CLOSURE/POST CLOSURE ACTIVITIES

Arising from or due costs associated with the Closure or Post Closure Activities

ENDORSEMENT NO. CONTINUED

7. Section **VI. CONDITIONS** is amended by the addition of the following:

Compliance with Permit - By acceptance of this Policy, the **Named Insured** agrees to comply with the **Permit for Injection** and acknowledges that this Policy is issued in reliance upon such agreement.

8. Section **VIII. DEFINTIONS** is amended by the addition of the following:

Injection Zone means the... this is a fill in and where we describe the zone as defined in the permit or other documents and figure if necessary.

Permit for Injection means.... this is a fill in and where we would list out the permit that specifically calls out the injection of carbon dioxide

All other terms, conditions, and exclusions shall remain the same.

AUTHORIZED REPRESENTATIVE
or countersignature (in states where applicable)

MCGRIFF OVERVIEW

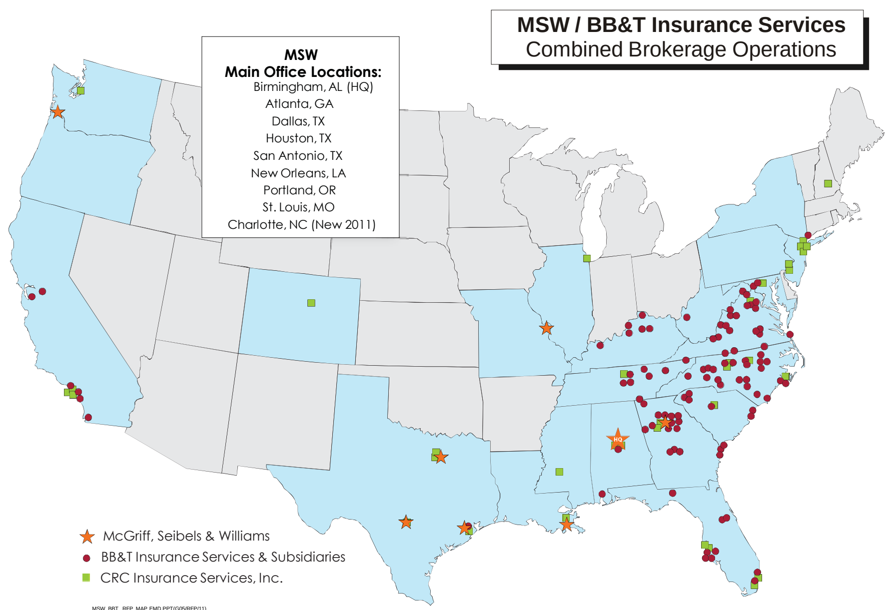
MCGRIFF, SEIBELS & WILLIAMS OVERVIEW

Headquartered in Birmingham, Alabama, McGriff operates as a separate, wholly-owned subsidiary of BB&T. BB&T Insurance Services is the 6th largest brokerage firm in the U.S. and the 7th largest worldwide, with over $1 Billion in combined revenues and $6 Billion in annual premium volume.

McGriff traces its history back over 100 years and was the 2nd largest privately-held broker prior to its acquisition by BB&T in February 2004.

BB&T Insurance Services Operating Entities include:

- McGriff, Seibels & Williams
- CRC (wholesale broker)
- BB&T Insurance Services



MSW is a full-service broker operating through eight (8) major divisions:

- Energy & Marine
- Transportation
- Construction Risk
- Surety Services
- Financial Services
- Commercial / National Accounts
- Employee Benefits
- Healthcare

ENERGY, MARINE AND INFRASTRUCTURE EXPERTISE

As the largest independent energy broker in the U.S., McGriff has earned its reputation by operating as a "niche" player within the Energy and Marine industry. We serve as the brokers and risk consultants to a wide array of infrastructure companies which include the following types of operations:

- Electric Generation, Transmission and Distribution Companies
- Natural Gas Transmission and Distribution Companies
- Marine Terminal and Port Operations
- Independent System Operators
- Independent Power Producers (IPP's)
- Water and Waste Water Treatment Companies
- Refining and Product Terminal Operations
- Telecommunication Companies
- Construction Contractors
- Energy Service Companies
- Port, Cargo, and Stevedoring Operations

Our team of 65 professionals in our Utility and Infrastructure Group, have average tenure of 15+ years, providing risk management / insurance advice based on deep experience in your industry. Our employee retention rate of over 90% means that our clients receive stable, dependable service from tested teams.

Our experience including work as brokers and risk consultants to our clients that represent:

- Approximately 300,000 megawatts of generating capacity providing power to over 75 million people
- 5 of the top 10 and 11 of the top 25, electric generation companies in the U.S.
- $300 Billion + Total Insured Values
- 40% of the natural gas pipeline transportation and storage facilities in the U.S.
- 8 of the 13 utilities on the Dow Jones Utilities Average
- Over 50 utility clients
- Distribution of natural gas to over 25% of the U.S. population
- 50% of the transportation and storage facilities of refined petroleum in the U.S.
- The Strategic Petroleum Reserve
- 25% of the Offshore Drilling Fleet
- Over $3.0 Bn in Premium to the Insurance Markets
- One of the Largest Renewable Power Portfolios in the U.S.

ENERGY CLIENTS – PARTIAL LISTING

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