4.0 Construction and Operations Plan

Work to construct and operate the injection operations will include the tasks listed below. Performance of some tasks may occur in parallel or sequential so as to optimize overall project quality and safety.

- Power plant retrofit and construction of flue gas process equipment.
- Construction and integrity testing of 12-in. transmission pipeline to storage site.
- Construction and testing of injection wells.
- Installation and testing of monitoring and control equipment along pipeline and at storage site.
- Connection of pipeline to injection wellhead manifolds and control equipment.
- Graduated startup of CO_2 pipeline and injection well operation.
- Upon verification of successful operation of entire pipeline and injection system, transition to routine injection operation as prescribed by the UIC permit.

This chapter describes how the Alliance will construct and complete its four Class VI injection wells to meet the requirements of 40 CFR 146.86. It also describes the logging, sampling, and testing the Alliance will undertake prior to injection well operation to meet the requirements of 40 CFR 146.87 and how the injection wells will be operated to meet the requirements of 40 CFR 146.88. Mechanical integrity testing required prior to the start of CO_2 injection, as required in 40 CFR 146.89, is also discussed. Mechanical integrity testing during the operational (i.e., injection) period is discussed in Chapter 5.0 (Section 5.3.2). In particular, Section 4.1 discusses operating data, including the source of CO_2, its chemical composition and physical characteristics, volumetric and mass flow rate, and pressure. Section 4.2 describes the proposed construction details for the injection wells as well as pre-operational characterization and formation testing that will be performed in the injection wells. Mechanical integrity testing is described in Section 4.3, Section 4.4 addresses well stimulation. Section 4.9 lists references for sources cited in this chapter.

4.1 Operating Data

This section describes the source of the CO_2 that will be delivered to the storage site, its chemical and physical properties, flow rate, and the anticipated pressure and temperature of the CO_2 at the pipeline outlet.

4.1.1 Source of CO_2

The source of the CO_2 will be the Meredosia Power Plant in Meredosia, Illinois. The Alliance plans to acquire a portion of the existing plant and repower one of its units with oxy-combustion and carbon capture technology. An oxy-combustion system combusts coal in the presence of a mixture of oxygen and CO_2. The heat produced by the combustion process is used to make steam. The steam is used to generate electricity. A byproduct of the oxy-combustion process is an emission stream that has a high concentration of CO_2 that can be captured and passed through a CO_2 purification and compression unit. In combination, these processes result in the capture of at least 90 percent of the power plant's CO_2 emissions and reduction of other conventional emissions to near zero levels. The facility will be designed to capture about 1.1 MMT of CO_2 per year, or 22 MMT of CO_2 over its 20-year contract period and supply it to the Alliance's pipeline for deep geological storage at the Morgan County CO_2 storage site.

4.1.2 Chemical and Physical Characteristics of the CO_2 Stream

The planned minimum acceptance specifications for the chemical composition of the CO_2 to the pipeline given in Table 4.1.

Table 4.1. CO_2 Acceptance Specifications

Component	Quantity
CO_2	97 percent dry basis
Inert constituents	1 percent
Trace constituents	2 percent
Oxygen (O_2)	<20 ppm
Total sulfur	<25 ppm
Arsenic	<5.0 ppm (5.0 mg/L)[(a)]
Selenium	<1.0 ppm (1.0 mg/L)[(a)]
Mercury (Hg)	<2 ppb[(b)]
Hydrogen sulfide (H_2S)	<20 ppm[(c)]
Water vapor	<30 lb/mmscf

(a) This is the Resource Conservation and Recovery Act standard.
(b) This is the Safe Drinking Water Act standard.
(c) This is a standard specification for the pipeline quality CO_2. However, no detectible amounts of H_2S are expected in the CO_2 stream from the Meredosia Power Plant.

4.1.3 Daily Rate and Volume and/or Mass and Total Anticipated Volume and/or Mass of the CO_2 Stream

The design basis for the capture facility is 85 percent availability (i.e., 310.25 d/yr). Therefore, the daily CO_2 flow rate when the system is operational will be 3,546 MT/d (1.1 MMT injected over 310.25 days). The planned lifetime of the project is 20 years; therefore, a total of 22 MMT of CO_2 will be injected at the Morgan County CO_2 storage site (20 yr x 1.1 MMT/yr).

4.1.4 Pressure and Temperature of CO_2 Delivered to the Storage Site

In 2011, Gulf Interstate Engineering developed a preliminary pipeline design which was based on a design basis of a mass flow rate of 1.3 MMT of CO_2 annually (GIE 2011). Based on this preliminary design, the CO_2 will be delivered to the storage site through a 12-in.-diameter pipeline. Based on design calculations performed by Gulf Interstate, the anticipated CO_2 pressure at the pipeline outlet (i.e., at the well site) will be 1,847 psi. This assumes an inlet pressure of 2,100 psi and an inlet temperature of 90°F. CO_2 temperature at the pipeline outlet was calculated assuming winter soil temperatures (40°F). Under summer conditions, the temperature of the CO_2 at the pipeline outlet will be slightly higher and the pressure will be slightly higher (i.e., the greatest pressure drop will occur during winter). Table 4.2 contains a summary of the pipeline design assumptions and results. Note that these results are for a mass flow rate of 1.3 MMT/yr rather than the current design basis of 1.1 MMT/yr because the Gulf Interstate calculations have not been updated since the design basis was changed from 1.3 MMT/yr to 1.1 MMT/yr. The next phase of the pipeline design, to be developed in 2013, will update this information.

Table 4.2. Pipeline Design Assumptions and Results

Parameter	Receiving Meter Station	Delivery Meter Station
Pressure (psig)	2,100	1,847
CO_2 Temperature (°F)	90	72.4
Mass Flow Rate (MMTA)	1.3	1.3
Flow Rate @ STP (mmscfd)	67.7	67.7
Actual Flow Rate (ft^3/d)	160,584	151,082
Density (lb/ft^3)	48.897	51.95
Viscosity (cP)	0.767	0.847
Molecular Weight	43.8	43.8

Source: Gulf Interstate Engineering (2011). Note data are for mass flow rate of 1.3 MMT/yr.

4.2 Well Design

Reservoir modeling discussed in Chapter 3.0 of this document determined that four horizontal injection wells will be required to achieve the target CO_2 injection rate. All four horizontal wells will originate from a common drilling pad. After construction of the drilling pad, a pilot boring will be advanced into the targeted injection zone. Following logging and characterization of the pilot hole, each of the Class VI injection wells will be advanced and constructed according to specific stratigraphy encountered in the pilot boring. Multiple concentric casing strings with cement fill will be installed to seal and encase the injection tubing down to the injection depth where each injection tube will extend horizontally into the formation of the injection zone. Detailed description of the well construction and testing procedures follow.

As shown in Section 4.2.8 (Figure 4.4), each horizontal well will include a vertical section that extends through the Potosi Formation to an approximate depth of 3,150 ft and a 1,500- to 2,500-ft-long horizontal section in the Upper Mount Simon Formation at an approximate depth of 4,030 ft bgs. (Note: a design depth of 4,030 ft was used in this section to design the well casing program; the actual depth will depend on site-specific characterization data obtained when drilling the injection wells). Each horizontal well will be oriented along a different azimuth from the two nearest (adjacent) wells to facilitate efficient distribution of the CO_2 and pore space use. A conceptual arrangement of the four horizontal injection wells is shown in Figure 3.18.

The ensuing sections describe the injection well design, including wellhead injection pressure requirements (Section 4.2.1); the casing and tubing specifications (Section 4.2.2); the cementing program (Section 4.2.3); packer (4.2.4); annular fluid (Section 4.2.5); wellhead (Section 4.2.6); and casing perforation (Section 4.2.7). Section 4.28 provides a schematic of the subsurface construction details of the injection wells.

4.2.1 Average and Maximum Wellhead Injection Pressure

A thermohydraulic analysis was conducted to determine the required surface (i.e., injection) pressure for the CO_2 injection wells. As discussed previously, the injection well site is designed to have a maximum instantaneous injection rate of 3,546 MT/d. This equates to an annual injection rate of 1.1 MMT/yr injected during 310.25 days to account for an 85 percent availability factor for the capture system. As discussed in Section 3.1.5, the representative case that is the current design basis for the CO_2 injection system is based on a 4 horizontal well configuration (see Table 3.11 for injection rates).

However, three well scenarios have also been considered and may be implemented (if formation hydraulic properties allow) to provide additional operational flexibility during injection and well maintenance activities. To account for this possible injection well configuration, the well and tubing design calculations presented in this section are based on a three well configuration

To achieve the target injection rate, the injection pressure must be greater than the minimum bottom-hole pressure required to drive the CO_2 into the reservoir formation, but the injection pressure must be maintained below the maximum safe pressure to avoid fracturing. The minimum bottom-hole pressure to provide the required flow rate into the Mount Simon Sandstone was determined by subsurface reservoir modeling (see Chapter 3.0, Area of Review and Corrective Action Plan). The maximum safe bottom-hole pressure was specified as 90 percent of the rock's fracture pressure (0.9 x 0.656 psi/ft = 0.585 psi/ft) at the depth where the CO_2 is injected (note: the fracture pressure is based on data obtained from the FutureGen Project 2.0 stratigraphic well, so this calculation will be updated after additional characterization data are obtained from the injection well). For conservatism, the required injection pressure was calculated based on the assumption that the required bottom-hole pressure is equal to the maximum safe bottom-hole pressure. These conditions are summarized in Table 4.3.

Table 4.3. Flow Rates and Limiting Pressures for Hydraulic Calculations

Parameter	Three Injection Wells
Depth injection horizon (ft)	4,030
Flow rate/well (MT/d)	1,182
Maximum bottom-hole injection pressure (psi) (injection depth × 0.585 psi/ft)	2,358

A steady-state, one-dimensional flow model was used to calculate the pressure drop along a series of segments of the well. Pressure changes from frictional loss, gravity head, and acceleration of the flow are included in the model. The CO_2 density is calculated from the pressure and temperature using the CO_2 state equation of Span and Wagner (1996). The CO_2 is assumed to be a liquid or supercritical fluid and the calculation stops if two-phase conditions occur. The internal energy at the end of a pipe segment was calculated from the energy equation accounting for the heat transfer from or into the CO_2 stream from the surrounding soil or rock, change in potential energy due to pressure and elevation, and kinetic energy of the flow. For the well, the ultimate heat sink is the rock far away from the well so steady-state heat transfer cannot be assumed. Instead, an equivalent heat conductance was defined at a given elapsed time after injection starts based on the heat flux calculated with a one-dimensional transient finite-difference conduction model. The effective conductance is greatest when injection is initiated, and then decreases over time as the rock near the well approaches the fluid temperature, eventually approaching zero effective heat transfer (adiabatic condition).

Depending upon the ambient rock temperature profile and the CO_2 temperature at the wellhead, net heat transfer may be from the fluid to the rock or from the rock to the fluid. Changes in the internal energy and temperature of the CO_2 with depth cause gradual changes in density, which in turn change the velocity and pressure drop. If the friction pressure drop is large (e.g., high velocity flow through small injection tubing), fluid expansion is significant as it moves down the pressure gradient. The resulting cooling effect can potentially have a greater impact on the CO_2 temperature than heat transfer to the surroundings.

Part of the bottom-hole pressure required to support the necessary flow into the rock is provided by hydrostatic head associated with the weight of the column of fluid in the well. This depends upon the fluid density, which varies with pressure and temperature because of the compressibility of $scCO_2$. Lower temperature at the wellhead increases the fluid density and decreases the wellhead pressure required to provide the necessary bottom-hole pressure. Frictional pressure drop in the injection tubing must also be overcome. High frictional losses associated with undersized tubing would make high wellhead pressures necessary to support a given flow rate. Larger tubing sizes require lower injection pressures but larger wells. Conversely, smaller tubing sizes require smaller wells but higher injection pressures. A well design was sought that does not require injection pressure greater than the pressure of the CO_2 at the outlet of the CO_2 pipeline (approximately 1,847 psi) in order to avoid the need for supplemental compression at the storage site.

Wellhead injection pressures were calculated for the following conditions: a flow rate of 1,182 MT/d (i.e., assuming 100 percent of the CO_2 is injected into three wells), five sizes of injection tubing ranging from 3.5 to 5.5 in. in diameter (3.5 in. 4.0 in., 4.5 in., 5.0 in., and 5.5 in.); and two different surface CO_2 temperatures (72.2°F and 90°F) to represent the range of anticipated CO_2 temperatures at the injection wells during winter and summer, respectively. All of these conditions were evaluated for the case where there is heat transfer with the surrounding rock and for the case where there is no heat transfer with the surrounding rock (adiabatic). Results are shown in Figure 4.1 (with heat transfer) and Figure 4.2 (adiabatic). As shown, the adiabatic case results in slightly higher wellhead injection pressures. Required injection pressures are higher in summer than winter due to lower density, leading to less hydrostatic head in the fluid column and higher frictional losses because of higher fluid velocities. The results of the thermohydraulic analysis (Figure 4.1 and Figure 4.2) show that required wellhead pressures for the 3.5-in. tubing case range from 1,197 psia to 1,378 psia, depending on the injection temperature and whether or not heat transfer is taken into account. These results also show that the required injection pressures are below the estimated pressure of the CO_2 at the outlet of the CO_2 pipeline (1,847 psi), even for the smallest tubing size evaluated. Therefore, supplemental compression will not be required. A well with a larger tubing size would require a lower injection pressure, but well costs would be higher. Therefore, the injection wells were designed to accommodate a 3.5-in.-diameter tubing string.

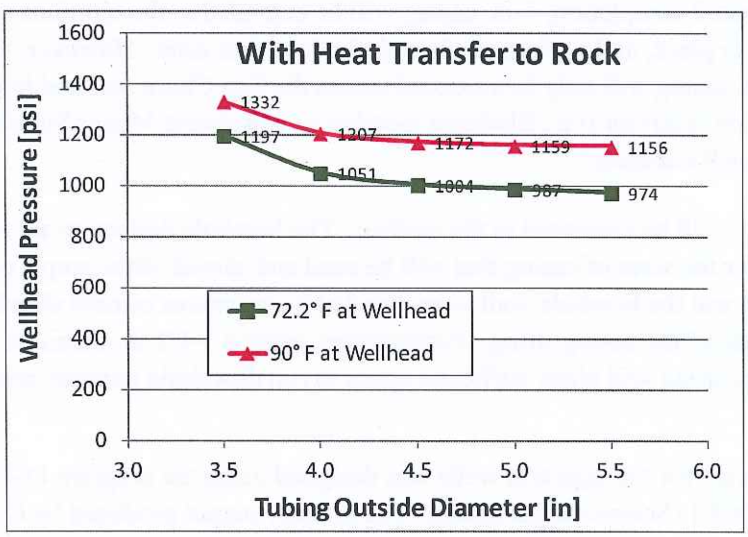

Figure 4.1. CO_2 Wellhead Injection Pressure for Various Outside Diameter Tubing Sizes (with heat transfer). The bottom-hole pressure is fixed at the top of the injection zone and is the same for all tubing sizes.

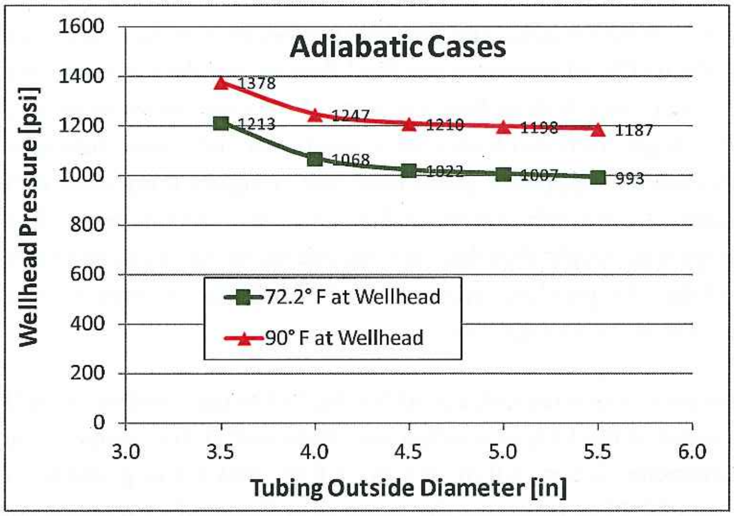

Figure 4.2. CO_2 Wellhead Injection Pressure for Various Outside Diameter Tubing Sizes (adiabatic). The bottom-hole pressure is fixed at the top of the injection zone and is the same for all tubing sizes.

4.2.2 Casing and Tubing Program

Based on the thermohydraulic analysis presented in the previous section, an injection well design has been developed to accommodate a 3-1/2-in.-diameter tubing string. Based on this starting point, it was decided that each horizontal injection well (see Section 4.2.8, Figure 4.4) will include the following casing strings: a 24-in.-diameter conductor string set at a depth of approximately 140 ft bgs inside a 30-in. borehole; a 16-in.-diameter surface string set at a depth of approximately 570 ft bgs inside a 20-in. borehole; a 10-3/4-in.-diameter intermediate string set at a depth of approximately 3,150 ft bgs inside a 14-3/4-in. borehole; and a 7-in.-diameter deep (injection) string set inside a 9-1/2-in. borehole. The depth of the 7-in. casing string will depend on the manner in which the well is completed. For a standard cemented and perforated completion, 7-in. casing will be extended to the terminus of the 9-1/2-in. borehole, cemented in place, and perforated through the injection zone. However, for an open-borehole completion, the 7-in. casing will only be extended across the Eau Claire seal and into the uppermost section of the injection reservoir (i.e., Elmhurst member or uppermost Mount Simon); below this point, the borehole will be left uncased.

All casing strings will be cemented to the surface. The borehole diameters are considered conventional sizes for the sizes of casing that will be used and should allow ample clearance between the outside of the casing and the borehole wall to ensure that a continuous cement sheath can be emplaced along the entire length of the casing string. Furthermore, using a 3-1/2-in.-diameter tubing string inside a 7-in.-diameter casing string will allow sufficient space to run downhole pressure and temperature gauges if desired.

The casing program for the injection wells was designed using the program OSPREY Tubular Designer, version 2008.1 (Schlumberger 2008). The primary output produced by OSPREY is a well-casing plan, which includes the weight, grades, and material for each casing string. The number of casing strings and their depths are specified by the user, but the casing specifications are determined based on a series of load scenarios that are programmed into the OSPREY program. The user also specifies a pore pressure gradient and a fracture pressure gradient. Load cases are defined by a temperature profile, an internal pressure profile (i.e., inside the casing), and an external pressure profile (i.e., outside the casing). Default load scenarios included in the OSPREY program are listed in Table 4.4. For each casing string, five design factors, including burst, collapse, tension, compression, and triaxial loading (i.e., Von Mises), are computed. The OSPREY program includes default minimum acceptable design factors, but these can be altered by the user. The default minimum acceptable design factors are as follows: burst (1.1), collapse (1.1), tension (1.5), compression (1.3), and triaxial loading (1.25). When designing the FutureGen injection wells, a minimum design criterion of 2.0 was used for all parameters to provide an added margin of safety. All casing strings included in the well design equal or exceed this design criterion for the load scenarios that were evaluated. By evaluating multiple load scenarios, a more rigorous well design is possible. The following subsections provide the results of the load analyses performed using the OSPREY program.

Table 4.4. Load Scenarios Evaluated

Load Name	Description	Casing String
Installed Load[a]	Casing is filled with mud with weight it was run in with; cement outside casing; static temperature profile.	All
1/3 Evacuation[a]	Casing is evacuated to a depth equal to one-third the depth of the next casing point (below this, mud is present with weight used to drill subsequent section); the mud with which the weight casing string was run in is present outside the casing; static temperature profile. Note that this results in complete evacuation of the casing if the depth of the subsequent casing point is >3x the depth of the casing string evaluated.	S, I
Full Evacuation[a]	Casing is completely evacuated; the mud with which the weight casing string was run in is present outside the casing; static temperature profile.	C, P
Pressure Test[a]	Casing is filled with the mud with which the weight casing was run in and surface pressure is applied that produces a pressure at the shoe equal to the fracture pressure plus a margin of safety (0.2 ppg); natural pore pressure gradient outside the casing; static temperature profile.	C, S, I
50 bbl Kick[a]	Simulates gas kick of specified volume; internal pressure profile depends on size of gas bubble and natural pore pressure gradient outside the casing; temperature profile is based on correlation by Kutasov and Taighi (as referenced in Schlumberger 2006).	S, I
1/3 Gas Replacement[a]	Casing is filled with 0.0 psi/ft gas to a depth equal to one-third the depth of the next casing point (below this, mud is present with weight used to drill subsequent section); natural pore pressure gradient outside the casing; static and circulating temperature profiles are both considered.	S, I
Surface Tubing Leak[a]	Surface Tubing Leak – The internal pressure profile is created by placing the shut-in tubing pressure on top of the packer fluid from the wellhead to the packer. Below the packer, bottom-hole pressure conditions exist. Pore pressure is used for the external pressure and static temperature is used for the temperature profile.	P
Full Evacuation[a]	Tubing is completely evacuated; external pressure is the hydrostatic pressure due to the packer fluid in the annulus surrounding the tubing; static temperature profiles.	T
Gas Shut-In[a]	Static Shut-In – Tubing is filled with gas at shut-in conditions; the packer fluid with which the tubing string was run in is used for the external pressure; static temperature conditions.	T
Injection Scenario	Internal pressure profile is defined by the maximum wellhead injection pressure at surface plus the hydrostatic pressure of the CO_2 in the tubing; external pressure is the hydrostatic pressure due to the packer fluid in the annulus surrounding the tubing; static temperature profiles.	T

(a) Standard default scenarios included in OSPREY (Schlumberger 2008).
C = conductor casing; S = surface casing; I = intermediate casing; P = production or long-string casing; T= tubing.

4.2.2.1 Conductor Casing

For the 24-in.-diameter conductor casing, 140-lb/ft K-55 casing with MTC (metal to metal seal) connections will meet or exceed the required design criteria. Table 4.5 summarizes the minimum design factors for the conductor casing and the corresponding load scenario and depth for each.

Table 4.5. Minimum Design Factors and Corresponding Scenarios for Conductor Casing String

Load	Design Factor	MD (ft)	Load Scenario[(a)]
Burst	>100	139	Pressure Test
Collapse	6.79	139	Full Evacuation
Tension	NA	NA	NA
Compression	38.22	139	Full Evacuation
Von Mises	32.17	139	Full Evacuation

(a) Load scenario with minimum design factor.
MD = measured depth.
NA = not applicable.

4.2.2.2 Surface Casing

For the 16-in.-diameter surface casing, 84-lb/ft K-55 casing with BTC (buttress thread coupling) connections will meet or exceed the specified design criteria. Table 4.6 summarizes the minimum design factors for the surface casing and the corresponding load scenario and depth for each.

Table 4.6. Minimum Design Factors and Corresponding Scenarios for Surface Casing String

Load	Design Factor	MD (ft)	Load Scenario[(a)]
Burst	5.6	0	1/3 Replacement
Collapse	4.96	569	1/3 Evacuation
Tension	27.3	0	1/3 Replacement
Compression	8.63	0	50 bbl Gas Kick
Von Mises	4.34	0	50 bbl Gas Kick

(a) Load scenario with minimum design factor.
MD = measured depth.

4.2.2.3 Intermediate Casing

For the 10-3/4-in.-diameter intermediate casing, 51-lb/ft K-55 casing with BTC connections will meet or exceed the specified design criteria. Table 4.7 summarizes the minimum design factors for the intermediate casing and the corresponding load scenario and depth for each.

Table 4.7. Minimum Design Factors and Corresponding Scenarios for Intermediate Casing String

Load	Design Factor	MD (ft)	Load Scenario[(a)]
Burst	4.26	0	50 bbl Gas Kick
Collapse	2.19	3,149	Installed Load
Tension	13.96	3,149	50 bbl Gas Kick
Compression	4.89	3,149	Installed Load
Von Mises	4.0	3,149	Installed Load

(a) Load scenario with minimum design factor.
MD = measured depth.

4.2.2.4 Long-String Casing

The long-string casing will be 7-in.-diameter pipe composed of two sections. The uppermost section (approximately 3,400 ft) will be carbon steel pipe and the lower section will be a corrosion-resistant alloy such as 13 percent chromium (13Cr) 110 stainless steel. The 29-lb/ft, N-80 steel casing with BTC connections attached to 29-lb/ft, P-110 or equivalent 13Cr will meet or exceed the specified design criteria for this casing string. Table 4.8 summarizes the minimum design factors for the long-string casing and the corresponding load scenario and depth for each.

Table 4.8. Minimum Design Factors and Corresponding Scenarios for Long-String Casing

Load	Design Factor	MD (ft)	Load Scenario[a]
Burst	4.12	3,150	Surface Tubing Leak
Collapse	3.74	3,400	Full Evacuation
Tension	8.89	0	Surface Tubing Leak
Compression	10.31	3,400	Full Evacuation
Von Mises	4.16	3,150	Surface Tubing Leak

(a) Load scenario with minimum design factor.
MD = measured depth.

4.2.2.5 Tubing

For the 3-1/2-in.-diameter tubing string, 9.3-lb/ft N-80 tubing with EUE (external upset end) connections will meet or exceed the specified design criteria. Table 4.9 summarizes the minimum design factors for the tubing-string and the corresponding load scenario and depth for each.

Table 4.9. Minimum Design Factors and Corresponding Scenarios for Tubing-String

Load	Design Factor	MD (ft)	Load Scenario[a]
Burst	5.38	0	Gas Shut-In
Collapse	5.29	3,900	Full Evacuation
Tension	6.68	0	Gas Shut-In
Compression	9.62	3,900	Full Evacuation
Von Mises	5.16	0	Gas Shut-In

(a) Load scenario with minimum design factor.
MD = measured depth.

4.2.2.6 Casing and Tubing Summary

Table 4.10 summarizes the casing program for the injection wells. Table 4.11 summarizes properties of each casing and tubing string. Depths are preliminary and may be adjusted based on actual conditions encountered when drilling the injection wells.

Table 4.10. Borehole and Casing and Tubing Program for the Horizontal CO_2 Injection Wells

Casing String	Casing Depth, TVD (ft bgs)	Casing Depth, MD (ft bgs)	Borehole Diameter (in.)	Casing Outside Diameter (in.)	Coupling Outside Diameter (in.)	Casing Material (weight/grade/ connection)	String Weight in Air (lb)
Conductor	140	140	30	24	25.198	140 lb/ft, K-55, MTC	19,600
Surface	570	570	20	16	17	84 lb/ft, K-55, BTC	47,880
Intermed.	0-3,150	3,150	14.75	10.75	11.25	51 lb/ft, K-55, BTC	160,650
Long String	0-3,398	0-3,400	9.5	7	7.656	29 lb/ft, N-80, BTC	98,600
	3,398-4,030[a] or 3,398-3,850[b]	3,400-7,004[a] or 3,400-3,949[b]		7	7.669	29 lb/ft, P-110, Premium[c]	91, 466[a] or 15,921[b]
Tubing	3,819.1[d]	3,900[d]	NA	3.5	4.5	9.3 lb/ft, N-80, EUE	36,270

(a) These depths apply if the 7-in. long-string casing is run completely to total depth (cemented and perforated scenario).
(b) If the injection well is completed as an open borehole, the 7-in. casing will be terminated at an approximate MD of 3,949 ft (TVD = 3,850 ft) in the uppermost Elmhurst member so that the borehole remains uncased below this depth.
(c) A corrosion-resistant alloy such as 13 Cr (13 percent chromium) having strength properties equal to or greater than 29-lb/ft P-110 and having premium connections will be used for this section
(d) These depths apply if the 7-in long-string casing is terminated at 3,949 ft MD (open borehole completion scenario). The tubing depth may be greater (up to 4,030 ft MD) if the 7-in. long-string casing is run completely to total depth (cemented and perforated scenario).
EUE = external upset end; TVD = total vertical depth; MD = measured depth.

Table 4.11. Properties of Well Casing and Tubing Materials

Casing String	Casing Material (weight/grade/ connection)	Casing Outside/Inside/ Drift Diameter (in.)	Yield (ksi)	Tensile (ksi)	Internal (Burst) Yield (psi)	Collapse (psi)	Tension (1,000 lb) Body (B) Joint (J)	Compression (1,000 lb)
Conductor	140 lb/ft, K-55, MTC	24/22.938/22.751	55	95	2,130	530	(1,967)	1,139
Surface	84 lb/ft, K-55, BTC	16/15.010/14.823	55	95	2,980	1,410	1,326 (B) 1,499 (J)	868
Intermediate	51 lb/ft, K-55, BTC	10.75/9.85/9.694	55	95	4,030	2,700	801 (B) 1,042 (J)	604
Long String	29 lb/ft, N-80, BTC	7.0/6.184/6.059	80	110	8,100	7,020	676 (B) 746 (J)	597
	29 lb/ft, P-110, BTC	7.0/6.184/6.059	110	125	11,220	8,530	929 (B) 955 (J)	488
Tubing	9.3 lb/ft, N-80, EUE	3.5/2.992/2.867	80	100	10,160	10,530	207.2 (B) 207.2 (J)	207.2

MTC = metal to metal seal threaded and coupled; BTC = buttress thread coupling; ksi = kilopound per square inch

4.2.3 Cementing Program

This section discusses the types and quantities of cement that will be used for each string of casing. All casing strings will be cemented back to the surface in accordance with requirements of the Class VI regulation. The proposed cement types and quantities for each casing string are summarized in Table 4.12. Note that two cementing programs are provided for the long-string casing, including one for the open-hole completion (casing total depth = 3,950 ft MD) and another for the cased hole/perforated completion (casing total depth = 7,004 ft MD).

Table 4.12. Cementing Program

Casing String	Casing Depth (ft)	Borehole Diameter (in.)	Casing O.D. (in.)	Cement Interval (ft)	Cement
Conductor Casing	140	30	24	0–140 (cemented to surface)	Class A with 2% $CaCl_2$ (calcium chloride) and 0.25-lb/sack cell flake; cement weight: 15.6 lb/gal; yield: 1.18 ft^3/sack; quantity: 400 sacks.
Surface Casing	570	20	16	0–570 (cemented to surface)	Lead-in: 65/35/10 Pozmix with 0.25-lb/sack cell flake; weight: 11.2 lb/gal; yield: 2.50 ft^3/sack; quantity: 225sacks.
					Tail: Class A with 2% $CaCl_2$ and 0.25-lb/sack cell flake; weight: 15.6 lb/gal; yield: 1.18 ft^3/sack; quantity: 200 sacks.
Intermediate Casing	3,150	14.750	10.750	0–2,750	Stage 2 Lead-in: 65/35 Pozmix with 10% gel; weight: 11.2 lb/gal; yield: 2.50 ft^3/sack; quantity: 755 sacks.
					Stage 2 Tail: 50/50/10 Pozmix; weight: 14.8 lb/gal; yield: 1.3 ft^3/sack; quantity: 215 sacks.
				2,750–3,150	Stage 1 Lead-in: Class A ESC with 10-lb/sack Cal Seal and 10% salt; weight: 16.6 lb/gal; yield: 1.4 ft^3/sack; quantity: 250 sacks.
Long Casing String (Open Hole Completion)	3,950	9.50	7.0	0–2,950	Lead-in: 65/35 Pozmix with 2% gel; weight: 12.5 lb/gal; yield: 2.01 ft^3/sack; quantity: 380 sacks.
				2,950–3,950	Tail: EverCRETE CO_2-resistant cement (or similar); weight:15.82 lb/gal; yield: 1.12 ft^3/sack; quantity: 285 sacks.
Long Casing String (Cased Hole/ Perforated Completion	6,504	9.50	7.0	0–2,950	Lead-in: 65/35 Pozmix with 2% gel; weight: 12.5 lb/gal; yield: 2.01 ft^3/sack; quantity: 380 sacks.
				2,950–7,004	Tail: EverCRETE CO_2-resistant cement (or similar); weight: 15.82 lb/gal; yield: 1.12 ft^3/sack; quantity: 1,080 sacks.

See acronym list for definition of abbreviations used in this table.

Casing centralizers will be used on all casing strings to centralize the casing in the hole and help ensure that cement completely surrounds the casing along the entire length of pipe. Except for the conductor casing, a guide shoe or float shoe will be run on the bottom of the bottom joint of casing and a float collar will be run on the top of the bottom joint of casing.

The intermediate casing will be cemented back to surface in two stages. To facilitate a two-stage cement job, a multiple-stage cementing tool will be installed at an approximate depth of 2,750 ft (±100 ft above the top of the Potosi Formation.) After the completion of the first-stage cement job, the multiple-stage cementing tool will be opened and fluid will be circulated down the casing and up the annulus above the cementing tool for a minimum of 8 hours to allow the first-stage cement job to acquire sufficient gel strength. The long string of casing will be cemented from total depth back to 200 ft up inside the 10-3/4-in. intermediate casing with Schlumberger's "EverCRETE" (or similar) CO_2 corrosion-resistant cement. Cement-bond logs will be run and analyzed for each casing string.

4.2.4 Packer

According to the Class VI regulation, the CO_2 must be injected through tubing that is secured with a packer installed near the bottom of the tubing string. In addition to providing a means for anchoring the tubing string, the packer provides structural stability for the tubing and isolation of the overlying annulus space from the injection interval so that the annular fluid can be monitored for tubing and packer leaks.

The packer will be installed inside the 29-lb/ft long-string casing at a point near the top of the injection interval (approximate measured depth of 3,900 ft). This will place the packer near or at the bottom of the curved section of the well. The packer will be rated to withstand the differential pressure that it will experience during installation, workovers, and the injection phase plus a factor of 2 margin of safety.

For the FutureGen horizontal injection wells, either the Weatherford WH-6 Hydraulic-Set Retrievable Packer (or similar) or the Weatherford BlackCat Retrievable Seal-Bore Packer (or similar) will be used. Both packers are available in sizes that are compatible with the 3-1/2-in.-diameter tubing and the 7-in.-diameter 29-lb/ft long-string casing. In addition, both packers can be manufactured using CO_2-compatible elastomer material (e.g., nitrile rubber) and corrosion-resistant steel materials, such as 13Cr stainless steel, or they can be nickel-plated.

For the WH-6 packer, an on-off tool will be installed just above the packer so the tubing string can be removed without removing the packer. This will require rotating the tubing approximately one-quarter turn at tool depth to release tubing from the packer. According to Weatherford, this minimal amount of rotation is considered acceptable when pressure/temperature control lines are attached to the outside of the tubing.

For the BlackCat model packer, the packer is set first on wireline or coil tubing, then the tubing and pressure and temperature gauges and associated control line are lowered to the packer. The tubing seats in the packer with a seal stem and requires no rotation of pipe to run or pull the tubing string. Although there is no rotational movement required with the BlackCat packer, there is greater potential for up/down movement of the tubing string due to differential stresses imposed by injecting CO_2; whereas with the WH-6 packer, there is essentially no potential for up/down movement of the tubing string. The WH-6 packer is rated to 6,000 psi differential and 275°F. The BlackCat packer is rated to 8,000 psi differential and 300°F.

4.2.5 Annular Fluid

The annular space above the packer between the 7-in. long-string casing and the 3-1/2-in. injection tubing will be filled with fluid to provide structural support for the injection tubing. If required, fluid pressure measured at the surface within the annulus will be maintained so as to exceed the maximum injection pressure within the injection tube at the elevation of the injection zone. Under this requirement, the maximum annulus (surface) pressure would not exceed a value that is more than ~200 psi greater than injection pressure at the surface. Alternatively, 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. Assuming that the packer is placed at a measured depth of 3,900 ft, the volume of the annular space will be approximately 98.3 bbl (4,128 gal).

The annular fluid will be a dilute salt solution such as potassium chloride (KCl), sodium chloride (NaCl), calcium chloride ($CaCl_2$), or similar solution. The fluid will be mixed onsite using dry salt and good quality (clean) freshwater or it will be acquired pre-mixed. The fluid will also be filtered to ensure that solids do not interfere with the packer or other components of the annular protection system. The final choice of the type of fluid will depend on its availability.

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

- TETRAHib Plus (corrosion inhibitor for carbon steel tubulars [i.e., casings, tubing]) – 10 gal per 100 bbl of packer fluid
- CORSAF™ SF (corrosion inhibitor for use with 13Cr stainless steel tubulars or a combination of stainless steel and carbon steel tubulars) – 20 gal per 100 bbl of packer fluid
- Spec-cide 50 (biocide) – 1 gal per 100 bbl of packer fluid
- Oxban-HB (non-sulfite oxygen scavenger) – 10 gal per 100 bbl of packer fluid.

These products were recommended and provided by Tetra Technologies, Inc., of Houston, Texas. Actual products may vary from those described above.

4.2.6 Wellhead

An illustration of the wellhead and Christmas tree is provided in Figure 4.3. The wellhead and Christmas tree assembly will consist of the following components, from bottom to top:

- 16-in. x 10¾ -in, 3,000-psi casing head (attaches to surface casing)
- 10 ¾ -in. x 7.0-in., 3,000-psi casing head (attaches to intermediate casing)
- 7-in. x 3-1/2-in., 3,000-psi tubing head (attaches to long casing)
- 3-1/2-in. tubing head adapter
- 3-1/2-in. 3,000-psi full-open master manual control gate valve
- 3-1/2-in. 3,000-psi automated tubing flow-control valve (for automatically shutting-in well)
- 3-1/2-in. 3,00-psi cross with one 3-1/2-in., 3,000-psi blind flange
- 3-1/2-in. 3,000-psi automated tubing flow-control valve (for automatically shutting-in well)
- 3-1/2-in. x 2-7/8-in., 3,000-psi top flange and pressure gauge.

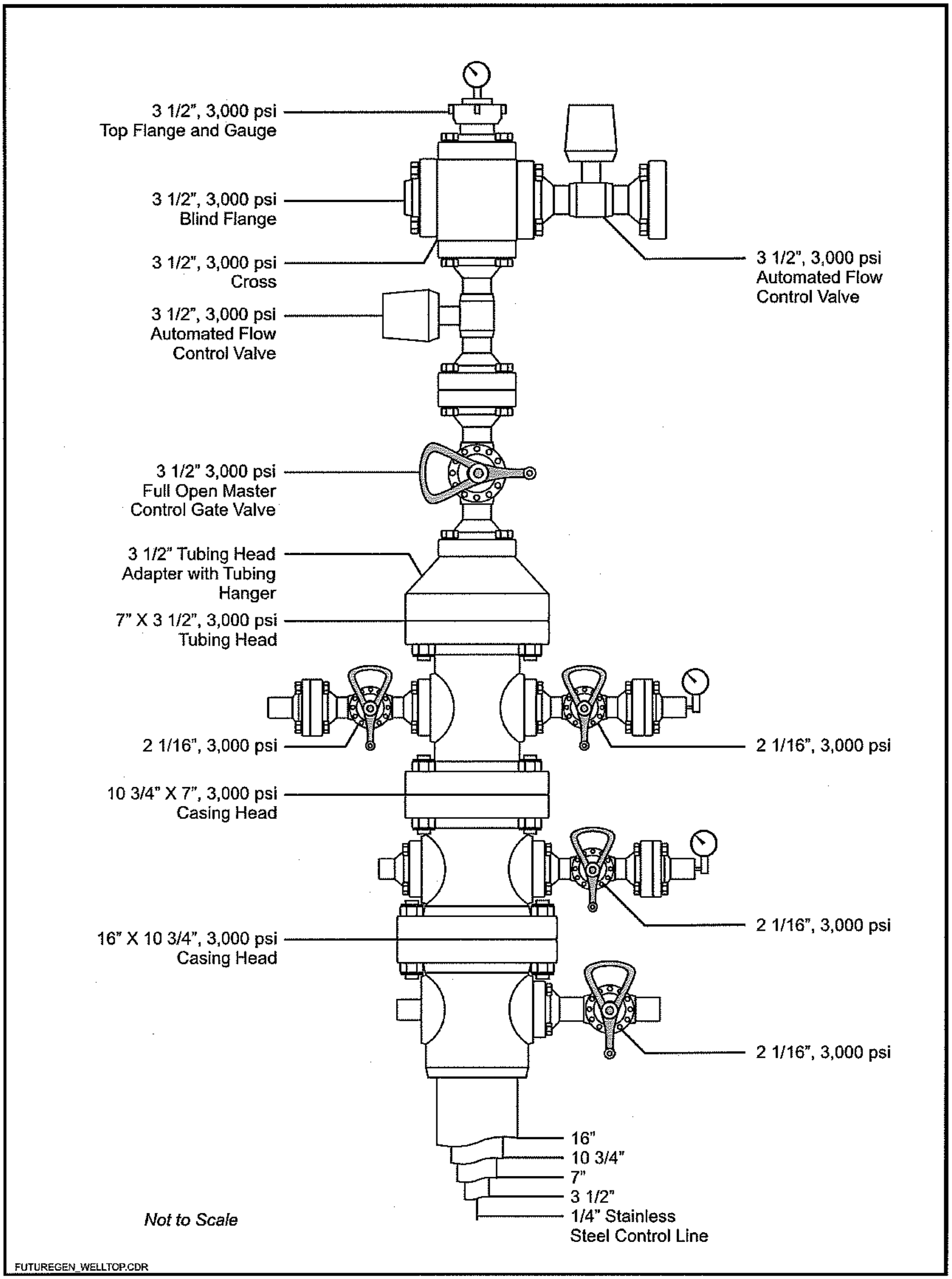

Figure 4.3. Illustration of the Wellhead and Christmas Tree

The wellhead and Christmas tree will be composed of materials that are compatible with the injection fluid to minimize corrosion. In general, all components that come into contact with the CO_2 injection fluid will be made of a corrosion-resistant alloy such as stainless steel. Because the CO_2 injection fluid will be very dry, use of stainless steel components for the flow-wetted components is a conservative measure to minimize corrosion and increase the life expectancy of this equipment. Materials that will not have contact with the injection fluid will be manufactured of carbon steel. All materials will comply with the API Specification 6A – Specification for Wellhead and Christmas Tree Equipment (Table 4.13).

Table 4.13. Material Classes from API 6A (Specification for Wellhead and Christmas Tree Equipment)

API Material Class	Body, Bonnet, End & Outlet Connections	Pressure Controlling Parts, Stems, & Mandrel Hangers
AA – General Service	Carbon or alloy steel	Carbon or low-alloy steel
BB – General Service	Carbon or low-alloy steel	Stainless steel
CC – General Service	Stainless steel	Stainless steel
DD – Sour Service[(a)]	Carbon or low-alloy steel[(b)]	Carbon or low-alloy steel[(b)]
EE – Sour Service[(a)]	Carbon or low-alloy steel[(b)]	Stainless steel[(b)]
FF – Sour Service[(a)]	Stainless steel[(b)]	Stainless steel[(b)]
HH – Sour Service[(a)]	Corrosion-resistant alloy[(b)]	Corrosion-resistant alloy[(b)]

Source: Cameron Surface Systems, Houston, Texas
(a) As defined by National Association of Corrosion Engineers (NACE) Standard MR0175.
(b) In compliance with NACE Standard MR0175.

4.2.7 Well Openings to Formation

The final construction of the well will be determined after the vertical pilot borehole has been completed. Two possible scenarios are being considered—an open-hole completion and a cased and perforated completion. In the case of the open-hole completion, the 7-in. production casing will be set (i.e., terminated) on a formation packer shoe in the upper Elmhurst member (approximate measured depth 3,950 ft bgs; approximate total vertical depth [TVD] of 3,850 ft bgs) and the remainder of the penetrated Elmhurst member and Mount Simon Formation would remain uncased.

In the cased-hole completion scenario, the long-string casing will be perforated across an approximately 1,500- to 2,500-ft-long section of the Mount Simon Sandstone. The exact perforation interval will be determined after the well is drilled and characterized with geophysical logging, core analyses, and hydrogeologic testing. It is possible that multiple intervals with varying lengths will be perforated rather than a single long perforation interval. Modeling will be used, incorporating the results of the site-specific testing activities, to aid in determining the total length of the perforated intervals and to optimize the placement and density of the perforations. After perforating, the perforations will be cleaned using an acid washing technique in which hydrochloric acid containing additives such as surfactants, clay stabilizers, and iron sequestering agents are pumped into the perforations, allowed to soak for a pre-determined amount of time, and then removed by swabbing.

The results of the characterization activities along with the proposed perforation interval(s) will be described in the Well Completion Report that will be submitted to the EPA after completion of the injection well drilling and characterization activities. Perforations would be cleaned to remove residual cement using an acid-washing technique.

4.2.8 Schematic of the Subsurface Construction Details of the Well

As discussed in the previous sections, the injection wells will be horizontal wells and will include the following casing strings: a 24-in.-diameter conductor string set at a depth of approximately 140 ft bgs; a 16-in.-diameter surface string set at a depth of approximately 570 ft bgs; a 10-3/4-in.-diameter intermediate string set at a depth of approximately 3,150 ft bgs; and a 7-in.-diameter long-string set at an approximate (measured) depth of 3,950 ft bgs (approximate TVD of 3,850 ft bgs) or 7,004 ft bgs (approximate TVD of 4,030 ft bgs) depending upon if the wells are completed as an open hole or cased well scenario. Schematics of the injection wells are shown in Figure 4.4 (cased-hole completion) and Figure 4.5 (open borehole completion). The decision to complete the injection wells as cased and perforated versus open hole will be made after the characterization of the initial vertical pilot borehole has been performed. Therefore, all depths are preliminary and will be adjusted based on additional characterization data obtained while drilling the vertical pilot borehole and the CO_2 injection wells.

The purpose of the conductor string is to provide a stable borehole across the near-surface, unconsolidated glacial deposits before drilling the remaining deeper casing strings, and to help protect the USDWs in these sediments. Groundwater in the vicinity of the site is normally obtained from sand and gravel deposits that are contained within the unconsolidated Quaternary-age material above bedrock. The sand and gravel deposits in the vicinity of the proposed site range in depth from about 25 to 125 ft bgs. Bedrock is known to be approximately 125 ft bgs based on the stratigraphic well drilled at the site in late 2011. The surface string will extend across the uppermost bedrock layers (Pennsylvanian age) and will help to further isolate and protect the overlying USDW from potential oil and gas-bearing zones in the Pennsylvania strata. The intermediate casing string will extend across and isolate deeper potentially unstable layers and formations, including the Potosi Formation where there is potential for lost circulation, to ensure that the well can be drilled to total depth. The intermediate casing string will also isolate the St. Peter Formation, which is considered a USDW aquifer, from the underlying CO_2 injection zone. The long-string casing string will be set into the Elmhurst member of the Eau Claire Formation in the case of an open-hole completion, or into the most porous and permeable zone in the Mount Simon Formation in the cased and perforated completion scenario.

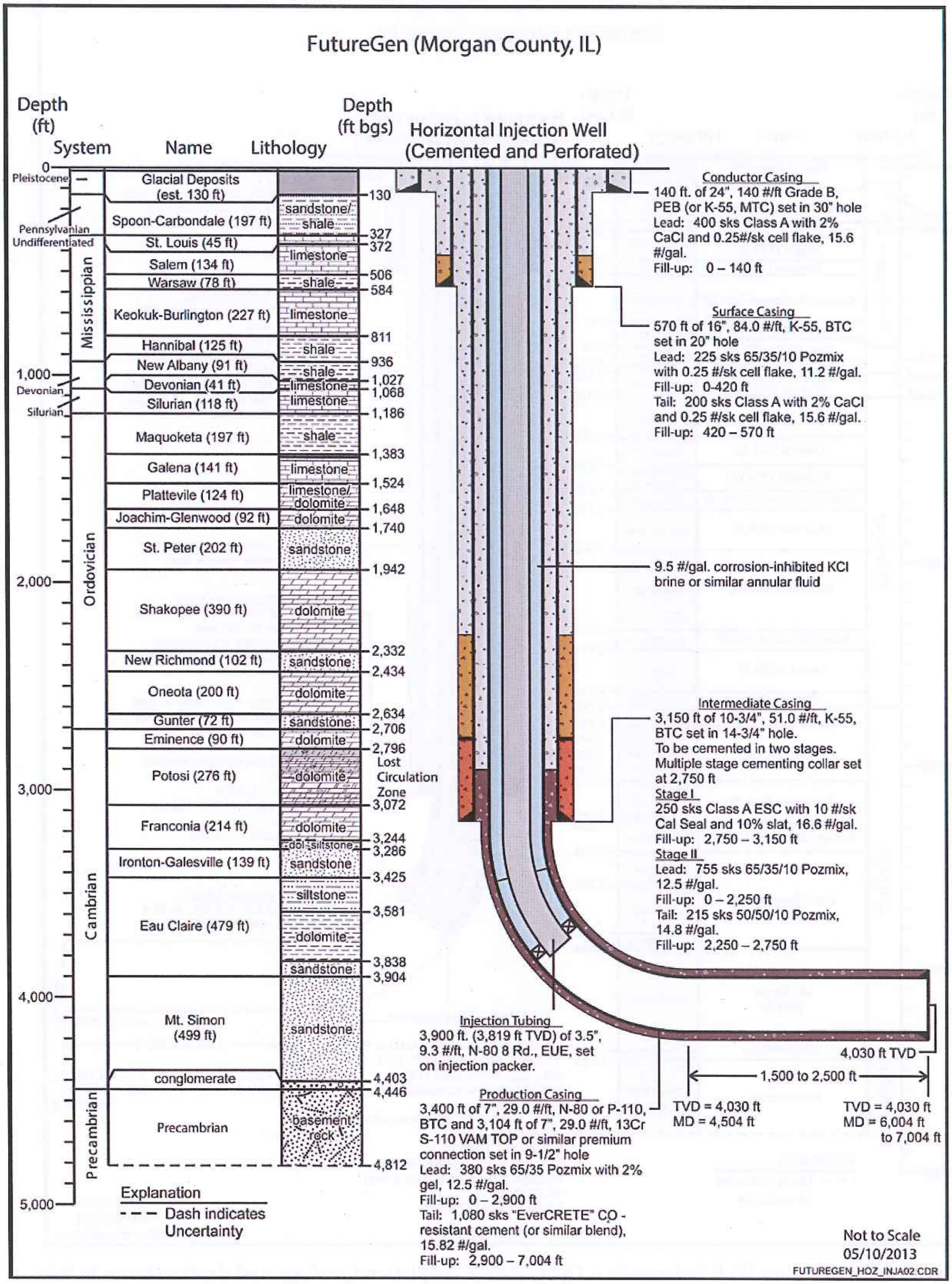

Figure 4.4. Injection Well Schematic – Cased-Hole Completion (geology and depths shown in this diagram are based on site-specific characterization data obtained from the FutureGen 2.0 stratigraphic well)

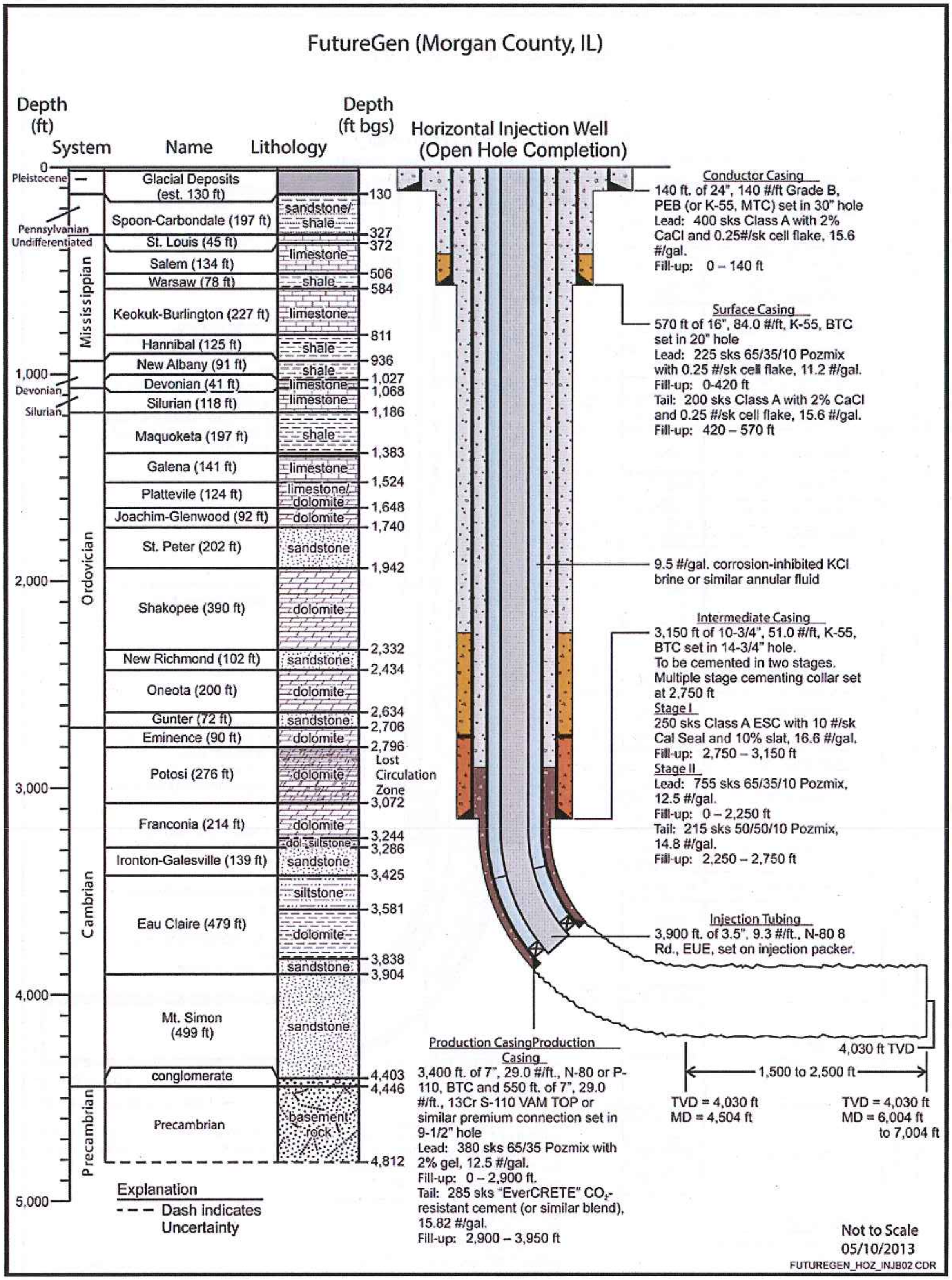

Figure 4.5. Injection Well Schematic – Open-Hole Completion (geology and depths shown in this diagram are based on site-specific characterization data obtained from the FutureGen 2.0 stratigraphic well)

4.2.9 Pre-Operational Formation Testing

The pre-operational formation testing program will be implemented to obtain an analysis of the chemical and physical characteristics of the injection zone and confining zone(s) and that meets the testing requirements of 40 CFR 146.87 and well construction requirements of 40 CFR 146.86. The pre-operational testing program will include a combination of logging, coring, formation geohydrologic testing (e.g., a pump test and/or injectivity tests), and other activities during the drilling and construction of the CO_2 injection well.

The pre-operational testing program will determine or verify the depth, thickness, mineralogy, lithology, porosity, permeability, and geomechanical information of the Mount Simon Sandstone (CO_2 injection zone), the overlying Eau Claire Formation (confining zone), and other relevant geologic formations. In addition, formation fluid characteristics will be obtained from the Mount Simon Sandstone to establish baseline data against which future measurements may be compared after the start of injection operations. The results of the testing activities will be documented in a report and submitted to the EPA after the well drilling and testing activities have been completed but before the start of CO_2 injection operations.

Before drilling the injection wells, a vertical pilot hole will be drilled through the Mount Simon Formation at the injection well location to collect pre-operational characterization and testing data for the injection wells. After completing the characterization and testing in the vertical pilot hole, the borehole will be plugged (cemented) from total depth to the kick-off point (approximate depth of 3,200 ft bgs) and converted to one of the horizontal injection wells. Additional selected pre-operational testing will be conducted within one or more lateral boreholes.

4.2.10 Wireline Logging

Open-borehole logs will be run to obtain densely spaced, in situ, structural, stratigraphic, physical, chemical, and geomechanical information for Mount Simon Sandstone, the Eau Claire confining zone, and other key formations. Open-borehole characterization logs will be obtained at the surface casing point, the intermediate casing point, and at the long-string casing point (i.e., total borehole depth) in the vertical pilot borehole. Open-borehole wireline logs will not be run in the 30-in.-diameter conductor casing borehole because logging tools are not suited for this large-diameter hole size. As detailed in Table 4.14, open-borehole logs will include caliper, gamma, spontaneous potential (or brine formation equivalent), resistivity, neutron, density, photoelectric cross-section, sonic (full waveform), nuclear magnetic resonance, resistivity-based and/or acoustic-based micro-image, and gamma spectroscopy logs.

Table 4.14. Wireline Logging Program

Depth Interval[(a)]	Log	Purpose/Comments	Well
Conductor Casing Interval (0 to 140 ft bgs); 30-in. borehole	• No open-borehole logs	• NA	All
	• No cement-bond log	• NA	All
Surface Casing Interval (below conductor casing to 570 ft bgs); 20-in. borehole	• Basic log suite (gamma ray,[(b)] formation density,[(b)] neutron porosity,[(b)] resistivity,[(b)] spontaneous potential,[(b)] photoelectric factor, caliper[(b)])	• Characterize basic geology (lithology, mineralogy, porosity)	Vertical pilot borehole
	• Cement-bond log[(b, d)]	• Evaluate cement integrity	All

Table 4.14. (contd)

Depth Interval[a]	Log	Purpose/Comments	Well
Intermediate Interval (below surface casing to 3,150 ft bgs); 14-3/4-in. borehole	• Basic log suite (gamma ray,[b] formation density,[b] neutron porosity,[b] resistivity,[b] spontaneous potential,[b] photoelectric factor, caliper[b])	• Characterize basic geology (lithology, mineralogy, porosity) • Evaluate borehole condition prior to cementing	Vertical pilot borehole
	• Enhanced log suite (spectral gamma,[c] dipole sonic shear log,[c] resistivity-based and/or acoustic-based image log,[c] nuclear magnetic resonance log,[c] elemental capture spectroscopy log[c])	• Enhanced characterization of geologic and geomechanical properties that control injectivity and confining zone/seal integrity • Dipole sonic log will also provide data to calibrate surface seismic and other purposes	Vertical pilot borehole
	• Cement-bond log[b, d]	• Evaluate cement integrity	All
Long-String Casing Interval[e] (Vertical borehole, below intermediate casing 3,150 to total depth); 9-1/2 –in. borehole	• Basic log suite (gamma ray,[b] formation density,[b] neutron porosity,[b] resistivity,[b] spontaneous potential,[b] photoelectric factor, caliper[b])	• Characterize basic geology (lithology, mineralogy, porosity) • Evaluate borehole condition prior to cementing	Vertical pilot borehole
Long-String Casing Interval (Lateral borehole); 9-1/2-in. borehole[f]	• Resistivity log[g] • Baseline oxygen-activation log (pulsed neutron capture tool) • Dipole sonic • Nuclear magnetic resonance • Resistivity based micro-image log	• Pulsed neutron capture log can be run in lieu of basic logs (porosity, density, resistivity) to provide basic characterization data for the lateral borehole. • Sonic log will allow geomechanical properties to be determined. • Nuclear magnetic resonance will characterize permeability. • Resistivity based micro-image log would provide borehole images for detection of fractures, structure (dip), sedimentary features, etc. This log could also be run along with the resistivity log while drilling.	Optional for one or more wells
	• Baseline temperature log[b, d] • Cement-bond log[b, d] • Baseline oxygen-activation log (pulsed neutron capture tool) –if it is not run in open borehole[d] • Baseline casing inspection log[c, d]	• Determine natural geothermal gradient outside well for comparison to future temperature logs for external mechanical integrity evaluations. • Evaluate cement integrity of long-string casing through confining zone. • Provide baseline measurement for future pulsed neutron capture logging runs aimed at detecting distribution of CO_2 outside the well for external mechanical integrity evaluations. • Obtain a baseline assessment of casing condition through confining zone for comparison to future casing inspection logs, if performed.	All

Table 4.14. (contd)

Depth Interval[(a)]	Log	Purpose/Comments	Well

(a) Well design is described in Section 4.3 of this document; borehole/casing depths are approximate and preliminary.
(b) Required by EPA UIC Class VI permit requirements (10 CFR 146.87).
(c) Optional logs: one or more of these logs may be run across selected intervals of this section of the well.
(d) Cased-hole log
(e) These logs will be run in the vertical pilot borehole.
(f) These logs may be run in the horizontal (lateral) open borehole of one or more injection wells (all are optional since all required logs will be run in the vertical pilot hole drilled on the same pad as the horizontal injection wells).
(g) The resistivity log would be run while drilling to help steer the borehole.
NA = not applicable.

4.2.11 Coring

Sections of whole core will be collected from the Mount Simon CO_2 injection zone and the overlying Eau Claire confining zone when drilling the vertical pilot borehole for the CO_2 injection wells. No additional whole core will be collected when drilling the horizontal injection wells. The coring program will provide core to augment core data obtained from the FutureGen 2.0 stratigraphic well that was drilled in late 2011. Fluid temperature, pH, conductivity, reservoir pressure and static fluid level of the injection zone will be measured prior to injection.

4.3 Demonstrating the Well's Mechanical Integrity Prior to Injection

Tests and logs will be conducted as needed to demonstrate the internal and external mechanical integrity of the injection wells prior to initiating regular CO_2 injection. Internal mechanical integrity refers to the absence of leaks in the tubing, packer, and casing above the packer. External mechanical integrity refers to the absence of fluid movement/leaks through channels adjacent to the injection well bore that could result in fluid migration into an USDW.

After the injection wells are completed, including the installation of tubing, packer, and annular fluid, a test of the well's internal mechanical integrity will be performed by conducting an annular pressure test (APT). The APT is a short-term test wherein the fluid in the annular space between the tubing and casing is pressurized, the well is shut-in (temporarily sealed up), and the pressure of the annular fluid is monitored for leak-off. EPA Region 5 (EPA 2008) requires comparison of the pressure change throughout the test period to 3 percent of the test pressure (0.03 x test pressure). If the annulus test pressure decreases by this amount or more, the well has failed to demonstrate internal mechanical integrity. If the annulus pressure changes by less than 3 percent during the test period, the well has demonstrated internal mechanical integrity. If the well fails the APT, the tubing and packer may need to be removed from the well to determine the cause of the leak. EPA Region 5 guidance (EPA 2008) for conducting the APT will be consulted when performing this test. During the active CO_2 injection phase, internal mechanical integrity will be continuously monitored by the well annular pressure maintenance and monitoring system, as discussed in more detail in the Testing and Monitoring Plan (see Section 5.2.3.1).

Accepted methods for evaluating external mechanical integrity include a tracer survey, such as oxygen-activation logging or radioactive tracer logging, or a temperature or noise log. During the service life of the wells, one or more of these methods will be used to periodically (annually) evaluate the external mechanical integrity of the injection wells. A baseline temperature log and oxygen-activation log will be run on the well after well construction but prior to commencing CO_2 injection to provide a baseline reference for comparing future temperature logs and oxygen-activation logs as they relate to the well's external mechanical integrity.

A more detailed discussion of internal and external mechanical integrity testing during the service life of the injection wells is provided in the Testing and Monitoring Plan (Section 5.3.2).

4.4 Stimulation Program

The need for stimulation to enhance the injectivity potential of the Mount Simon Sandstone is not anticipated at this time. The need for stimulation will be determined once the characterization data from the CO_2 injection wells are available and have been evaluated (i.e., results of geophysical logs, core analyses, hydrogeologic testing). If it is determined that stimulation techniques are needed, a stimulation plan will be developed and submitted to EPA Region 5 for review and approval prior to conducting any stimulation.

4.5 References

40 CFR 146.86. Code of Federal Regulations, Title 40, *Protection of Environment.* Part 146, Underground Injection Control Program: Criteria and Standards; Subpart H: Criteria and Standards Applicable to Class VI Wells, Injection well construction requirements.

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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).

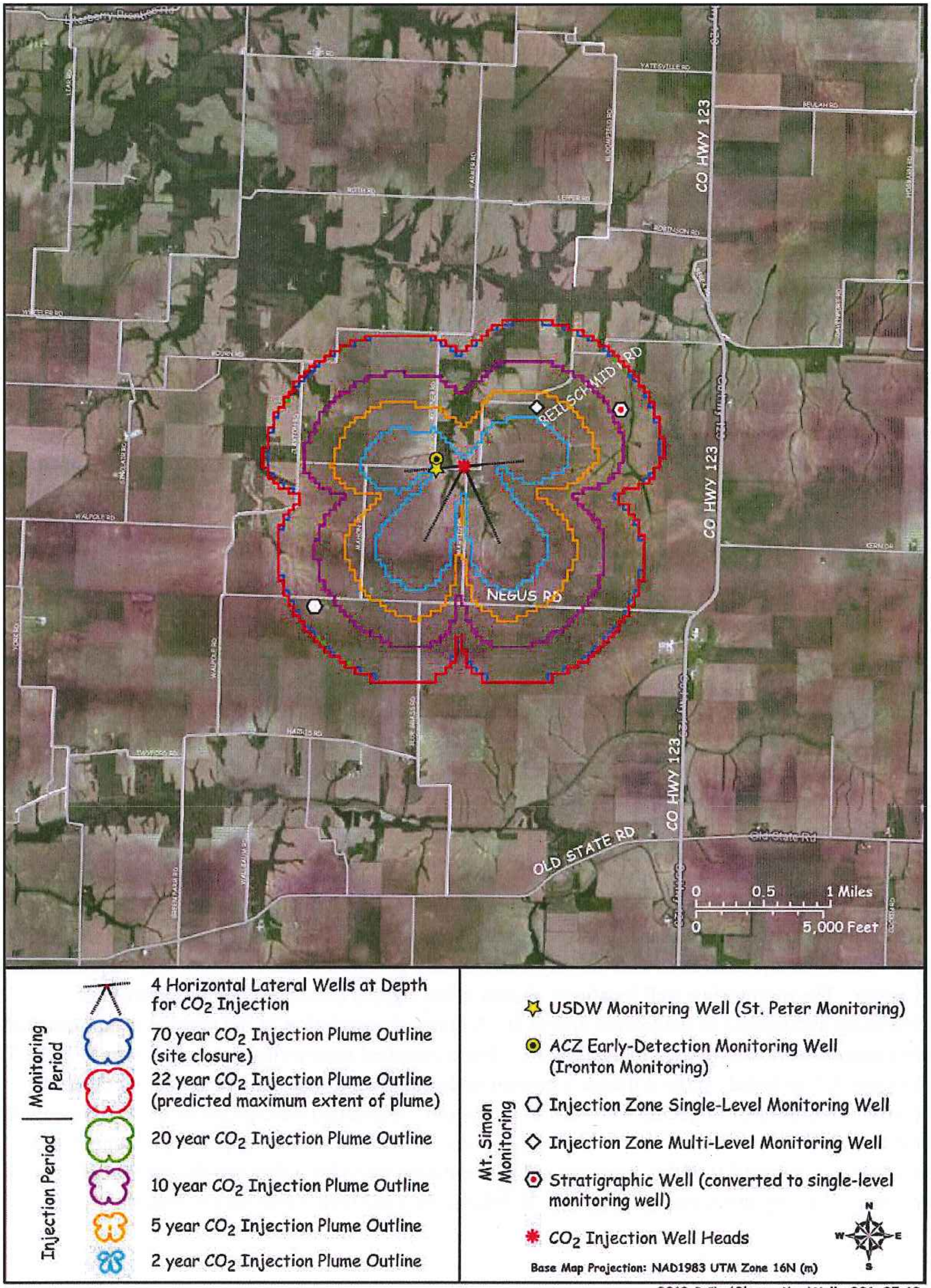
In addition to the reservoir modeling described in Chapter 3.0 that is being performed to satisfy requirements of the UIC permit application, an additional modeling effort focused on evaluation of environmental release scenarios, may be performed. This environmental release model would be developed to 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.



2013-DCL-6PlumesMonWells-001_05-10

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

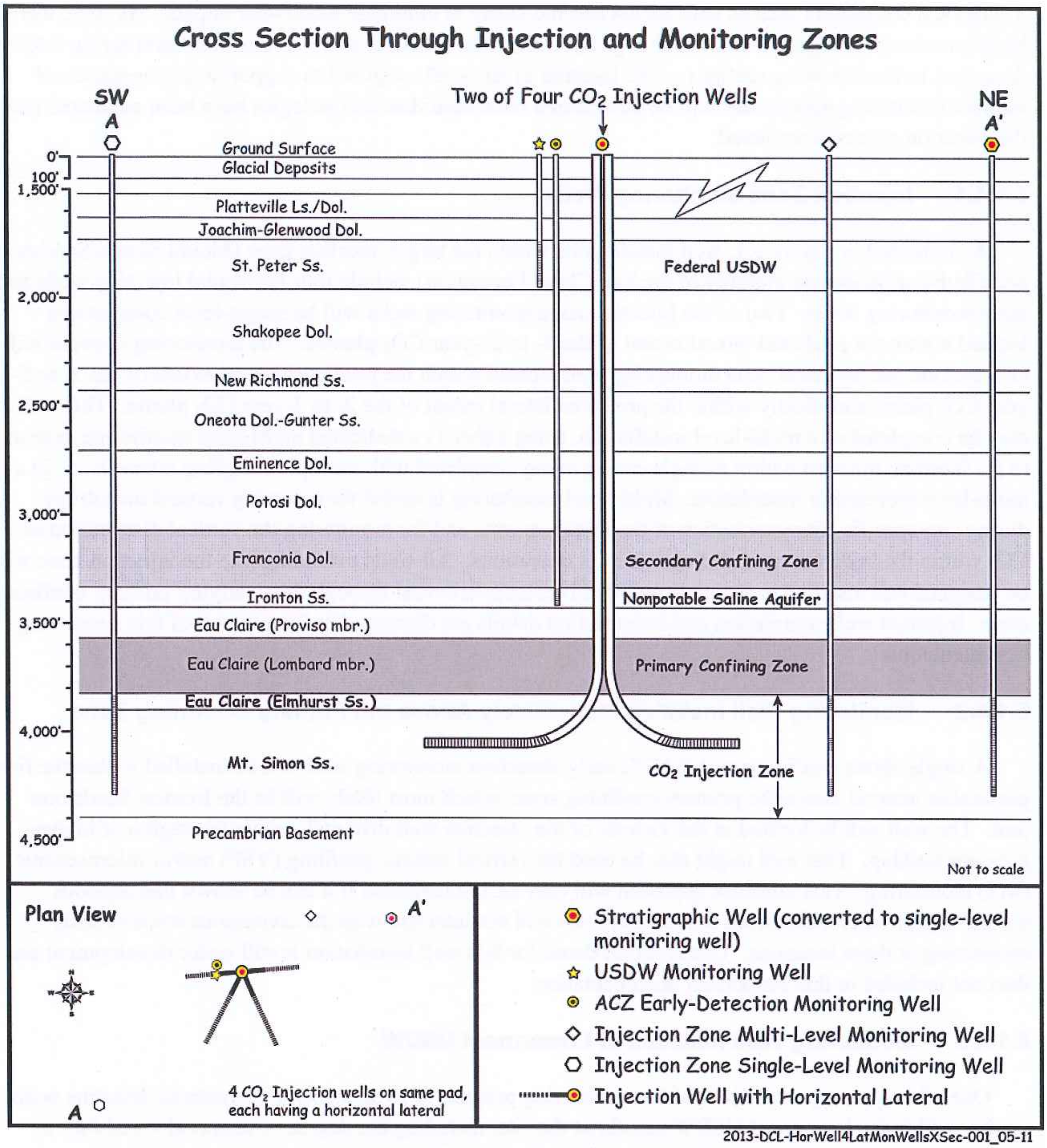


Figure 5.2. Cross-Sectional View of Injection and Monitoring Well Network

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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