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 (ºF)	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.

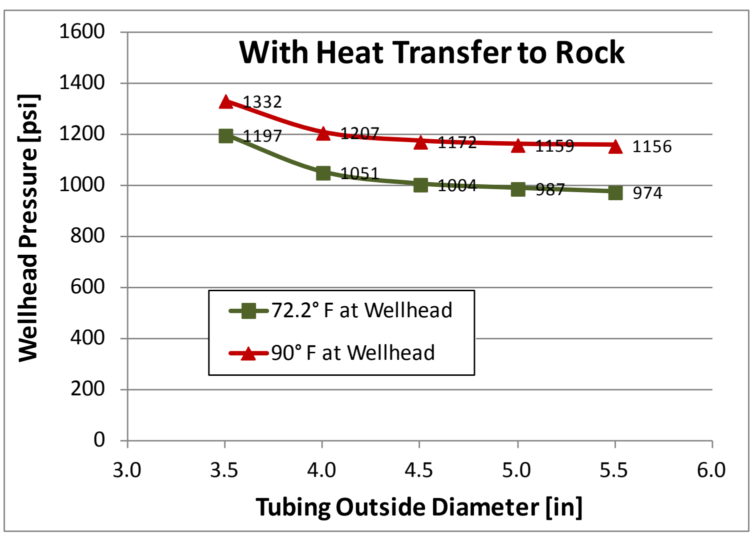

Figure 4.1. CO_2 Wellhead Injection Pressure for Various Outside Diameter Tubing Sizes (with heat transfer). The bottom-hole pressure is fixed at the top of the injection zone and is the same for all tubing sizes.

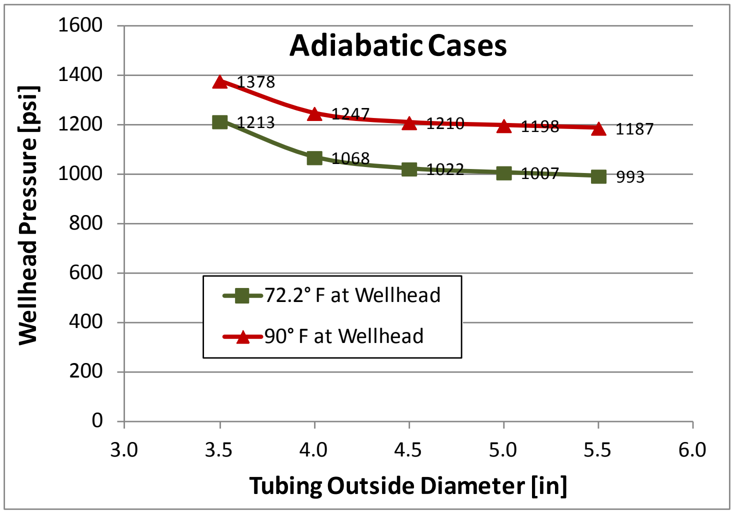

Figure 4.2. CO_2 Wellhead Injection Pressure for Various Outside Diameter Tubing Sizes (adiabatic). The bottom-hole pressure is fixed at the top of the injection zone and is the same for all tubing sizes.

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.

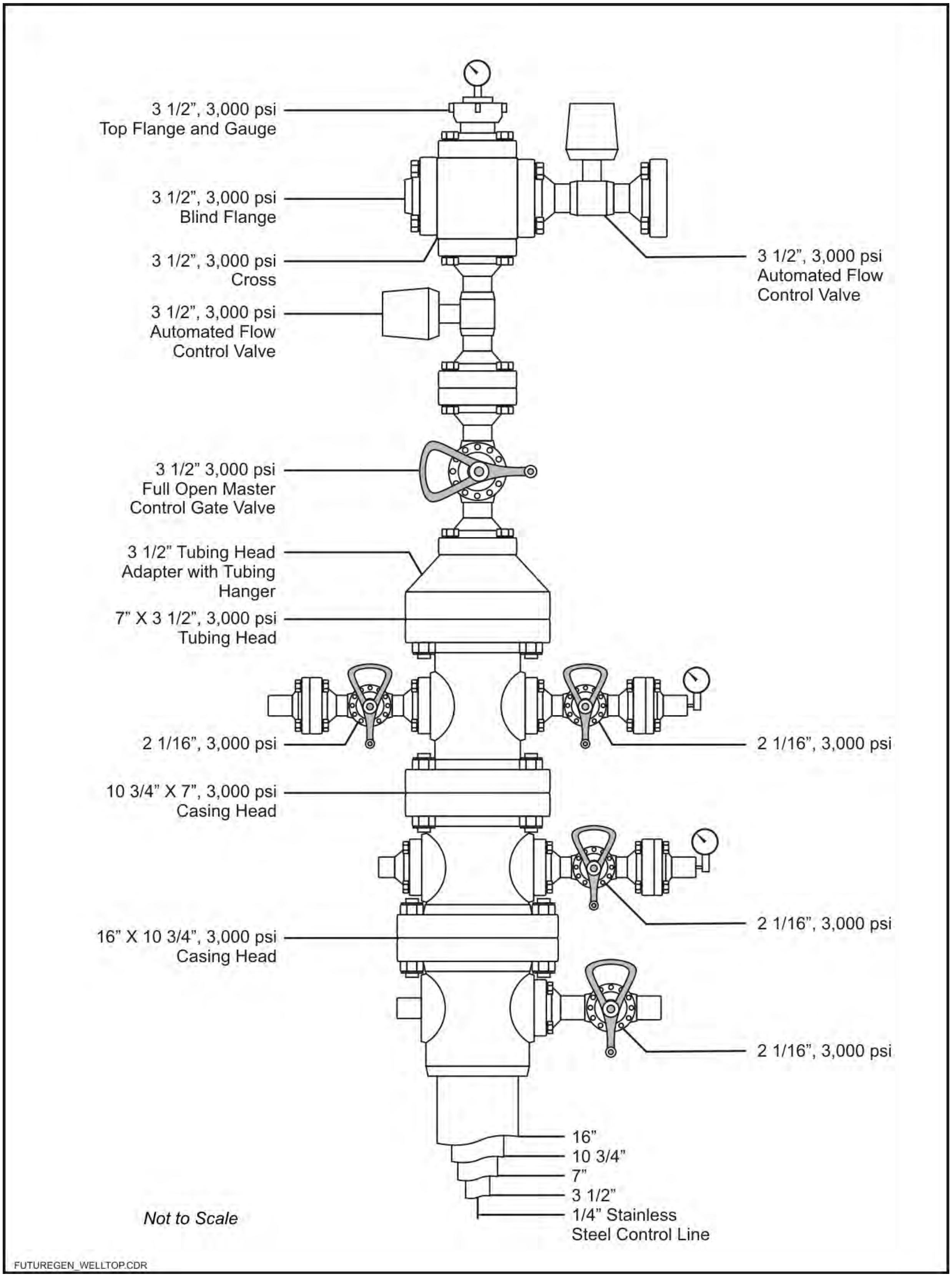

Figure 4.3. Illustration of the Wellhead and Christmas Tree

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.

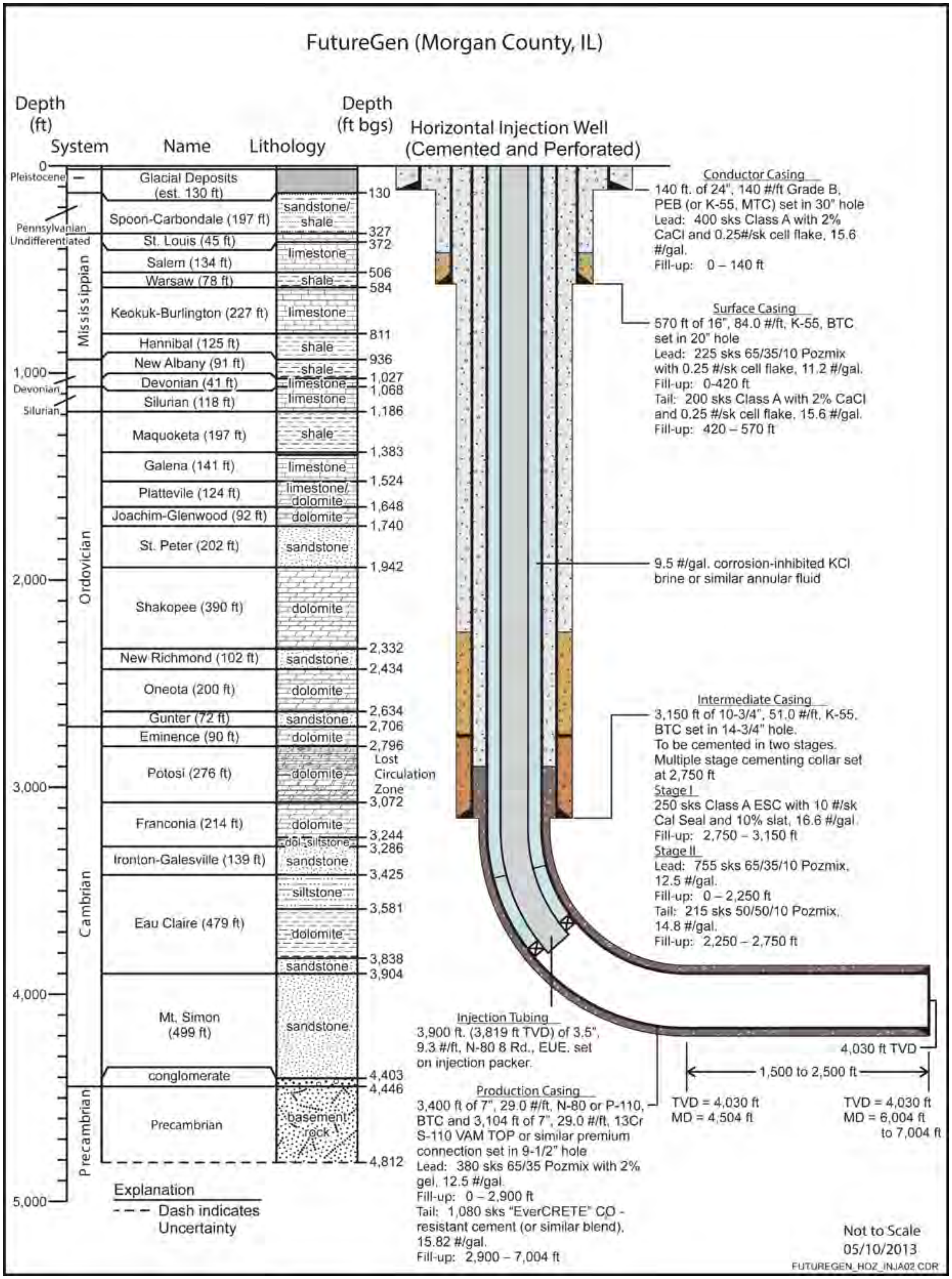

Figure 4.4. Injection Well Schematic – Cased-Hole Completion (geology and depths shown in this diagram are based on site-specific characterization data obtained from the FutureGen 2.0 stratigraphic well)

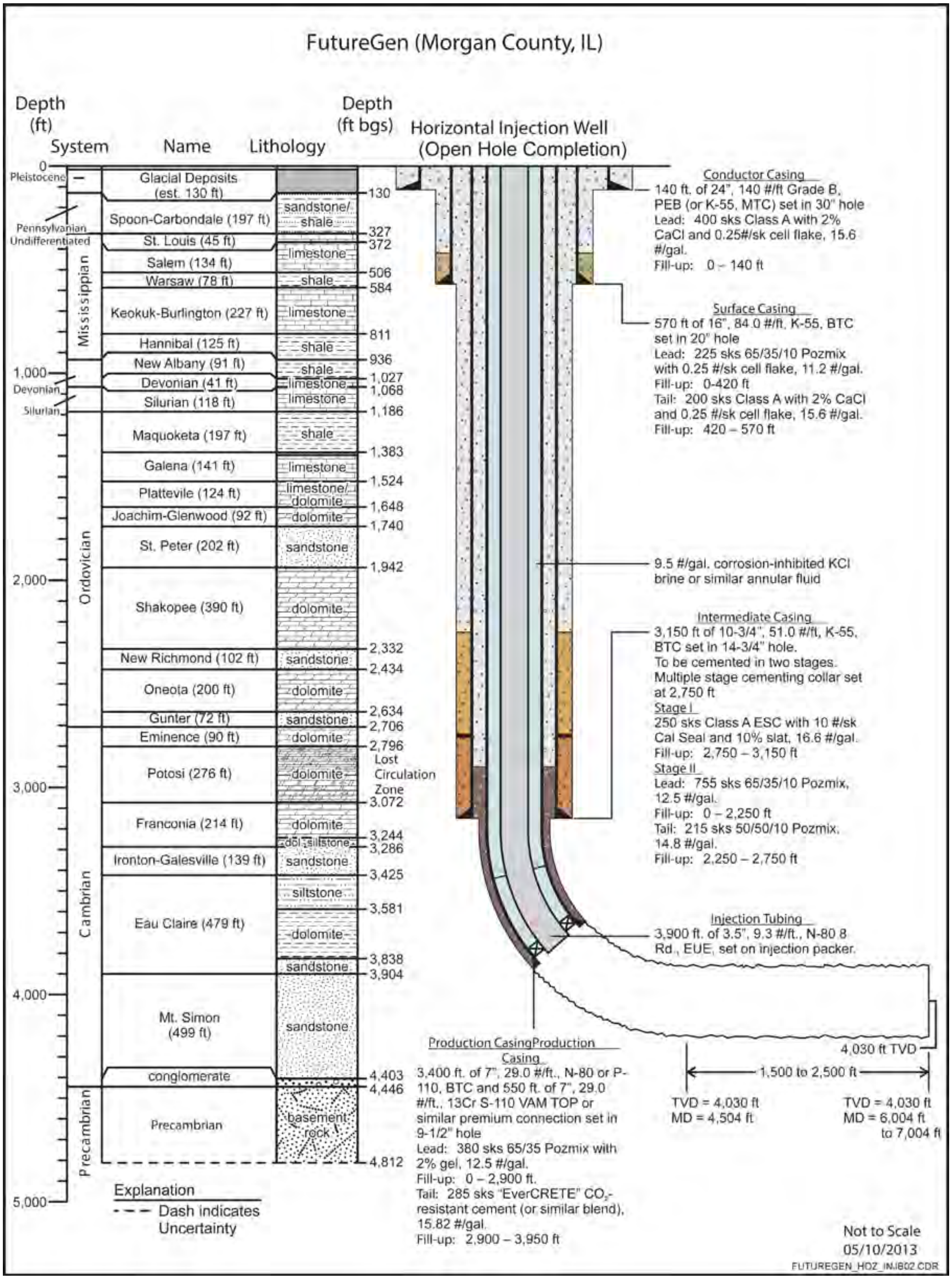

Figure 4.5. Injection Well Schematic – Open-Hole Completion (geology and depths shown in this diagram are based on site-specific characterization data obtained from the FutureGen 2.0 stratigraphic well)

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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