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INJECTION WELL Construction
40 CFR 146.82(a)(9), (11), and (12)

Hoosier #1 Project

Facility Information

Project Name:	Hoosier #1
Facility Name:	Cardinal Ethanol
Facility Contact:	Jeremey Herlyn, Project Manager Cardinal Ethanol
Well Location:	1554 N. 600 E. Union City, IN 47390 CO_2 Injection Well Location for Cardinal CCS1 Latitude 40.186587° Longitude -84.864284°
Operator Name:	One Carbon Partnership, LP 1554 N. 600 E. Union City, IN 47390

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List of Acronyms

API	American Petroleum Institute
APT	Annulus Pressure Test
BGS	Below Ground Surface
BHP	Bottomhole Pressure
BOPs	Blow Out Preventers
CBL	Cement Bond Log
CCS	Carbon Capture and Sequestration
CCS1	Proposed Injection Well
DST	Drill Stem Test
EOR	Enhanced Oil Recovery
FOT	Fall-off Test
HCl	Hydrochloric
HF	Hydrofluoric
IAC	Indiana Administrative Code
KCl	Potassium chloride
LTC	Long Thread Coupling
MAIP	Maximum Allowable Injection Pressure
Mtpa	million tonnes per annum
OBS1	Deep Observation Well
POOH	Pulled out of Hole
ppg	pounds per gallon
SCADA	Supervisory control and data acquisition
SDS	Safety Data Sheet
STC	Short Thread Coupling
TD	Total Depth
USDW	Underground Source of Drinking Water
US EPA	United States Environmental Protection Agency
WBM	Water Based Mud

Well Construction Plan Change Log				
Item Changed	Date	Version	Initials	Description
Page 5	02/11/2022	1.0	MLC	Added information about the downhole pressure and temperature sensors
schematic	28/10/2022	1.0	RAE	Added pressure and temperature gauges, densitometer, and flowmeter to the wellhead schematic

1 Injection Well Construction

This section summarizes the methods and materials to be used for the construction of the Cardinal proposed Injection Well (CCS1). Schematics of the well that illustrates the construction, are provided within the contents of this document. Please note that these schematics are not meant to portray final products and are subject to change pending availability of materials listed and the completion of well installation. The work will be performed in accordance with guidance documents, approved work plans, and reporting timelines as approved by the US EPA. CCS1 will be constructed with multiple casing strings, each string smaller in diameter than the previous and cemented to surface to provide multiple layers of protection for Underground Sources of Drinking Water (USDWs).

The injection well proposed in this document will be constructed as a new well. The injection well will be drilled into the Precambrian Granite Basement (basement) with enough hole present such that the basement rock can be properly characterized. It is noted that, while CCS1 is currently planned to be the well that penetrates basement, the deep observation well (OBS1) will potentially serve to collect the basement characterization data. Should OBS1 be used to characterize the basement, CCS1 will not penetrate the basement.

Once the basement characterization data has been collected, whether in CCS1 or OBS1, the open basement section will be plugged back to the injection zone such that the CO_2 will not be directly injected into the basement. This will be done prior to running and cementing the long string casing in place.

Figure 1 displays a schematic of the proposed well construction for CCS1. Figure 2 displays a schematic of the proposed wellhead for CCS1.

Downhole pressure and temperature gauges will be installed [redacted] The downhole pressure gauge will be used to help ensure that the maximum allowable bottomhole pressure (BHP) does not exceed 90% of the fracture pressure (40 CFR 146.88 [a]). The downhole temperature gauge will used to calculate the bottomhole density and volume of the injected fluid. The BHP gauges will be programed to take data at the intervals outlined in the testing and monitoring program section of this application (Attachment 7: Testing And Monitoring, 2022). The data collected from these measurement systems will be collected continuously and sent to a surface SCADA system. More information about these sensors is provided in the Well Operations and Testing and Monitoring Plans (Attachment 6: Well Operations, 2022; Attachment 7: Testing And Monitoring, 2022).

The Mt. Simon Sandstone, the targeted storage formation for the project, is a thick sandstone. The Eau Claire Shale is approximately 500 ft thick and serves as the primary confining layer for the project. The contact of the Eau Claire Siltstone with the Mt. Simon Sandstone is transitional with the base of the Eau Claire Formation being a glauconitic siltstone and very fine-grained sandstone known as the Eau Claire Siltstone. The Eau Claire Siltstone could serve as a secondary storage as CO_2 migrates upwards due to density effects; however, there is no plan to inject directly into the Eau Claire Siltstone.

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[redacted]

Figure 1. Proposed Injection Well Construction Schematic

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[redacted]

Figure 2. Proposed Injection Wellhead Schematic for CCS1

1.1 Hole Sections and Cement Information

Table 1 provides a summary of the openhole sections of the CCS1 injection well construction. All depths provided in the table are in reference to below ground surface (BGS).

Table 1. Open Hole Section Diameters and Intervals

Section Name	Depth (feet)	Open hole Diameter (inches)	Comment
Surface	[redacted]	[redacted]	[redacted]
Longstring[1]	[redacted]	[redacted]	[redacted]

[redacted]

Table 2 provides a summary of the casing strings to be used in construction of the injection well. All casing (weight, grade, and threading) to be used will conform with American Petroleum Institute (API) standards. The casing and cementing plans are designed to ensure the injected carbon dioxide (CO_2) stays within the Mt. Simon Sandstone and prevents upward migration of injection zone fluids from reaching the deepest USDW.

Table 2. Casing String Setting Depths, Diameters, and Specifications

Casing String	Casing Depth (feet)	External Diameter (inches)	Casing Material (weight, grade, thread)
Surface	[redacted]	[redacted]	[redacted]
Longstring (Carbon)	[redacted]	[redacted]	[redacted]
Longstring (Chrome)	[redacted]	[redacted]	[redacted]

Table 3 provides a summary of the cement systems for use on the casing strings during the injection well construction. All cement systems used will conform with API standards. Cement will be pumped with the following excess:

- Surface – 100% excess
- Longstring – 30% excess

Note that the excess cement pumped is subject to change pending field results.

EverCRETE* CO_2 resistant cement system is highly resistant to the CO_2 stream and formation fluids in the Mt. Simon Sandstone (Schlumberger, 2021). The cement will be of sufficient quality and quantity to maintain integrity over the design life of the CCS1 injection well. Should EverCRETE be unavailable, a suitable replacement will be used.

*Mark of Schlumberger

Table 3. Cement System Details for Each Hole Section

Casing String	Sacks of Cement	Yield (cu-ft/ sack)	Weight (lbs./ gal)	Cement Class	Additives
Surface	Sensitive, Confidential, or Privileged Information [redacted]				
Longstring (Carbon)	[redacted]				
Longstring (Chrome)	[redacted]				

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The surface casing cement system will provide the required isolation of the deepest USDW. The deepest USDW is currently anticipated to be in the Maquoketa Formation as defined by the State of Indiana (Attachment 1: Project Narrative, 2022). The surface casing and cement will isolate the deepest USDW from the CO_2 injected into the Mt. Simon Sandstone. The cement and cement system used will conform with API standards.

The quality of the bond between the cement, casing, and borehole will be verified by the cased hole logs that will be run after each string of casing is cemented in place (Attachment 5: Pre-Op Testing Program, 2022). The long string lead cement system used will conform with API standards. The tail cement system, in addition to standard Portland cement, will be EverCRETE (or equivalent).

As with the surface cement section, the quality of the bond between the cement, casing, and borehole will be verified using cased hole logs (Attachment 5: Pre-Op Testing Program, 2022). These cased hole logs include: CBL with radial arms, Ultrasonic Cement Evaluation, Temperature, and Pulsed Neutron. Table 4 provides a summary of the tubing and packer system to be used in the construction of CCS1.

Sensitive, Confidential, or Privileged Information [redacted]

Table 4. Tubing and Packer Setting Depth, Diameters, and Specifications

Equipment	Setting Depth (feet)	External Diameter (inches)	Tubing Material
Tubing	Sensitive, Confidential, or Privileged Information [redacted]		
Packer	[redacted]		

Sensitive, Confidential, or Privileged Information [redacted] Material specifications and suitability for use documentation is provided in this document (Tuboscope - NOV Wellbore Technologies, 2017).

The Signature F™ Injection packer system from Baker Hughes will be used for this project. The packer can be used with either a retrievable or permanent configuration and will be internally and externally coated with chrome and nickel to resist corrosion effects of the CO_2 stream. The Baker Hughes engineers confirmed that the chrome/nickel plating is suitable for the required service. Materials specifications and suitability for use document is provided in this document (Baker Hughes, a GE Company, 2019).

1.2 Construction Procedures [40 CFR 146.82(a)(12)]

This section details the procedures that will be followed during the drilling, completion, and testing portions of the CCS1 installation. Note that these procedures are subject to change based upon field conditions and/or the availability of equipment/materials. An updated and detailed procedure will be provided prior to well construction.

1.2.1 Drilling Procedures

1. A [redacted] bit will be used to drill [redacted] for the conductor casing.
    a. The [redacted] will be used to drill until bedrock is encountered.
2. [redacted] conductor casing will then be run to the section TD. The casing will be cemented to surface using [redacted] cement.
    a. A [redacted] rat hole will be utilized.
3. A [redacted] bit will be used to drill [redacted]. Sufficient rat hole should be drilled such that open hole and cased hole logs can be run to assess the entire lowermost USDW.
    a. The drilling mud in this section of the hole will be WBM.
4. At the section TD, the hole will be circulated clean, and the drill string will be POOH.
5. Open hole logs will be run across the open hole interval (conductor casing shoe to the section TD).
    a. Log run details are provided in Section 4.
    b. Cement volumes for this hole section will be determined based on the results of the caliper log.
6. [redacted] surface casing will then be run to the section TD.
    a. The casing will be run as follows (bottom to top):
        i. Float shoe
        ii. One joint of casing
        iii. Float collar
        iv. Casing to surface
    b. One centralizer will be used every third joint to surface
7. The [redacted] casing will be cemented [redacted].
    a. Wet samples will be collected during mixing.
    b. After pumping all cement, a plug will be dropped, and the cased hole volume will be displaced with water.
8. After allowing cement to harden approximately 24 hours, cased hole logs will be run to assess the overall bond quality of the cement.
    a. Details on the logs that will be run are provided in Section 4.
9. Once the bond is of sufficient quality, NU blow out preventers (BOPs) and test per API Standard 53.

10. Once the BOPs have been nippled up and tested, the casing will be tested to at least twenty percent (20%) greater than the anticipated maximum pressure to which the casing will be exposed for a minimum of thirty (30) minutes with a pressure drop of no more than ten percent (10%) (312 Indiana Administrative Code [IAC] 29-20-3 (b)(2)(B)).
    a. The pressure to be used for testing will be provided as part of the final installation procedures to be made available prior to the installation of the well.
11. An [redacted] bit will be used to drill the long string section. [redacted]
    a. The drilling mud in this section of the hole will be WBM.
    b. While drilling this section, the drilling assembly will be run out of the hole [redacted] in the Eau Claire Formation and Mt. Simon Sandstone.
        i. Core may also be taken while drilling OBS1.
12. At the section TD, the hole will be circulated clean, and the drilling string will be pulled out of hole.
13. Open hole logs will be run across the open hole interval (surface casing shoe to the section TD).
    a. Details on the logs that will be run are provided in (Attachment 5: Pre-Op Testing Program, 2022)
    b. Cement volumes for this hole section will be determined based on the results of the caliper log.
14. A drill stem test (DST) tool will be run into the Mt. Simon Sandstone to collect a fluid sample for analysis.
    a. If a DST is not run at this time, the well will be swabbed to collect a representative fluid sample during the well completion operations.
15. [redacted] Longstring casing will be run [redacted].
    a. The casing will be run as follows (bottom to top):
        i. Float shoe ([redacted])
        ii. Two joints of casing ([redacted])
        iii. Float collar ([redacted])
        iv. [redacted] casing to the top of the Eau Claire Formation
        v. [redacted] casing to surface
    b. One centralizer per joint will be utilized for the [redacted] casing. One centralizer every third joint will be utilized for the [redacted] casing.
16. The [redacted] casing will be cemented using a system that uses EverCRETE as a tail cement ([redacted]), and [redacted] cement ([redacted]).
    a. The top of the tail cement is targeted to be above the top of the Eau Claire Formation.
    b. Wet samples will be collected during mixing.
    c. After pumping the cement, a plug will be dropped, and the cased hole will be displaced with water.
17. After the cement has been allowed to harden for at least 24 hours, the casing will be tested to at least twenty percent (20%) greater than the anticipated maximum pressure to which the casing will be exposed for a minimum of thirty (30) minutes with a pressure drop of no more than ten percent (10%) (312 IAC 29-20-3 (b)(2)(B)).

   a. The pressure to be used for testing will be provided as part of the final installation procedures to be made available prior to the installation of the well.

18. The drilling rig will be disassembled. The BOPs will also be nippled down and a Night Cap will be installed.

The subsurface and surface design (casing, cement, and wellhead) exceeds the minimum requirements to sustain the integrity of the confining interval to ensure that the CO_2 remains in the Mt. Simon Sandstone. The final well design meets strength and CO_2 compatibility requirements. This procedure concludes the drilling portion of the well installation.

1.2.2 Well Deviation Survey Plan

The wellbore trajectory will be surveyed every 500 feet of depth to ensure the well has less than 5° inclination. These surveys will be performed using a wireline conveyed, timer-based survey tool. The following presents the survey plan and tolerances:

- If the wellbore trajectory is more than 1° inclination, then the wellbore trajectory will be surveyed every 250 feet of depth.
- If the wellbore trajectory is 2° or more inclination, then the wellbore trajectory will be surveyed every 100 feet.
- This will be repeated until the wellbore is within 1° of inclination.

1.2.3 Completion Procedures

The completion portion of the well installation is detailed below. Note that these procedures are subject to change as based on field conditions or the availability of equipment or materials. A detailed procedure will be provided prior to the installation of the well.

19. A workover rig will be installed, and BOPs will be nippled up. The BOPs will be tested per API Standard 53.
20. Cased hole logs will be run to assess the overall bond quality of the cement.
    b. Details on the logs that will be run are provided in (Attachment 5: Pre-Op Testing Program, 2022).
        i. These logs may or may not be run prior to the workover rig being on location.
        ii. Two runs will likely be performed, 1) under anticipated operation pressure, 2) under no pressure
21. The Mt. Simon sandstone will be perforated in select intervals.
    [redacted]
22. Following the perforations, acid will be bullheaded into the well to clean up the perforations.
    e. Should the well need to be swabbed for a fluid sample, it would be done at this time.
23. The [redacted] packer assembly will be run in on work string as follows
    f. Blow-out disk ([redacted])
    g. 1 joint [redacted]
    h. [redacted] packer
    i. Stinger On/Off tool

   j. Work string
24. Once the packer has been set, the work string will be stung off the packer and run out of hole.
25. The [redacted] injection tubing will be run in the hole as follows:
   k. On/Off tool
   l. Crossover
   m. [redacted] tubing to surface
   n. Crossover
   o. Landing joint
26. Once the injection tubing has been latched onto the packer, the BOPs will be closed, and a preliminary annulus pressure test (APT) will be performed.
   p. The APT will be run as detailed in (Attachment 5: Pre-Op Testing Program, 2022).
27. After the APT has been successfully completed, the [redacted] tubing will be stung off the packer and the annulus will be displaced with the treated annulus fluid.
   q. This treated annulus fluid will be comprised of one, or more, of the following:
      i. Fresh water
      ii. Packer fluid
      iii. Inhibiters
      iv. Biocide
      v. Scale reducer
28. Once this annulus fluid has been pumped, the [redacted] tubing will be stung onto the packer, and the tubing will be landed in the tubing hanger.
29. After the tubing hanger is landed, a final APT will be run.
30. The BOPs will be nippled down, and the wellhead will be installed.
31. Following the installation of the wellhead.
32. The workover rig will be rigged down, and the well installation will be considered complete.

1.2.4 Testing Procedure

The testing portion of the well installation is detailed below. Note that these procedures are subject to change as based on field conditions or the availability of equipment or materials. A detailed procedure will be provided prior to the installation of the well. These procedures are consistent with those provided in Section 4. Testing will use the permanent downhole pressure gauges.

1. Rig up pump truck and the associated auxiliary equipment. Ensure proper fluid is on location for injection testing.
2. Pressure test pump truck equipment.
3. Blow out the burst disk.
4. Run step-rate test as detailed in (Attachment 5: Pre-Op Testing Program, 2022).
5. Run FOT test as detailed in (Attachment 5: Pre-Op Testing Program, 2022).
6. Rig-down pump truck.
7. Secure the well.

1.2.5 Casing and Cementing

Design analysis was performed to evaluate the casing selection. This analysis included reviewing the burst, collapse, tensile loads, and a Von Mises analysis, using Lame's equations, that were anticipated to be experienced as a part of the casing installation and normal well operation. Prior to performing any analyses on design criteria, an 80% derating factor was applied to the pipe ratings. This 80% derating equates to a base 1.2 safety factor.

The equation to determine the safety factor is provided below,

$$SF = \frac{Pipe\ Rating}{Load}$$

In addition to this derating, additional, standard derating was performed. The yield strength of the pipe was derated based on applied tensile loading, this consisted of a biaxial analysis. This is consistent with the method presented in API Bulletin 5C3, Formulas and Calculations for Casing, Tubing, Drill pipe and Line Pipe Properties (American Petroleum Institute, 1994). Cyclical loading was considered in the analysis performed by Baker (Baker Hughes InQuest TUBEMOVE, 2022).

This derating is only considered when evaluating collapse parameters under tension. Compressive analysis was not performed on the casing strings, as they are not anticipated to undergo any major compressive loads except for when being run in-hole.

Standard API equations were used to calculate all design ratings and loads.

The safety factors utilized for analysis are provided in Table 5.

Table 5. Casing Safety Factors for Design.

Burst	Collapse	Tensile	Von Mises
Sensitive, Confidential, or Privileged Information [redacted]			

The results of the analyses are provided in Table 6.

Table 6. Casing Safety Factor Loads for Design.

String	Burst	Collapse	Tensile*	Von Mises*
Surface	Sensitive, Confidential, or Privileged Information [redacted]			
Intermediate (Contingency)	[redacted]			
Long String	[redacted]			
Injection Tubing	[redacted]			

The down-hole temperature of the Mt. Simon sandstone is estimated to be approximately 100 °F. The temperature of the CO_2 injection stream will be approximately 130 °F. An approximately 30 °F temperature differential is expected. It is not anticipated that this temperature differential is of a large enough magnitude to impact the performance of the casing and cement over the life of the project.

Table 7. Casing and Tubing details

Casing String	Casing Depth	Borehole Diameter	Wall Thickness	External Diameter	Casing Material	String Weight
Surface	Sensitive, Confidential, or Privileged Information [redacted]					
Long String						
Long String (Chrome)						
Injection Tubing						
Intermediate (Contingency)						

Table 8. Casing and Tubing Design Parameters

Material	Setting Depth (feet)	Tensile Strength	80% of Tensile Strength	Burst Strength	80% of Burst Strength	Collapse Strength	80% of Collapse Strength	Material of Construction
Surface Casing	Sensitive, Confidential, or Privileged Information [redacted]							
Long Strong Casing								
Injection Tubing								
Intermediate (contingency)								
Baker Signature F								

1.3 Additional Design Considerations – 40 CFR 146.86 (c)

Table 6 provides discussion on the design ratings for the injection tubing and packer. This section discusses the application of these design ratings to ensure the suitability of the construction materials for this project.

A safety factor of 20% has been used to evaluate the materials of construction. As such, all ratings have been derated to 80% of their initial ratings. All comparative evaluations detailed in this section are in reference to these derated values.

The packer (Baker Signature F) to be used has a differential rating of 80,000 psi.

It is noted that the project anticipates continuously injecting at a rate up to, but not exceeding, 450,000 Mtpa. As such, the well and analysis of well conditions have been performed based on this consideration.

1.3.1 Injection Pressure Considerations

[redacted]

Table 9. Bottomhole Pressure Considerations.

Parameter	Value
Depth to Mt. Simon sandstone (ft)	[redacted]
Fracture Gradient (psi/ft)	
Formation Fracture Pressure (psi)	
Safety Factor	
Fracture Gradient with Safety Factor (psi/ft)	
Predicted Bottomhole Pressure (BHP)(psi)	

[redacted]

The maximum allowable bottomhole injection pressure is approximately 3.0% of the differential rating for the packer. This assumes the annulus space is evacuated, which is an extremely improbable event.

Based on these worst-case analyses, the tubing and packer to be used for this project are acceptable.

1.3.2 Annulus Pressure Considerations

The proposed operating annular pressure range at surface is between 500 and -15 psi. Based on this range, the maximum proposed annular pressure downhole will be calculated based on the hydrostatic pressure of a [redacted] brine (with additives) at the packer added to the maximum anticipated annular pressure.

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[redacted]

The packer is sufficiently designed such that the worst-case scenario occurs at a pressure that is 2.5% of the rated pressure differential.

During operations, this worst-case scenario of an evacuated portion of the well is extremely improbable.

1.3.3 Formation Pressure Considerations (During initial completions)

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[redacted]

The injection tubing is sufficiently designed such that the worst-case scenario during the initial completion is 29.3% of the derated collapse rating of the pipe.

1.3.4 Tensile Loading Considerations

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[redacted]

1.3.5 Cyclic Loading Considerations

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[redacted]

1.3.6 Corrosion Considerations

All components selected for construction will use corrosion resistant materials. Verification of the suitability for these components is provided with this document and referenced in previous sections and subsections.

Refer to the corrosion monitoring in testing and monitoring plan for corrosion monitoring of the materials of construction (Attachment 7: Testing And Monitoring, 2022). In addition, regular sampling and monitoring of the CO_2 stream will be performed, as detailed in the testing and monitoring plan.

Details and specifications of the corrosivity of the CO_2 and projected chemical content, temperature and density have been provided within the well operations and testing and monitoring sections of this permit application.

1.3.7 Operational Considerations

Emergency shut-down equipment will be used for this project. Details on this equipment are provided in the well operation section as well as the testing and monitoring section (Attachment 6: Well Operations, 2022), (Attachment 7: Testing And Monitoring, 2022).

Surface monitoring equipment, as detailed in the testing and monitoring section, will be connected to the surface SCADA system.

Permanent downhole gauges used to monitor pressure and temperature at the packer will be utilized for this project. These gauges will be landed in a gauge nipple above the packer. These gauges will transmit data through a wire, run up the annulus, to the SCADA system.

Tubulars have been designed such that logging tools and other equipment needed for routine and annual monitoring will be able to pass through with no restrictions.

1.4 Contingency plan for Intermediate string.

In the event that a lost circulation zone is encountered in the Potosi Formation, the drill string will be pulled out of the well and the following procedure will be incorporated.

1. A [redacted] bit will be used to ream [redacted] below the lost circulation zone. Sufficient rat hole will be drilled such that open hole and cased hole logs can be run to assess the entire intermediate section of the well.
    a. The drilling mud in this section of the hole will be water-based mud (WBM).
2. At the section TD, the hole will be circulated clean, and the drill string will be pulled out of hole.
3. Open hole logs will be run across the open hole interval (surface casing shoe to the section TD).
    a. Details on the logs that will be run are provided in Section 4.
    b. Cement volumes for this hole section will be determined based on the results of the caliper log.
4. [redacted] intermediate casing will then be run to the section TD.
    a. The casing will be run as follows (bottom to top):
        i. Float shoe
        ii. One joint of casing
        iii. Float collar
        iv. Casing to surface
    b. One centralizer will be used per joint to surface
5. The [redacted] casing will be cemented [redacted].
    a. Wet samples will be collected during mixing.
    b. After pumping all cement, a plug will be dropped, and the cased hole volume will be displaced with water.
6. After allowing cement to harden for approximately 24 hours, cased hole logs will be run to assess the overall bond quality of the cement.
    a. Details on the logs that will be run are provided in Section 4.
7. Once the bond is of sufficient quality, blow out preventers (BOPs) will be nippled up and tested per API Standard 53.
    a. BOPs will already be installed prior to reaming up the hole section. BOPs might need to be changed out and retested to accommodate the [redacted] casing string.
8. After the cement has been allowed to harden for at least 24 hours, the casing will be tested to at least twenty percent (20%) greater than the anticipated maximum pressure to which the casing will be exposed for a minimum of thirty (30) minutes with a pressure drop of no more than ten percent (10%) (312 IAC 29-20-3 (b)(2)(B)).
9. Once the intermediate string has been set, an [redacted] bit will be used to drill the long string section. [redacted].

Table 10. Contingency Plan for Intermediate Hole Section Diameter and Interval

Section Name	Depth (feet)	Open Hole Diameter (inches)	Comment
Intermediate	[redacted]		

Table 11. Contingency Plan for Intermediate Casing Depth, Diameters, and Specifications

Casing String	Casing Depth (feet)	External Diameter (inches)	Casing Material (weight, grade, thread)
Intermediate	[redacted]		

Table 12. Contingency Plan for Intermediate and Long String Cement Systems

Casing String	Sacks of Cement	Yield (cu-ft/ sack)	Weight (lbs./ gal)	Cement Class	Additives
Intermediate	[redacted]				
Longstring (Carbon)					
Longstring (Chrome)					

Sensitive, Confidential, or Privileged Information [redacted]

Refer to step #12 of the Construction Procedure for the drilling of the long string section of the injection well.

Figure 3 displays a schematic of the proposed contingency well construction for CCS1. Figure 4 displays a schematic of the proposed contingency wellhead for CCS1.

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[redacted]

Figure 3. Proposed Contingency Well Construction Schematic

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[redacted]

Figure 4. Proposed Contingency Wellhead Schematic

2 Proposed Stimulation Program [40 CFR 146.82(a)(9)]

Based on analysis and results of the Class I, AK Steel and BP Lima wells in Ohio, it is unlikely that any well stimulation, such as hydraulic fracturing, will be required upon initial completion of the injection well. If there appears to be significant reduction in actual permeability and porosity compared to the analyzed core data and information gathered during the fluid injection test, then a stimulation program may be considered.

Routine well or formation remediation might be necessary to reduce lost injectivity due to routine injection operations. Lost injection capacity may be due to geochemical reactions, scale build-up, or pore throat plugging amongst other things.

Should injection capacity be diminished enough to impact the effectiveness of the well, chemical or mechanical remediation may be required. Such remediation may occur using one, or more of the following methods:

- Bullhead acid stimulation – an acid such as hydrochloric (HCl) acid will be used in a dilute concentration (i.e., 7.5%-15%) with other potential additives (citric acid, scale reducer, defoamer, etc.).
    - Acid will be pumped down the injection string and be allowed to soak in the near wellbore area before being pushed into formation or flushed back up to surface.
- Bullhead acid stimulation with mud acid – HCl and hydrofluoric (HF) acid mix will be used with potential additives.
- Coil tubing acid stimulation – HCl will be used with potential additives.
    - Coil tubing will be used to nitrify and place the acid over specific intervals. Acid will be allowed to soak and will be pushed into the formation or flushed back up to surface.
- Coil tubing acid stimulation with mud acid – HCl and HF acid mix will be used with potential additives.
- Coil tubing chemical treatment – should certain precipitates require treatment using fluids other than acid, targeted chemical remediation will be performed.
- Coil tubing clean out – mechanical cleaning of scale and buildup from the cased hole interval
    - Samples of this scale/buildup may be taken to design effective treatment strategies
- Reperforating

Note that this list is not intended to be an exhaustive list of potential treatment methods, chemical treatments, or chemical additives.

If it is determined that stimulation is needed to increase permeability of the injection zone, then a proposed stimulation procedure will be submitted in writing to the Director at least 30 days in advance. This proposal will have a description of the treatment, chemicals to be used, and procedures to be followed. A safety data sheet will be provided for all chemicals used during stimulation activities.

All chemical treatments will be performed at working pressures less than the determined fracture pressure of the formation unless otherwise specified. The safe working pressure will be determined using hydrostatic pressure calculations, equipment ratings, materials of construction, and other pertinent details. Details on such calculations will be provided in the notification of stimulation activities.

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

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

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

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

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