CONSTRUCTION DETAILS
40 CFR 146.86

Facility Information

Facility Name: Pelican Renewables, LLC
Well Names: Rindge Tract CCS Well #1
Rindge Tract CCS Well #2

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Well Locations: Rindge Tract Island, San Joaquin County, California
38.021507, -121.428926 (Well #1)
38.014567, -121.415405 (Well #2)

Introduction

The construction details for the injection wells are described herein. Pelican Renewables, LLC (Pelican) proposes constructing two new injection wells for the permanent sequestration of supercritical carbon dioxide (CO_2), Rindge Tract CCS Well #1 and Rindge Tract CCS Well #2. Pelican will ensure that the injection wells are constructed and completed to prevent the movement of fluids into or between USDWs or unauthorized zones. Also, the wells' construction will allow the use of appropriate testing devices and workover tools and continuous monitoring of the annulus space between the injection tubing and the long string casing.

After the construction of the drilling pads, a conductor casing will be driven to the specified depth. The vertical wells will be drilled and completed with surface casing and long string-cased hole to total depths of approximately 6946 ft. (Well #1) and 6880 ft. (Well #2). Surface and long string casings will be cemented. Long string casings will be completed with CO_2-resistant cement from total depth through the confining zone. Conceptual well construction diagrams are provided in **Figures 5-1** and **5-2**. Actual depths will depend on site-specific characterization data obtained when drilling the injection wells.

Formation lithology and relative depths are described in Section 2 – Site Characterization. Using a temperature gradient of 14°F per 1000 ft., the bottom hole temperature at 6946 ft. is approximately 169°F and at 6880 ft. is approximately 168°F. The following subsections include information on construction procedures, casing cementing specifications, tubing and packer program, annulus fluid, and wellhead.

Injection Well Construction Details

Construction Procedures

During drilling and completion operations, all activities are conducted in compliance with the U.S. Environmental Protection Agency (EPA) as listed in the Class VI Rule 40 CFR 146.86. Drilling fluids will be maintained during all drilling stages to; control bottom hole pressures, support the wellbore and maintain stability, prevent formation influx and seal permeable formations, circulate cuttings away from the drilling bit to the surface, mitigate drilling damage to the targeted reservoir, and to cool the drilling bit and work string. Maintaining proper drilling fluids is important to prevent the movement of fluids into or between USDWs. Mud samples will be analyzed throughout drilling to ensure downhole pressure control. Well control will be maintained at all times through the use and frequent testing of blowout preventers. Care will be taken to prevent or minimize the discharge or spillage of construction-related fluids and debris. All personnel will be trained in proper emergency response, and a response plan will be maintained onsite. All drilling and completion activities will be annotated on daily drilling reports.

The following general construction procedures will be used in construction and completion of the injection wells. Section 6 - Pre-Operational Logging and Testing contains information on deviation surveys, formation samples, logs and tests to be conducted during drilling and before the operation of the injection well.

Prepare the location. Survey the well pads; provide notification of subsurface work to local underground utility location authority; conduct earthwork grading to level the location and construction well pad mats; drive conductor casing; excavate and board cellar; lay down containment where rig substructure will be placed.

Mobilize in and rig up. Set rig substructure and rig appurtenances; raise derrick and install remaining equipment; mix spud fluids; make ready to drill surface hole.

Drill and complete surface hole. Commence drilling a surface hole from surface to casing set depth; conduct deviation (1 degree or less) surveys; conduct logging; run casing with centralizers; cement casing with approximately 25% excess; wait on cement; run cement bond log.

Drill and complete production hole. Drill out float shoe; drill to core point; conduct straight hole surveys; run core barrels and bit to core confining interval; drill to core point; conduct straight hole surveys; run core barrels and bit to core injection interval; drill to total depth; condition hole; conduct logging; run casing with centralizers and strapped fiber optic monitoring system; cement casing with approximately 25% excess; wait on cement; pressure test casing; run cement bond log.

Run tubing and packer. Run tubing with packer; set packer; displace annular fluids with treated fresh water; set the liner hanger packer; pack off tubing in the surface head; top off annulus with treated fresh water; pressure test annulus.

Rig down and demobilize. Rig down; off-rent equipment; demobilize; restore location.

Pre-operational testing. Set wellhead; pressure test of wellhead; conduct reservoir testing; test fiber optic monitoring system.

Proposed pilot hole depths and diameters are referenced in **Table 5-1**.

Table 5-1. Open Hole Diameters and Intervals

Name	**Depth Interval** (feet)	**Open Hole Diameter** (inches)	**Comment**
Rindge Tract CCS Well #1			
Conductor	80	N/A	Drilled to bedrock
Surface	600	17½	Drilled to the primary seal
Intermediate	N/A	N/A	N/A
Long-string	5396	12¼	Drilled to tubing seal assembly (stabbed into seal bore packer)
Rindge Tract CCS Well #2			
Conductor	80	N/A	Drilled to bedrock
Surface	600	17½	Drilled to the primary seal
Intermediate	N/A	N/A	N/A
Long-string	5330	12¼	Drilled to tubing seal assembly (stabbed into seal bore packer)

The operational injection schedule is presented in **Table 5-2**.

Table 5-2. Injection Schedule

Years	**Injection Interval** (Cretaceous Sand Identifier)	**Volume** (metric tons per year)
Rindge Tract CCS Well #1		
20	Mokelumne River Formation	1,250,000
Rindge Tract CCS Well #2		
20	Mokelumne River Formation	750,000

Casing and Cementing

As specified in 40 CFR 146.86(b), casing and cement or other materials used in the construction of the injection well will have sufficient structural strength and be designed for the life of the geologic sequestration project. All well materials, including casing, cement, tubing and packer will be compatible with fluids with which the materials may be expected to come into contact and will meet or exceed standards developed for such materials by the American Petroleum Institute (API), ASTM International or comparable standards. The casing and cementing program is designed to prevent movement of fluids into or between USDWs as summarized in **Table 5-3**.

Table 5-3. Casing Program

Casing (1)	**Depth Interval** (feet)	**Outside Diameter** (inches)	**Inside/Drift Diameter** (inches)	**Weight** (lbs/ft)	**Grade** (API)	**Design Coupling**	**Burst Strength** (psi)	**Collapse Strength** (psi)
Conductor	0 - 80	24	UNK	N/A	N/A	N/A	N/A	N/A
Surface	0 - 600	13.375	12.615	68	J-55	STC	3,450	1,950
Rindge Tract CCS Well #1								
Long-string	0 - 5494	8.625	7.921	43.5	HCL-80	LTC	6,330	3,810
Rindge Tract CCS Well #2								
Long-string	0-5428	8.625	7.921	43.5	HCL-80	LTC	6,330	3,810

(1) Conceptual casing program may be revised based on products available at the time of completion

Casing centralizers will be used on the surface and long string casings to ensure sufficient cement bond to the borehole and casing. Float shoes will be run on the lowermost joint of the surface and long string casing strings. Surface casing will extend through the base of the USDW and will be cemented to the surface. One long string casing, using a sufficient number of centralizers, will extend into the injection zone and will be completed with conduits which allow for flow into the appropriate sand zone.

Cementing will occur in stages so that CO_2 resistant latex is uniformly placed from total depth through the confining zone. If cement returns are not observed at the surface remedial cementing techniques will be used to ensure sufficient bond. Cement and cement additives will be compatible with the carbon dioxide stream and formation fluids from total depth through the confining zone and of sufficient quality and quantity to maintain integrity over the design life of the geologic sequestration project. The integrity and location of the cement will be verified using cement bond logs and/or casing inspection logs capable of evaluating cement quality radially and identifying the location of channels to ensure that USDWs are not endangered. The conceptual cementing program is summarized in **Table 5-4**.

Table 5-4. Cementing Program

Casing	**Casing Depth Interval** (feet)	**Borehole Diameter** (inches)	**Casing Outside Diameter** (inches)	**Cement Interval** (feet)	**Cement** (1)(2)
Conductor	0 - 100	24	24	N/A (3)	N/A (3)
Surface	0 - 250	17½	13⅜	0 - 250	1130 sacks Light cement (Class A, 12.80#, 1.85 cf/sk, 9.77 gal water/sk) premixed 1 #/sk pheno seal medium (lost circulation additive), 3% NaCl, followed with 470 sacks Standard cement (Class A, 15.6#, 1.18 cf/sk, 5.25 gal water/sk); If necessary, perform 80 sacks top job cement premixed 3% CaCl2 (top job will be performed if cement level drops in the annulus)
Intermediate	N/A	N/A	N/A	N/A	N/A
Rindge Tract CCS Well #1					
Long-string	0 - 5494	12¼	8.625	0 – 5494	900 Sks Light Cement premixed with 3% KCl, 0.4% Halad-322, 0.25 PPS Pheno Seal, 0.1% FWCA, 0.2% HR-7(12.8 Lb/Gal, 1.48 CuFt/Sk, 7.63 Gal/Sk) followed with 1080 sacks Class A cement premixed with 1.5 gallons/sack Latex plus liquid dispersant, and liquid defoamer (1.1 ft^3/sk yield, 16.3 ppg); 60 sacks Class A with 3% CaCl2 top job if cement column drops
Rindge Tract CCS Well #2					
Long-string	0 - 5428	12¼	8.625	0 – 5494	900 Sks Light Cement premixed with 3% KCl, 0.4% Halad-322, 0.25 PPS Pheno Seal, 0.1% FWCA, 0.2% HR-7(12.8 Lb/Gal, 1.48 CuFt/Sk, 7.63 Gal/Sk) followed with 1080 sacks Class A cement premixed with 1.5 gallons/sack Latex plus liquid dispersant, and liquid defoamer (1.1 ft^3/sk yield, 16.3 ppg); 60 sacks Class A with 3% CaCl2 top job if cement column drops

(1) Conceptual cement program may be revised based on similar products available at completion

(2) Cement calculations are estimates and include 25% excess

(3) Conductor casing driven, will not require cement

Tubing and Packer

Supercritical carbon dioxide will be injected into the well through tubing and packer that are comprised of corrosion resistant materials. The CO_2 stream will originate from a Pelican-controlled facility.

The CO_2 stream will be transported from the facilities to the injection well in a supercritical state. The anticipated liquid CO_2 stream composition is characterized in **Table 5-5**.

Table 5-5. Chemical Composition of Liquid CO_2 Stream

Component	Composition by Volume (Maximum or Minimum)	
Carbon Dioxide (CO_2) 99.0%	Min	
Air	0.8%	Max
Ethanol (C_2H_6O)	100 ppm	Max
Methanol (CH_3OH)	100 ppm	Max
Other Alcohols	10 ppm	Max
Acetaldehyde (CH_3CHO)	100 ppm	Max
Ethyl Acetate ($C_4H_8O_2$)	80 ppm	Max
Acetic Acid (CH_3COOH)	10 ppm	Max
Nitric Oxide (NOx)	2 ppm	Max
Nitrogen Dioxide (NO_2)	2 ppm	Max
Hydrogen Sulfide (H_2S)	15 ppm	Max
Other Sulfurs	2 ppm	Max
Methane (CH_4)	20 ppm	Max
Acetone $(CH_3)_2CO$	20 ppm	Max
Others	none	Max

Tubing and packer materials used in the construction of the injection well will be compatible with fluids with which the materials may be expected to come into contact. These materials and/or coatings will meet or exceed standards developed by the API, ASTM International, or comparable standards.

A packer will be placed at the terminus of the injection tubing and isolate the annulus from the injection zone for continuous monitoring for tubing and packer leaks, as described in Section 8 – Testing and Monitoring. The packer will be installed inside the long string casing near the top of the injection interval.

The tubing will stab into a seal bore packer, AS-1X mechanical packer (or equivalent). The packer will be manufactured or plated with corrosion resistant materials and will be rated with a minimum

7,000 psi differential, which exceeds the anticipated differential during installation, workovers, and injection.

Specifications for the conceptual design tubing and packer are provided in **Tables 5-6** and **5-7** below.

Table 5-6. Tubing Specifications (1)

Name	Depth Interval (feet)	Outside Diameter (inches)	Inside/Drift Diameter (inches)	Weight (lbs/ft)	Grade (API)	Design Coupling	Axial Load lbs (in air)	Tensile Strength (MPa)	Yield Strength (MPa)	Burst Strength (psi)	Collapse Strength (psi)
Injection tubing	5396	5.500	4.892	17	N-80, SMAX-TSR	LTC	91,732	689	552 - 758	7,740	6,390
Injection tubing	5330	5.500	4.892	17	N-80, SMAX-TSR	LTC	90,610	689	552 - 758	7,740	6,390

(1) Conceptual tubing program may be revised based on similar products available at the time of completion

Table 5-7. Packer Specifications (1)

Packer Type and Material	Packer Setting Depth (feet)	Length (inches)	Packer Main Body Outer Diameter (inches)	Packer Inner Diameter (inches)
Rindge Tract CCS Well #1				
Stainless steel, 7K, AS-1X	5396	98	7.921	5.5
Rindge Tract CCS Well #2				
Stainless steel, 7K, AS-1X	5330	98	7.921	5.5

(1) Conceptual packer program may be revised based on similar products available at the time of completion

Annulus Fluid

The annular space above the packer between the long string casing and injection tubing will be filled with fluid to provide structural support for the injection tubing and continuous monitoring of internal mechanical integrity. If required, fluid pressure measured at the surface within the annulus will be maintained to exceed the maximum injection pressure within the injection tube at the elevation of the injection zone. This pressure differential (surface) will not exceed a value that is more than 200 psi greater than the injection pressure at the surface. For Well #1, assuming packer placement at a measured depth of 5396 ft., the volume of the annular space will be approximately 15325 gallons and for Well #2, assuming packer placement at a measured depth of 5330 ft., the volume of the annular space will be approximately 15138 gallons.

The annulus fluid will be freshwater with a corrosion inhibitor, biocide and an oxygen scavenger. Depending on final selection of tubing, long string and packer materials, the annulus may include a dilute salt solution such as potassium chloride (KCl), sodium chloride

(NaCl), calcium chloride ($CaCl_2$), or similar solutions. The fluid will be mixed onsite using 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 annulus monitoring system.

Wellhead

The wellhead and Christmas tree will be composed of materials 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.