WELL CONSTRUCTION DETAILS
40 CFR 146.82(a)(9), (11), (12), and 40 CFR 146.86

RUSSELL CO_2 CAPTURE AND SEQUESTRATION

Facility Information

Facility name: Russell CO_2 Storage Complex
CSS #1

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Well location: Un-incorporated, Russell County, Kansas
Lat: 38.8855219472 Long: -98.7504253861 NAD 83 (2011)
Sec 27 T 13 S R 13 W 0' FSL – 2005' FEL

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List of Acronyms and Abbreviations

AoR = Area of Review	MMA = Maximum monitoring area
API = American Petroleum Institute	PCC = PureField Carbon Capture, LLC
ASTM = ASTM International	PISC = Post-Injection Site Care
CO_2 = carbon dioxide	ppg = pounds per gallon
CR = Chrome	ppmv = parts per million by volume
ft = feet	psig = pound-force per square inch, gauge
ft bgs = feet below ground surface	UIC = Underground Injection Control
ft^3/sx = cubic feet per sack	US EPA = United States Environmental Protection Agency
GS = geologic sequestration	USDW = Underground Source of Drinking Water
lbs = pounds (weight)	
Lbs = pounds (force)	
lb/ft = pounds per foot	

A.II.1. Summary

PureField Carbon Capture, LLC (PCC) will utilize the following wells to meet the requirements of the United States Environmental Protection Agency (US EPA) Underground Injection Control (UIC) Class VI rule:

CSS #1: This well was designed, drilled, and cased in 2022 as a stratigraphic test well under a permit issued to PCC by the State of Kansas - Kansas Corporation Commission (American Petroleum Institute [API] number 15-167-24129) for the purpose of providing necessary field data to support a US EPA UIC Class VI permit application. The stratigraphic test well was designed and built to the injection well requirements of 40 CFR 146.86. The plan is for CSS #1 to be re-permitted and completed as a Class VI injection well for the Injection period, and later re-purposed as a monitoring well during the Post-Injection Site Care (PISC) period.

MW #1: This well was drilled and cased in 2024 as a stratigraphic test well under a permit issued to PCC by the State of Kansas – Kansas Corporation Commission (API Number 15-167-24143) for the purpose of providing necessary field data to support a US EPA UIC Class VI permit application. The well is designed as a dual zone monitoring well that penetrates the upper confining zones and injection zone. The upper zone of MW #1 allows for formation fluid sampling and pressure/temperature measurements in the first aquifer above the primary upper confining zone (i.e., the Iola Limestone member in the Kansas City Group). The lower zone of MW #1 allows for direct monitoring of the carbon dioxide (CO_2) plume and pressure front by formation fluid sampling and pressure/temperature measurements in the injection zone (i.e., the Arbuckle Group). MW #1 is designed to the standards of 40 CFR 146.86 since it penetrates the upper confining zones within the Area of Review (AoR). The plan is for MW #1 to be re-purposed as a monitoring well for the Injection and PISC periods of the project. The design of MW #1 also provides long-term flexibility in project configuration should PCC decide to re-permit for injection into the secondary injection zone target (i.e., Lansing-Kansas City Groups) at a future date.

Groundwater Monitoring Wells: A series of above confining zone monitoring wells are used to provide information on groundwater conditions in the water table and lowermost underground source of drinking water (USDW) across the maximum monitoring area (MMA).

Soil Gas Monitoring Wells: A series of above confining zone monitoring wells are used to provide information on soil gas conditions in the upper and lower vadose zone across the MMA.

Passive Seismic Sensor Wells: A series of monitoring wells house seismometers that provide information on micro-seismic activity across the extent of the geologic sequestration (GS) project.

A.II.2. Construction of CSS #1

CSS #1 was designed, drilled, and cased in 2022 as a stratigraphic test well under a permit issued to PCC by the State of Kansas - Kansas Corporation Commission (API 15-167-24129) for the purpose of providing necessary field data to support a US EPA UIC Class VI permit application. The plan is for CSS #1 to be re-permitted and completed as a Class VI injection well for the Injection period, and later re-permitted as a Class VI injection zone monitoring well during the PISC period. Additional basic information about CSS #1 is provided in Table A.II.2-1.

Table A.II.2-1. Basic Information for CSS #1

Parameter	Value
Well Name	CSS #1
Operator	PureField Carbon Capture, LLC
API	15-167-24129
Location	Un-incorporated, Russell County, KS
GPS Coordinates (NAD 83(2011])	Lat.: 38.8855219472; Long.: -98.7504253861
Section, Township, Range	SEC 27, T13S, R13W 0' FSL - 2005' FEL

A.II.2.1. Proposed Stimulation Program [40 CFR 146.82(a)(9)]

No stimulation program for CSS #1 is proposed at this time. If PCC later determines that stimulation techniques are needed, a stimulation plan will be developed and submitted for review and approval by the Program Director. Such plan will conform to the requirements of 40 CFR 146.82(a)(9) and include a description of stimulation fluids to be used and a determination that stimulation will not interfere with containment. Once the plan is approved, PCC will notify the US EPA Program Director in writing 30 days in advance of any planned stimulation activities per 40 CFR 146.91(d)(2).

A.II.2.2. Construction Procedures [40 CFR 146.82(a)(12)]

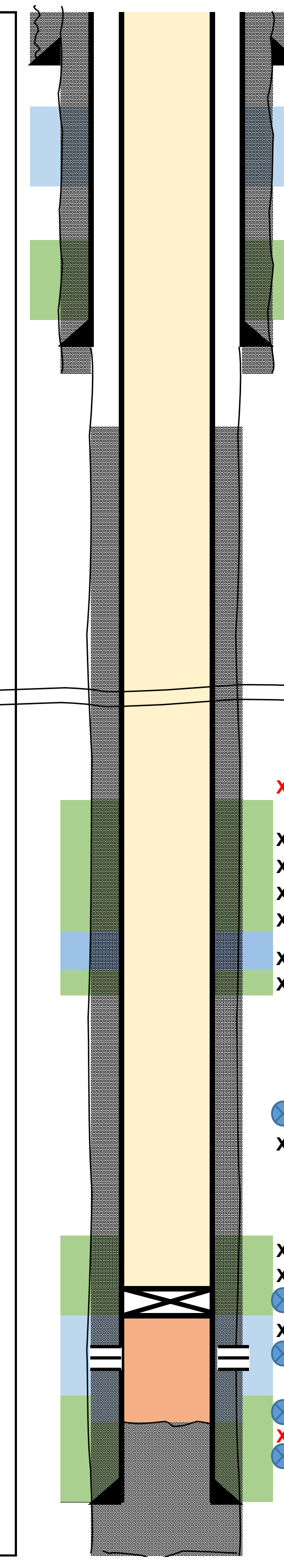
Construction procedures are covered in separate subsections for CSS #1 service as a stratigraphic test well, completion as a Class VI injection well, and re-permitting as a Class VI monitoring well.

A.II.2.2.1. Design, Drilling, Casing and Cementing of CSS #1 as a Stratigraphic Test Well

CSS #1 was initially designed and constructed as a stratigraphic test well; however, it was built to conform to the general requirements of 40 CFR 146.86(a) and the casing and cementing requirements of 40 CFR 146.86(b) to provide PCC with the option to later re-purpose the well for injection and/or monitoring services under the US EPA UIC Class VI rule.

Figure A.II.2-1. CSS #1 Construction for Stratigraphic Well Service

Geologic Unit	Depth	Hydrogeologic Role	Hole Size	Cement Details	Casing Size	Tubing, Packer, and Perfs	Notes
Loess, Carlile Sh, Greenhorn Ls, and Graneros Sh	surface - ~125'	Confining Unit (Great Plains confining system)	20"	150 sx.	16" 65# H-40 STC 40 ft.		
Dakota Formation (Upper Dakota Aquifer/Great Plains Aquifer)	~125' - 375'		12 1/4"	350 sx cemented to Surface	9 5/8" 36# J-55 LTC		USDW (Great Plains Aquifer System) Groundwater Monitoring Well Data TDS (mg/L): 619 to 3,900
Kiowa Fm and Cheyenne Ss (Lower Dakota Aquifer/Great Plains Aquifer)	~375'-495' **BASE OF USDW**	Aquifer (Great Plains aquifer system)					
Nippewalla Group (Lower Permian Units)	495'-770'	Confining Unit (Western Interior Plains confining system); some interbedded carbonates have porosity and would be considered minor aquifers					Permian Red Bed Shales / Start of Western Interior Plains Confining System
Stone Corral (Anhydrite) - Regional Seal	770'-809'				873 ft.		Stone Corral Anhydrite - Regional Seal
Ninnescah Shale	809'-948'		883 ft				
Wellington	948'-1,124'						Schlumberger Litho-Scanner with Chlorine shows no zones beneath 1,500' with TDS below 10,000ppm
Hutchinson Salt Mbr	1,124'-1,402'						
Geuda Springs Shale Mbr	1,402'-1,529'						
Shale and Limestone Sequences	1,529-2,909'						X = WATER SAMPLE @ 2,874' TDS 78,900 mg /L
Heebner Shale Member - Secondary Confining	2,909' - 2,927'		8 3/4"	875 sx cement TOC = 1675' CBL	7" 26# 13CR-80 Wedge-513		X = *CORE SAMPLES* 2,920'- 3,126' X X X X X
Lansing & Kansas City Groups Potential Secondary Sequestration Interval Iola Limestone Member	2,993' 3,080'-3,128'	First porous interval above Arbuckle					X = *CORE SAMPLES* 2,920'- 3,126'
Marmaton Group	3,262'						*SIDEWALL CORE @ 3,275'*
Top Primary Upper Confining Zone	3,274'						X = *CORE SAMPLES* 3,285' - 3,350'
Top of Arbuckle Group	3,277'	confining unit					
Base Primary Upper Confining Zone	3,438'						
Gross Sequestration Zone	3,448'-3,606'	Aquifer in Western Interior Plains aquifer system				Retrievable Bridge Plug @ 3,535' **Perfs** **3580-3600** 6 SPF, 60 Shots Acidize 500 gal 15% HCl	X = CORE SAMPLES 3,430' - 3,451' X = CORE SAMPLES 3,483' - 3,489' *SIDEWALL CORES @ 3,505', 3,525'* X = *CORE SAMPLES* 3,550' - 3,562' *SIDEWALL CORES @ 3,570'*
Primary Lower Confining Zone	3,647'-3,659'	confining unit			PBTD = 3660'		*SIDEWALL CORES @ 3,640'*
Top Reagan Sandstone	3,659'	Aquifer					X = WATER SAMPLE @ 3,665' TDS 25,800 mg /L *SIDEWALL CORES @ 3,690', 3,700' & 3730'*
Top of Quartzite Basement	3,735'	Basement confining system	3756'		3740'		



TVD (ft KB)	Elevation (ft MSL)
0	1820
200	1620
400	1420
600	1220
800	1020
1000	820
1200	620
1400	420
1600	220
2800	-980
2900	-1080
3000	-1180
3100	-1280
3200	-1380
3300	-1480
3400	-1580
3500	-1680
3600	-1780
3700	-1880
3800	-1980

Table A.II.2-2. Open Hole Diameters and Intervals for CSS #1

Open Holes	Depth Interval [ft]	Open Hole Diameter [inches]
Conductor	0 – 40	20
Surface	40 – 883	12 ¼
Long String	883 – 3,740	8 ¾

Table A.II.2-3. Casing Specifications for CSS #1

String	Depth Interval [ft]	Outside Diameter [inches]	Inside Diameter [inches]	Weight [lb/ft]	Grade [API]	Coupling	Burst Rating [psig]	Collapse Resistance [psig]
Conductor	0 – 40	16	15.250	65	H-40	STC	1,640	670
Surface	0 – 873	9 5/8	8.921	36	J-55	LTC	3,520	2,020
Long String	0 – 3,740	7	6.276	26	13CR-80	Wedge 513	7,240	5,410

ft = feet
lb/ft = pounds per foot
psig = pound-force per square inch, gauge
13 Chrome (CR) 80

Figure A.II.2-1 relates the construction of CSS #1 for stratigraphic well service to the geologic- and hydrogeologic-stratigraphic columns and the pre-injection testing program. Table A.II.2.-2 provides information on the open hole diameters and intervals for CSS #1. Table A.II.2-3 provides casing specifications for CSS #1.

The casing strings for CSS #1 will be subject to different stresses during the different phases of construction, operation, and closure. To estimate the maximum axial loading on the casing strings, it is conservatively assumed the strings are "hanging in air" with no buoyant force exerted by the drilling fluids, formation fluids, or cement in the borehole. For any other condition, the stresses on the component will be less. Nevertheless, this unrealistic condition is used here for a worst possible case condition. The resulting equation is given by:

Max Tension Load = Weight of Casing (lb/ft) * Depth of Casing (ft)

The maximum axial (tension) loading calculations for the three different casing strings at CSS #1 are provided below:

- Max Tension Load$_{conductor}$ = 65 lb/ft *40 ft. = 2,600 lbs
- Max Tension Load$_{surface}$ = 36 lb/ft * 873 ft. = 31,428 lbs
- Max Tension Load$_{longstring}$ = 26 lb/ft *3,740 ft. = 97,240 lbs

For the purpose of these calculations, the weight (lbs) of these casing strings would be equivalent to the maximum tensile loading force (Lbs) acting on them to potentially cause their failure. These casing specific tension loading estimates are substantially less than the joint strength and yield strength for these respective casings, as presented in Table A.II.2-4 below.

Table A.II.2-4. Casing Joint and Yield Strength for CSS #1

Casing	Weight [lb/ft]	Grade [API]	Coupling	Joint Strength (Lbs)	Yield Strength (Lbs)
Conductor	65	H-40	STC	439,000	736,000
Surface	36	J-55	LTC	453,000	564,000
Long String	26	13CR-80	Wedge 513	377,000	604,000

Lbs = pound-force

PCC carefully selected the metals for the casing to account for potential corrosion from contact with formation fluids and CO_2/water mixtures. The conductor casing was constructed from H-40 steel, which is a standard metal selection for contact with formation fluids in this service, and it has sufficient internal yield and external collapse ratings to prevent failures. There is no need for special CO_2 corrosion resistant metals since the conductor casing is not expected to contact CO_2/water mixtures. The surface casing was constructed from J-55 steel, which is a standard metal selection for contact with formation fluids in this service, and it has sufficient internal yield and external collapse ratings to prevent failures. In addition, the joint yield strength is sufficient to prevent the surface casing from failing during operations. There is no need for special CO_2 corrosion resistant metals since the surface casing is not expected to contact CO_2/water mixtures. The long string casing was constructed from 13CR-80 steel with internal yield, external collapse, joint yield strength, and body yield strength to prevent failure during operations. 13CR-80 was selected to provide corrosion resistance to both formation fluids and CO_2/water mixtures, based upon its history of successful use in similar long string service for other Class VI wells and CO_2 enhanced oil recovery. See Attachment A.II-1 for additional information on metals selected for construction of CSS #1.

Likewise, PCC carefully selected the cement to account for potential degradation from contact with formation fluids and CO_2/water mixtures. The conductor casing was cemented in place with 8 sacks of ASTM Type 1 cement, which is a standard cement selection for contact with formation fluids in this service. There was no need to use a CO_2 resistant formulation since the cement for the conductor casing is not expected to contact CO_2/water mixtures. The surface casing was cemented in place using Class H cement, which is a standard cement selection for contact with formation fluids in this service. The cement was pumped as a lead and tail slurry. The lead slurry had a density of 12.0 pounds per gallon (ppg) and a yield of 2.56 cubic ft per sack (ft^3/sx). The tail slurry had a density of 14.8 ppg and a yield of 1.41 ft^3/sx. The tail cement was designed to cover the entire interval with the lead being utilized as excess. The cement on the surface string provides a secondary barrier to protect the base of the USDW; it should not come in contact with CO_2/water mixtures and thus the cement formulation does not require CO_2 resistance. The long string casing was cemented in place utilizing a 50/50 Pozmix cement with Liquid Latex added to the cement blend to prevent deterioration from contact with both formation fluids and CO_2/water mixtures. This cement formulation was recommended by well service providers and has been successfully used to provide CO_2 resistance for similar services in other Class VI wells. The cement was pumped as a lead and tail slurry. The lead slurry had a density of 12.8 ppg and a yield of 1.90 ft^3/sx. The tail was pumped with a density of 14.7 ppg and a yield of 1.15 ft^3/sx. The tail cement was designed to cover from 3,740 to 2,592 ft and the lead was designed to cover from 2,592 to 0 ft. See Attachment A.II-1 for additional information selected on cements selected for construction of CSS #1.

The drilling spud date was October 18, 2022. A 20-inch diameter borehole was drilled to a depth of 40 feet below ground surface (ft bgs), inside of which a 16-inch diameter conductor casing was set and cemented. Inside the conductor casing, a 12 ¼-inch diameter borehole was drilled to a depth of 883 ft bgs. Surface casing of 9 5/8-inch diameter was set at 873 ft bgs, which is below the Stone Corral Anhydrite that acts as a regional seal. Surface casing was successfully cemented to surface. The completion and cementing of this surface casing are also below the base of the Dakota Aquifer (aka Great Plains Aquifer) that are the lowermost USDW within Russell County and this part of central Kansas. Therefore, the USDW will be isolated from the proposed CO_2 injection activities, horizontally by multiple well casings and cement layers and vertically by numerous confining layers. The 8¾-inch diameter borehole was drilled for the 7-inch diameter long string casing and was set past the target injection formation down to a depth of 3,740 ft bgs and was cemented in place using 50/50 Pozmix with Liquid Latex additive. The plug back total depth for setting the long string casing was 3,700 ft bgs.

An 8-¾-inch diameter wellbore for CSS #1 was selected to allow passage of certain proprietary logging tools provided by SLB (formerly Schlumberger). Additionally, drilling the wellbore at this diameter allowed setting of 7-inch diameter 13CR-80 VAM TOP®[1] casing. This casing has an inner diameter of 6.276 inches, a burst rating of 7,240 psig, and collapse rating of 5,410 psig, and a tensile strength rating of 377,000 Lbs. This casing should provide enough space for any downhole tools that need to be run in the cased hole environment. The maximum measured bottom hole temperature during the testing operations was 110 °F, and reservoir pressure was 1,245 psig, roughly 23% of the rated collapse pressure.

The cement for the long string was prepared in a total volume equal to 77% in excess of the volume required to fill the annular space between the wellbore/surface string and the outside of the long string casing, and the cement was pumped into the annular space in a single treatment with an expectation the cement would circulate to surface. The cement did not circulate to surface, suggesting an un-expected loss of cement from hydrostatic head induced flow of the cement slurry into incompetent pockets in the rock face. See Attachment A.II-2 for a comprehensive discussion of the cement logs for all CCS #1 strings, plus a remediation plan designed to bring the long string cement up to Class VI standards (i.e., circulate cement to surface per requirement of 40 CFR 146.86(b)(3)).

Following the initial completion of the cement job for the long string casing, the casing was perforated between the depths of 3,580 to 3,600 ft bgs, and subsequently acidized with 1,500 gallons of 15% hydrochloric acid.

There were no unplanned or emergency events during the drilling operations.

[1] VAM TOP is a registered trademark owned by Vallourec Oil and Gas, France.

A.II.2.2.2. Completion of CSS #1 as an Injection Well

Completion of CSS #1 as an injection well requires the design and installation of tubing, a packer, a wellhead, safety devices, an annulus fluid system, and various additional testing and monitoring equipment. The following list is provided to assist with locating the information on the tubing and packer (and other CSS #1 internals) required by 40 CFR 146.86(c)(3):

i. Depth of Setting See Table A.II.2-5, Table A.II.2-6, and Figure A.I.2-1 in this subsection.

ii. Characteristics of CO_2 Stream and Formation Fluids See Section A.7.2 of the Application Narrative for a discussion on the chemical content of the CO_2 stream. The CO_2 stream has been dehydrated to less than 400 parts per million by volume (ppmv) water, nonetheless the stream is still potentially corrosive to metals used in the internals that come into direct contact with the stream. The US EPA Class VI Well Construction Guidance document discourages the use of carbon steel as a material of construction for well components that come into direct contact with the CO_2 stream if the water content of the CO_2 is greater than 50 ppmv (EPA 2012). The pressure, temperature, and density of the CO_2 stream varies depending upon location within the system, time of year, and several other factors. The system is designed to supply dense phase CO_2 to the CSS #1 surface facilities at approximately 1,300 psig and 100 °F in the summer, resulting in a stream density of 37.0 lb/ft^3. The characteristics of the formation fluids are discussed in Section A.I.9 of the Site Characterization attachment to the Application Narrative.

iii. Maximum Proposed Injection Pressure See Section A.7 of the Application Narrative.

iv. Maximum Proposed Annular Pressure The maximum annular pressure occurs downhole at the packer. It will not be measured, but it can be estimated from the extreme case where the annulus is pressurized to the point where the relief valve PSV-0502 at the surface of the annulus pressure control system begins to lift. The set pressure for PSV-0502 is determined by:

$$\text{PSV-0502}_{Set\ Pressure} = 80\% * Casing\ Burst\ Rating - Annulus\ Hydrostatic\ Pressure$$
$$\text{PSV-0502}_{Set\ Pressure} = 80\% * 7{,}240\ psig - \left(\frac{0.4333\ psi}{ft}\right) * 3{,}400\ ft = 4{,}319\ psig$$

The collapse rating of the tubing does not need to be considered since it is far greater than the burst rating of the casing. The above analysis is conservative since the actual failure pressure of the casing is higher than its burst rating because it is supported by a cement sheath.

v. Proposed Injection Rate See Section A.7 of the Application Narrative

vi. Size of Tubing and Casing See Table A.II.2.4 for the size of the tubing, see Table A.II.2-3 for the size of the casing.

vii. Tubing Tensile Burst, and Collapse Strengths See Table A.II.2.4

The tubing is constructed from 13CR-80 – a CO_2 corrosion resistant metal. The tubing string has a minimum collapse pressure of 10,540 psig, a minimum burst pressure of 10,160 psig, and a minimum tensile strength of 207,000 Lbs.

The bottom hole assembly for this injection well consists of the following:

- A subsurface safety valve that will provide pressure isolation from the injection zone to the surface if a surface failure occurs.
- A permanent packer that will isolate the injection zone from the annulus.
- Profile nipples both below and above the packer to allow for well intervention.

The tubing was landed in the packer with a seal assembly that allows for the tubing and packer to withstand the forces applied due to the temperature changes of the injection stream.

Figure A.II.2-2 provides a well schematic. The stratigraphic columns are shown on the left side of the figure, the center illustrates the casing and internals, and the right side summarizes the Pre-Operational Testing Program.

Table A.II.2-5. Injection Tubing and Subsurface Safety Valve Specifications for CSS #1

Name	Depth Interval [ft]	Outside Diameter [inches]	Inside Diameter [inches]	Weight [lb/ft]	Grade [API]	Coupling	Burst Strength [psig]	Collapse Strength [psig]
Injection Tubing	0 – 3,558	3.5	2.992	9.2	13CR-80	JFEBEAR	12,070	12,080
Subsurface Safety Valve	3,569	2.615	1.38	Not Applicable	Nickel Alloy 925	2 1/4-12 OTIS SLB	11,000	11,00

Table A.II.2-6. Packer Specifications for CSS #1

Packer								Casing Interface		
Type and Material	Setting Depth [ft]	Length [ft]	Outer Diameter [inches]	Inner Diameter [inches]	Tensile Rating [Lbs]	Burst Rating [psig]	Collapse Rating [psig]	Nominal Weight [lb]	Max Inner Diameter [inches]	Min Inner Diameter [inches]
Permanent Nickel Alloy 925	3,550	7.47	5.875	2.897	232,800	9,800	9,300	Not Applicable	4.0	2.5

Figure A.II.2-2. Subsurface Schematic of CSS #1 in Injection Well Service

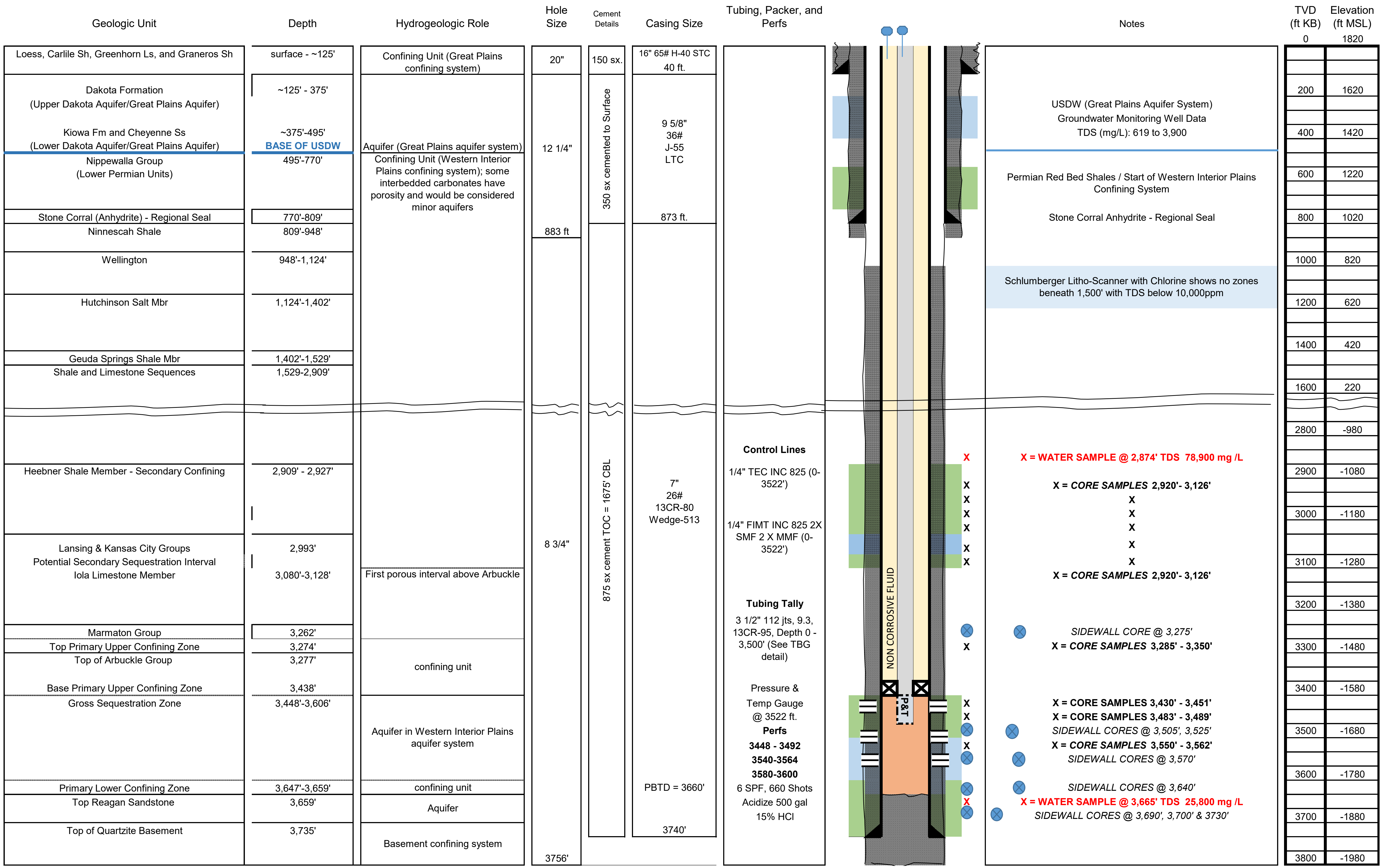


Figure A.II.2-3. Schematic of Above Ground Equipment for CSS #1

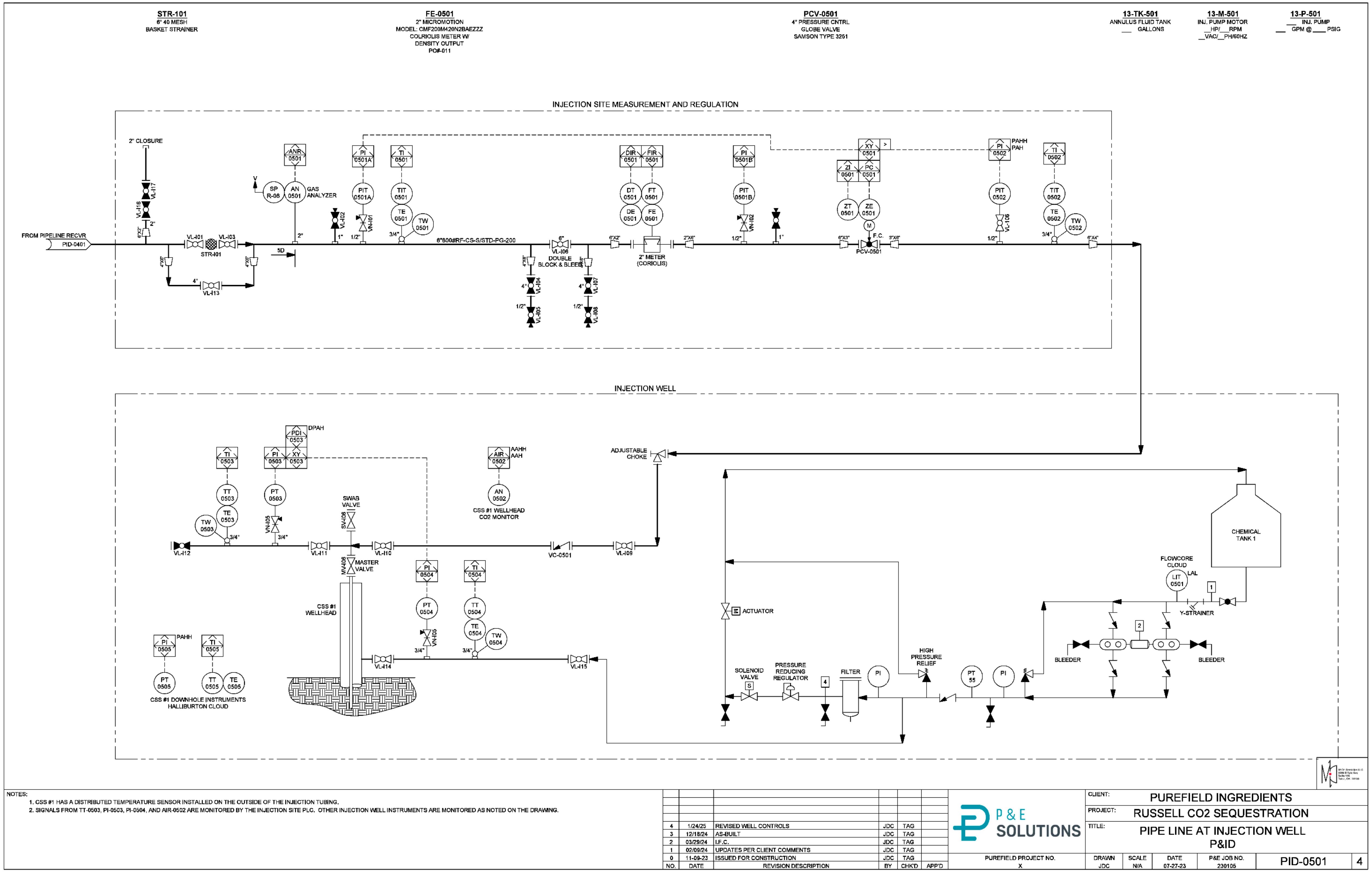


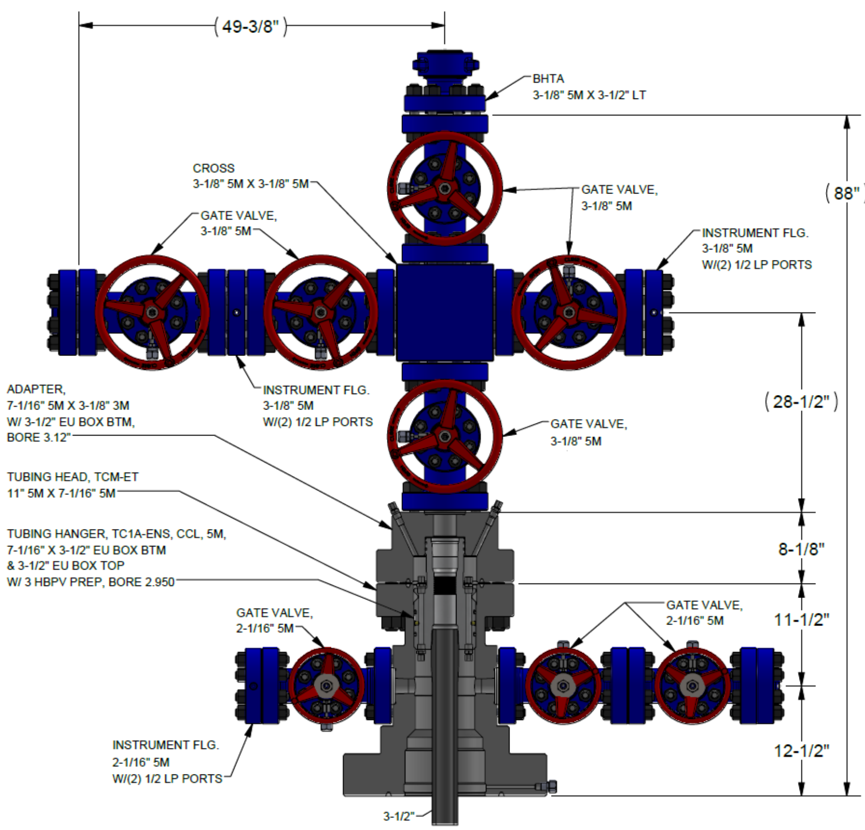
Figure A.II.2-3 provides a schematic of the above ground equipment. The injection line contains an automatic shut off valve (SDV-0502) that is set to close for either a high pressure event (i.e., shut off valve closes to prevent overpressure of injection system) or a low pressure event (i.e., the shut off valve closes to shut in the well in the event of a CO_2 supply failure).

The annular fluid is a freeze resistant water/glycol mixture with corrosion inhibitors. An injection pump (13-P-501) maintains a minimum of 100 psi differential between the surface annulus pressure (PI-0504) and the surface injection pressure (PI-0503) at all times during injection. The difference in fluid densities between the CO_2 stream (density ~ 37 lb/ft^3) and the annulus fluid (density ~ 62 lb/ft^3) will result in a larger annulus pressure differential at the packer versus the annulus pressure differential at the surface, thus ensuring a minimum 100 psig annulus pressure differential along the entire depth of the well. The Annulus Fluid Tank is instrumented with an automated level gauge to record changes in annular volume.

The wellhead (see Figure A.II.2-4) was constructed with appropriate CO_2 resistant materials and has a pressure rating of 5,000 psi. The injection tree was constructed to provide double isolation to all downhole pressure paths in accordance with well control best practices.

All data from the injection well is recorded locally to a multi-terabyte hard drive and transmitted by telemetry to the PCC control facility.

Figure A.II.2-4. CSS #1 Wellhead



A.II.2.2.3. Re-Purposing CSS #1 as a Monitoring Well

PCC plans to re-purpose CSS #1 as a monitoring well for the PISC period. CSS #1 will retain its configuration from the Injection period into the Initial PISC period. The pressure in the annular fluid management system will be reduced during the Initial PISC period while still maintaining a 100 psi positive pressure differential at the surface with respect to the injection tubing.

PCC may elect to re-complete CSS #1 for monitoring well service by removing the internal tubing and/or removing the annulus pressure control system in order to simplify operations during PISC. Any such plans for re-completing CSS #1 during PISC will be reviewed with the US EPA Program Director; no changes will be made to the configuration of CSS #1 without prior approval from the US EPA Program Director.

A.II.3. Construction of MW #1

This well is designed as a dual zone monitoring well that penetrates the upper confining zones and injection zone. The upper zone of MW #1 allows for formation fluid sampling and pressure/temperature measurements in the first aquifer above the primary upper confining zone (i.e., the Iola Limestone member in the Kansas City Group). The lower zone of MW #1 allows for direct monitoring of the carbon dioxide (CO_2) plume and pressure front by formation fluid sampling and pressure/temperature measurements in the injection zone (i.e., the Arbuckle Group). MW #1 is designed to the standards of 40 CFR 146.86 since it penetrates the upper confining zones within the AoR. The design of MW #1 also provides long-term flexibility in project configuration should PCC decide to re-permit for injection into the secondary injection zone target (i.e., Lansing-Kansas City Groups) at a future date. Basic information about MW #1 is provided in Table A.II.3-1.

Table A.II.3-1. Basic Information for MW #1

Parameter	Value
Well Name	MW #1
Operator	PureField Carbon Capture, LLC
API	15-167-24143
Location	Un-incorporated, Russell County, KS
GPS Coordinates (NAD 83(2011])	Lat: 38.8822905; Long: -98.7466046
Section, Township, Range	SEC 34, T13S, R13W 1168' FNL - 908' FEL

Figure A.II.3-1. Schematic of MW #1 in Monitoring Well Service

Geologic Unit	Depth	Hydrogeologic Role
Loess, Carlile Sh, Greenhorn Ls, and Graneros Sh	surface - ~136'	Confining Unit (Great Plains confining system)
Dakota Formation (Upper Dakota Aquifer/Great Plains Aquifer)	~136' - 377'	Aquifer (Great Plains aquifer system)
Kiowa Fm and Cheyenne Ss (Lower Dakota Aquifer/Great Plains Aquifer)	~377'-512'	
	BASE OF USDW	**Base of Lowermost USDW**
Nippewalla Group (Lower Permian Units)	512'-782'	Confining Unit (Western Interior Plains confining system); some interbedded carbonates have porosity and would be considered minor aquifers
Stone Corral (Anhydrite) - Regional Seal	782'-820'	
Ninnescah Shale	820'-965'	
Wellington	965'-1,153'	
Hutchinson Salt Mbr	1,153'-1,448'	
Geuda Springs Shale Mbr	1,448'-1,561'	
Shale and Limestone Sequences	1,561'-2,935'	
Heebner Shale Member - Secondary Confining	2,935' - 2,954'	
Lansing & Kansas City Groups Potential Secondary Sequestration Interval	3,004'	
Iola Limestone Member	3,106'-3,147'	First porous interval above Arbuckle
Marmaton Group	3,282'	
Top Primary Upper Confining Zone	3,292'	confining unit
Top of Arbuckle Group	3,299'	
Base Primary Upper Confining Zone	3,460'	
Gross Sequestration Zone	3,464'-3,624'	Aquifer in Western Interior Plains aquifer system
Primary Lower Confining Zone	3,668'-3,679'	confining unit
Top Reagan Sandstone	3,679'	Aquifer
Top of Quartzite Basement	3,752'	Basement confining system

Hole Size	Cement Details	Casing Size
20"	150 sx.	16" 65# H-40 STC 40 ft.
13 1/2" (883 ft)	365 sx cemented to Surface	10 3/4" 40.5# J-55 BTC (873 ft.)
9 7/8" (3,770')	800 sx cement TOC @ Surface	7" 29# HCL-80
		7" 29# 13-CR80
		PBTD = 3695'
		3,740'

Tubing, Packer, and Perfs

Control Lines

1/4" TEC INC 825 (0-3,650')

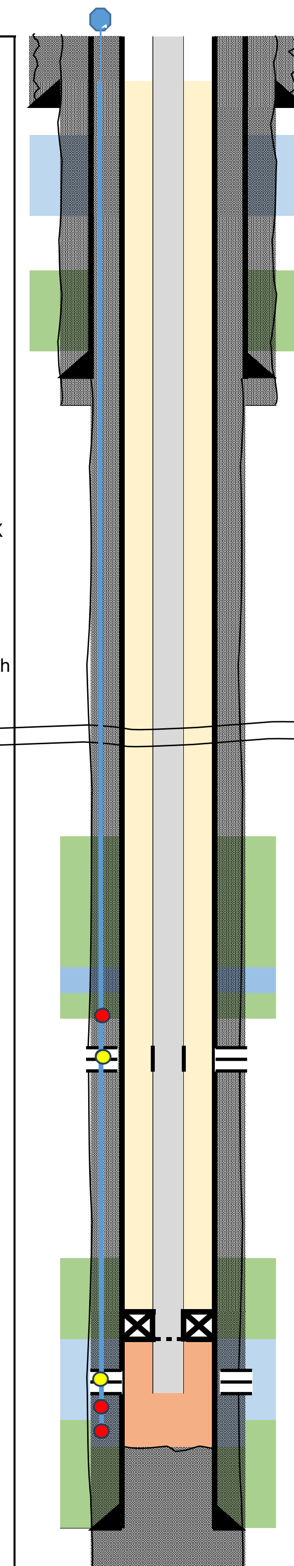
1/4" FIMT INC 825 2X SMF 2 X MMF (0-3,650')

Tubing Tally

2-7/8" 6.50, L-80, Depth 0 - 3,417.5 (See TBG detail)

Perfs
3,106 - 3,126'

Perfs
3,490 - 3,510'



Notes

USDW (Great Plains Aquifer System)
Groundwater Monitoring Well Data
TDS (mg/L): 619 to 3,900

Base of Lowermost USDW

Permian Red Bed Shales / Start of Western Interior Plains Confining System

Stone Corral Anhydrite - Regional Seal

TVD (ft KB)	Elevation (ft MSL)
0	1820
200	1620
400	1420
600	1220
800	1020
1000	820
1200	620
1400	420
1600	220
2800	-980
2900	-1080
3000	-1180
3100	-1280
3200	-1380
3300	-1480
3400	-1580
3500	-1680
3600	-1780
3700	-1880
3800	-1980

Table A.II.3-2. Open Hole Diameters and Intervals for MW #1

Open Holes	Depth Interval [feet]	Open Hole Diameter [inches]
Conductor	0 - 40	20
Surface	40 - 918	13 1/2
Long String	883 - 3,770	9 7/8

Table A.II.3-3. Casing Specifications for MW #1

String	Depth Interval [ft]	Outside Diameter [inches]	Inside Diameter [inches]	Weight [lb/ft]	Grade [API]	Coupling	Burst Rating [psig]	Collapse Resistance [psig]
Conductor	0 - 40	16	15.250	65	H-40	STC	1,640	670
Surface	0 - 873	10 3/4	10.05	40.5	J-55	BTC	3,130	1,580
Long String	0 - 2,900	7	6.184	29	HCL-80	BTC	8,160	9,200
Long String	2,900 - 3,740	7	6.276	26	13CR-80	JFELION	8,160	7,030

ft = feet
lb/ft = pounds per foot
psig = pound-force per square inch, gauge

A.II.3.1. Construction Procedures

The construction of MW #1 follows the general design and construction as CSS #1. Figure A.II.3-1 relates the construction of MW #1 for monitoring well service to the geological and hydrogeologic-stratigraphic columns. Table A.II.3.2 provides information on the open hole diameters and intervals for MW #1. Table A.II.3-3 provides casing specifications for MW #1.

The casing strings for MW #1 will be subject to different stresses during the different phases of construction, operation, and closure. To estimate the maximum axial loading on the casing strings, it is conservatively assumed the strings are "hanging in air" with no buoyant force exerted by the drilling fluids, formation fluids, or cement in the borehole. For any other condition, the stresses on the component will be less. Nevertheless, this unrealistic condition is used here for a worst possible case condition. The resulting equation is given by:

Max Tension Load = Weight of Casing (lb/ft) * Depth of Casing (ft)

The maximum axial (tension) loading calculations for the three different casing strings at CSS #1 are provided below:

- Max Tension Load$_{conductor}$ = 65 lb/ft *40 ft. = 2,600 lbs
- Max Tension Load$_{surface}$ = 36 lb/ft * 873 ft. = 31,428 lbs
- Max Tension Load$_{longstring}$ = 26 lb/ft *3,740 ft. = 97,240 lbs

For the purpose of these calculations, the weight (lbs) of these casing strings would be equivalent to the maximum tensile loading force (Lbs) acting on them to potentially cause their failure.

These casing specific tension loading estimates are substantially less than the joint strength and yield strength for these respective casings, as presented in Table A.II.3-4 below.

Table A.II.3-4. Casing Joint and Yield Strength for MW #1

Casing	Weight [lb/ft]	Grade [API]	Coupling	Joint Strength (Lbs)	Yield Strength (Lbs)
Conductor	65	H-40	STC	430,000	736,000
Surface	40.5	J-55	BTC	700,000	629,000
Long String	29	HCL-80	BTC	780,000	676,000
Long String	29	13CR-80	JFELION	676,000	676,000

Lbs = pound-force

PCC carefully selected the metals for the casing to account for potential corrosion from contact with formation fluids and CO_2/water mixtures. The conductor casing is constructed from H-40 steel, which is a standard metal selection for contact with formation fluids in this service, and it has sufficient internal yield and external collapse ratings to prevent failures. There is no need for special CO_2 corrosion resistant metals since the conductor casing is not expected to contact CO_2/water mixtures. The surface casing is constructed from J-55 steel, which is a standard metal selection for contact with formation fluids in this service, and it has sufficient internal yield and external collapse ratings to prevent failures. In addition, the joint yield strength is sufficient to prevent the surface casing from failing during operations. There is no need for special CO_2 corrosion resistant metals since the surface casing is not expected to contact CO_2/water mixtures. The long string casing is constructed from HCL-80 steel for depths above 2,900 ft, and transition to 13CR-80 below 2,900 ft. This transition between HCL-80 and 13CR-80 provides appropriate corrosion resistance to both formation fluids and CO_2/water mixtures at the lower depths. See Attachment A.II-1 for additional information on the metals selected for construction of MW #1.

Likewise, PCC carefully selected the cement to account for potential degradation from contact with formation fluids and CO_2/water mixtures. The conductor casing was be cemented in place with 8 sacks of ASTM Type 1 cement, which is a standard cement selection for contact with formation fluids in this service. There is no need to use a CO_2 resistant formulation since the cement for the conductor casing is not expected to contact CO_2/water mixtures. The surface casing was be cemented in place using ASTM Type 1L cement, which is a standard cement selection for contact with formation fluids in this service. The cement was pumped as a lead and tail slurry. The lead slurry had a density of 12.0 pounds per gallon (ppg) and a yield of 2.56 cubic ft per sack (ft^3/sx). The tail slurry had a density of 14.8 ppg and a yield of 1.41 ft^3/sx. The tail cement was designed to cover the entire interval with the lead being utilized as excess. The cement on the surface string provides a secondary barrier to protect the base of the USDW; it should not come in contact with CO_2/water mixtures and thus the cement formulation does not require CO_2 resistance. The long string casing was cemented in place utilizing Halliburton CorrosaCem Pozmix cement with latex added to the cement blend to prevent deterioration from contact with both formation fluids and CO_2/water mixtures. This cement formulation is recommended by well service providers and has been successfully used to provide CO_2 resistance for similar services in other Class VI wells. The cement was pumped as a lead and tail slurry. The lead slurry had a density of 12.8 ppg and a yield of 1.90 ft^3/sx. The tail was pumped with a density of 14.7 ppg and a yield of 1.15 ft^3/sx. The tail cement was designed to cover from 3,740 to 2,592 ft and the lead was designed to cover from 2,592 to 0 ft. See Attachment A.II-1 for additional information selected on cements selected for construction of MW #1.

A 20-inch diameter borehole was be drilled to a depth of 40 feet below ground surface (ft bgs), inside of which a 16-inch diameter conductor casing was set and cemented. Inside the conductor casing, a 13 1/2-inch diameter borehole was drilled to a depth of 918 ft bgs. Surface casing of 10 3/4-inch diameter was be set at 908 ft bgs, which is below the Stone Corral Anhydrite formation that acts as a regional seal. Surface casing was cemented to surface. The landing and cementing of this surface casing is below the base of the Dakota Aquifer (aka Great Plains Aquifer) that is the lowermost USDW within Russell County and this part of central Kansas. Therefore, the USDW will be isolated from the proposed CO_2 injection activities, horizontally by multiple well casings and cement layers and vertically by numerous confining layers. The 9 7/8-inch diameter borehole was drilled for the 7-inch diameter long string casing and was set past the target injection formation down to a depth of 3,740 ft bgs and was cemented in place using Halliburton CorrosaCem Pozmix with latex additive. The plug back total depth for setting the long string casing is approximately 3,700 ft bgs.

A 9-7/8-inch diameter wellbore for MW #1 was selected to allow setting of 7-inch diameter casing. HCL-80 LTC casing was ran from surface to approximately 2,900 ft. This casing has an inner diameter of 6.184 inches, a burst rating of 8,160 psig, and collapse rating of 9,200 psig, and a tensile strength rating of 655,000 Lbs. 13CR-80 Wedge 513 casing was ran from 2,900 ft to 3,740 ft. This casing has an inner diameter of 6.276 inches, a burst rating of 8,160 psig, and collapse rating of 7,030 psig, and a tensile strength rating of 377,000 Lbs. This casing should provide enough space for any downhole tools that need to be run in the cased hole environment. The maximum measured bottom hole temperature during pre-operational testing of CSS #1 in stratigraphic well service was 110 °F, and reservoir pressure was 1,245 psig, roughly 23% of the rated collapse pressure for the lower long string of MW #1. The cement utilized for the long string was Halliburton CorrosaCem Pozmix with latex and was pumped in a single treatment.

A fiber cable containing a distributed temperature sensor (DTS) was cemented in place on the outside of the production casing. This will allow monitoring of temperature along the entire depth of MW #1. Following completion of the cement job for the long-string casing, the casing was perforated to allow direct access to fluids in the Arbuckle Group injection zone and the Iola Limestone member of the Kansas City Group. The perforation charges were aligned to prevent damage to the DTS fiber cable.

Completion of MW #1 as a dual monitoring well requires the design and installation of tubing with a sliding side door, and a packer assembly with a profile nipple and removable plug. Table A.II.3-5 provides information about the tubing and sliding side door. Table A.II.3-6 provides specifications for the packer. All tubing above the packer and the sliding side door are be made from L-80 steel since corrosion resistance from long-term contact with CO_2/water mixtures is not needed. The packer and tubing below the packer is made from Alloy 925 and 13CR-80, respectively, to provide corrosion resistance from exposure to CO_2 and CO_2/formation fluid mixtures.

Formation fluids in the first aquifer above the primary confining zone (i.e., Iola Limestone member of the Kansas City Group) are accessible from the upper zone of MW #1 when the sliding side door is open and the plug is inserted into the packer. Formation fluids in the injection zone (i.e., Arbuckle Group) when the sliding side door is closed and the plug is removed from the packer. Section E.I.2.2 of the QASP provides details on the procedures for taking formation fluid samples from the upper and lower zones of MW #1.

Table A.II.3-5. Tubing Specifications for MW #1

Name	Depth Interval [ft]	Outside Diameter [inches]	Inside Diameter [inches]	Weight [lb/ft]	Grade [API]	Coupling	Burst Strength [psig]	Collapse Strength [psig]
Tubing (above door)	0 - 3,080	2.875	2.44	9.2	L-80	EUE	10.570	11,160
Sliding Side Door	3,080 - 3,084	4.55	2.813	9.3	L-80	EUE	9,710	8,431
Tubing (below door, above packer)	3,084 - 3,434	2.875	2.44	6.5	L-80	EUE	10,570	11,160
Tubing (below packer)	3,446 - 3463	2.875	2.44	6.5	13CR-80	EUE	10,570	11,160

Table A.II.3-6. Packer Specifications for MW #1

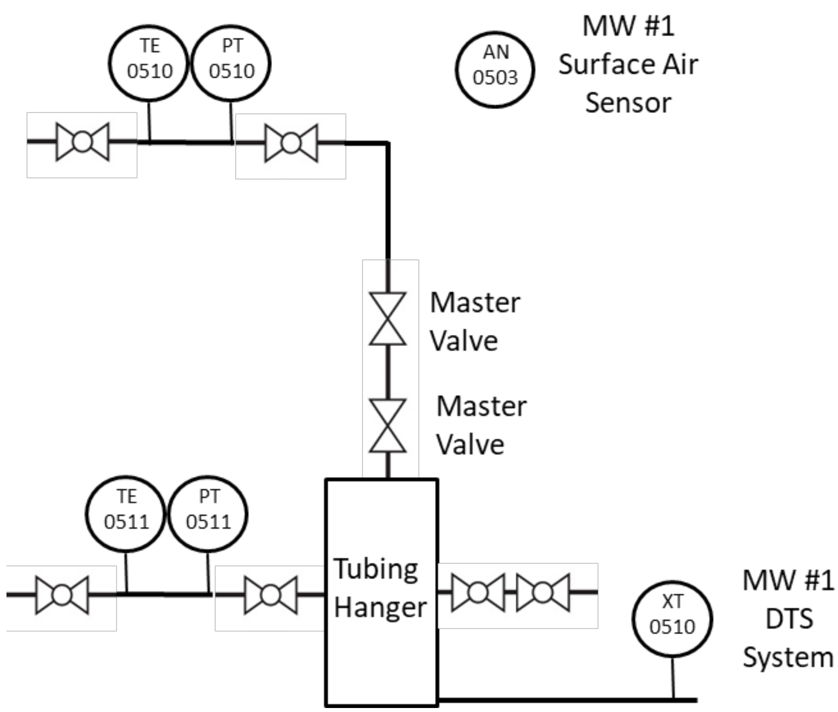
Packer								Casing Interface		
Type and Material	Setting Depth [ft]	Length [ft]	Outer Diameter [inches]	Inner Diameter [inches]	Tensile Rating [Lbs]	Burst Rating [psig]	Collapse Rating [psig]	Nominal Weight [lb]	Max Inner Diameter [inches]	Min Inner Diameter [inches]
Hydraulic Set Perma-Latch Packer – Alloy 925	3,441	6.32	6	2.377	145,000	8,710	8,400	Not Applicable	4.0	2.5

Sections E.9 and E.10 of the Testing and Monitoring Plan describe the plan to take formation fluid samples from both the upper and lower zones of MW #1 during the initial Injection period until the CO_2 plume has passed MW #1. Sampling will cease from the lower zone once the plume has passed since further sampling will provide little additional information; however sampling will continue from the upper zone of MW #1 throughout the balance of the Injection period and the PISC period. PCC plans to plug and abandon the lower zone of MW #1 after the CO_2 plume has passed, using CO_2 resistant cement per the plans for Lift 1 in Section G.7.2 of the Post Injection and Site Closure Plan. PCC will not plug and abandon the lower zone of MW #1 without prior approval of the US EPA UIC Program Director.

Figure A.II.3-2 provides a schematic of the above ground equipment for MW #1, which consists of discrete temperature and pressure gauges at the surface for both the tubing and annulus, the afore described DTS system, and a surface air sensor to measure CO_2 concentration in air at the wellhead.

All data from the monitoring well will be recorded locally to a multi-terabyte hard drive and transmitted by telemetry to the PCC control facility.

Figure A.II.3-2. Schematic of Above Ground Equipment for MW #1



A.II.4. Construction of Above Confining Zone Groundwater Monitoring Wells

PCC has installed a network of 11 monitoring stations (MS-1 through MS-11) within and in the vicinity of the AoR and MMA as illustrated in Figure A.II.4-1. Monitoring stations MS-1, MS-2, and MS-4 through MS-6 contain a shallow monitoring well (SMW-1, SMW-2, and SMW-4 through SMW-6) for monitoring groundwater within the water table. The shallow monitoring well at MS-3 (i.e., SMW-3) and the four deep monitoring wells (DMW-1, DMW-2, DMW-4, and DWM-11) monitor the lowermost USDW (i.e., the Dakota formation). A schematic of the geologic cross-sections and the depth of the wells is provided as Figure A.II.4-2.

These groundwater monitoring wells were constructed in general accordance with the appropriate state, ASTM International (ASTM), and US EPA standard operating procedures for Design and Installation of Monitoring Wells – see Attachment A.II-3. The well construction logs are included in Attachment A.II-4 and are summarized in Figures A.II.4-3 and A.II.4-4.

Figure A.II.4-1. Monitoring Well Locations

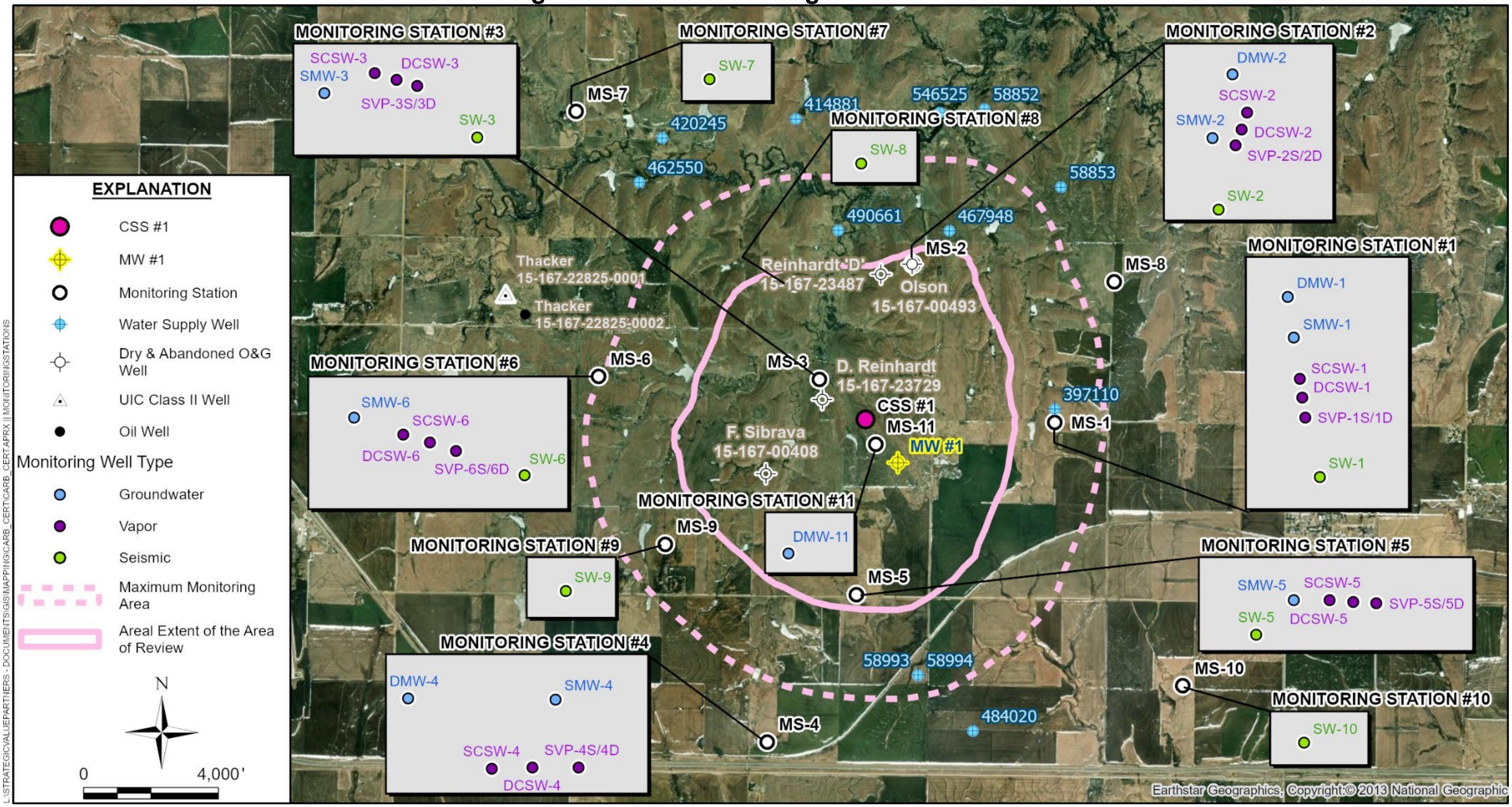


Figure A.II.4-2. Groundwater Monitoring Wells Depths and Geologic Cross-Sections

Summary of Groundwater Monitoring System - PCC Project Site - Russell Co. Kansas

	MS # 1		MS #2		MS #3	MS #4		MS #5	MS #6	MS #11
Well ID	SMW-1	DMW-1	SMW-2	DMW-2	SMW-3	SMW-4	DMW-4	SMW-5	SMW-6	DMW-11
Ground Elev.	1823	1823	1817	1817	1736	1835	1835	1824	1825	1820
TOS Elev.	1753	1591	1742	1642	1677	1745	1678	1726	1745	1588
BOS Elev.	1733	1571	1722	1622	1657	1725	1658	1706	1725	1568

System	Series	Formation	Lithologic Unit/member		Aquifer Systems	Approx. Top Elevation (ft NGVD)	Approx. Thickness (ft)
Quaternary	Pleistocene	Unnamed Pleistocene	Loess	Ql		1815-1850	10-40
Cretaceous		Carlile Shale Formation	Fairport Chalk Member	Kcf		1800-1835	20-30
		Greenhorn Limestone	Fencepost Ls			1790-1800	0-5
			Greenhorn Limestone	Kgh	Shallow unconfined aquifer	1700-1800	75-85
		Graneros Shale	Graneros Shale	Kgr	Semi-confining Unit	1690-1700	20-30
		Dakota Formation	Dakota Formation	Kd	Upper Dakota Aquifer	1670-1680	< 250

Approx. Depth

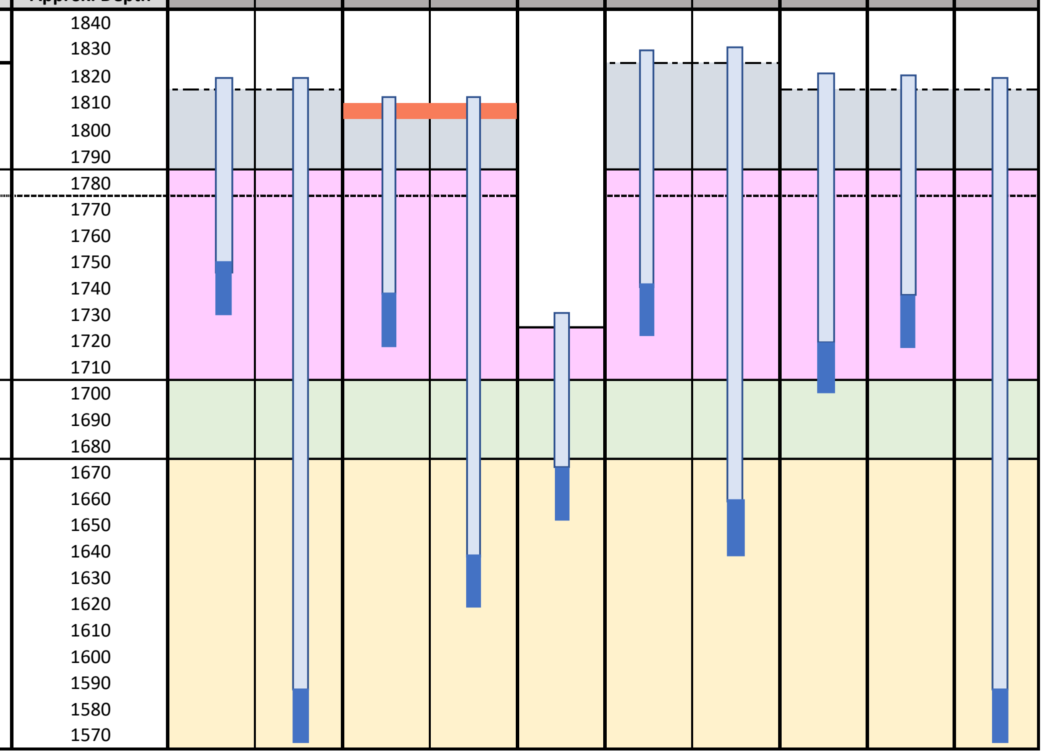
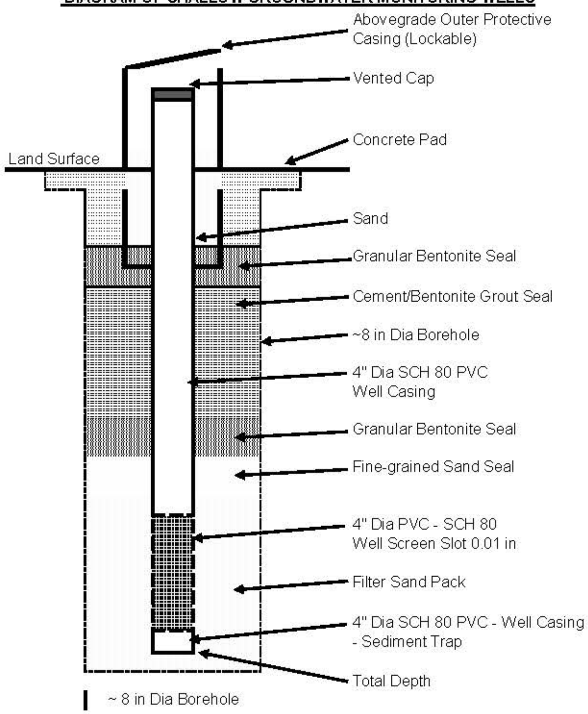


Figure A.II.4-3. Groundwater Monitoring Well Schematic Diagram and Construction Details – Shallow

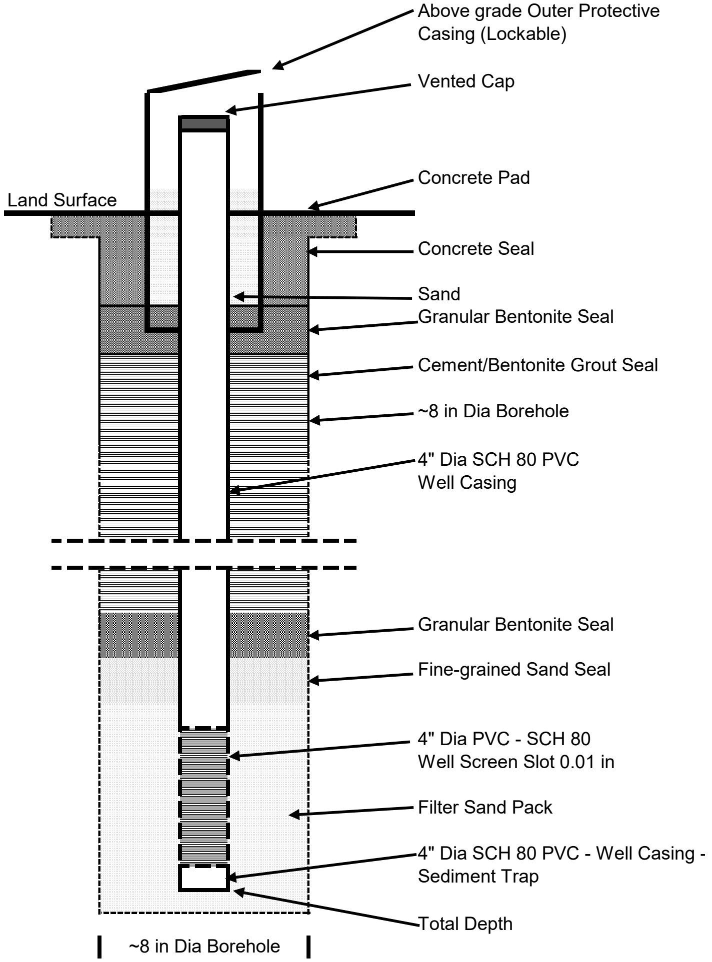
DIAGRAM OF SHALLOW GROUNDWATER MONITORING WELLS



CONSTRUCTION DETAILS	SMW-1	SMW-2	SMW-3	SMW-4	SMW-5	SMW-6
Above Grade Prot. Casing						
Material	Metal	Metal	Metal	Metal	Metal	Metal
Approx. Height (feet)	2	2	2	2	2	2
Well Casing						
PVC Casing Material	Schd 80	Schd 80	Schd 80	Schd 80	Schd 80	Schd 80
PVC Casing Length (feet)	90	95	77	108	116.5	98
TOC Elev (AMSL) (feet)	1,824.95	1,818.67	1,736.14	1,834.72	1,823.52	1,824.70
TOC Height (feet)	1.82	2.04	2.06	1.65	1.20	1.86
Concrete Surface Pad						
Approx. Dimensions (inches)	32	32	32	32	32	32
Grnd Surf. Elev (AMSL) (feet)	1,823.13	1,816.63	1,734.08	1,833.07	1,822.32	1,822.84
Concrete Pad Thickness (feet)	2.5	2.5	2.5	2.5	2.5	2.5
Concrete Pad Depth (feet)	0-2.5	0-2.5	0-2.5	0-2.5	0-2.5	0-2.5
Upper Bentonite Seal - Granules						
Bentonite Seal Thickness (feet)	2	2	2	2	2	2
Bentonite Seal Depth (feet)	2.5-4.5	2.5-4.5	2.5-4.5	2.5-4.5	2.5-4.5	2.5-4.5
Concrete/Grout Seal						
Concrete/Grout Seal Thickness (feet)	47.5	59.5	39.5	78.5	49.5	49.5
Concrete/Grout Seal Depth (feet)	4.5-52	4.5-64	4.5-44	4.5-83	4.5-54	4.5-54
Lower Bentonite Seal - Granules						
Bentonite Seal Thickness (feet)	4	4	4	4	4	4
Bentonite Seal Depth (feet)	52-56	64-68	44-48	79-83	54-58	54-58
Fine Sand Seal						
Seal Sand Pack Material	70/30	70/30	70/30	70/30	70/30	70/30
Seal Sand Pack Thickness (feet)	2	2	2	2	2	2
Seal Sand Pack Depth (feet)	56-58	68-70	48-50	83-85	58-60	58-60
Shallow GW Monitoring Well						
Filter Sand Pack Material	20/40	20/40	20/40	20/40	20/40	20/40
Filter Sand Pack Depth (feet)	58-90	70-96	50-78	85-110	60-117.5	60-99
Screen Slot Size (inches)	0.01	0.01	0.01	0.01	0.01	0.01
Screen Length (feet)	20	20	20	20	20	20
Screen Depth (feet)	69-89	75-95	57-77	89-109	96.5-116.5	78-98
Screen Elevation (AMSL) (feet)	1,754.13-1,734.13	1,741.63-1,721.63	1,677.08-1,657.08	1,744.07-1,724.07	1,725.82-1,705.82	1,744.84-1,724.84
Sediment Trap Length (feet)	1	1	1	1	1	1
Approx. Sediment Trap Depth (feet)	89-90	95-96	77-78	109-110	116.5-117.5	98-99
CTD Data Logger Depth (feet)	87.27	83.09	65.44	98.24	103.56	87.6
Approx. GeoTech Pump Depth (feet)	90	88	70	103	111.5	93
Total Depth						
Total Depth (feet)	90	96	78	110	117.5	99

Figure A.II.4-4. Groundwater Monitoring Well Schematic Diagram and Construction Details – Deep

DIAGRAM OF DEEP GROUNDWATER MONITORING WELLS

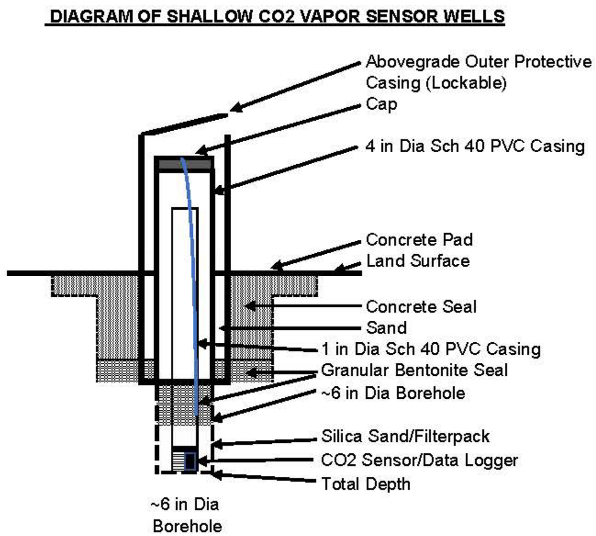


CONSTRUCTION DETAILS	DMW-1	DMW-2	DMW-4	DMW-11
Above Grade Prot. Casing				
Material	Metal	Metal	Metal	Metal
Approx. Height (feet ags)	2	2	2	2
Well Casing				
PVC Casing Material	Schd 80	Schd 80	Schd 80	Schd 80
PVC Casing Length (feet)				
TOC Elev (AMSL) (feet)	1,824.81	1,818.41	1834.72	TBD
TOC Height (feet ags)	1.80	2.07	1.65	TBD
Concrete Surface Pad				
Approx. Dimensions (inches)	32⌀	32⌀	32⌀	32⌀
Grnd Surf. Elev (AMSL) (feet)	1,823.01	1,816.34	1833.07	1820
Concrete Pad Thickness (feet)	2.5	2.5	2.5	2.5
Concrete Pad Depth (feet)	0-2.5	0-2.5	0-2.5	0-2.5
Upper Bentonite Seal - Granules				
Bentonite Seal Thickness (feet)	2	2	2	2
Bentonite Seal Depth (feet)	2.5-4.5	2.5-4.5	2.5-4.5	2.5-4.5
Concrete/Grout Seal				
Concrete/Grout Seal Thickness (feet)	193.5	153.5	130.5	TBD
Concrete/Grout Seal Depth (feet)	4.5-198	4.5-158	4.5-135	TBD
Lower Bentonite Seal - Granules				
Bentonite Seal Thickness (feet)	4	4	4	4
Bentonite Seal Depth (feet)	198-202	158-162	135-139	TBD
Fine Sand Seal				
Seal Sand Pack Material	70/30	70/30	70/30	70/30
Seal Sand Pack Thickness (feet)	2	2	2	2
Seal Sand Pack Depth (feet)	202-204	162-164	141-139	TBD
Deep GW Monitoring Well				
Filter Sand Pack Material	20/40	20/40	20/40	20/40
Filter Sand Pack Depth (feet)	204-236	164-196	141-175	TBD
Screen Slot Size (inches)	0.01	0.01	0.01	0.01
Screen Length (feet)	20	20	20	20
Screen Depth (feet)	214-234	174-194	153-173	TBD
Screen Elevation (AMSL) (feet)	1,609.01-1,589.01	1,642.34-1,622.34	1680.07-1660.07	TBD
Sediment Trap Length (feet)	2	2	2	2
Approx. Sediment Trap Depth (feet)	223-225	194-196	173-175	TBD
Approx. CTD Data Logger Depth (feet)	220.40	179.92	172.92	N/A
Approx. GeoTech Pump Depth (feet)	225	190	174	TBD
Total Depth				
Total Depth (feet)	236	196	175	~280-220

A.II.5. Construction of Soil Gas Monitoring Wells

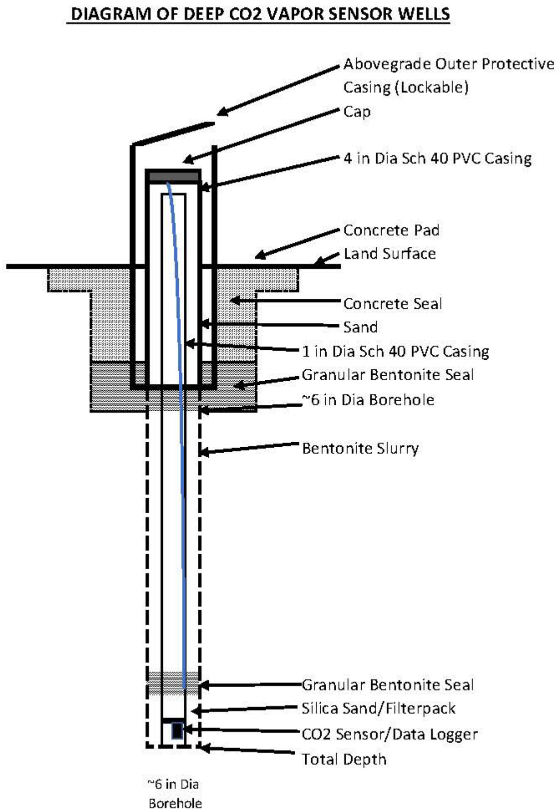
PCC has installed a network of 11 monitoring stations (MS-1 through MS-11) within and in the vicinity of the AoR and MMA as illustrated in Figure A.II.4-1 (previous section). Six of the monitoring stations contain instruments for measuring CO_2 concentrations in the upper vadose zone at approximately 5 ft bgs (SCSW-1 through SCSW-6) and in the lower vadose zone at approximately 10 ft bgs (DCSW-1 through DSCW-6). In addition, each monitoring station with soil gas monitoring capabilities also contains a soil gas well (SVP-1 through SVP-6) with nested sampling points in the upper vadose zone (SVP-1S through SVP-6S) and the lower vadose zone (SVP-1D through SVP-6D). These monitoring locations were constructed in general accordance with the appropriate state, ASTM, and US EPA standard operating procedures for Design and Installation of Monitoring Wells – see Attachment A.II-3. The well construction logs are included in Attachment A.II-5 and are summarized in Figures A.II.5-1 through A.II.5-3.

Figure A.II.5-1. CO_2 Soil Gas Well Schematic Diagram and Construction Details – Shallow



CONSTRUCTION DETAILS	SCSW 1	SCSW 2	SCSW 3	SCSW 4	SCW 5	SCSW 6
Above Grade Prot. Casing						
Material	Metal	Metal	Metal	Metal	Metal	Metal
Height (feet bgs)	2	2	2	2	2	2
Protective PVC Casing						
Material	Sch 40 PVC	Sch 40 PVC	Sch 40 PVC	Sch 40 PVC	Sch 40 PVC	Sch 40 PVC
Height (feet)	1.68	1.81	1.64	1.85	1.67	1.64
TOC Elev (AMSL) (feet)	1824.93	1818.00	1735.69	1835.53	1823.46	1824.40
Concrete Surface Pad						
Approx. Dimensions (inches)	32	32	32	32	32	32
Grnd Surf. Elev (AMSL) (feet)	1823.25	1816.19	1734.05	1833.68	1821.78	1822.76
Concrete Pad Thickness (feet)	0.50	0.50	0.50	0.50	0.50	0.50
Concrete Pad Depth (feet)	0-0.5	0-0.5	0-0.5	0-0.5	0-0.5	0-0.5
Concrete/Grout Seal						
Concrete/Grout Thickness (feet)	2.0	2.0	2.0	2.0	2.0	2.0
Concrete/Grout Depth (feet)	0.5-2.5	0.5-2.5	0.5-2.5	0.5-2.5	0.5-2.5	0.5-2.5
Bentonite Seal - Granules						
Bentonite Seal Thickness (feet)	1.5	1.5	1.5	1.5	1.5	1.5
Bentonite Seal Depth (feet)	2.5-4.0	2.5-4.0	2.5-4.0	2.5-4.0	2.5-4.0	2.5-4.0
Well Casing Material						
PVC Casing Material	Sch 40 PVC	Sch 40 PVC	Sch 40 PVC	Sch 40 PVC	Sch 40 PVC	Sch 40 PVC
PVC Casing Length (feet)	5.0	5.0	5.0	5.0	5.0	5.0
Shallow Soil Gas Sensor Well						
Sand Pack Material	20/40	20/40	20/40	20/40	20/40	20/40
Sand Pack Thickness (feet)	1	1	1	1	1	1
Sand Pack Depth (feet)	4.0 - 5.0	4.0 - 5.0	4.0 - 5.0	4.0 - 5.0	4.0 - 5.0	4.0 - 5.0
Screen Slot Size (inches)	0.01	0.01	0.01	0.01	0.01	0.01
Screen Length (feet)	0.5	0.5	0.5	0.5	0.5	0.5
Screen Depth (feet)	4.5 - 5	4.5 - 5	4.5 - 5	4.5 - 5	4.5 - 5	4.5 - 5
CO_2 Sensor Depth (feet)	5	5	5	5	5	5
Total Depth						
Total Depth (feet)	5	5	5	5	5	5

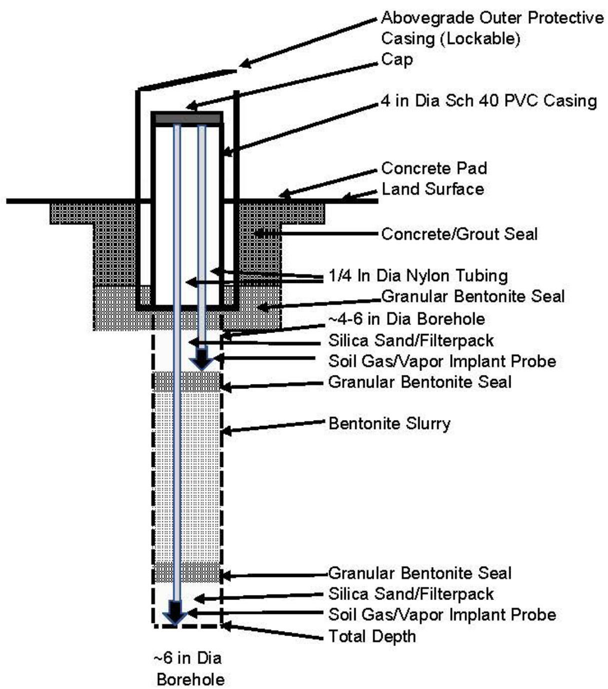
Figure A.II.5-2. CO_2 Soil Gas Well Schematic Diagram and Construction Details – Deep



CONSTRUCTION DETAILS	DCSW 1	DCSW 2	DCSW 3	DCSW 4	DCSW 5	DCSW 6
Above Grade Prot. Casing						
Material	Metal	Metal	Metal	Metal	Metal	Metal
Height (feet bgs)	2	2	2	2	2	2
Protective PVC Casing						
Material	Sch 40 PVC	Sch 40 PVC	Sch 40 PVC	Sch 40 PVC	Sch 40 PVC	Sch 40 PVC
Height (feet)	1.68	1.81	1.64	1.85	1.67	1.64
TOC Elev (AMSL) (feet)	1824.93	1818.00	1735.69	1835.53	1823.46	1824.40
Concrete Surface Pad						
Approx. Dimensions (inches)	32	32	32	32	32	32
Grnd Surf. Elev (AMSL) (feet)	1823.25	1816.19	1734.05	1833.68	1821.78	1822.76
Concrete Pad Thickness (feet)	0.50	0.50	0.50	0.50	0.50	0.50
Concrete Pad Depth (feet)	0-0.5	0-0.5	0-0.5	0-0.5	0-0.5	0-0.5
Concrete/Grout Seal						
Concrete/Grout Thickness (feet)	2.5	2.5	2.5	2.5	2.5	2.5
Concrete/Grout Depth (feet)	0.5-3.0	0.5-3.0	0.5-3.0	0.5-3.0	0.5-3.0	0.5-3.0
Bentonite Seal - Granules						
Bentonite Seal Thickness (feet)	1	1	1	1	1	1
Bentonite Seal Depth (feet)	3.0-4.0	3.0-4.0	3.0-4.0	3.0-4.0	3.0-4.0	3.0-4.0
Well Casing Material						
PVC Casing Material	Sch 40 PVC	Sch 40 PVC	Sch 40 PVC	Sch 40 PVC	Sch 40 PVC	Sch 40 PVC
PVC Casing Length (feet)	10.0	10.0	10.0	10.0	10.0	10.0
Bentonite Slurry						
Bentonite Slurry Thickness (feet)	4.0	4.0	4.0	4.0	4.0	4.0
Bentonite Slurry Depth (feet)	4.0-8.0	4.0-8.0	4.0-8.0	4.0-8.0	4.0-8.0	4.0-8.0
Bentonite Seal - Granules						
Bentonite Seal Thickness (feet)	1	1	1	1	1	1
Bentonite Seal Depth (feet)	8.0-9.0	8.0-9.0	8.0-9.0	8.0-9.0	8.0-9.0	8.0-9.0
Shallow Soil Gas Sensor Well						
Sand Pack Material	20/40	20/40	20/40	20/40	20/40	20/40
Sand Pack Thickness (feet)	1	1	1	1	1	1
Sand Pack Depth (feet)	9-10	9-10	9-10	9-10	9-10	9-10
Screen Slot Size (inches)	0.01	0.01	0.01	0.01	0.01	0.01
Screen Length (feet)	0.5	0.5	0.5	0.5	0.5	0.5
Screen Depth (feet)	9.5-10	9.5-10	9.5-10	9.5-10	9.5-10	9.5-10
CO_2 Sensor Depth (feet)	10	10	10	10	10	10
Total Depth						
Total Depth (feet)	10	10	10	10	10	10

Figure A.II.5-3. Nested Soil Gas Well Schematic Diagram and Construction Details – Deep

DIAGRAM OF NESTED SOIL GAS WELLS



CONSTRUCTION DETAILS	SVP 1 S/D	SVP 2 S/D	SVP 3 S/D	SVP 4 S/D	SVP 5 S/D	SVP 6 S/D
Above Grade Prot. Casing						
Material	Metal	Metal	Metal	Metal	Metal	Metal
Approx. Height (feet)	2	2	2	2	2	2
Protective PVC Casing						
Material	Sch 40 PVC	Sch 40 PVC	Sch 40 PVC	Sch 40 PVC	Sch 40 PVC	Sch 40 PVC
Height (feet)	1.57	1.89	1.48	1.69	1.19	1.34
TOC Elev (AMSL) (feet)	1824.86	1818.30	1735.56	1835.33	1823.52	1823.94
Concrete Surface Pad						
Approx. Dimensions (inches)	32	32	32	32	32	32
Grnd Surf. Elev (AMSL) (feet)	1823.30	1816.42	1734.08	1833.64	1822.32	1822.60
Concrete Pad Thickness (feet)	0.50	0.50	0.50	0.50	0.50	0.50
Concrete Pad Depth (feet)	0-0.5	0-0.5	0-0.5	0-0.5	0-0.5	0-0.5
Concrete/Grout Seal						
Concrete/Grout Thickness (feet)	2.0	2.0	2.0	2.0	2.0	2.0
Concrete/Grout Depth (feet)	0.5-2.5	0.5-2.5	0.5-2.5	0.5-2.5	0.5-2.5	0.5-2.5
Bentonite Seal - Granules						
Bentonite Seal Thickness (feet)	1.5	1.5	1.5	1.5	1.5	1.5
Bentonite Seal Depth (feet)	2.5-4.0	2.5-4.0	2.5-4.0	2.5-4.0	2.5-4.0	2.5-4.0
Shallow Vapor Probe						
Sand Pack Material	20/40	20/40	20/40	20/40	20/40	20/40
Sand Pack Thickness (feet)	1	1	1	1	1	1
Sand Pack Depth (feet)	4.0-5.0	4.0-5.0	4.0-5.0	4.0-5.0	4.0-5.0	4.0-5.0
Vapor Probe Depth (feet)	5	5	5	5	5	5
Bentonite Seal - Granules						
Bentonite Seal Thickness (feet)	0.5	0.5	0.5	0.5	0.5	0.5
Bentonite Seal Depth (feet)	5.0-5.5	5.0-5.5	5.0-5.5	5.0-5.5	5.0-5.5	5.0-5.5
Bentonite Slurry						
Bentonite Slurry Thickness (feet)	3	3	3	3	3	3
Bentonite Slurry Depth (feet)	5.5-8.5	5.5-8.5	5.5-8.5	5.5-8.5	5.5-8.5	5.5-8.5
Bentonite Seal - Granules						
Bentonite Seal Thickness (feet)	0.5	0.5	0.5	0.5	0.5	0.5
Bentonite Seal Depth (feet)	8.5-9.0	8.5-9.0	8.5-9.0	8.5-9.0	8.5-9.0	8.5-9.0
Deep Vapor Probe						
Sand Pack Material	20/40	20/40	20/40	20/40	20/40	20/40
Sand Pack Thickness (feet)	1	1	1	1	1	1
Sand Pack Depth (feet)	9.0-10.0	9.0-10.0	9.0-10.0	9.0-10.0	9.0-10.0	9.0-10.0
Vapor Probe Depth (feet)	10	10	10	10	10	10
Total Depth						
Total Depth (feet)	10	10	10	10	10	10

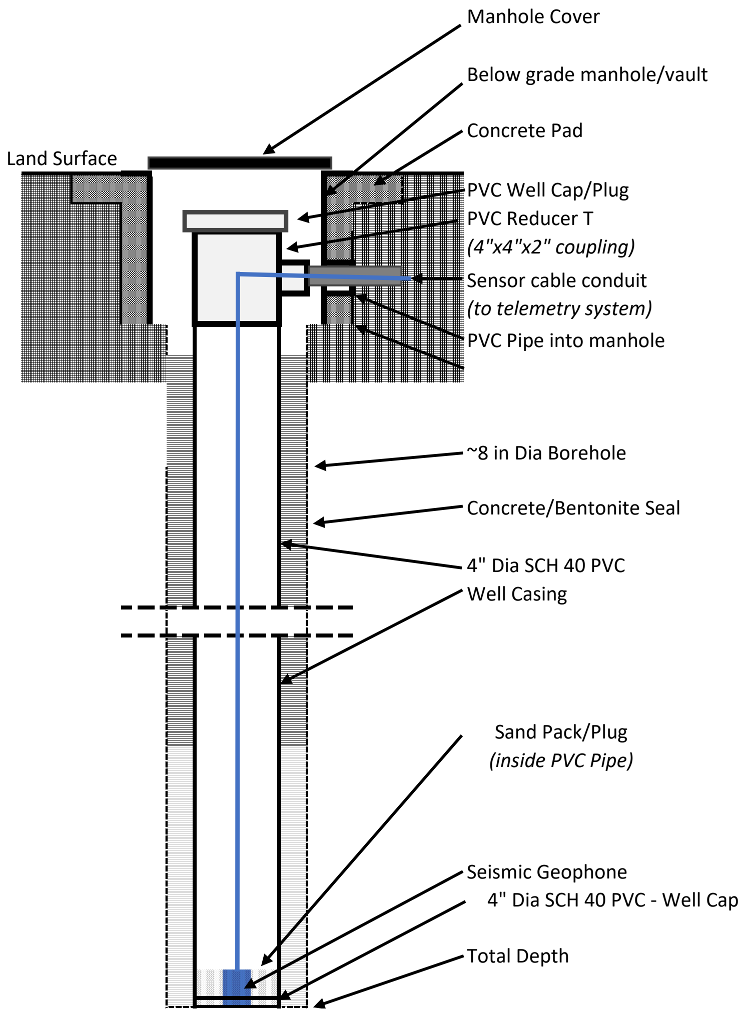
A.II.6. Construction of Passive Seismic Sensor Wells

The passive seismic system utilizes a network of nine seismic sensor well stations (SW-1, SW-2, SW-3, and SW-5 through SW-10 [no station #4]) within and in the vicinity of the AoR and MMA as illustrated previously in Figure A.II.4-1. Five of these seismic sensor stations are co-located within the existing monitoring stations (MS-1 through MS-3, MS-5 through MS-6). The primary purpose of MS-4 is to provide a background reference for groundwater and soil gas properties in the general vicinity; No seismic sensor was installed at MS-4 since it is located near an interstate highway – the highway traffic would induce excessive vibrational noise in a seismometer measurement, thus a sensor at this location would not benefit the performance of the passive seismic system.

Each seismic monitoring well consists of a four-inch diameter schedule 40 PVC well riser casing extending from the land surface to a depth of either 100 ft or 150 ft as illustrated in Figure A.II.6-1. SW-1/2/3/5/6/8/9 utilize 100 ft wells, SW-7/10 utilize 150 ft wells to reduce seismometer noise from nearby traffic. The PVC casing was grouted into the borehole, and a borehole seismometer was placed in the bottom of the PVC casing and covered with sand to ensure contact with the well casing and subsurface geologic formations.

Figure A.II.6-1. Passive Seismic Sensor Well Construction

DIAGRAM OF PASSIVE SEISMIC SENSOR BOREHOLE



CONSTRUCTION DETAILS	100 foot boreholes MS-1, MS-2, MS-3, MS-5, MS-6, MS-8, MS-9	150 foot boreholes MS-7, MS-10
Below Grade Manhole/Vault		
Material	Metal	Metal
Approx. Dimensions (feet Dia)	1.5 *or similar*	1.5 *or similar*
Well Casing		
PVC Casing Material	Schd 40	Schd 40
PVC Casing Length (feet)	100	150
TOC Elev (AMSL) (feet)	Variable	Variable
TOC Height (feet bls)	Variable	Variable
Concrete Surface Pad		
Approx. Dimensions (radius/square - feet)	2.5 -3	2.5 -3
Ground Surface Elev (AMSL) (feet)	Variable	Variable
Concrete Pad Thickness (feet)	0.5-1.5	0.5-1.5
Concrete Pad Depth (feet)	0.5-1.5	0.5-1.5
Bentonite-Grout Seal		
Concrete/Grout Seal Thickness (feet)	~80	~130
Concrete/Grout Seal Depth (feet)	~20-100	~20-150
Sand Pack/Plug - Inside PVC Pipe		
Sand Pack Material	20/40 (or equiv.)	20/40 (or equiv.)
Sand Pack Thickness (feet)	2	2
Sand Pack Depth (feet bls)	~98-100	~148-150
Geophone Placement		
Geophone Depth (feet) (bls)	~98-100	~148-150
Total Depth		
Total Depth (feet)	~100	~150

A.II.7. References

EPA 2012, Geologic Sequestration of Carbon Dioxide: Underground Injection Control (UIC) Program Class VI Well Construction Guidance, EPA 816-R-11-020, May 2012. Available at: https://www.epa.gov/sites/default/files/2015-07/documents/epa816r11020.pdf.