INJECTION WELL CONSTRUCTION PLAN
40 CFR §146.82(a)(11) and (12), §146.86, §146.87, and §146.88 (a), (b), (c), and (e)

Brown Pelican CO_2 Sequestration Project

1.0 Facility Information

Facility name: Brown Pelican CO_2 Sequestration Project
BRP CCS1, CCS2 and CCS3 Wells

Facility contact: [redacted]

Well location: Penwell, Texas

BRP CCS1	31.76481926	-102.72891895
BRP CCS2	31.76994887	-102.73320589
BRP CCS3	31.76024766	-102.71013484

2.0 Overview

Oxy Low Carbon Ventures, LLC (OLCV) constructed UIC Class VI CO_2 injection wells for the Brown Pelican CO_2 Sequestration Project (BRP Project or Project) according to the procedures in this document. The matter of construction details is relevant to the requirements of Environmental Protection Agency (EPA) document 40 CFR Subpart H – Criteria and Standards Applicable to Class VI Wells. The main topics covered in this attachment are special construction requirements, open hole diameters and intervals, casing specifications, tubing specifications, data acquisition and testing plan, and demonstration of mechanical integrity.

The BRP CCS1, BRP CCS2, and BRP CCS3 wells were constructed with the highest standards and best practices for drilling and well construction. The design and materials were selected to ensure mechanical integrity and to optimize the operation during the life of the Project.

3.0 Design Parameters and Specifications

The UIC Class VI wells were designed to maximize the rate of injection while maintaining the bottomhole pressure below 90% of the fracture gradient. The selected design provides enough clearance to deploy the pressure and temperature gauges on tubing and install a fiber optic cable on the long string casing to ensure continuous surveillance of external integrity and conformance.

Design parameters that will be employed during the life of the well are shown in Table 1, and CO_2 specifications for the Project are shown in Table 2. A nodal analysis was used to perform sensitivities on the tubing size, rate of erosion, and potential movement of the tubulars. The nodal analysis results, operating parameters, and CO_2 specifications were used in selecting materials to construct the well.

Table 1—Design Parameters

Parameter	Value or Range
Injection rate (MTPD)	417-1319
Tubing pressure (psi)	1,000 to 1,800
Annular surface pressure (psi)	0 to 400
Surface temperature (°F)	60 to 90
Bottomhole temperature (°F)	120

Note:
Annular surface pressure between the tubing and long string will be kept between 0 and 400 psi to monitor changes during injection. It is not recommended to apply the maximum injection pressure to the annulus between the tubing and the long string casing to avoid unnecessary stress on the cement sheath, which could lead to a micro-annulus or microfractures.

Table 2—Specification of CO_2 Injectate

Component	Specification
CO_2 content	>95 mol%
Water	<30 lbm/MMscf
Nitrogen	<4 mol%
Sulphur	<35 ppm by weight
Oxygen	<5 mol%
Glycol	<0.3 gal/MMscf
Carbon Monoxide	<4,250 ppm by weight
NOx	<6 ppm by weight
SOx	<1 ppm by weight
Particulates ($CaCO_3$)	<1 ppm by weight
Argon	<1 mol%
Surface pressure	>1,600 psig
Surface temperature	>65°F and <120°F

4.0 Well Design

OLCV constructed three UIC Class VI CO_2 injector wells: BRP CCS1, BRP CCS2, and BRP CCS3 for the Project. The locations and orientations of those wells are shown in Figure 1 below.

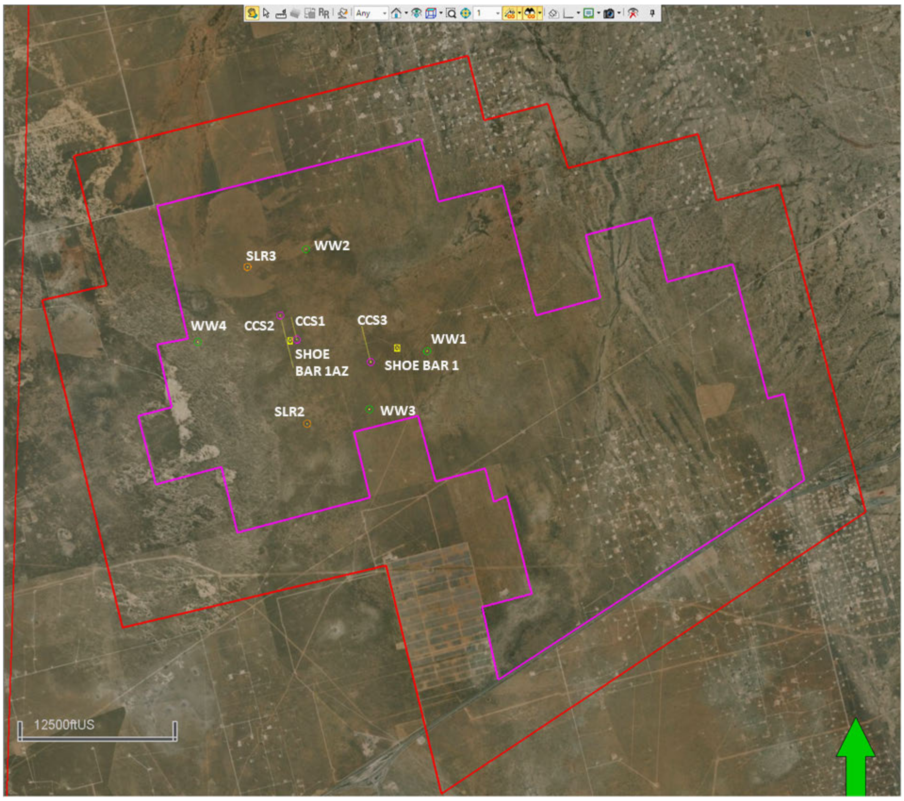

Figure 1—BRP CCS1, BRP CCS2 and BRP CCS3 Well Locations

4.1 BRP CCS1

4.1.1 Design for BRP CCS1

The BRP CCS1 well design includes three main casing sections: 1) surface casing to cover the USDW and provide integrity while drilling to the Injection Zone, 2) intermediate section, and 3) a long string section to acquire formation data and isolate the target formation while running the upper completion equipment. Figure 2 presents wellbore trajectory of BRP CCS1 and Figure 3 is BRP CCS1 as-drilled wellbore schematic

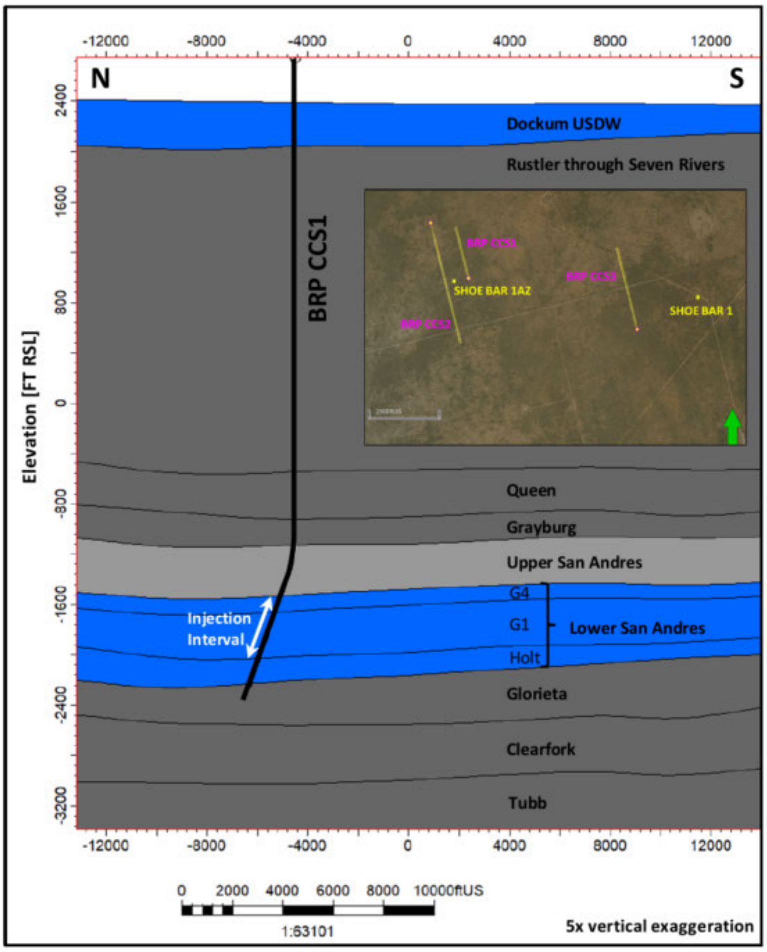

Figure 2—Wellbore trajectory of BRP CCS1 with completion interval in sub-zone G4-G1 highlighted in white.

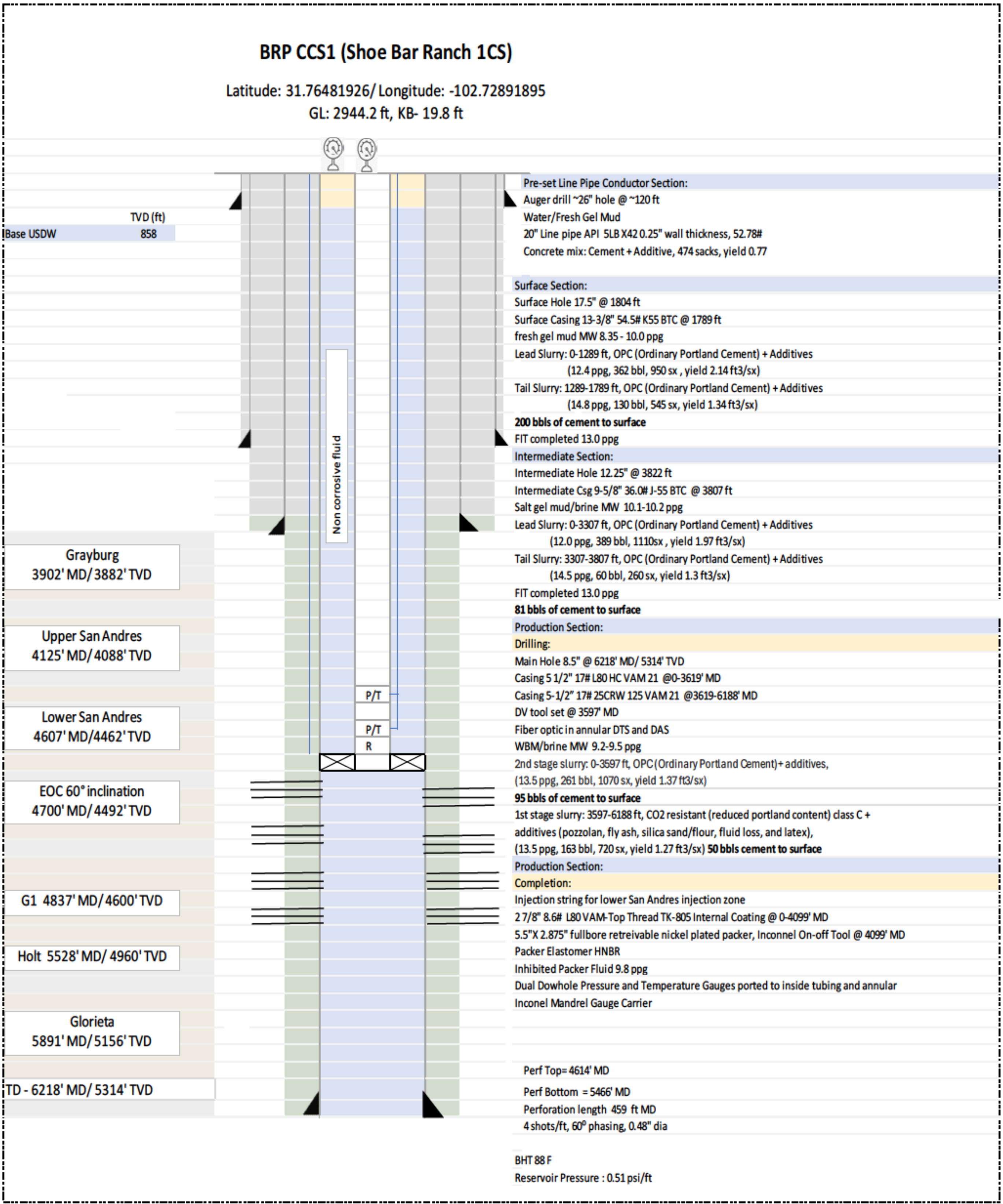

Figure 3—BRP CCS1 well schematic (as drilled)

Details of BRP CCS1 well design are provided in the following tables. Table 3 contains the open hole diameters of each section, Table 4 lists the casing specifications, and Table 5 details the casing material properties. In addition, Table 7 contains the upper completion equipment specifications, and Table 8 shows the tubing material properties.

Table 3—Open Hole Diameters and Intervals for BRP CCS1

Name	Depth Interval (ft)	Open Hole Diameter (in.)	Comment
Conductor Section	0 to 120	26	Auger drill
Surface section	0 to 1,804	17 ½	Below base of USDW
Intermediate section	1,804 to 3,807	12 ¼	Intermediate section
Long string section	3,807 to 6,218	8 ½	To total depth (TD)

Notes:

- The well TD included approximately 50 ft of cement shoe track, and 100 ft casing rat hole for completion operations in the Glorieta Formation.
- The USDW depth was confirmed with open hole logs.

Table 4—Casing Specifications for BRP CCS1

Name	Depth Interval (ft)	OD (in.)	ID (in.)	Drift (in.)	Weight (lbm/ft)	Grade (API)	Coupling
Pre-set conductor	0 to 120	20	19.5	19.25	52.78	5LB X42	weld
Surface string	0 to 1,798	13 3/8	12.615	12.459	54.5	K-55	BTC
Intermediate string	0 to 3,822	9 5/8	8.921	8.765	36	J-55	BTC
Long string	0 to 3,619	5 1/2	4.892	4.767	17	L80	Vam 21
Long string	3,619 to 6,188	5 1/2	4.892	4.767	17	SM25CRW-125	Vam 21

Note: OD is outer diameter; ID is inner diameter

Table 5—Casing Material Properties for BRP CCS1

Casing	Depth Interval (ft)	Burst (psi)	Collapse (psi)	Body Yield (Klb)
20 in conductor	0 to 120	-	-	-
13 3/8-inch 54.5# K-55 BTC	0 to 1,804	2,730	1,130	853
9 5/8-inch 36# J-55 BTC	0 to 3,822	3,520	2,020	564
5 1/2-inch 17# L80	0 to 3,619	7,740	6,290	397
5 1/2-inch 17# SM25CRW-125	3,619 to 6,188	12,090	7,890	829

Notes:

- A stage tool was located at 3,597 ft in the 5 1/2-inch casing to perform the two-stage cement job.
- The centralization program aimed at 70-90% standoff and was adjusted using the field data for deviation, caliper, and hole conditions.
- DTS/DAS fiber optic cable was deployed alongside the casing as part of the monitoring program. Special clamps, bands, and centralizers were installed to protect the fiber and provide a marker for wireline operations.

Table 6—Direction Design for BRP CCS1

Name	MD (ft)	Inclination (°)	Azimuth (°)	TVD (ft)	Dogleg (°/100ft)	Description
SHL	0	0	0	0	0.00	Surface hole location
KOP	2627	0	346	2627	0.00	Kick of point
EOC	4700	60	346	4492	5.00	End of curve
Well TD	6218	60	346	5314	0.00	Tangent section

Table 7—Upper Completion Equipment Specifications for BRP CCS1

Name	Depth Interval (ft)	OD (in.)	ID (in.)	Drift (in.)	Weight (lbm/ft)	Grade (API)	Coupling
Injection (Coated TK-805) tubing	0 to 4,099	2 7/8	2.441	2.347	8.6	L80	Special
Nickel Plated Packer with HBNR (RGD) Elastomers)	4,099 to 4,107	4-5/8	2.38	2.347	-	P-110 (Nickel plated)	VAM-TOP

Table 8—Tubing Material Properties for BRP CCS1

Tubing	Depth Interval (ft)	Burst (psi)	Collapse (psi)	Body Yield (Ksi)
2 7/8-in. 6.5# L80 Special – Coated TK-805	0 to 4,099	10,570	11,170	80

Notes:

- Pressure and temperature gauges are external tubing-deployed and ported to the tubing and casing. Cable material is Inconel®, and gauge carriers are made by CO_2-resistant material.
- The internal diameter of the tubing is slightly reduced due to the TK-805 coating that was applied.
- The annular space between the 2 7/8-inch tubing and 5 1/2-inch casing is filled with packer fluid.

4.1.2 Drilling Procedure for BRP CCS1

The next section describes the drilling procedure for BRP CCS1.

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1 Distributed acoustic sensing (DAS) and distributed temperature sensing (DTS)

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4.1.3 Completion Procedure for BRP CCS1

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[2] Cement bond long (CBL), variable density log (VBL), ultrasonic imager tool (USIT), casing collar locator (CCL)

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4.2 BRP CCS2

The BRP CCS2 well design includes three main casing sections: 1) surface casing to cover the USDW and provide integrity while drilling to the Injection Zone, 2) intermediate section, and 3) a long string section to acquire formation data and isolate the target formation while running the upper completion equipment. Figure 4 presents wellbore trajectory of BRP CCS2 and Figure 5 is the BRP CCS2 as-drilled wellbore schematic

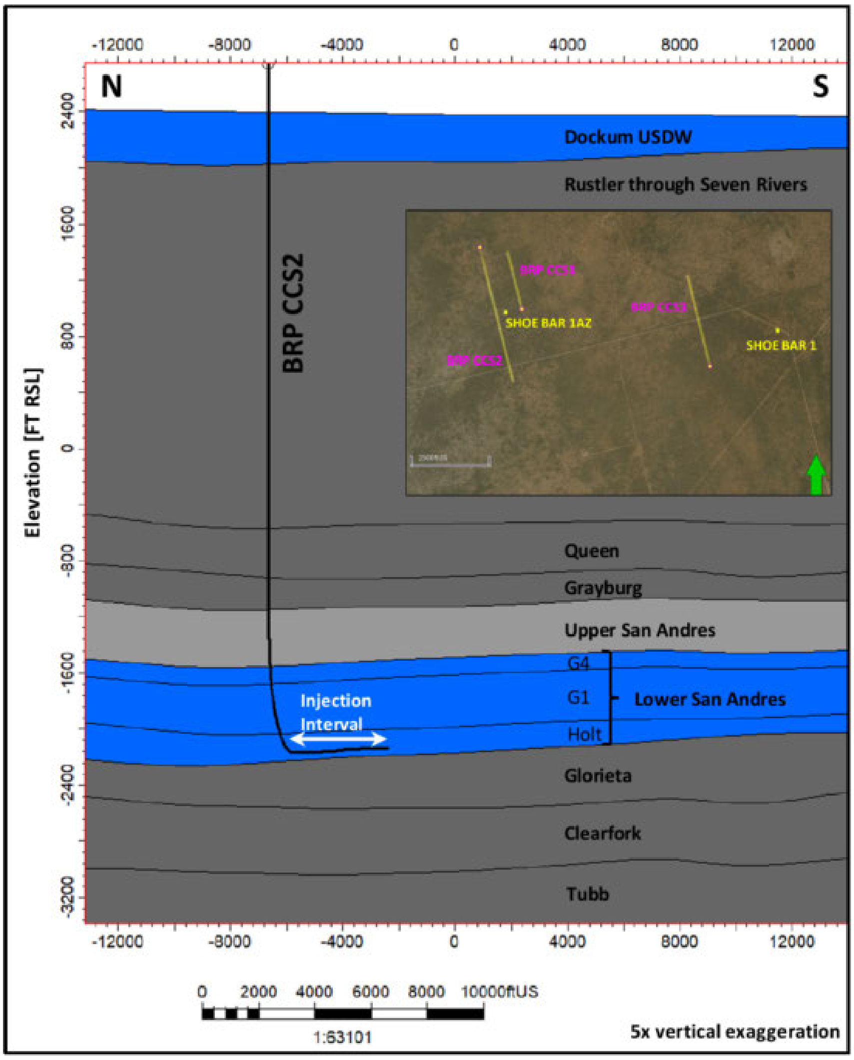

Figure 4—Wellbore trajectory of BRP CCS2 horizontal well with completion interval in sub-zone Holt highlighted in white.

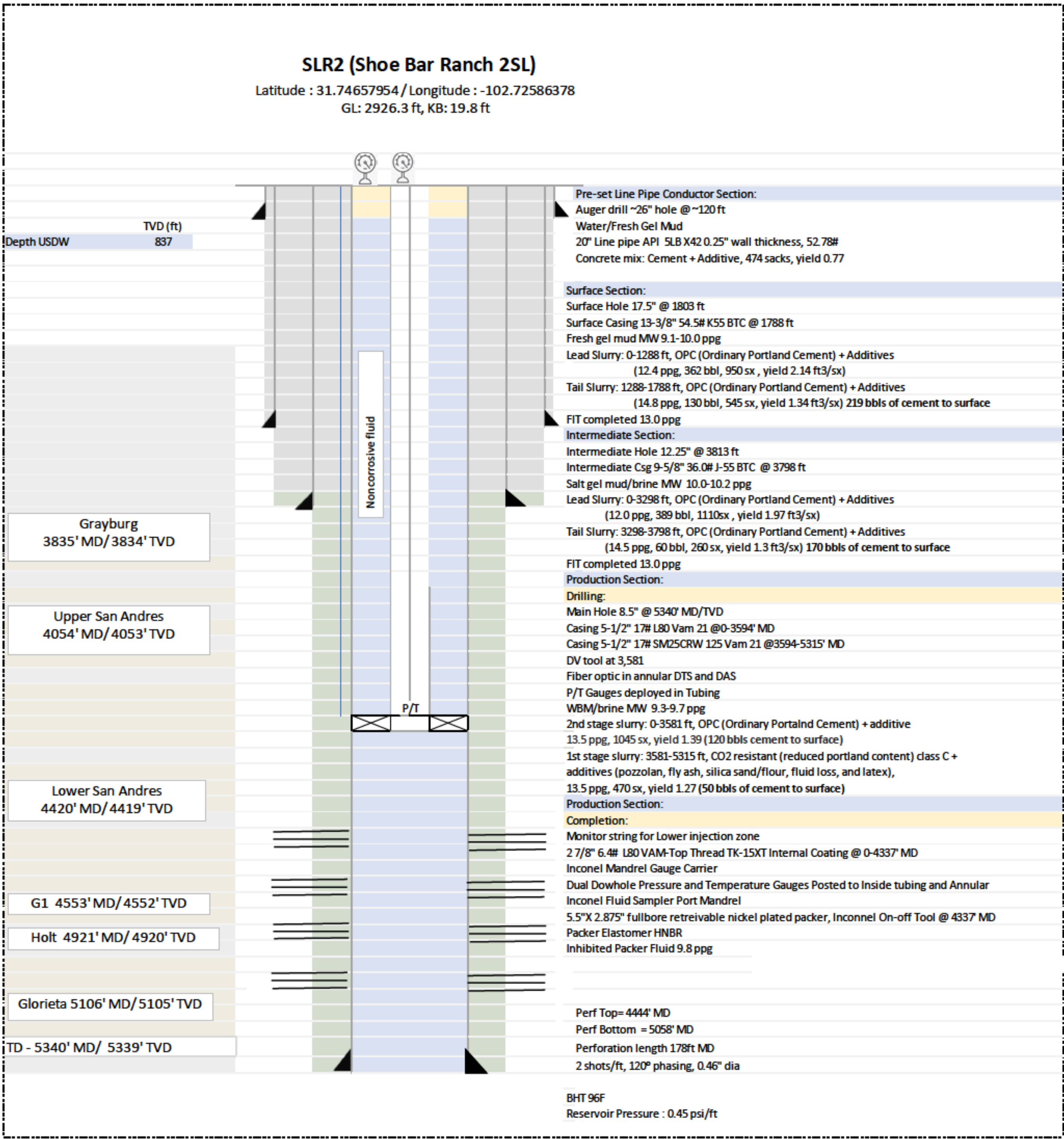

Figure 5—BRP CCS2 well schematic (as drilled)

4.2.1 Design for BRP CCS2

Details regarding the BRP CCS2 well design are provided in the following tables. Table 9 contains the open hole diameters of each section, Table 10 lists the casing specifications, and Tables 11 details the casing material properties. In addition, Table 13 contains the upper completion equipment specifications, and Table 14 shows the tubing material properties.

Table 9—Open Hole Diameters and Intervals for BRP CCS2

Name	Depth Interval (ft)	Open Hole Diameter (in.)	Comment
Conductor Section	0 to 120	26	Auger drill
Surface section	0 to 1,803	17 1/2	Below base of USDW
Intermediate section	1,803 to 3,811	12 1/4	Intermediate section
Long string section	3,811 to 9,312	8 1/2	To total depth (TD)

Notes:

- The well TD included approximately 80 ft of cement shoe track in the Holt Formation.
- The USDW depth was confirmed with open hole logs.

Table 10—Casing Specifications for BRP CCS2

Name	Depth Interval (ft)	OD (in.)	ID (in.)	Drift (in.)	Weight (lbm/ft)	Grade (API)	Coupling
Pre-set conductor	0 to 120	20	19.5	19.25	52.78	5LB X42	weld
Surface string	0 to 1,788	13 3/8	12.615	12.459	54.5	K-55	BTC
Intermediate string	0 to 3,797	9 5/8	8.921	8.765	36	J-55	BTC
Long string	0 to 3,578	5 1/2	4.892	4.767	17	L80	Vam 21
Long string	3,578 to 9,291	5 1/2	4.892	4.767	17	SM25CRW-125	Vam 21

Table 11—Casing Material Properties for BRP CCS2

Casing	Depth Interval (ft)	Burst (psi)	Collapse (psi)	Body Yield (Klb)
20-inch conductor	0 to 120	-	-	-
13 3/8-inch 54.5# K-55 BTC	0 to 1,788	2,730	1,130	853
9 5/8-inch 36# J-55 BTC	0 to 3,797	3,520	2,020	564
5 1/2-inch 17# L80	0 to 3,578	7,740	6,290	397
5 1/2-inch 17# SM25CRW-125	3,578 to 9,291	12,090	7,890	829

Notes:

- A stage tool is located at 3,565 ft MD in the 5 1/2-inch casing to perform the two-stage cement job.
- The centralization program aimed for 70-90% standoff and was adjusted using the field data for deviation, caliper, and hole conditions.
- DTS/DAS fiber optic cable were deployed alongside the casing as part of the monitoring program. Special clamps, bands, and centralizers were installed to protect the fiber and provide a marker for wireline operations.

Table 12—Direction design for BRP CCS2

Name	MD (ft)	Inclination (°)	Azimuth (°)	TVD (ft)	Dogleg (°/100ft)	Description
SHL	0	0	0	0	0.00	Surface hole location
KOP	3,885	0	346	3885	4.65	Kick of point

LP	5,835	90.63	166	5117	4.64	Landing point
Well TD	9,291	90.53	166	5083	0.00	Lateral section

Table 13—Upper Completion Equipment Specifications for BRP CCS2

Name	Depth Interval (ft)	OD (in.)	ID (in.)	Drift (in.)	Weight (lbm/ft)	Grade (API)	Coupling
Injection (Coated TK-805) tubing	0 to 4,470	2 7/8	2.441	2.347	6.5	L80	Special
Nickel Plated Packer with HBNR (RGD) Elastomers)	4,470-4,478	4 5/8	2.38	2.347	-	P-110 (Nickel plated)	VAM-TOP

Table 14—Tubing Material Properties for BRP CCS2

Tubing	Depth Interval (ft)	Burst (psi)	Collapse (psi)	Body Yield (Ksi)
2 7/8-in. 6.5# L80 Special – Coated TK-805	0 to 4,470	10,570	11,170	80

Notes:

- Pressure and temperature gauges are tubing-deployed above and below casing. Cable material is Inconel®, and gauge carriers are constructed with CO_2-resistant material.
- The internal diameter of the tubing is slightly reduced due to the TK-805 coating.
- The annular space between the 2 7/8-inch tubing and 5 1/2-inch casing is filled with packer fluid.

4.2.2 Drilling Procedure for BRP CCS2

The next section describes the drilling procedure for BRP CCS2.

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4.2.3 Completion Procedure for BRP CCS2

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4.3 BRP CCS3

4.3.1 Design for BRP CCS3

The BRP CCS3 well design includes three main casing sections: 1) surface casing to cover the USDW and provide integrity while drilling to the Injection Zone, 2) intermediate section, and 3) a long string section to acquire formation data and isolate the target formation while running the upper completion equipment. Figure 6 presents wellbore trajectory of BRP CCS3 and Figure 7 is the BRP CCS3 as-drilled wellbore schematic.

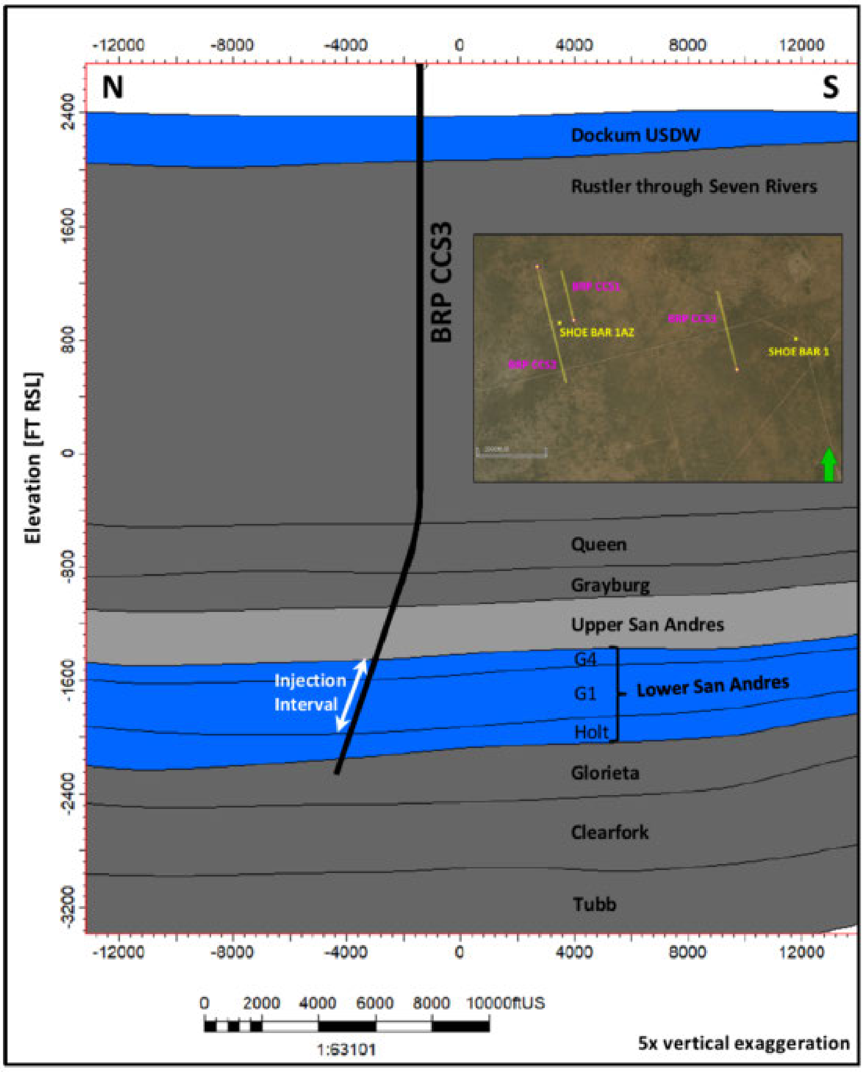

Figure 6—Wellbore trajectory of BRP CCS3 with completion interval in sub-zone G4-G1 highlighted in white

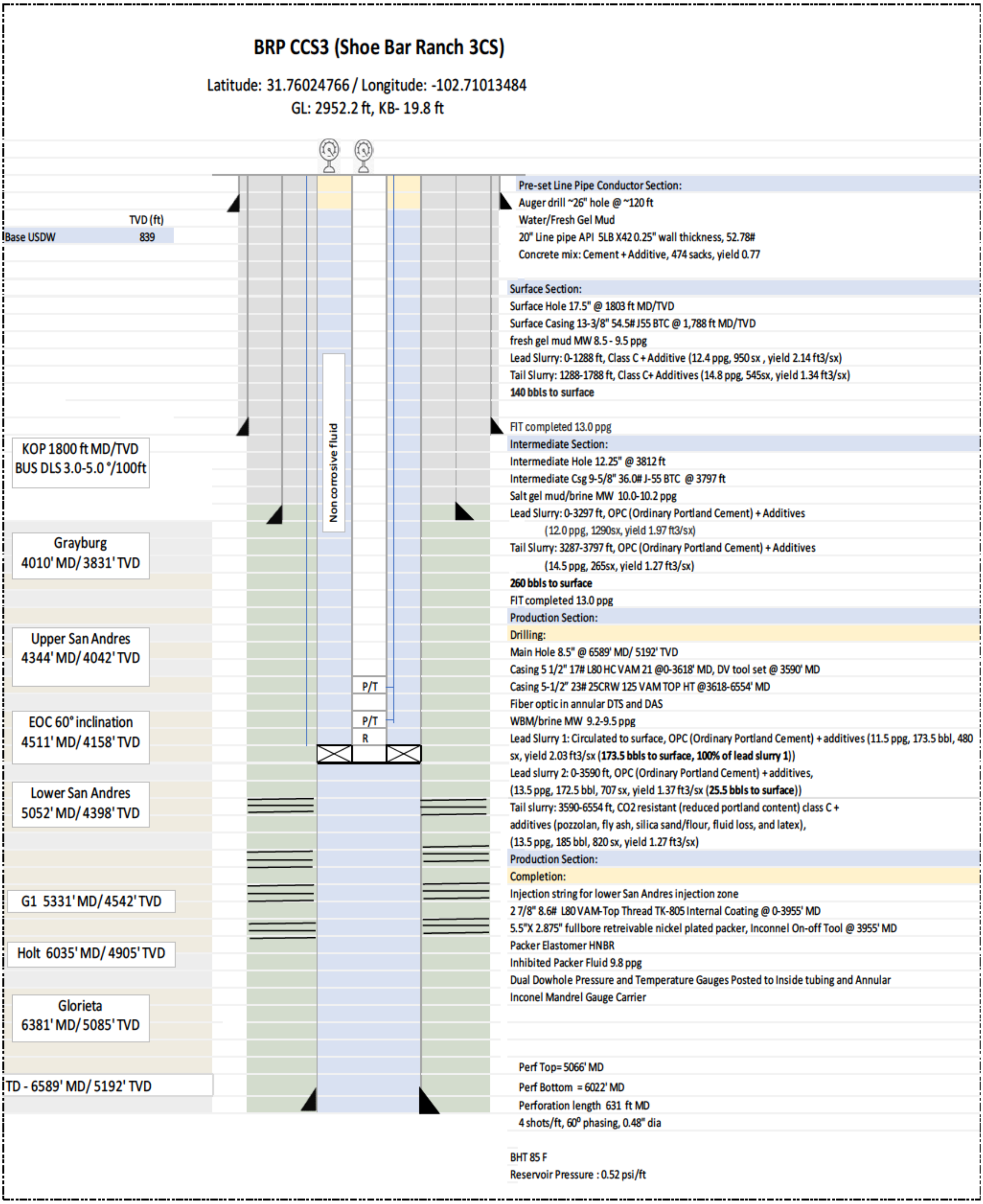

Figure 7—BRP CCS3 well proposed schematic

Details of BRP CCS3 well design are provided in the following tables. Table 15 contains the open hole diameters of each section, Table 16 lists the casing specifications, and Table 17 details the casing material properties. In addition, Table 19 contains the upper completion equipment specifications, and Table 20 shows the tubing material properties.

Table 15—Open Hole Diameters and Intervals BRP CCS3

Name	Depth Interval (ft)	Open Hole Diameter (in.)	Comment
Conductor Section	0 to 120	26	Auger drill
Surface section	0 to 1,803	17 1/2	Below base of USDW
Intermediate section	1,803 to 3,812	12 1/4	Intermediate section
Long string section	3,812 to 6,589	8 1/2	To total depth (TD)

Notes:

- The well TD includes approximately 80 ft of cement shoe track, and 100 ft casing rat hole for completion operations in the Glorieta Formation.
- The USDW depth were confirmed with open hole logs.

Table 16—Casing Specifications BRP CCS3

Name	Depth Interval (ft)	OD (in.)	ID (in.)	Drift (in.)	Weight (lbm/ft)	Grade (API)	Coupling
Pre-set conductor	0 to 120	20	19.5	19.25	52.78	5LB X42	weld
Surface string	0 to 1,788	13 3/8	12.615	12.459	54.5	K-55	BTC
Intermediate string	0 to 3,797	9 5/8	8.921	8.765	36	J-55	BTC
Long string	0 to 3,618	5 1/2	4.892	4.767	17	L80	Vam 21
Long string	3,618 to 6554	5 1/2	4.892	4.767	23	SM25CRW-125	Vam 21

Table 17—Casing Material Properties for BRP CCS3

Casing	Depth Interval (ft)	Burst (psi)	Collapse (psi)	Body Yield (Klb)
20-inch conductor	0 to 120	-	-	-
13 3/8-inch 54.5# K-55 BTC	0 to 1,788	2,730	1,130	853
9 5/8-inch 36# J-55 BTC	0 to 3,797	3,520	2,020	564
5 1/2-inch. 17# L80	0 to 3,618	7,740	6,290	397
5 1/2-inch 17# SM25CRW-125	3,618 to 6554	12,090	7,890	829

Notes:

- The centralization program was aimed at 70- 90% standoff and was adjusted using the field data for deviation, caliper, and hole conditions.
- DTS/DAS fiber optic cable was deployed alongside the casing as part of the monitoring program. Special clamps, bands, and centralizers were installed to protect the fiber and provide a marker for wireline operations.

Table 18—Direction design for BRP CCS3

Name	MD (ft)	Inclination (°)	Azimuth (°)	TVD (ft)	Dogleg (°/100ft)	Description

SHL	0	0	0	0	0.00	Surface hole location
KOP	1800	0	346	1800	0.00	Kick of point
EOC	4511	60	346	4158	5.00	End of curve
Well TD	6589	60	346	5192	0.00	Tangent section

Table 19—Upper Completion Equipment Specifications

Name	Depth Interval (ft)	OD (in.)	ID (in.)	Drift (in.)	Weight (lbm/ft)	Grade (API)	Coupling
Injection (Coated TK-805) tubing	0 to 3955	2 7/8	2.441	2.347	6.5	L80	Special
Nickel Plated Packer with HBNR (RGD) Elastomers)	3,995-3,963	4 5/8	2.38	2.347	-	P-110 (Nickel plated)	VAM-TOP

Table 20—Tubing Material Properties

Tubing	Depth Interval (ft)	Burst (psi)	Collapse (psi)	Body Yield (Ksi)
2 7/8-in. 6.5# L80 Special – Coated TK-805	0 to 3955	10,570	11,170	80

Notes:

- Pressure and temperature gauges were tubing-deployed above and below casing. Cable material is Inconel®, and gauge carriers are constructed with CO_2-resistant material.
- The internal diameter of the tubing is slightly reduced due to the TK-805 coating that was applied.
- The annular space between the 2 7/8-inch tubing and 5 1/2-inch casing is filled with packer fluid.

4.3.2 Drilling Procedure for BRP CCS3

The next section is the drilling procedure for BRP CCS3.

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4.3.3 Completion Procedure for BRP CCS3

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4.4 Material Selection

Casing string materials for the injection wells were selected based on the risk of corrosion. Casing constructed with alloy steel was installed in zones where there is low risk of CO_2 contact with the casing. Corrosion resistant alloy (CRA) was used in zones that will be in contact with CO_2 and formation. The primary casing below the packer and 3 to 5 joints above the packer are composed of CRA. The remainer of the well casing is alloy steel.

Appendix A discusses the material selection process.

4.5 Cement Program

To ensure long term barrier integrity under anticipated CO_2 conditions at and near the Injection Zone, modifications have been made to the slurry design(s) that improve chemical and mechanical resistance to the effects of carbonic acid exposure. These are and will be referenced as '*CO_2 Resistant Slurries*.' The modifications, while may vary slightly due to well conditions, formation pressures and strengths, etc. all contain the following composition adjustments when compared to conventional and/or ordinary Portland cement (OPC).

Additional discussion about the cement selection and additives is in Appendix B

Table 21—Cementing Program for BRP CCS1

Section	Type	Depths (ft)	Density (ppg)	Sacks	Excess
20 in	Concrete blend	0 to 120	-	474	100%
17 ½ -in.	OPC (Ordinary Portland Cement) with additives	0 to 1,289	12.4	950	125%
	OPC (Ordinary Portland Cement) with additives	1,289 to 1,789	14.8	545	100%
12 ¼-in.	OPC (Ordinary Portland Cement) with additives	0 to 3,307	12.0	1,110	225%
	OPC (Ordinary Portland Cement) with additives	3,307 to 3,807	14.5	260	100%
8 ½ -in.	OPC (Ordinary Portland Cement) with additives	0 to 3,597	13.5	1,070	50%
	CO_2 resistant (reduced Portland content) Class C, with additives (pozzolan, fly ash, silica sand/flour, fluid loss, and latex)	3,597 to 6,188	13.5	720	50%

Table 22—Cementing Program for BRP CCS2

Section	Type	Depths (ft)	Density (ppg)	Sacks	Excess
20 in	Concrete blend	0 to 120	-	474	100%

17 ½ -in.	OPC (Ordinary Portland Cement) with additives	0 to 1,288	12.4	950	125%
	OPC (Ordinary Portland Cement) with additives	1,288 to 1,788	14.8	545	100%
12 ¼-in.	OPC (Ordinary Portland Cement) with additives	0 to 3,297	12.0	1,110	225%
	OPC (Ordinary Portland Cement) with additives	3,297 to 3,797	14.5	320	100%
8 ½ -in.	OPC (Ordinary Portland Cement) with additives	0 to 3,565	13.5	1,045	50%
	CO_2 resistant (reduced Portland content) class C, with additives (pozzolan, fly ash, silica sand/flour, fluid loss, and latex)	3,565 to 9,260	13.5	1,540	50%

Table 23—Cementing Program for BRP CCS3

Section	Type	Depths (ft)	Density (ppg)	Sacks	Excess
20 in	Concrete blend	0 to 120	-	474	100 %
17 ½ -in.	OPC (Ordinary Portland Cement) with additives	0 to 1,288	12.4	950	125%
	OPC (Ordinary Portland Cement) with additives	1,288 to 1,788	14.8	545	100%
12 ¼-in.	OPC (Ordinary Portland Cement) with additives	0 to 3,297	12.0	1290	225%
	OPC (Ordinary Portland Cement) with additives	3,297 to 3,797	14.5	265	100%
8 ½ -in.	OPC (Ordinary Portland Cement) with additives	0	11.5	480	0%
	OPC (Ordinary Portland Cement) with additives	0 to 3,590	13.5	707	0%
	CO_2 resistant (reduced Portland content) class C, with additives (pozzolan, fly ash, silica sand/flour, fluid loss, and latex)	3,590 to 6,554	13.5	820	50%

4.6. Mud Program

Table 24--Mud Program for BRP CCS1

Hole	Type	Depths (ft)	Density (ppg)	PV (cP)	YP (lbm/ 100 ft^2)	Funnel Viscosity (sec)	API Fluid Loss (cm^3)	LGS (%)
17 ½ -in	Fresh water gel	0 to 1,804	8.5 to 9.5	12 to 14	14 to 18	40 to 50	<20	<8

12 ¼-in	Fresh gel mud/ Brine water inhibited	0 to 3,822	9.5 to 10.2	14 to 18	16 to 18	40 to 50	<6	<3
8 1/2-in	Brine water inhibited	3,822 to 6,218	9.5 to 10.2	14 to 18	16 to 18	40 to 50	<6	<3

Table 25--Mud Program for BRP CCS2

Hole	Type	Depths (ft)	Density (ppg)	PV (cP)	YP (lbm/ 100 ft^2)	Funnel Viscosity (sec)	API Fluid Loss (cm^3)	LGS (%)
17 ½ -in	Fresh water gel	0 to 1,803	8.5 to 9.5	12 to 14	14 to 18	40 to 50	<20	<8
12 ¼-in	Fresh gel mud/ Brine water inhibited	0 to 3,811	9.5 to 10.2	14 to 18	16 to 18	40 to 50	<6	<3
8 1/2-in	Brine water inhibited	3,811 to 9,312	9.5 to 10.2	14 to 18	16 to 18	40 to 50	<6	<3

Table 26--Mud Program for BRP CCS3

Hole	Type	Depths (ft)	Density (ppg)	PV (cP)	YP (lbm/ 100 ft^2)	Funnel Viscosity (sec)	API Fluid Loss (cm^3)	LGS (%)
17 ½ -in	Fresh water gel	0 to 1,803	8.5 to 9.5	12 to 14	14 to 18	40 to 50	<20	<8
12 ¼-in	Fresh gel mud/ Brine water inhibited	0 to 3,891	9.5 to 10.2	14 to 18	16 to 18	40 to 50	<6	<3
8 1/2-in	Brine water inhibited	3,891 to 6,598	9.5 to 10.2	14 to 18	16 to 18	40 to 50	<6	<3

5.0 Data Acquisition and Testing Plan Summary

Comprehensive details on pre-operational testing are provided in the Pre-Operational Testing Plan that is part of this application. The information below summarizes key components of the plan.

The pre-operational testing program determined or verified the depth, thickness, mineralogy, lithology, porosity, permeability, and geomechanical information of the Injection Zone, the overlying Upper Confining Zone, and other relevant geologic formations. In addition, formation fluid characteristics of the Injection Zone were obtained to establish baseline data against which future measurements may be compared after the start of injection operations. Section 5.0 lists the wireline logs and tests conducted for the BRP CCS1, BRP CCS2, and BRP CCS3. Consult Table 14 of the Pre-Operations Plan or Table 6 in the QASP for details on fluid analyses.

Table 27— Open hole logs acquired during the construction phase of BRP CCS1

Method	Interval Section(s)	Purpose
Deviation survey	Every 100 ft while drilling as minimum, from surface to TD	Define well trajectory, displacement, and tortuosity
Wireline – Spontaneous Potential	Surface, Intermediate, Production	Correlation log, volume of shale indicator, estimate salinity
Wireline – Resistivity	Surface, Intermediate, Production	Fluid identification, estimate salinity, correlation log
Wireline – Caliper	Surface, Intermediate, Production	Identify borehole enlargement and calculate cement volume
Wireline – Gamma ray	Intermediate, Production	Define stratigraphy, correlation log, shale indicator
Wireline – Magnetic resonance image	Production	Estimate porosity, pore size distribution, permeability index
Wireline – Sonic Scanner	Intermediate, Production	Estimate mechanical properties, validation of velocity model, well tie to seismic
Wireline – Spectral gamma ray	Surface, Intermediate, Production	Define uranium-rich formation, clay indicator
Wireline – Density / neutron	Surface, Intermediate, Production	Estimate porosity, mineralogical characterization
Wireline – High-definition image	Production	Identify fracture, structural information, minimum stress orientation
Wireline – Litho-scanner or equivalent	Production	Identify mineralogy
Wireline – Formation Dynamics Testing	Production	Measure formation pressures, fluid sampling, mini-frac testing
Mud Logging	Surface to TD (every 30 ft)	Identify lithology, hydrocarbon shows, gases composition

Table 28--Cased hole logs acquired during the drilling and completion phases of BRP CCS1.

Method	Interval Section(s)	Purpose
Cased Hole Logs and surveys Before Injection		
Wireline – CBL-VDL-CCL	Surface, Intermediate	Cement bond, Validate external mechanical integrity
Wireline – CBL-VDL-USIT (Casing inspection log)-CCL	Production	Cement bond, casing inspection log (USIT); Validate external mechanical integrity
Annulus Pressure Test – Long string casing	Annular between tubing and long string	Validate internal mechanical integrity between the tubing, long-string, and packer
Wireline – Activate pulsed neutron (Oxygen Activation Log) – Long string casing	Surface, Intermediate, Production	CO_2 saturation, baseline for monitoring
Wireline – Temperature Log	Surface, Intermediate, Production	Measure baseline temperature profile on the well from surface to top of perforation
Fiber Optic – DAS, DTS survey	Surface, Intermediate, Production.	Measure baseline temperature profile on the well from surface to top of perforation Acquire baseline 3D VSP survey for monitoring plume migration over time

Table 29-- Open hole logs acquired during the construction phase of BRP CCS2.

Method	Interval Section(s)	Purpose
Deviation survey	Every 100 ft while drilling as minimum, from surface to TD	Define well trajectory, displacement, tortuosity
Wireline – Spontaneous Potential	Surface, Intermediate	Correlation log, volume of shale indicator, estimate salinity
Wireline – Resistivity	Surface, Intermediate, Production	Fluid identification, estimate salinity, correlation log
Thrubit – Resistivity	Production	Fluid identification, estimate salinity, correlation log
Wireline – Caliper	Surface, Intermediate	Identify borehole enlargement and calculate cement volume
Thrubit – Caliper	Production	Identify borehole enlargement and calculate cement volume
Wireline – Gamma ray	Surface, Intermediate	Define stratigraphy, correlation log, shale indicator
Thrubit – Gamma ray	Production	Define stratigraphy, correlation log, shale indicator
Wireline – Sonic Scanner	Intermediate	Estimate mechanical properties, validation of velocity model, well tie to seismic
Thrubit – Dipole Sonic	Production	Estimate mechanical properties, validation of velocity model, well tie to seismic
Wireline – Spectral gamma ray	Surface, Intermediate	Define uranium-rich formation, clay indicator

Method	Interval Section(s)	Purpose
Thrubit – Spectral gamma ray	Production	Define uranium-rich formation, clay indicator
Wireline – Density / neutron	Surface, Intermediate	Estimate porosity, mineralogical characterization
Thrubit – Density / neutron	Production	Estimate porosity, mineralogical characterization
Thrubit – High-definition image	Production	Identify fracture, structural information, minimum stress orientation
Thrubit – Litho-scanner or equivalent (Pulsar)	Production	Identify mineralogy
Wireline and TLC – Formation Dynamics Testing	Production	Measure formation pressures, fluid sampling, mini-frac testing
Mud Logging	Surface to TD (every 30 ft)	Identify lithology, hydrocarbon shows, gases composition

Table 30-- Cased hole logs acquired during the drilling and completion phases of BRP CCS2.

Method	Interval Section(s)	Purpose
Cased Hole Logs and surveys Before Injection		
Wireline – CBL-VDL- CCL	Surface, Intermediate	Cement bond, Validate external mechanical integrity
Wireline – CBL-VDL-USIT (Casing inspection log)-CCL	Production	Cement bond, casing inspection log (USIT); Validate external mechanical integrity
Annulus Pressure Test – Long string casing	Annular between tubing and long string	Validate internal mechanical integrity between the tubing, long-string, and packer
Wireline – Activate pulsed neutron (Oxygen Activation Log) – Long string casing	Surface, Intermediate, Production	CO_2 saturation, baseline for monitoring
Wireline – Temperature Log	Surface, Intermediate, Production	Measure baseline temperature profile on the well from surface to top of perforation
Fiber Optic – DAS, DTS survey	Surface, Intermediate, Production	Measure baseline temperature profile on the well from surface to top of perforation Acquire baseline 3D VSP survey for monitoring plume migration over time

Table 31--Open hole logs acquired during the construction phase of BRP CCS3.

Method	Interval Section(s)	Purpose
Deviation survey	Every 100 ft while drilling as minimum, from surface to TD	Define well trajectory, displacement, tortuosity
Wireline – Spontaneous Potential	Surface, Intermediate, Production	Correlation log, volume of shale indicator, estimate salinity
Wireline – Resistivity	Surface, Intermediate, Production	Fluid identification, estimate salinity, correlation log

Method	Interval Section(s)	Purpose
Wireline – Caliper	Surface, Intermediate, Production	Identify borehole enlargement and calculate cement volume
Wireline – Gamma ray	Surface, Intermediate, Production	Define stratigraphy, correlation log, shale indicator
Wireline – Magnetic resonance image	Production	Estimate porosity, pore size distribution, permeability index
Wireline – Sonic Scanner	Intermediate, Production	Estimate mechanical properties, validation of velocity model, well tie to seismic
Wireline – Spectral gamma ray	Surface, Intermediate, Production	Define uranium-rich formation, clay indicator
Wireline – Density / neutron	Surface, Intermediate, Production	Estimate porosity, mineralogical characterization
Wireline – High-definition image	Production	Identify fracture, structural information, minimum stress orientation
Wireline – Litho-scanner or equivalent	Production	Identify mineralogy
Wireline – Formation Dynamics Testing	Production	Measure formation pressures, fluid sampling, mini-frac testing
Mud Logging	Surface to TD (every 30 ft)	Identify lithology, hydrocarbon shows, gases composition

Table 32-- Cased hole logs acquired during the drilling and completion phases of BRP CCS3.

Method	Interval Section(s)	Purpose
Cased Hole Logs and surveys Before Injection		
Wireline – CBL-VDL- CCL	Surface, Intermediate	Cement bond, Validate external mechanical integrity
Wireline – CBL-VDL-USIT (Casing inspection log)-CCL	Production	Cement bond, casing inspection log (USIT); Validate external mechanical integrity
Annulus Pressure Test – Long string casing	Annular between tubing and long string	Validate internal mechanical integrity between the tubing, long-string, and packer
Wireline – Activate pulsed neutron (Oxygen Activation Log) – Long string casing	Surface, Intermediate, Production	CO_2 saturation, baseline for monitoring
Wireline – Temperature Log	Surface, Intermediate, Production	Measure baseline temperature profile on the well from surface to top of perforation
Fiber Optic – DAS, DTS survey	Surface, Intermediate, Production	Measure baseline temperature profile on the well from surface to top of perforation Acquire baseline 3D VSP survey for monitoring plume migration over time

In addition to the logging and testing listed above, OLCV performed mini-fracs in distinct porosity / permeability packages within the proposed Injection Zone and Upper and Lower Confining Zones. Thin intervals that were interpreted to have limited horizontal extent were not tested. The interval for mini-frac was selected following a review of logging data. The Fracture Propagation Pressure was interpreted by qualified OLCV reservoir and completions engineers to determine injection limits throughout the Injection Zone.

OLCV measured reservoir pressures and acquired fluid samples in the Injection Zone. Based on data from the Shoe Bar 1 and Shoe Bar 1AZ, OLCV anticipated encountering three distinct porosity zones. OLCV collected fluid samples in each of these porosity zones. The sampling depths were selected after reviewing logging data. The fluid and dissolved gas samples were transported under pressure to a third-party lab for comprehensive analysis. See Section 5.1 of Appendix B Baseline report to the Pre-Operations Plan for fluid and dissolved gas results. Fluid level testing was conducted following well completion. The test measured static fluid level using an echometer.

An injectivity test was performed in the Injection Zone after well completion and installation of the tubing and packer. The pre-operation injectivity testing is a baseline for future pressure fall-off testing. The purpose of injectivity testing was to verify or establish the injection well operating parameters and constrain the inputs used for dynamic injection simulation modeling. See section 4.1.12, 4.2.12, and 4.3.12 of Appendix B Baseline report to the Pre-Operations Plan for details on injectivity testing procedures.

OLCV submitted the pre-injection procedures for logging, sampling, and testing to the Program Director 30 days prior to performing the first test, as required by 40 CFR §146.87.

6.0 Demonstration of Mechanical Integrity and Baseline for Monitoring

Table 33 below summarizes the tests that were conducted in the UIC Class VI injection well to prove mechanical integrity.

Table 33—Summary of Pre-Injection Testing at Injection Well Site

Test	Purpose
Annulus pressure test	MIT – Internal
Temperature and pressure log	MIT – External
Ultrasonic Inspection Tool Log	MIT – External
Casing Pressure Test	MIT - Internal
Injectivity and Pressure fall-off test	Injection Zone properties
Pulsed Neutron Log	Baseline for CO_2 saturation
Cement Bond Log, Variable Density Log	Casing and Cement verification

7.0 Blowout Preventer and Wellhead Requirements

The criteria below describe how well equipment for the UIC Class VI wells was selected.

7.1 Blowout Preventer Equipment (BOPE)

- BOPE shall be API-monogramed and adhere to API Standard 53 and Specifications 16A and 16C at a minimum and shall meet or exceed all applicable regulatory specifications.
- BOPE other than annular preventers shall have a minimum working pressure exceeding the maximum anticipated surface pressure (MASP).
- All BOPE stacks shall incorporate a set of blind rams.
- Blind rams shall be located in the lower ram cavity of a two-ram stack or the middle ram cavity of a three-ram stack.
- Choke and kill line outlets shall be located below the blind rams on either a two-ram or three-ram stack.
- All rigs shall have a calibrated trip tank. The trip tank and trip sheet are used to measure the fluid required to fill or displace fluid from the hole during all tripping operations, including when running the casing or completion string. Trip sheets shall include the number of joints or stands run into or pulled from the hole vs. the calculated and actual displacements per step and a running total as a minimum.
- A full-opening safety valve (FOSV) and an inside-BOP safety valve (IBOPSV) shall be always available on the rig floor for each drill pipe and drill collar size and connection type in use. The FOSV is used to stab into the string and shut off flow through the drill string. The IBOPSV is used above the FOSV to prevent backflow through the drill string. These valves shall remain in the fully open position until installed. **Note:** This requirement is in addition to any integral safety valve in the top drive system inclusive of casing running operations. In the event of a power failure on a variable frequency drive (VFD) rig, it is impossible to slack off and make up the top drive to the string; therefore, there is a need for additional independent stabbing valve(s) to be available on the floor always.
- If a wireline lubricator is utilized for wireline operations, it shall not be the type that slips into and is held by the annular preventer or rams. A hydraulic cutter or other means of safely cutting the wireline shall be available if a lubricator is not in use.
- Pressure-energized metal ring gaskets shall be used on flanged well-control equipment. These gaskets shall not be reused on equipment that will be nippled-up on the wellbore.

7.2 Choke Manifolds and Kill Line

- The choke manifold shall be API-monogrammed, meet API SPEC 16C as a minimum, and meet or exceed all applicable regulatory specifications.
- All BOPE shall include a choke manifold with at least one remotely operated choke and one manual choke installed. The control panel shall contain calibrated drill pipe and casing pressure gauges that shall be both accurate and properly maintained. The choke manifold casing pressure should have the capability of being recorded on the drilling rig's recorder. If necessary, for clear dialogue, an

electronic means of direct communication with the driller should be in place. This equipment shall be tested and its calibration checked at each casing shoe and at every BOPE test, and results shall be logged on every BOPE test report.

- Flare / vent lines shall be as long as practical, a minimum of 150 ft from the well center, as straight as possible, without sumps, collection areas, or uphill flow areas (to prevent fluid buildup and resulting backpressure) and shall be securely anchored.

7.3 Closing Units

- BOPE closing units shall adhere to API Spec 16D and API STD 53 as a minimum and meet or exceed all applicable regulatory specifications.
- BOPE control systems shall include full controls on the closing unit and at least one remote control station. One control station shall be located within 10 ft of the driller's console.
- BOPE closing units shall have two separate charging pumps with two independent power sources, as specified in API Spec 16D, or have nitrogen bottle backup.
- When pumps are inoperative, BOPE closing units shall have sufficient usable hydraulic fluid volume to close one annular preventer, close all ram preventers, and open one HCR valve against zero wellbore pressure with 200 psi remaining pressure above the pre-charge pressure.

7.4 Pressure Testing

- BOPE components (including the BOP stack, choke manifold, and choke lines) shall be pressure tested at the following frequency:
  - When installed. If the BOPE is stump tested, only the new connections are required to be tested at installation.
  - Before 21 days have elapsed since the last BOPE pressure test. When the 21-day test is due soon, consider testing the BOPE prior to drilling H_2S, abnormal pressure, or any lost return zones to avoid having to test while drilling these intervals.
  - Anytime a BOPE connection seal is broken, the connection shall be pressure tested after reassembly and before use.
  - When utilizing tapered strings, variable bore-type rams and annular preventers shall be pressure tested with all tubing or drill pipe sizes anticipated to be used.
- BOPE shall be tested using a test plug or other means to isolate the casing and open hole from the test pressures. The casinghead valve shall be opened and monitored to avoid exerting BOPE test pressure on the casing or open hole.
- BOPE components shall first be low-pressure tested to between 250 and 350 psi. If the pressure exceeds 350 psi during this test, the pressure shall be bled off to 0 psi and the test restarted. Pressuring up beyond 350 psi can induce a seal and give a false test result.

- BOPE components, excluding the annular preventer, shall be tested to the lesser of rated working pressure (RWP) or wellhead RWP if less than BOPE RWP. The annular preventer shall be tested to 70% of its RWP. In all cases, the test pressure shall not exceed the RWP of any of the components being tested.
- Use of a cup tester should be avoided. If a cup tester is utilized for BOP testing, consideration shall be given to casing burst pressure and possible pressure applied to the casing string or open hole below the cup tester in the event of a leaking cup tester.
- An accumulator closing test shall be performed after the initial nipple-up of the BOP, after any repairs that required isolation or partial isolation of the system, or at initial nipple-up on each well.
- During drilling, the pipe rams shall be functionally operated at least once every 24 hours. The blind rams shall be functionally operated each trip out of the wellbore.

7.5 Wellhead Schematic

Figure 8 below is a schematic diagram of the wellhead to be used for the BRP CCS1, BRP CCS2 and BRP CCS3 wells.

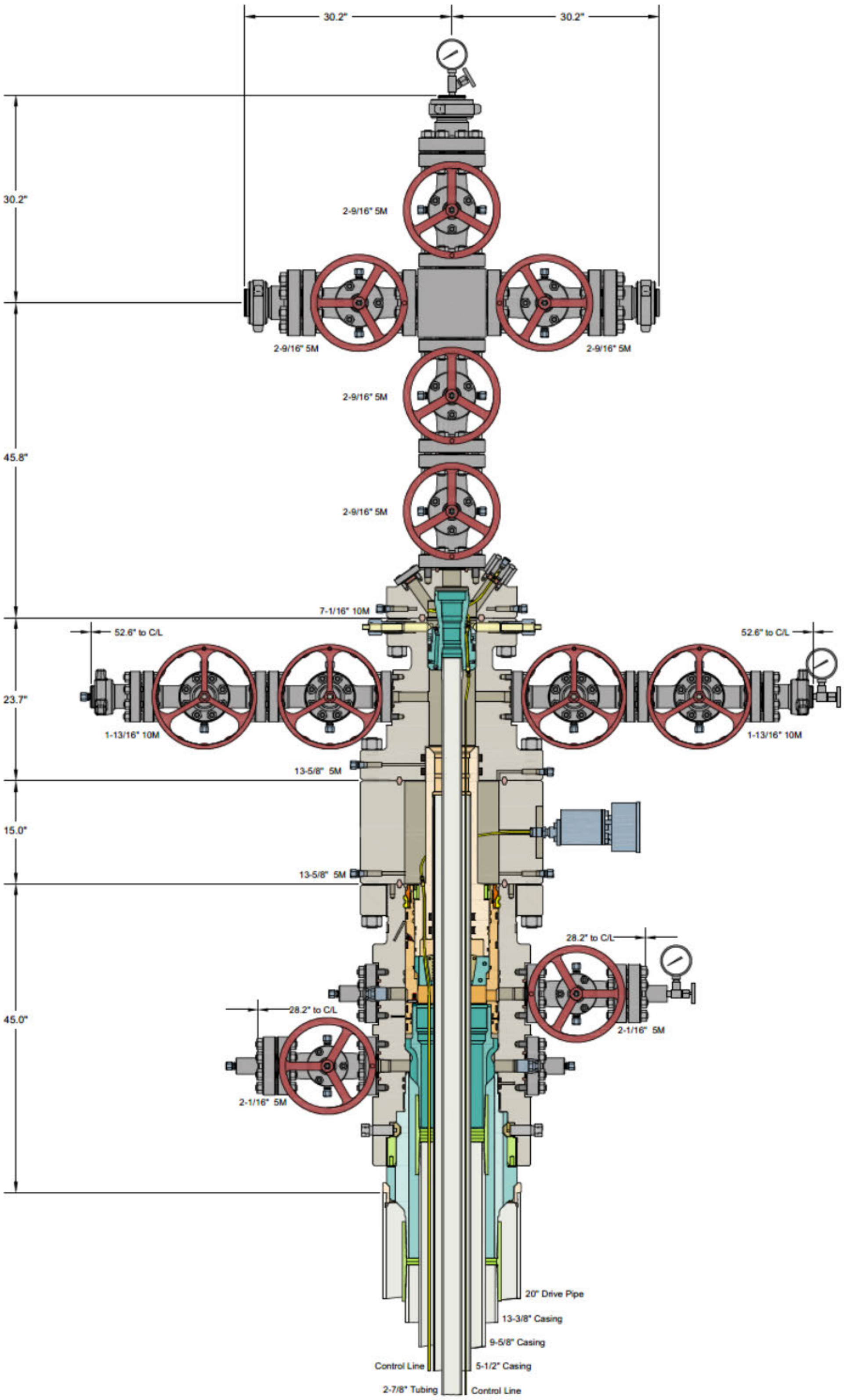

Figure 8—Schematic diagram of the wellhead used on UIC Class VI wells