CLASS VI PERMIT INJECTION WELL PLUGGING PLAN

40 CFR 146.92(b)

SHELL U.S. POWER AND GAS
ST. HELENA PARISH SITE

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TABLE OF CONTENTS

List of Tables

List of Figures

1.0 FACILITY INFORMATION

Facility Name:	Shell U.S. Power & Gas – St. Helena Parish Site Two Class VI Injection Wells
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Well Locations:	SOTERRA IF 1-1 [redacted] SOTERRA IT 2-1 [redacted]

Shell U.S. Power and Gas (Shell) will conduct injection well plugging and abandonment according to the procedures below.

2.0 BOTTOMHOLE PRESSURE DETERMINATION

A bottomhole reservoir pressure will be determined prior to commencing injection well plugging operations [40 CFR 146.92(b)(1)]. During the injection well operations, downhole pressure gauges will be installed to continuously monitor the injection pressure. After cessation of injection operations, the downhole gauges will be used to measure the bottomhole pressure of the injection zone at final static conditions (a period after injection operations have ceased) prior to proceeding with the plugging.

If these gauges are damaged or malfunction at the time of well plugging, pressure and temperature gauges will be run down hole via wireline, after the well has been flushed with a brine kill fluid to record the bottomhole pressure.

3.0 MECHANICAL INTEGRITY TESTS

To verify well integrity Shell will conduct at least one of the tests listed in Table 1 prior to plugging the injection well as required by 40 CFR 146.92(a). Tubing and Packers will be retrieved at the end of injection operations as part of the plugging procedures. Casing will remain in the well and be examined for integrity.

Table 1: Planned Mechanical Integrity Tests (MIT)

Test Description	Location
Cement Bond Log(s) (CBL) (External MIT)	Run CBL & Ultrasonic logs: Compare to initial run logs Discrepancies, if any, can be noted between the logs as an indication of cement quality improvement or degradation (due to casing movement or other cement sheath disturbance).
Radioactive Tracer Log- Alternate Log (External MIT)	Run radioactive tracer survey to register any fluid movements external to the long string casing;
Temperature Log (External MIT)	Run temperature log post-injection to register any fluid movements external to the long string casing;
Pressure Test (Internal MIT)	Place tubing plug in profile nipple below permanent packer; pressure test long string casing from tubing plug to surface using packer fluid. Test pressure to be greater than annulus pressure maintained during injection activities.
Casing Caliper Log (Internal MIT)	Casing caliper log optional if long string casing successfully passes the pressure test (above). Caliper log will provide information about long string casing wall thickness loss due to corrosion or erosion, information useful for future projects.

Prior to testing, the well(s) will be flushed with brine to force the carbon dioxide away from the wellbore into the formation [per 40 CFR 146.92(a)]. Tools will be run on wireline. Quality assurance for the planned logs will be provided by the service vendor at time of selection. The quality control will be reviewed and will be documented in the Quality and Assurance Surveillance Plan (contained as an Appendix to the "*E.1. – Testing and Monitoring Plan*").

3.1 EQUIPMENT DETAILS

If wireline deployed pressure/temperature gauges are used to record bottomhole pressure, the wireline should be corrosion resistant (such as MP-35 line), and the deployed gauges should consist of a surface read-out gauge with a memory backup. Gauge specifications should be as follows or similar to those listed in Table 2:

Table 2: Injection/Falloff Pressure Potential Gauge Information – Wireline Testing Operations

Pressure Gauge	Property	Value
Surface Readout Pressure Gauge	Range Resolution	0 – 10,000 psi/356 ºF +/-0.01 psi/0.01 ºF
	Accuracy	+/-0.03% of full scale (+/-3 psi/+/-0.1 ºF)
	Manufacturer's Recommended Calibration Frequency	Minimum Annual
Memory Pressure Gauge	Range Resolution	0 – 10,000 psi/356 ºF +/-0.01 psi/0.01 ºF
	Accuracy	+/-0.03% of full scale (+/-3 psi/+/-0.1 ºF)
	Manufacturer's Recommended Calibration Frequency	Minimum Annual

Prior to running MIT, the wellbore may be displaced with water or brine, in either case, the well will be allowed to thermally stabilize prior to all testing operations. It is recommended that the well be shut-in for 36 hours to allow for temperature effects to dissipate. The external MIT logs will be run on all injection wells.

All equipment used during the well plugging operation will be corrosion resistant.

3.2 PASS/FAIL CRITERIA

Well Plugging is considered a "PASS" when it meets the objective of well plugging, which is minimizing the chance of leak to environment and reducing the possibility unintended flow of fluid outside the confining unit to as low as reasonably practicable (ALARP). Verification of meeting the objective will be conducted at the end of each plugging operation. The verification objective is to assess the sealing effectiveness and required position of a permanent isolation. All verification methods have limitations. As an example, a single positive test will not provide the required assurance as positively pressure tested cement plugs have found to be leaking because plugging materials in the drilling fluid can mask a leak potential. Similarly, a successful tagging may confirm position, but is not conclusive evidence for effective isolation, as a channel can still be present. In view of this the verification step is part of a larger quality assurance process that includes proper cement job planning and plug placement. Verification methods can be direct such as tagging, weight testing, dressing-off, inflow testing, pressure testing or indirect such as volume/losses records, cementing pressure records, laboratory slurry testing (compressive strength development), surface cement sample setting, logging, and long-term monitoring (pressure and/or bubbles).

3.2.1 Temperature Survey

A baseline differential temperature survey may be run in the well after allowing the well a period to reach approximate static conditions. The temperature log is one of the approved logs for detecting fluid movement outside pipe. A final differential temperature survey will be run during plugging operations and will provide a final temperature curve. The log will include both an absolute temperature curve and a differential temperature curve. The well should be shut-in for at least 36 hours to allow for temperature stabilization prior to running the temperature survey.

If a distributed temperature sensing fiber is run in the injection/monitor wells, the fiber will be used for the temperature testing, otherwise, a wireline truck will be used.

If wireline operations are used, the temperature will be logged down from the surface to total depth in the well. Recommended line speed for the logging operations is 30 to 40 feet per minute. A correlation log(s) will be presented in track 1, and the two temperature curves will be presented in tracks 2 and 3. The temperature log will be scaled at or about 20° F (or 10° C degrees) per track. The differential curve will be scaled in a manner appropriate to the logging equipment design but will be sensitive enough to readily indicate anomalies. In general, the procedure for wireline operations will be as follows:

1. Attach a temperature probe and casing collar locator (CCL) to the wireline.
2. After a minimum of 36 hours of well static conditions, begin the temperature survey. The tools will be lowered into well at 30 to 40 feet/minute, recording temperature in wellbore. The temperature survey will be run to the deepest attainable depth (top of solids fill) in the wellbore. The wireline may be flagged, if needed, to assist in depth correlation.
3. Following completion of the survey, the wireline tools will be retrieved from the wellbore.

A successful temperature log will "PASS" if there are no observed, unexplained anomalies outside of the permitted injection zone.

If temperature anomalies are observed outside of the permitted zone, additional logging may be conducted to determine whether a loss of mechanical integrity or containment has occurred. Depending on the nature of the suspected movement, radioactive tracer, noise, oxygen activation, or other logs approved by the UIC Director may be required to further define the nature of the fluid movement or to diagnose a potential leak.

3.2.2 Radioactive Tracer Survey

A Radioactive Tracer Survey (RTS) may be run as an alternative to the temperature survey. The tool consists of a gamma detector above the ejector port and one or two detectors below the ejector port. In order to run the RTS, the well will need to be flushed with brine and the test will be conducted using brine to convey the radioactive iodine tracer material. The tool should be able to continuously record during tracer fluid ejection. The upper detector will be recorded in track 1 at a scale of 0 to 100 or 150 API units, and the lower detector(s) will be recorded in tracks 2 and 3 at a higher (less sensitive) scale, typically 0 to 1,000 API units.

Prior to testing, an initial gamma ray base log will be recorded from at least 100 feet above the injection tubing packer to total depth of the well. The initial gamma ray survey can be made under low flow conditions or with the well in static conditions.

A concurrent casing collar locator log for depth correlation will be run on the wireline tool string. Two five (5) minute time drive statistical checks will be run prior to the ejection of tracer fluid. One of the statistical checks will be run in a confining unit immediately above the uppermost perforation in the well. The second check should be run within the Injection Zone(s) sandstone. The baseline log and statistical checks will be run to determine background radiation prior to tracer fluid ejection.

Injection should be initiated or increased during testing operations. During the survey, injection flow rates will be set at the rate at which the fluid will be under laminar flow conditions, while remaining within the maximum permitted operating parameters anticipated for the well. The volume of the tracer fluid slug will be sufficient to cause a gamma curve deflection on the order of 25x background reading as the ejected slug passes the lower detector(s). This would typically be a full-scale deflection.

A constant injection (moving) survey will be run from above the packer to the perforations to check for leaks between those two points. This survey will consist of ejecting a slug above the packer, verifying the ejection, dropping down through the slug, and then logging up through the slug to above where the slug was first ejected. The tool will be successively dropped down through the slug again, and logging will continue upward to above where the slug was encountered on the previous pass. This process will be repeated a minimum of two times, until the slug flows out into the formation. If necessary, the injection rate may be adjusted to accomplish this test.

A stationary survey will be run approximately 20 feet or less above the top of the perforated interval to check for upward fluid migration outside the cemented casing. Flow during the stationary surveys will be at sufficient rates to approximate normal operating conditions anticipated for the well. The procedure consists of setting the tool and logging on time drive, ejecting a slug, verifying the ejection, and waiting an appropriate amount of time that would allow the slug to exit the wellbore and return through channels outside pipe, if present. The time spent at the station will vary but should be at least twice the time estimated to detect the tracer fluid if channeling existed, or for 15 minutes, whichever is greater. If tracer fluid is detected channeling outside of the pipe at any time during the stationary survey, then the survey may be stopped, and the tracer fluid's movement will be documented by logging up on depth drive, until the tracer exits the channel. The stationary survey should be repeated at least one time.

Additional stationary or moving surveys may be required, depending upon well construction, test results, or to investigate known problem conditions. At least two repeatable logs of every tracer survey, moving and stationary, should be run. On completion of the tracer surveys, a final background gamma log will be run for comparison with the initial background log. In general, the test procedure will be as follows:

1. Attach radioactive tracer tools, including casing collar locator (CCL), gamma ray detectors and ejector modules to the wireline. Lower tools in wellbore to deepest attainable depth (top of solids fill). Record the depth of solids fill in the well, if any. Correlate tools on depth with the injection packer and any other cased-hole log(s) run in the well.
2. A baseline gamma log will be run from deepest attainable depth to approximately 4,500 feet (must be at least 100 feet above the packer). Statistical tool checks will be conducted 10 feet above the set depth of the injection packer and approximately 15 feet above the top perforation. (*Specific depths will be identified and updated after the injection well(s) completion*).
3. With the tool set a minimum of 100 feet above the packer, start injecting brine fluid at approximately 50 gpm (or defined acceptable rate). Eject a slug of tracer material and verify ejection.
4. Lower the tool through the slug and log up through the slug. Repeat slug-tracking sequence, following the slug down the tubing and into the injection zone until the slug is dissipated.

Note: It is desired to achieve a minimum of three or more passes below the injection packer before the radioactive slug exits the perforations. Adjust or reduce injection rate if needed to achieve this objective.

5. Repeat Steps 3 and 4.
6. Position lower detector of RTS tool at approximately 15 feet above the top perforation. Initiate and maintain injection at approximately 250 gpm (or defined acceptable rate).
7. Eject a slug of tracer material and record on time drive for a minimum of 15 minutes to determine if upward flow around the casing occurs.
8. Repeat Step 7.
9. Cease pumping, lower the tool to the deepest attainable depth, and run a repeat baseline gamma ray log to verify that the radiation level has returned to background.
10. Dump remaining tracer material from the tool and pump remaining test fluid to flush the tracer material from the wellbore.
11. Retrieve the wireline tools from the wellbore and rig down wireline unit.

A successful test will "PASS" if the radioactive iodine material stays within the Injection Zone and within the Sequestration Complex.

3.2.3 Cement Bond Log & Ultrasonic Log

Cement Bond and Ultrasonic logging will be run to verify the mechanical integrity of the near-well area behind the casing in the injection and monitoring wells prior to plugging. The surveys will be compared to the original baseline survey run in the well during completion operations. Should downhole well completion change at any time, a new baseline log will be run. The Cement Bond and Ultrasonic logging surveys will be run from the Injection Zone up to through the base of the identified lowermost underground source of drilling water (USDW), just inside the surface casing, in the injection wells. Note that we logs may be repeated while applying surface pressure to evaluate micro-annulus effects.

3.2.4 Casing Pressure Test

Subsequent to setting the initial plug across the well completion interval, a casing pressure test will be made. Casing pressures will be recorded on a time-drive recorder for at least 60 minutes in duration and the chart or digital printout of times and pressures will be certified as true and accurate. The pressure scale on the chart will be low enough to readily show a 5 percent change from the starting pressure. In general, the test procedure will be as follows:

1. Connect a high-resolution pressure transducer to the well casing and increase wellbore pressure to at least 200 psig over the permitted maximum tubing/injection pressure. Conduct a casing pressure test by holding casing pressure a minimum of 100 psi above the well's maximum permitted surface injection pressure for a minimum of 60 minutes.
2. At the conclusion of the test, casing pressure will be lowered to a static pressure with no pressure at the top of the casing string.

A successful pressure test will "PASS" if the pressure holds to +/-5 percent of the starting pressure. IF the test is not able to hold the pressure for a selected time period, then the test will be considered a "FAIL". The test will be repeated and if the well continues to "FAIL", the construction of the well may have lost its integrity. Additional tests at progressively lower pressures may be run to identify the pressure at which the casing can hold a differential. A review of the continuous monitoring of the annulus system will be performed to identify if there are any data that may lead to a potential leak and assist in diagnosing potential issues with the annulus.

4.0 DETAILS ON PLUGS

Shell will use the materials and methods noted in Table 3 and 4 to plug the injection well. The volume and depth of the plug or plugs will depend on the final geology and downhole conditions of the well as assessed during construction. The cement(s) formulated for plugging will be compatible with the carbon dioxide stream. The cement formulation and required certification documents will be submitted to the agency with the well plugging plan. Shell will report the wet density and will retain duplicate samples of the cement used for each plug. The permeant isolation plugs position should be such that the formation fracture pressure exceeds the maximum anticipated pressure under the isolation. This is normally easily met by placing the isolation plugs across a suitable caprock which is an impermeable rock without natural or induced fractures that is continuous over the field. The caprock immediately above the zone of injection is considered suitable caprock.

Industry practice has shown that 100 ft - 200 ft along the hole (AH) of good cement is sufficient for permanent isolation. Excess volume should be pumped to cater for contamination and uncertainty in placement such as in high angle wells or high expectation of slurry contamination. Cement placement software will determine the exact volume.

It is planned to plug the CO_2 injection wells using at least four plugs. These are

1- Plug set from cement retainer to bottom perforation, plugging the injection interval.
2- 200 ft plug above injection zone. The plug will be set across the caprock and across good, cemented casing.
3- 200 feet plug set below/across the USDW and across good, cemented casing.
4- 25 feet surface plug.

It is believed that with at least four plugs per well the objective of well plugging, which is minimizing the chance of leak to environment and reducing the possibility of unintended flow of fluid out of the confining zone to ALARP, can be met. Adding extra plugs will be contingent upon the external well integrity status at the time of plugging the well. If well integrity was found to be poorer than expected, then a risk assessment would be conducted to identify if extra plugs would be required. The tables below show preliminary calculations of the plugs for the two storage reservoirs, Frio and Tuscaloosa.

Table 3: Proposed Plugging Details - Frio Injection Well; Soterra IF 1-1

Plug Information	Plug #1	Plug #2	Plug #3	Plug #4
Diameter of boring in which plug will be placed ID *(inches)*	6.184	6.184	6.184	6.184
Depth to bottom of tubing or drill pipe (ft)	4,957	4,757	2,730	2
Sacks of cement to be used (each plug)	368	36	36	4
Slurry volume to be pumped (ft^3)	408* w/ 20% excess	42	42	5.25
Slurry weight (lb./gal)	16.0	16.0	15.6	15.6
Calculated top of plug (ft)	4,977	4,777	2,750	3
Bottom of plug (ft)	6,605	4,977	2,950	28
Type of cement or other material	EverCRETE*	EverCRETE*	G or A	G or A
Method of emplacement (*e.g.*, balance method, retainer method, or two-plug method)	Retainer method	Retainer method	Retainer method	Retainer method

Note: Calculated cement volume is equivalent to a 200 ft reservoir plug. 200 ft USDW plug and 25 ft surface plug in 7'' OD/6.184 ID casing. This could be changed to 100 ft plug if 100 ft found sufficient at the time of well plugging
**or similar industry material*

Table 4: Proposed Plugging Details - Tuscaloosa Injection Well; Soterra IT 2-1

Plug Information	Plug #1	Plug #2	Plug #3	Plug #4	Plug #5
Diameter of boring in which plug will be placed ID *(inches)*	6.184	6.184	6.184	6.184	6.184
Depth to bottom of tubing or drill pipe (ft)	14,306	14,086	13,430	2,830	2
Sacks of cement to be used (each plug)	50	36	36	36	4
Slurry volume to be pumped (ft^3)	56* w/ excess	42	42	42	5.25
Slurry weight (lb./gal)	16.0	16.0	15.6	15.6	15.6
Calculated top of plug (ft)	14,306	14,106	13,450	2,850	3
Bottom of plug (ft)	14,454	14,306	13,650	3,050	28
Type of cement or other material	EverCRETE*	EverCRETE*	G or A	G or A	G or A
Method of emplacement (*e.g.*, balance method, retainer method, or two-plug method)	Retainer method	Retainer method	Retainer method	Retainer method	Retainer method

Note: Calculated cement volume is equivalent to a 148 ft injection interval plug (with excess), 200 ft reservoir plug, 200 ft 9-5/8" casing shoe plug, 200 ft USDW plug and 25 ft surface plug in 7'' OD/6.184 ID casing. This could be changed to 100 ft plug if 100 ft found sufficient at the time of well plugging
**or similar industry material*

Volume calculations will be based upon the final dimensions of the long string/production casing. Also, pending the condition of the well at the time of plugging, number of isolation plugs might be increased. Plugs will be tagged at the cement plug top to verify location and integrity. The well will be plugged with fluid/mud of at least 9.5 ppg.

Prior to plugging each well, Shell will consider the operational and monitoring history of the sequestration project and identify whether any information or events warrant amendment of the original Well Plugging Plan. Shell will use the materials and methods noted in Tables 3 and 4 to plug the injection wells. The volume and depth of the plug or plugs will depend on the final geology and "as built" well completion and conditions of the well as assessed during mechanical integrity testing prior to closure. The cement(s) formulated for plugging will be compatible (*i.e.*, carbon dioxide-resistant cement) with the stored carbon dioxide and water mixtures where exposure may occur.

Because of its intrinsic low permeability, EverCRETE or a similar industry material carbon dioxide-resistant cement system resists cement matrix attack from wet supercritical carbon dioxide and water saturated with carbon dioxide conditions. Accelerated reaction kinetics can lead to a stabilized matrix within days of exposure to the carbon dioxide environment, leading to stabilized mechanical properties. This makes it ideal for plugging the primary Injection Zones and into the overlying containment intervals as well as the primary Confining Zone.

Any final modifications to the cement formulation and required certification documents will be submitted to the agency with the proposed well plugging plan prior to field operations. Shell will include the wet density in the final ***Report of Plugging and Abandonment*** for each well and will retain duplicate samples of the cement used for each plug. Cement volumes will be calculated and verified using industry accepted equations for cement volumes, using openhole diameter, casing size, annular areas, and total length of cement plugs. Top of each plug will be verified by load testing.

5.0 PLUGGING PLAN DETAILS

The following plugging and abandonment plans have been developed for the Shell St. Helena Parish Site in accordance with 40 CFR 146.92(c) & LAC §3631.A.4 (*Louisiana State Code*). The proposed plugging and abandonment plan for the proposed injection wells at the Shell is shown below, subject to modification by the UIC director. The plugging procedure will be implemented if well operations are abandoned or if a well has reached the end of its useful life.

5.1 NOTIFICATIONS, PERMITS, AND INSPECTIONS

In compliance with 40 CFR 146.92(c), Shell will notify the regulatory agency at least 60 days before plugging the well and provide updated Injection Well Plugging Plan, if applicable. Shell will also submit a request for plugging and abandonment through the Louisiana Department of Natural Resources pursuant to LAC §137(A)(4) and §137(F)(1). Notice of intent to plug and abandon the subject disposal well will be given at least 60 working days prior to closure of that well to the regulatory authorities. Inspections will be made available to the regulatory authority at their request. A closure report certifying that the well or wells were closed in accordance with applicable requirements will be submitted to the proper agencies within 60 days of plugging each well. The report will include records for any newly constructed or discovered wells within the Area of Review.

When plugging and abandonment is complete, Shell will submit certification to the authorized regulatory body (by the plant and by a licensed, professional engineer with current registration, who is knowledgeable and experienced in practical drilling engineering and who is familiar with the special conditions and requirements of injection well construction) that the injection well(s) has been closed in accordance with the regulations. Plugging reports will be submitted within 60 days of well plugging and Shell will retain a copy of the plugging report for a minimum of 10 years following site closure [40 CFR 146.92(d)].

5.2 PLUGGING PROCEDURES

The plugging and abandonment procedures and materials have been designed to contain the sequestered carbon dioxide and prevent movement out of the Sequestration Complex or into

USDW's. The materials to be used will be resistive to the corrosive nature of carbon dioxide and water. Proposed well plugging schematics are contained in Figures 1 and 2 and are based upon the proposed drilling and completion schematics. Final plan adjustment will be made for "as built" well conditions and penetrated formation tops.

5.2.1 Frio Injection Well – Soterra IF 1-1

Prior to conducting the following plugging and abandonment procedure, Shell will inject a sufficient quantity of brine buffer fluid to displace the carbon dioxide from the immediate wellbore area into the storage reservoir. This volume of fluid will be determined by the project prior to initiating closure activities using data on the volume of carbon dioxide injected during the lifetime of the well and the results of previous well formation pressure testing. Specific plugging plans will be updated for each well after the drilling and completion with as built well specifics and penetrated formation tops.

The outline of plugging procedures is as follows:

1. In compliance with 40 CFR 146.92(c), notify the EPA UIC Program Director at least 60 days before plugging the well and provide updated plugging plan.
2. Bottom hole reservoir pressure will be obtained prior to well plugging.
3. Well will be flushed by brine to displace CO_2 into the reservoir. Normally the well is flushed by pumping 2 times well volume brine at pressure lower than 80% of frac pressure.
4. Temperature log will be run and compared with the baseline temperature log in addition to temperature logs during injection and post-injection to determine external mechanical integrity. In addition, either a noise log or oxygen activation log could also be run and evaluated for external mechanical integrity.

   Note: If the external well integrity was found to be poorer than expected then a proper risk assessment will be conducted to assess if four plugs are sufficient to meet well plugging objectives or not.
5. Pull out/remove tubing and packer from the well.
6. Run and set a cement retainer at approximately 4,978 ft.
7. Rig up cementing equipment and pump a fluid spacer, followed by CO_2 resistant cement mixed at a minimum density of 16.0 pounds per gallon (ppg).

8. Circulate the cement to the bottom of the cementing string and sting into the retainer. Pump the cement into the wellbore to cement off the injection zone. If cement squeezes off prematurely, pull stinger out of retainer and displace remainder of cement on top of cement retainer.
9. Pull the end of the work string 250 feet above the calculated top of cement and reverse-circulate wellbore until fluid returns are clean.
10. Lower stinger to the top of cement retainer. Pump a fluid spacer, followed by CO_2 resistant cement mixed at a minimum density of 16.0 ppg. Displace the cement and pull the end of the work string 250 feet above the calculated top of cement and reverse-circulate wellbore until fluid returns are clean.
11. After waiting for enough time for the cement to harden, locate the top of the cement plug and pressure test the cement plug to 1,500 psi to verify its competency.
12. Displace the wellbore with fluid of a minimum density of 9.5 PPG.
13. Repeat the above for the 3rd cement plug, Bridge plug at approximately 2,951 ft.
14. Repeat the above for the 4th cement plug, Bridge plug at approximately 29 ft.
15. Remove wellhead, cut the casing three feet below the ground surface, and weld steel plate on top.
16. Erect a permanent marker on the well with the permit number, date of plugging and company name identified on the marker.
17. In accordance with the requirements of 40 CFR 146.92(d), within 60 days of plugging and closure, a plugging report will be submitted to the UIC director. This report will be certified as accurate by the Shell, and by the person who has performed the plugging operations. Shell will retain the well plugging report for 10 years following the site closure.

A proposed plugged schematic for the Frio Injection Well – Soterra IF 1-1 is presented in Figure 1.

5.2.2 Tuscaloosa Injection Well - Soterra IT 2-1

Prior to conducting the following plugging and abandonment procedure, Shell will inject a sufficient quantity of brine buffer fluid to displace the carbon dioxide from the immediate wellbore area. This volume of fluid will be determined by the project prior to initiating closure activities using data on the volume of carbon dioxide injected during the lifetime of the well and the results of previous well formation pressure testing. Specific plugging plans will be updated for each well after the drilling and completion with as built well specifics and penetrated formation tops.

The outline of plugging procedures is as follows:

1. In compliance with 40 CFR 146.92(c), notify the EPA UIC Program Director at least 60 days before plugging the well and provide updated plugging plan.
2. Bottom hole reservoir pressure will be obtained prior to well plugging.
3. Well will be flushed by brine to displace CO_2 into the reservoir. Normally the well is flushed by pumping 2 times well volume brine at pressure lower than 80% of frac pressure.
4. Temperature log will be run and compared with the baseline temperature log in addition to temperature logs during injection and post-injection to determine external mechanical integrity. In addition, either a noise log or oxygen activation log could also be run and evaluated for external mechanical integrity.

   Note: If the external well integrity was found to be poorer than expected then a proper risk assessment will be conducted to assess if five plugs are sufficient to meet well plugging objectives or not.
5. Pull out/remove tubing and packer from the well.
6. Run and set a cement retainer at approximately 14,307 ft.
7. Rig up cementing equipment and pump a fluid spacer, followed by CO_2 resistant cement mixed at a minimum density of 16.0 pounds per gallon (ppg).
8. Circulate the cement to the bottom of the cementing string and sting into the retainer. Pump the cement into the wellbore to cement off the injection zone. If cement squeezes off prematurely, pull stinger out of retainer and displace remainder of cement on top of cement retainer.
9. Pull the end of the work string 250 feet above the calculated top of cement and reverse-circulate wellbore until fluid returns are clean.
10. Lower stinger to the top of cement retainer. Pump a fluid spacer, followed by CO_2 resistant cement mixed at a minimum density of 16.0 ppg. Displace the cement and pull the end of the work string 250 feet above the calculated top of cement and reverse-circulate wellbore until fluid returns are clean.

11. After waiting for enough time for the cement to harden, locate the top of the cement plug and pressure test the cement plug to 1500 psi to verify its competency.
12. Displace the wellbore with fluid of a minimum density of 9.5 PPG.
13. Repeat the above for the 3rd cement plug. Bridge plug at approx. 13,651 ft.
14. Repeat the above for the 4th cement plug. Bridge plug at approx. 3,051 ft.
15. Repeat the above for the 5th cement plug, Bridge plug at approx. 29 ft.
16. Remove wellhead, cut the casing three feet below the ground surface, and weld steel plate on top.
17. Erect a permeant marker on the well with the permit number, date of plugging and company name identified on the marker.
18. In accordance with the requirements of 40 CFR 146.92(d), within 60 days of plugging and closure, a plugging report will be submitted to the UIC director. This report will be certified as accurate by Shell, and by the person who has performed the plugging operations. The Shell will retain the well plugging report for 10 years following the site closure.

A proposed plugged schematic for the Tuscaloosa Injection Well – Soterra IT 2-1 is presented in Figure 2.

5.3 CONTINGENCY PLANS

Should any of the cement plugs fail a sample of the retained slurry will be sent to the cementing company's laboratory for root-cause analysis to identify failure mechanism of the slurry. Cement pumping and mixing equipment will be inspected for equipment malfunction or cement contamination sources. Corrective actions will be applied prior to resetting the failed cement plug. The failed cement plug will be either drilled out or toped up with new plug and the well will be recirculated down to the previous plug depth.

Frio Injector Well; Soterra IF 1-1 (Class VI)
Proposed Plugging Plan

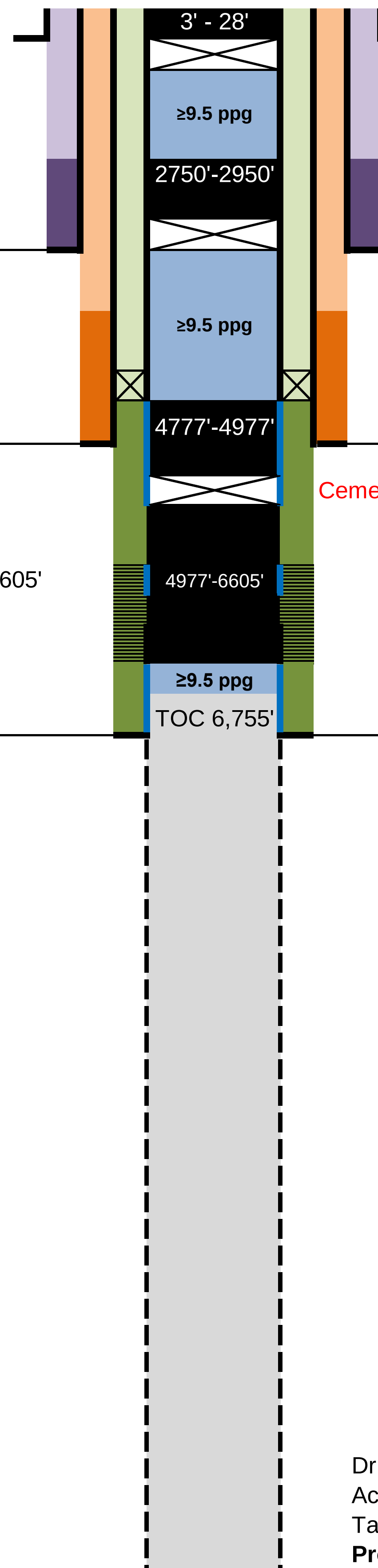
SHL Location: [redacted]

NAD-27-LA South
X = [redacted]
Y = [redacted]

NWN:
GLE 166.1
DFE

Planned BHL: Vertical well, same as SHL

Objectives: Drill & acquire Class VI data in Frio formation, deliver usable CO_2 injection well in Frio



Evaluation	Formation	TVD	Casing & Cement	Mud Program	Directional
	Cement plug		20" Conductor w/ 0.25" wall thickness set at ~100 ft or refusal		
	Mechanical plug		17-1/2" Open Hole		
Wireline logs Pressures (contingent)				Fresh Water Mud 8.5 - 9.5 ppg	Maintain vertical, use directional BHA
	Cement plug		**13-3/8" 54.5# J55 BTC set at 2900 ft**		
	Base USDW	~2,776	Lead Slurry: 0-2400', 30% excess: 386 bbls (yld, sks TBD)		
CBL/VDL	Mechanical plug		Tail Slurry: 2400-2900', 30% excess: 80 bbls (yld, sks TBD)		
			12-1/4" Open Hole		Maintain vertical,
	Miocene Top	~3,276		9.5 - 10 ppg OBM	use directional BHA
Wireline logs Pressures/fluid samples (cont.)	Miocene Base	~4,473	**9-5/8" 47# P110IC BTC set at 4807 ft** Lead Slurry: 0-3807', 30% excess: 310 bbls (yld, sks TBD)		
CBL/VDL	Top Frio Confining Zone	~4,777	Tail Slurry: 3807-4807', 30% excess: 73 bbls (yld, sks TBD)		
	Cement plug		8-1/2" Open Hole	9.5 - 10 ppg OBM	Maintain vertical,
	Cement Retainer		Cement Retainer above Frio at 4,978'		use directional BHA
Wireline logs Pressuers and fluid samples	Top Frio	~5,207			
Microfrac	Perforate Frio ~5,809' - 6,605'				
Rotary sidewall cores			**7" 29# P110IC BTC from 0 - 4777 ft, packer at 4730 ft**		
Whole core	Base Frio	~6,605	**7" 29# SM25CRW-125 VAM 21 from 4777 - 6805 ft** Lead Slurry: 0-4777', 30% excess: 159 bbls (yld, sks TBD)		
CBL/VDL			Tail Slurry: 4777-6805', 30% excess: 60 bbls (yld, sks TBD)		
			6" Open Hole		Maintain vertical,
				10 - 11.5 ppg OBM	use directional BHA
	Sparta Top (Wilcox Caprock)	~7,286			
	Top Wilcox	~7,970			
Wireline logs Pressures (contingent)					
	Base Wilcox	~12,172			
	Base Austin Chalk (top Tuscaloosa caprock)	~13,586			
	Top Tuscaloosa	~14,434	Drill potentially as deep as 150 ft below base of Tuscaloosa Acquire data and plug back with cement to inside 7" shoe		
	Base Tuscaloosa	~14,696	Tail slurry: 6705-14781', 10% excess: 311 bbls (yld, sks, TBD) **Proposed TD 14,781 ft**		

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Relevant Regulations for Well Construction
LAC, Part XVII, Injection and Mining, Subpart 6, Statewide Order No. 29-N-6 (Regulations specific to Class VI wells)
LAC, Part XIX, Office of Conservation - General Operations, Subpart 1, Statewide Order No. 29-B (General drilling regulations for all wells)

Specific Regulations to Highlight
§3617.A.3.a - All casing strings to have 1-hr pressure test after stabilization, allowable pressure loss is 5%, 500 psi test for surface casing, 1000 psi for all others
§3617.A.3.b - Intermediate and injector string must have casing seat tests, min. 10 ft below shoe, 1000 psi min. pressure, 1-hr test, 5% allowable pressure loss
§3617.B.1.b.ii and c.ii - Cement bond and variable density log, and temperature log required after each casing string is cemented
§3617.B.6 - Office of Conservation must be notified 72 hours before conducting any wireline logging (or well tests, or reservoir tests)
§111.F.2.a - If BOP is coming to the rig from a shop it must be tested prior to transporting to the rig
§111.F.2.c - BOP must be tested every 14 days
§111.F.2.d - BOP must be tested before drilling out each casing string
7" casing must have cement bong log, pressure test and casing test affidavit

Figure 1 - Proposed Plugging and Abandonment of the Frio Injection Well; Soterra IF 1-1

Tuscaloosa Injector Well; Soterra IT 2-1 (Class VI)
Proposed Plugging Plan

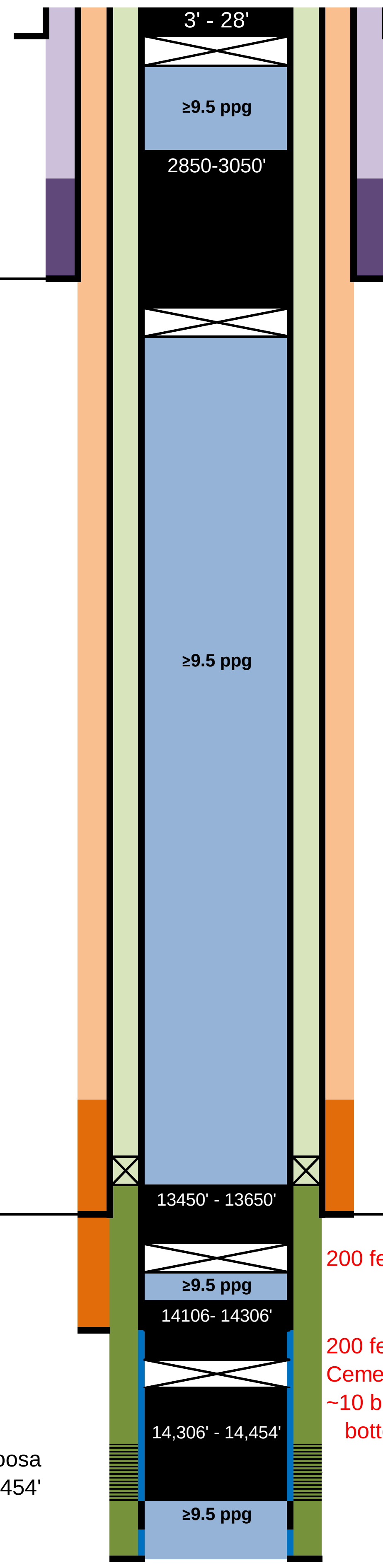
SHL Location: [redacted]

NAD-27-LA South
X = [redacted]
Y =

NWN:
GLE 108.2
DFE

Planned BHL: Vertical well, same as SHL

Objectives: Drill & acquire Class VI data in Tuscaloosa formation, deliver usable CO_2 injection well in Tuscaloosa



Evaluation	Formation	TVD	Casing & Cement	Mud Program	Directional
	Cement plug		20" Conductor w/ 0.25" wall thickness set at ~100 ft or refusal		
	Mechanical plug		17-1/2" Open Hole		
			25 feet of standard cement set at surface		
				Fresh Water Mud	Maintain vertical,
Wireline logs				8.5 - 9.5 ppg	use directional BHA
	Cement plug		200 feet of standard cement set across USDW and 13-3/8" casing shoe		
	Base USDW	~2,886	**13-3/8" 54.5# J55 BTC set at 3000 ft**		
	Mechanical plug		Lead Slurry: 0-2500', 30% excess: 402 bbls (yld, sks TBD)		
			Tail Slurry: 2500-3000', 30% excess: 80 bbls (yld, sks TBD)		
			12-1/4" Open Hole		Maintain vertical,
	Miocene Top	~3,386		9.5 - 10 ppg OBM	use directional BHA
	Miocene Base	~4,564			
	Top Frio Confining Zone	~5,064			
	Top Frio	~5,345			
Wireline logs Pressures/fluid samples (cont.) CBL/VDL					
	Base Frio	~6,759			
	Sparta Top	~7,400			
	Top Wilcox	~8,019			
	Base Wilcox	~12,077			
			9-5/8" 47# P110IC BTC set at 13550 ft		
			Lead Slurry: 0-12550', 30% OH excess: 886 bbls (yld, sks TBD)		
	Base Austin Chalk	~13,494	Tail Slurry: 12550-13550', 30% excess: 73 bbls (yld, sks TBD)		
	Cement plug		8-1/2" Open Hole		Maintain vertical,
	Mechanical Plug		200 feet of standard cement set across 9-5/8" casing shoe		
	Cement plug			10 - 11.5 ppg OBM	use directional BHA
Wireline logs	Top Tuscaloosa Containment Interval	~14,206	200 feet of CO2 resistant cement set above cement retainer (~7.4 bbls)		
Pressures and fluid samples	Cement Retainer		Cement Retainer above Lower Tuscaloosa at 14,307'		
Microfrac	Top Lower Tuscaloosa	~14,306	~10 bbl of CO2 resistant cement pumped below cement retainer (volume to bottom perforation is 5.5 bbl)		
Rotary sidewall cores					
Whole core	Perforate Lower Tuscaloosa				
CBL/VDL		~14,374' - 14,454'	**7" 29# P110IC BTC from 0 - 14156 ft, packer at 13500 ft**		
			7" 29# SM25CRW-125 VAM 21 from 14156 - 14721 ft		
	Base Tuscaloosa	~14,571	Lead Slurry: 0-13450', 10% excess: 378 bbls (yld, sks TBD)		
			Tail Slurry: 13450'-14721', 30% excess: 37 bbls (yld, sks TBD)		

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§111.F.2.d - BOP must be tested before drilling out each casing string
7" casing must have cement bong log, pressure test and casing test affidavit

Figure 2 - Proposed Plugging and Abandonment of the Tuscaloosa Injection Well; Soterra IT 2-1