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INJECTION WELL PLUGGING PLAN
40 CFR 146.92(b)

Project Goose Lake

Contents

1.0 Facility Information

Facility name:	Project Goose Lake Wells 1 & 2
Facility contact	Benjamin Heard, Principal 2417 Shell Beach Drive, Lake Charles, Louisiana 70601 (713) 320.2497; bheard@gcscarbon.com
Well location:	Calcasieu/Cameron Parish, Louisiana [redacted] [redacted]

Gulf Coast Sequestration (GCS) will conduct injection well plugging and abandonment according to the procedures below.

2.0 Planned Tests or Measures to Determine Bottom-Hole Reservoir Pressure

60-day notice will be provided prior to plugging operations. Adjustments to the plugging plan will be incorporated to meet the Director's guidance.

It is unlikely that a homogenous liquid will exist from the surface wellhead gauge down to the perforations. The homogenous liquid is required to accurately determine the downhole pressure at the perforations; a mixture of gas and super-critical phase CO_2 are not conducive to making accurate pressure calculations. Consequently, a wireline unit will deploy a tubing downhole pressure gauge with either surface read-out or recorded memory data, and the pressure at the perforations will be measured directly.

After determining the downhole pressure at perforations, the equivalent density of the fluid to balance, this pressure will be calculated using the equation: Density = Pressure ÷ 0.052 ÷ TVD, where density is in pounds-per-gallon, pressure is psi, and TVD is feet.

A working fluid with the density calculated as above from the downhole pressure will be mixed from a freshwater base, with bentonite added for viscosity and barite added for weight. This fluid is robust at the expected temperatures and is compatible with common cement spacers and cement.

A work string likely consisting of 2-7/8" tubing will be run into the well using a workover rig. If the well has an existing tubing string with a packer, the workover rig will make up a working joint to the existing tubing, pull tension to unseat the tubing hanger from the wellhead, and pull further tension to unseat the packer; if the packer has to be removed by milling, this can also be done with the work string. With the tubing work string in the hole or the existing tubing/packer unseated, the working fluid will be slowly pumped down the tubing toward the perforations. The pre-drill model indicates 0.8278psi/ft or in other words 15.92 pounds per gallon (ppg) equivalent hydrostatic as fracture gradient, this can be varied after injection well life, but unlikely to be any lower than pre-drill depletion. Circulating a volume of approximately 700 bbl to fill the well with a homogeneous fluid can be displaced at a reduced pump rate (< 2 barrels per minute) to minimize friction pressure loss and circulate out with the fluid density required. The intent is not to inject into the formation at this stage but simply displace a single column of fluid from TD to the surface and these measures are meant to ensure fluid can be lifted back to surface without losses. If losses are encountered, lost circulation material can be used.

3.0 Planned External Mechanical Integrity Test(s)

GCS will conduct an acoustic log of the cement barrier behind the 9-5/8" casing from Injection Zone to surface as described in Table 3.0-1. Additionally, GCS may include other tests listed in Table 3.0-1 to verify external mechanical integrity prior to plugging the injection wells as required by 40 CFR 146.92(a).

3.1 Procedures that will be followed for each type of test

At the end of injection activities, the (internal test) pressure test can be performed with the tubing in place, still connected to the packer. The pressure inside the 9-5/8" long string casing can be increased to a value above the standard pressure applied during the injection. The other tests require that the tubing be pulled out of the way. The logs will be run inside the long string.

3.2 Gauges and/or other equipment

Injection of CO_2 is expected to occur at a surface pressure of 1,950 psi, and the tubing/casing annular pressure is expected to be 100 psi greater, or 2,050 psi. These pressures can easily be read on 0 – 3,000 psi or 0 – 5,000 psi gauges. The pressure test could be 2,200 psi, again measured with 3,000 psi or 5,000 psi rated gauges (Table 3.0-1). For both Injector Wells (GL No. 1 and GL No. 2), the maximum pressure test is estimated at 2,200 psi casing and tubing side. A 3,000-psi gauge will be installed on the wing outlets valves for tubing and 9 5/8" x 5 ½" annular space and in the 5 ½" tubing for pressure monitoring.

3.3 What constitutes a "pass" or "fail" for each test?

A temperature and Pulse Echo Log in combination with a cement bond log (CBL) will be run on a wireline to confirm any temperature or casing/cement changes in acoustic response. Confirming a moving fluid behind the casing will require additional analysis to determine the nature of the movement. Fluid movement behind the casing can occur across the Injection Zone interval but should not extend across the confining zone interval (Anahuac Formation). If micro-annulus with fluid movement is detected behind the casing from Injection Zone to confining zone, this will constitute a failed test, and the integrity addressed by remediation through cement squeeze operations.

Another tool to confirm the existence of micro-annulus with fluid movement behind casing is to run a Spectral Pulse Neutron (SPN) that will provide a Hydro-log or Flow Shots utilizing oxygen (O_2) activation to see the O_2 spectrum and if it is moving across micro annulus space. The same criteria are used for pass/fail for the pulse neutron testing in those fluids moving across the Injection Zone are acceptable, but any fluid movement into or across the confining zone is not.

The combination of a good CBL along with the acoustic log will confirm no fluid movement across the confining zone along the casing back side and will be considered a "PASS".

4.0 Information on Plugs

GCS will use the materials and methods noted in [redacted] 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 UIC Program Director with the well plugging plan. GCS will report the wet density and will retain duplicate samples of the cement used for each plug.

5.0 Methods used for volume calculations

[redacted] After running casing and cementing, a casing caliper log will be run as a baseline against which to measure future corrosive and/or erosive loss of wall thickness. Prior to plugging, casing i.d. data will be evaluated and compared to the original baseline data. Calculations to determine cement plug and displacement volumes will use the final casing i.d. values. An example of the possible sensitivity of one-half casing wall thickness loss:

Original Capacity = $\frac{8.535^2 \text{ in}^2}{1029.4}$ = 0.0708 bbl per foot. 1,000 ft of casing holds 70.8 bbl. Original wall thickness 0.535".

Final Capacity = $\frac{9.079^2 \text{ in}^2}{1029.4}$ = 0.0801 bbl per foot. 1,000 ft of casing holds 80.1 bbl. Final wall thickness 0.273".

Volume calculations will be based upon the final dimensions of the long string casing.

6.0 Notifications, Permits, and Inspections

In compliance with 40 CFR 146.92(c), GCS will notify the following at least 60 days before plugging the well and provide updated Injection Well Plugging Plan, if applicable:

- UIC Program Director
  - Ken Johnson
  - johnson.ken-e@epa.gov
  - Phone (214)-665-8473

- Calcasieu Parish Office of Emergency Preparedness (OEP)
  - Dick Gremillion, Director
  - ohsep@calcasieuparish.gov
    Phone (337) 721-3500

- Cameron Parish Office of Emergency Preparedness (OEP)

  - Danny Lavergne, Director
  - oep@cameronpj.org
  - Phone (337) 775-7048

- Louisiana Department of Natural Resources
  - Stephen Lee, PG, Esq, Injection & Mining Division Director
  - Stephen.Lee@la.gov
  - Phone (225) 342-5569

- Texas Commission on Environmental Quality
  - oce@tceq.texas.gov

- Railroad Commission of Texas
  - UIC@rrc.texas.gov

- Orange County Office of Emergency Management
  - John h. Gothia, County Judge
  - jgothia@co.orange.tx.us
  - Phone (409) 882-7070
  - Emergency Management Coordinator (EMC)
  - (409) 882-7895
  - LEPC@co.orange.tx.us

7.0 Plugging Procedures

Plug-and-abandonment (P&A) cementing operations should occur when fluids in the wellbore are at balance with the exposed formation (in this case, via perforations in the long string). Water is the major component of the working fluid and is the liquid component of the cement. Additionally water is effectively incompressible. A barrel of water introduced into a closed system will cause one barrel of water to be displaced out of the system.

The interval depths, length and method to place every cement plug is described in Table 4.0-1; the cement in the fluid form will be precisely placed by accurately measuring the volumes of the spacer, cement, and working fluid so that the cement height outside the work string will match the height inside the work string. As soon as the cement is in place, the work string will be slowly pulled from the still-fluid cement mixture, leaving a cement column of a known height.

The density difference between the working fluid and fluid cement will not cause disruption to the placement of cement, because the major component of water is incompressible, through managing the injection pressure - a barrel in leads to a barrel out.

Salt can be an accelerator to the hydration process of cement, and it is possible that the work fluid might contain salt if it is made from the packer fluid used during the injection activities. To prevent cement from coming into contact with any salt in the work fluid, a fluid spacer containing no salt is pumped ("in the space") between cement and the work fluid. The standard cement plug placement thus consists of pumping accurate amounts of each of these three (3) fluids: spacer, cement, work fluid.

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

After displacing the cement plug to the balanced depth, the tubing work string will be slowly pulled to a point at least 500 ft above the top of the cement, and the tubing work string will be circulated (the long way, down the tubing and up the annulus) to clear any excess cement out of the well; reciprocate and rotate the tubing continuously during this circulation. Wait-on-cement (W.O.C.) for 24 hours, with periodic short circulations down the tubing to ensure it remains open-ended. After W.O.C. 24 hours (or such time recommended by the cementing contractor for the plug to achieve 100 Bc or 1,000 psi compressive strength), run tubing work string slowly into the well to tag the top of the cement. Circulate through the work string during the final 90 ft (3 joints) to ensure that the tubing remains open-ended when it encounters cement, and to begin to move contaminated, viscous cement up and out of the wellbore. Tagging the hardened cement top will determine the precise location of the cement compared to desired placement; set down 10,000 lbs of work string weight on top of the cement plug to prove its competency. The cross-sectional area of 2-7/8" tubing is approximately 2.7 in^2, and the force exerted on the cement top would be approximately 10,000 lbs ÷ 2.7 in^2 ≈ 3,700 psi.

After successfully tagging the cement plug top and proving its competency, immediately pick up the tubing work string and circulate through it to clear any cement from the open end and to circulate any contaminated cement out of the wellbore. Mix and pump via the balanced method another 500 ft cement plug similar to the first plug, placing it on top of the first plug. Repeat the process of pulling at least 500 ft above the calculated top of cement, circulating out any excess cement, W.O.C. while periodically circulating and tagging the top of the second plug and proving its competency.

As a conservative approach, each of the plugs will be tagged using the method described. Tagging each plug will prove its location and competency, thus removing doubt about the suitability of the plugging process. It will be a time-consuming process due to the W.O.C. intervals, but successfully placed cement plugs will protect USDW.

8.0 Contingency procedures/measures

Discussed in Section 7.0 above in the bulleted points concerning real-world implications of tubing lengths, cement volumes, and spacer/cement interface contamination.