SUMMARY OF OPERATING CONDITIONS
40 CFR 146.82 (a)(7) and (10) and 146.88 (e)

South Texas Sequestration Project (Kleberg Hub)

1.0 Facility Information

Facility name: South Texas Sequestration Project (Kleberg Hub)
Well Name: Garcias_CCS_01_02

Facility contact: [redacted], Project Manager
5 Greenway Plaza, Suite 110, Houston, TX 77046
[redacted]

Well location: Kleberg County, Texas

WELL_NAME	LAT_NAD27	LONG_NAD27
Garcias_CCS_01_02	[redacted]	[redacted]

2.0 Injection Well Operating Conditions

Key injection well operating and project reporting requirements for Garcias_CCS_01_02 are specified in this attachment and summarized below in Table OP-1. Injection rates included in this section may continue to be refined as 1PointFive acquires, processes, evaluates, and interprets additional data from stratigraphic test wells, as described in this application.

Table OP-1—Injection Well Operating Conditions

Parameter/Condition	Limitation or Permitted Value	Units
Maximum Injection Rate	[redacted]	Metric tons per day
Operating Injection Rate		Metric tons per day
Maximum Surface Wellhead Injection Pressure @ 90F inlet temperature reference		psig
Maximum bottom hole pressure @ Downhole Gauge (90% of frac gradient [redacted] psi/ft)		psig
Minimum Annulus Pressure/Tubing Differential		psig
Total mass injected		Million metric tons

Limitations or permitted values for the maximum surface wellhead injection pressure, maximum bottomhole injection pressure, minimum annulus pressure, and minimum annulus pressure/tubing differential limitation are set as follows:

- **Maximum Bottomhole Injection Pressure:** The maximum injection pressure for the Garcias_CCS_01_02 well will be equal to or less than 90% of the fracture pressure of the injection zone. The fracture pressure was determined by a step rate test in the Becerra IZM 01 stratigraphic test well, yielding a fracture gradient of [redacted] psig/ft (See Section 2.9 of the Area of Review and Corrective Actions document). The downhole gauge for injection pressure monitoring in the Garcias_CCS_01_02 is projected to be located at [redacted] ft below the ground surface. The top of perforations is approximately 100 ft below the gauge, so the maximum pressure is calculated at the gauge depth due to the small difference. The maximum injection pressure using a downhole pressure gauge is calculated as follows:

  Maximum Bottomhole Injection Pressure: [redacted]

  The packer and gauge settings will be adjusted based on logs and well information after the well is constructed.

- **Maximum Surface Wellhead Injection Pressure:** The maximum surface wellhead injection pressure will be controlled at the booster pump station. The design pressure of the booster pump discharge is planned to be [redacted] psig, consistent with ASME [redacted] flange class piping specifications, though the operating conditions will be significantly lower than design. Normal operating pressure at the wellsite are estimated to be between [redacted] psig, with high and high-high wellsite pressure set points of [redacted] and [redacted] psig, respectively, to protect against operational excursions (set points to be confirmed during detailed engineering). Wellbore tubing curves representative of the Garcias_CCS_01_02 were created in [redacted] for [redacted]. The bottomhole pressure is not expected to be greater than [redacted] psi at the maximum rate and tubing head pressure, which is below the maximum bottom hole pressure limit of [redacted] psig. The wellhead injection pressure will not exceed the maximum bottom hole pressure because the automated high-high pressure shutdown is set at [redacted] psig. Calibration of the tubing curves will be performed after well construction.

- **Wellhead Minimum Differential Annulus/Tubing Pressure:** The well is designed to inject through tubing and packer. The annulus space will be filled with inhibited completion fluid with a minimum density of [redacted] ppg. The project will maintain at least 100 psi differential pressure between the annulus and bottom of the injection string as proposed in Table OP-1.

If the downhole pressure gauge fails to function properly, then the maximum injection pressure shall immediately be limited by the maximum surface wellhead injection pressure until the downhole pressure gauge can be repaired or replaced.

3.0 Reporting Frequencies

Kleberg Sequestration Hub, LLC (1PointFive) will follow the reporting frequencies as summarized below in Table OP-2.

Table OP-2—Class VI Reporting Frequencies

Activity	Minimum Reporting Frequency
[redacted]	

Note: All testing and monitoring frequencies as well as methodologies are included in the Testing and Monitoring Plan document of this permit.

The events that trigger an immediate emergency response should be reported within 24 hours, according to the 40 CFR §146.91 reporting requirements.

4.0 Startup Monitoring and Reporting Procedures

The special procedures related to the startup of operations, monitoring, and reporting during the first several months are specified in this section. The injection rates will be gradually increased to the planned rate over a period of [redacted] days.

These additional procedures, which are detailed below, describe how 1PointFive will initiate injection and conduct startup-specific monitoring of the Garcias_CCS_01_02 well pursuant to 40 CFR 146.90. Actual initial injection and start-up-specific monitoring may differ from the procedures set forth below based on technical, operational, and safety considerations at the time of injection and startup begins.

The multi-stage (step-rate) startup procedure and period only apply to the initial start of injection operations until the well reaches the full injection rate. Monitoring frequencies and methodologies after the initial startup will follow the Testing and Monitoring Plan document of this permit.

(1) This procedure will be performed using the existing surface and downhole pressure and temperature gauges in the Garcias_CCS_01_02 well.

(2) During the startup period, 1PointFive will submit a daily report summarizing and interpreting the operational data. At the request of the EPA, 1PointFive may be required to schedule a daily conference call to discuss this information.

(3) A series of successively higher injection rates will be applied as shown in Table OP-3 below in Step 4. The elapsed time and pressure values will be read and recorded for each rate and time step. At no point during the procedure will the injection pressure be allowed to exceed the maximum injection pressure of [redacted] psig, which is measured at the wellhead.

(4) The planned injection rates are shown in Table OP-3:

Table OP-3—Planned Injection Rates During Startup

Rate (tonnes per day)	Duration (hours)	Percent of Permit Maximum Injection Rate (%)
[redacted]		

(5) The injection rates will be controlled with process control valves.

(6) The injection rates will be measured and recorded using Coriolis flow meters. Surface and downhole pressures and temperatures will be measured and recorded for the Garcias_CCS_01_02 as well as continuous reading of temperature profile from the fiber optic.

(7) During the startup period, a plot of injection rates and their corresponding stabilized pressure values will be graphically represented. During this period, the project team will also look for any evidence of anomalous pressure behavior.

(8) If during the startup period any anomalous pressure behavior is observed, the project team may conduct additional logging and modify the injection rate program to characterize the anomaly better. The project team will also determine if the observed anomalous pressure behavior indicates formation fracturing, which will cause the injection to cease and the line valve to be closed, allowing the pressure to bleed off into the injection zone, as discussed below:

(a) The instantaneous shut-in pressure (ISIP) will be measured
(b) 1PointFive will notify the agency within 24 hours of the determination.
(c) 1PointFive will consult with the agency before initiating any further injection.

5.0 Operations after startup:

Automatic alarms and automatic shutoff systems will be installed and maintained. Successful function of the alarm system and shutoff system will be demonstrated prior to injection and once annually thereafter.

At all times, pressure will be maintained on the well to prevent the return of the injection fluid to the surface. The wellbore must be filled with a high-specific-gravity fluid during workovers to maintain a positive (downward) gradient and/or a plug shall be installed that can resist the pressure differential. A blowout preventer must be installed and kept in proper operational condition whenever the wellhead is removed to work on the well.

1PointFive shall cease injection should it appear that the well is lacking mechanical integrity or that the injected CO2 stream and/or associated pressure front may cause an endangerment to a USDW.