CLASS VI PERMIT APPLICATION NARRATIVE
40 CFR 146.82(A)

South Texas Sequestration Project (Kleberg Hub)

1.0 Project Background and Contact Information

Facility name:	South Texas Sequestration Project (Kleberg Hub) Well Name: Becerra_CCS_01_01
Facility contact:	[redacted], Project Manager 5 Greenway Plaza Houston, TX 77046 [redacted]
Well location:	Kleberg County, Texas [redacted] (NAD 27)

The Becerra_CCS_01_01 well is part of the South Texas Sequestration Project (Kleberg Hub) being constructed by 1PointFive Sequestration, LLC (1PointFive) to demonstrate technical feasibility of Carbon Capture and Storage (CCS) utilizing CO_2 from industrial emitters along the Texas Gulf Coast. The advancement of CCS technology is critically important in addressing CO_2 emissions and global climate change concerns. The Kleberg Hub is designed to demonstrate utility-scale integration of transport and permanent storage of captured CO_2 into a deep geologic formation (i.e., geologic sequestration). A commercial-scale CCS system will be designed, built, and operated with the capability of storing CO_2 gas.

1PointFive intends to demonstrate that the geologic sequestration process can be done safely and that injected CO_2 will be retained within the intended storage reservoir at the Kleberg Hub. By using safe and proven pipeline technology, the CO_2 will be transported to a storage site located in Kleberg County, Texas, where it will be injected into the [redacted] at a proposed rate of [redacted] million metric tons (MMT) of CO_2 each year for a planned duration of [redacted] years, subject to further interpretation and evaluation of geologic data as further described in this permit application.

There are no known places of worship or cemeteries within a 2-mile buffer zone surrounding the AOR. There are no known schools, hospitals, or nursing homes within the AOR or buffer zone surrounding the AOR.

GSDT Submission - Project Background and Contact Information
GSDT Module: Project Information Tracking ***Tab(s):*** General Information tab; Facility Information and Owner/Operator Information tab Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☒ Required project and facility details ***[40 CFR 146.82(a)(1)]***

2.0 Site Characterization

Characterization of subsurface both regionally and locally pertinent to the Kleberg Hub was conducted with geological, geophysical, petrophysical, and reservoir engineering data obtained from public literature, public data, and Oxy-licensed data.

A detailed discussion of the regional and local surface and subsurface geology, geomechanics, seismic history, injection and confining zone details, and area of review site suitability is in the Area of Review and Corrective Action document of the permit. Below are key highlights of the detailed discussion.

An onshore storage complex called the South Texas Sequestration Hub or Kleberg Hub has been identified and characterized in [redacted] Kleberg County, Texas (Figure NAR-1).

[redacted]

Figure NAR-1: Kleberg Hub location with greenhouse gas emitters scaled by Mt/year. Zoom in shows leased acreage and Area of Review over satellite imagery.

The South Texas Sequestration Hub is strategically located near a concentration of industrial power generating plants, refineries, chemical production, natural gas processing, and natural gas liquefaction facilities in the Corpus Christi area. Direct Air Capture (DAC) facilities planned for the Kleberg Hub area also provide a source of CO_2 for sequestration (Figure NAR-1).

The Kleberg Hub site is geologically favorable for carbon sequestration due to 1) its accumulation of passive margin fluvial-deltaic and shoreface/strandplain sediments, 2) stratigraphically stacked injection targets and confining units, and 3) favorable burial history in a hydrostatically pressured setting. The upper confining system is a regionally correlatable marine shale modeled as preventing vertical migration of CO_2 into the USDW. The site targets an area of minimal faulting within the [redacted] fault detachment trend, which developed as loading of the shelf by sediment delivered by the Oligocene Rio Grande delta system drove fault detachment in Eocene shales. The paleo Rio Grande sourced the Norias fluvial-deltaic system, while longshore currents, wave, and storm action reworked and redeposited that sediment into the updrift Greta strandplain/barrier island system.

The overall site development plan will include additional Class VI permits with wells targeting both the [redacted] and [redacted] zones, to sequester additional CO_2 as demand for sequestration increases at the Kleberg Hub.

1PointFive Sequestration, LLC (through its affiliates) has leased [redacted] acres in [redacted] Kleberg County. These agreements include control of the pore space, surface use, and land access that is necessary to facilitate this proposed carbon sequestration project. From September – December 2023 Oxy drilled three stratigraphic test wells in eastern Kleberg County: the [redacted]. [redacted] collected in these wells will be used to refine and update extant models of pore space, injectivity, and plume and pressure front migration after 1PointFive has been able to fully process, evaluate, and interpret the data.

2.1 Regional Geology, Hydrogeology, and Local Structural Geology

The Kleberg Hub is situated in the Rio Grande Embayment in the south Texas coastal plain physiogeographic province (e.g. USGS, 2013). The site currently targets nearly 4,000 feet of stacked Late Oligocene fluvial, deltaic, barrier island, and strandplain sandstones that were deposited in sequential packages punctuated with shales deposited during transgressive events (e.g. BEG, 1982). The site's position updrift of the mouth of the paleo Rio Grande resulted in very high sedimentation rates that resulted in a thick wedge of high net-to-gross material which is comprises the [redacted] injection target. These stacked successions represent several sea level cycles over ~4myr and are ultimately overlain by the Latest Oligocene/Earliest Miocene regionally transgressive marine [redacted], which is the upper confining unit and is locally around [redacted] feet thick (Brown et al., 2004). The lower confining system is the shaley [redacted] unit. The Upper Oligocene wedge comprises part of a the larger prograding Cenozoic deposition in the Gulf of Mexico (Figure NAR-2).

[redacted]

Figure NAR-2: Schematic of the Kleburg Hub site based on cross section from USGS (2013) proprietary 2D seismic.

[redacted]

Figure NAR-3: Geological Stratigraphic Chart showing project storage complex, stratigraphic, and hydrogeologic units

The Rio Grande source terrain is heterolithic, resulting in sediment that has a relatively high composition of non-quartzose material compared to other areas of the Gulf Coast (Loucks et al., 1986, Galloway et al., 2011). Porosity reduction due to time temperature history results due to compaction and deformation of ductile grains, diagenetic processes including calcite and quartz cementation, and fluid movement through the rock. In the Kleberg Hub, regional published porosity-depth trends are consistent with local well log and rock data (Loucks et al, 1986).

As prograding clastic wedges were deposited, loading of the shelf margin drove the development of large listric faults that sole into mobile substrate (allochthenous salt or overpressured shales) and strike parallel to the Gulf margin (e.g. Ewing 1986, Diegel et al., 1995) (Figure NAR-2). These growth faults both accommodated and influenced deposition: just north of the Kleburg Hub in Corpus Christi Bay, thick successions of shoreface sands accumulated on the hanging wall during lowstand systems tracts (Brown et al, 2004). Subsequent sea level rise and lower sedimentation rates resulted in transgressing shales that healed topography until the next lowstand progradational loading and fault reactivation. The AoR associated with the Kleburg Hub is modeled to fall in between the named [redacted] to the west and a similar-sized fault to the east. Regional dip is to the east, but within the fault blocks dip is gently down to the SSE. CO_2 plume migration due to buoyancy forces is therefore to the NNE; this also follows sand distribution patterns observed in seismic attribute extractions, which show distributary systems oriented subparallel to faults

2.2 Maps and Cross Sections of the AOR

Structure maps were created using both seismic and well data. Time horizons were mapped on 2D and 3D seismic data and tied to relevant geological markers. Preliminary interpretation of subsurface faults was performed using the same data. Figure NAR-4 shows a depth-structure map of the top of the storage reservoir. Preliminarily interpreted faults are overlaid and the two major bounding faults, [redacted] to the west and [redacted] to the east, can be seen to be beyond the bounds of the AOR. Overall dip is to the east, but within the AOR fault block it is down to the south. Figure NAR-5 shows a west-east cross section through the Kleberg Hub. Within the geomodel and subregionally, there are no stratigraphic pinchouts; mapped and modeled zones extend many miles beyond the Hub. Further detailed delineation of faults and stratigraphic elements within the [redacted] formations will help constrain the storage complex and refine the plume distribution.

[redacted]

Figure NAR-4: [redacted] depth structure map from seismic interpretation. Current mapped faults (brown) overlain, wells are annotated as black symbols, AOR shown in blue; geomodel extent in red; black line shows location of cross section in Figure AOR-5. Note that AOR is bounded by major labelled growth faults: [redacted]

[redacted]

Figure NAR-5: West-East color-replaced seismic cross section showing faults and geological formations. Transect was constructed from 2D and 3D seismic coverage. Wells shown in black. Major bounding growth faults do not intersect with AOR.

[redacted]

Figure NAR-6: West-east subregional wells cross section in similar orientation to NAR-5. Gamma logs are not normalized, but character and motifs can be used to correlate shales regionally. [redacted] confining zone and [redacted] confining unit separate the [redacted] and [redacted] injection target from the USDW. Faults are schematic based on regional understanding.

2.3 Faults and Fractures

Failure analysis focused on the propensity of large bounding faults for reactivation, as this was identified as the greatest risk. Upper and lower confining systems and storage reservoirs are not in a critical state of failure at present. Pore pressure was modeled as hydrostatic and calibrated to repeat formation tester pressure measurements. Maximum principal stress is the overburden, and least horizontal stress is defined by closure pressure interpreted from leak off tests performed in the bottom half of the upper confining unit. The mean pore pressure within the [redacted] storage reservoir is [redacted] psi ([redacted] psi/ft at a depth of [redacted]) and extrapolated fracture gradient pressure is [redacted] ([redacted] psi/ft at [redacted]). The subsequent Mohr-Coulomb analysis estimates the magnitude of pressure change required to instigate shear slip on the bounding fault to be [redacted] psi. An increase in pressure of [redacted] psi would be required to drive the Mohr circle into tensile stress.

[redacted]

Figure NAR-7: Stress model for [redacted] well. Red arrows indicate depths of Mohr-Coulomb analysis. Pressure data from [redacted] well.

2.4 Injection and Confining Zone Details

Surface and subsurface site characterization was conducted using data from public and private sources including well data, 2D and 3D seismic, remote sensing data, published maps and databases, and published literature. [redacted] wells with digital logs were interpreted with regionally correlatable tops; [redacted] had scoping petrophysical interpretation. Tops were used to tie wells to 2D and 3D time seismic data so a velocity model could be created to convert surfaces to depth. The [redacted] (top storage reservoir) surface was used as the master structural grid from which the other key surfaces were calculated using well-based isochores. Porosity and permeability measurements from percussion sidewall core samples from [redacted] wells were used as a basis for the poro-perm transform incorporated into the geomodel.

[redacted]

Figure NAR-8: Subsurface data control in the region that was used for site characterization and Geomodel building. Map on left shows all wells, wells with digital logs, wells with petrophysical analysis, and wells with core data. Map at right shows 3D and 2D seismic data untilized in the construction of the Geomodel as well as select wells with sonic data.

Figure NAR-9 shows a petrophysical type log with stratigraphic tops and geomodel zonation. Petrophysical average porosity, permeability, and net reservoir for the zones compiled from [redacted] wells within the geomodel footprint are annotated on Figure NAR-8.

The [redacted] shale and [redacted] Formation are both marine shales with very low porosity and permeability. The [redacted] shale thickness varies from [redacted] ft to [redacted] ft. The Oligocene [redacted] Formation injection zone starts at [redacted] ft true vertical depth (TVD) and has an average of [redacted] ft net sand [redacted]) with an average porosity of [redacted]% and average permeability of [redacted] mD. [redacted] ft of stacked brine-filled sand and shales overlie the

Upper Oligocene storage complex. These include the shale-prone Burkeville confining unit between the Jasper and Evangeline aquifers. The USDW is very shallow regionally due to proximity to the Gulf of Mexico.

[redacted]

Figure NAR-9: Type log from Kleberg Hub shows petrophysically interpreted gamma ray, SP, facies, porosity, permeability, and volume of shale curves. Also shown are geomodel zones, stratigraphic units, tops, gross depositional environment interpretation, and sequestration complex details. The [redacted] is the upper confining zone; [redacted] and [redacted] comprise the upper injection zone and storage reservoir and lower injection zone and storage reservoir, respectively. [redacted] horizon defines the base of the lower injection zone and top of the lower confining unit, which is the stratigraphic [redacted].

Figure NAR-10 shows how petrophysical properties were modeled within the geomodel, which was then used for dynamic simulations of CO_2 plume migration.

[redacted]

Figure NAR-10: West to East cross section through static Geomodel; injection well is projected in and labeled with a red star. Properties shown (top to bottom) are: NetSand, Porosity, Permeability, and Volume Shale.

2.6 Seismic History

Regional earthquakes were identified using the USGS online database and cross-checked against the Bureau of Economic Geology's TEXNET database to determine the location of events (Figure NAR-11). Two recorded events of Magnitude 3 were identified within 50 miles of the Kleberg site from 1973 to present. A 3.8 magnitude event was recorded in 1997, and a 3.9 event was recorded in 2010. The USGS Long-Term Seismic Hazard Map (Figure NAR-12) indicates that this area is at relatively low risk for natural earthquake activity.

[redacted]

Figure NAR-11: Seismometer stations (pink and blue circles) and historic seismic activity (yellow stars) from BEG TEXNET and IRIS databaes.

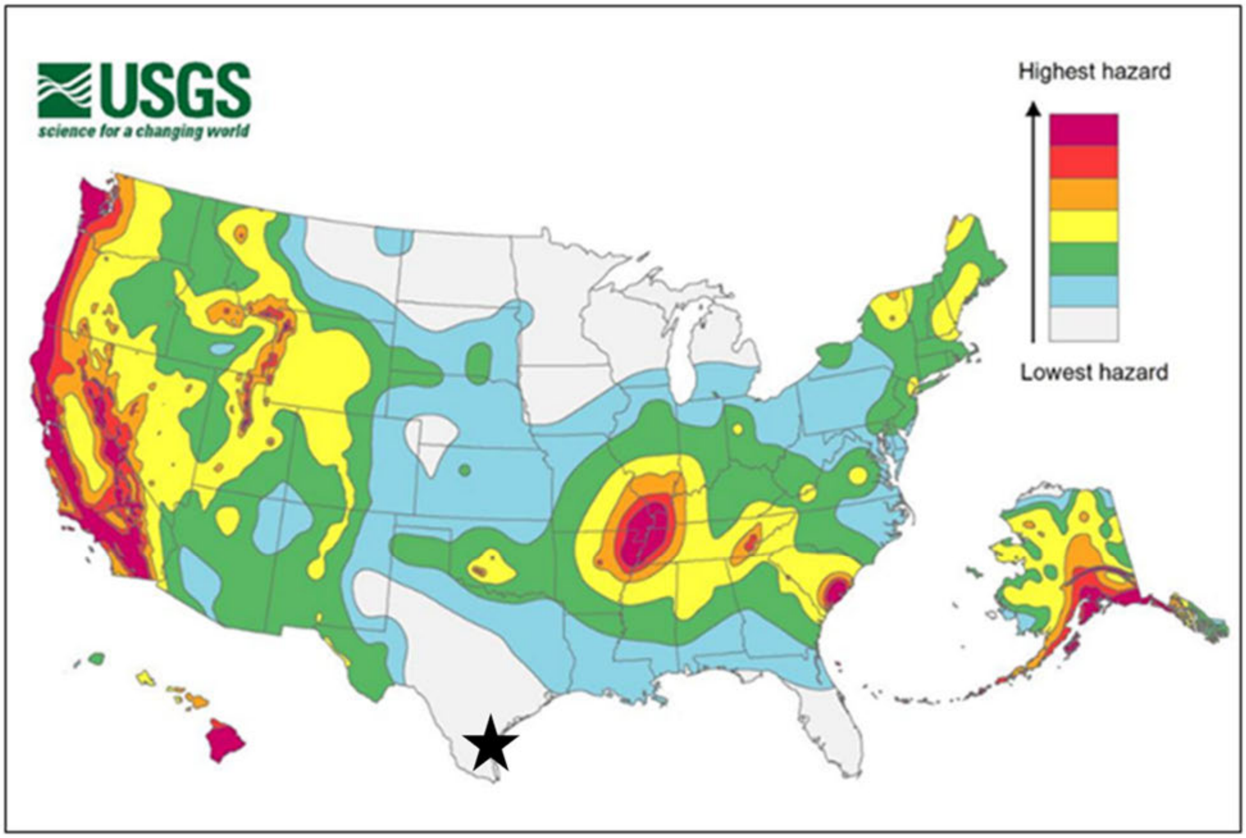

Figure NAR-12: Seismic hazard map showing that peak ground accelerations have a 2% probability of being exceeded in 50 years from USGS 2018 Long-Term National Seismic Hazard Map (USGS, 2018). Seismic hazard potential in the study area is one of the lowest in the U.S.

2.7 Hydrologic and Hydrogeologic Information

The only aquifer in the area is the Gulf Coast Aquifer System, which is divisible (from shallowest to deepest) into the Chicot, Evangeline, and Jasper aquifers (Figure NAR-13). The Burkeville confining unit separates the Evangeline aquifer from the underlying Jasper aquifer and is a secondary confining zone above the [redacted] confining zone and the shallower Chicot and Evangeline aquifers, which contain the underground sources of drinking water (USDW) in the region. Municipal, ranching, and other use draws exclusively from the Chicot and Evangeline aquifers; no pumping is done from the Jasper. The underground source of drinking water (USDW), which is defined by the USEPA as an aquifer or part of an aquifer that contains fewer than 10,000 ppm TDS, ranges in depth from 2500 feet below ground level (bgl) to the south and ~1000 feet bgl to the north (Figure NAR-13). Within the Kleberg Hub area, deep resistivity logs show transition across the 2-ohm marker around 2,000 ft bgl. While salinity generally increases with depth, there are localized salinity reversals, whereby the shallower Chicot has higher salinities due to seawater incursion from the Gulf.

[redacted]

Figure NAR-13: Map to depth of groundwater where TDS <10,000 mg/L with regional cross section locations. West to East cross sections through Gulf Coast Aquifer hydrogeoloic units include projected Kleberg Hub AOR and approximate depth to TDS> 10,000 mg/L (i.e. USDW). After Young, 2016 and Shi et al,, 2022.

2.8 Site Storage Capacity

An initial estimation of the site storage capacity was performed using the U.S. DOE methodology provided by Goodman et. al. (2011) for storage in saline formations, described by Equation 1.

$$G_{CO_2} = 4.536x10^{-4} * A * h_g * \emptyset_{tot} * \rho_{CO_2} * E_{saline} \quad \text{............(Equation 1)}$$

Where:

G_{CO_2} is the static storage capacity in tonne;
A is area in ft^2;
h_g is gross formation thickness in ft;
$\emptyset_{tot}$ is total porosity (fraction);
ρ_{CO_2} is CO_2 density in lb/ft^3;
and E_{saline} is a saline formation storage efficiency factor (fraction).

The average petrophysical properties of the storage formations were determined from the analysis of [redacted] wells with electronic logs and [redacted] wells with percussion sidewall core. Average properties from petrophysical analysis of these wells were used in Equation 1 along with estimated values for the efficiency factor for clastic formations reported in literature (Goodman et al, 2011). The inputs and results are shown in Table NAR-1 using a basis of a [redacted] mi^2 unit area.

Table NAR-1—Input data and results of static storage capacity using DOE methodology

Formation	TVD (ft)	Pressure (psi)	Temp (°F)	Gross Formation Thickness (feet)	Net Thickness (feet)	Total Porosity (P)	CO_2 Density (lb/ft^3)	P10 G_{CO_2} (tonne/ mi^2) $E_{saline} = 0.005$	P50 G_{CO_2} (tonne/ mi^2) $E_{saline} = 0.02$	P90 G_{CO_2} (tonne/ mi^2) $E_{saline} = 0.054$
[redacted]										

Based on the analysis of the petrophysical properties of the storage formations described above, using a conservative estimate of the total pore-space acreage at [redacted] acres ([redacted] mi^2), the total storage capacity of the Kleberg Hub sequestration site in the formation intervals totals between approximately [redacted] million tonne CO_2. The DOE methodology provides an order-of-magnitude of variation in the storage capacity estimate and is considered a high-level estimate to assess the site's potential.

3.0 AoR and Corrective Action

The Area of Review and Corrective Action Plan document meets the requirements of the Environmental Protection Agency (EPA) document 40 CFR Subpart H - Criteria and Standards Applicable to Class VI Wells. The key challenges are detailed characterization of the injection and confining zones, delineating all underground sources of drinking water, and implementing corrective action on existing wells within the Area of Review. The document describes the subsurface characterization, computational modeling, current AoR delineation, corrective action plan and schedule, wells requiring corrective action, and future AoR re-evaluation plan and schedule.

The plan delineates the Area of Review (AoR) and provides any corrective action that is needed in the wells that penetrate the upper confining zone within the AoR. Delineation of the AoR is one of the key elements of the Class VI Rule to ensure USDWs in the region surrounding the geologic sequestration project are not endangered by the injection activity.

At a fixed frequency specified in the Area of Review and Corrective Action Plan or more frequently when monitoring and operational conditions warrant, 1PointFive will reevaluate the AoR and perform any required corrective action in the manner specified in 40 CFR 146.84. 1PointFive will also update the Area of Review and Corrective Action Plan or demonstrate to the Director that no update is needed.

Following each Area of Review and Corrective Action Plan reevaluation or demonstration showing that no new evaluation is needed, 1PointFive will submit the resultant information in an electronic format to the Director for review and approval of the results. Once approved by the

Director, the revised Area of Review and Corrective Action Plan will become an enforceable condition of this permit.

AoR and Corrective Action GSDT Submissions
GSDT Module: AoR and Corrective Action ***Tab(s):*** All applicable tabs Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☒ Tabulation of all wells within AoR that penetrate confining zone ***[40 CFR 146.82(a)(4)]*** ☒ AoR and Corrective Action Plan ***[40 CFR 146.82(a)(13) and 146.84(b)]*** ☒ Computational modeling details ***[40 CFR 146.84(c)]***

4.0 Financial Responsibility

1PointFive shall maintain financial responsibility and resources to meet the requirements of 40 CFR 146.85 and the conditions of this permit. Financial responsibility shall be maintained through all phases of the project. The approved financial assurance mechanisms are found in the Financial Assurance Plan document of this permit. The financial instrument(s) must be sufficient to cover the cost of:

- Corrective action (meeting the requirements of 40 CFR 146.84);
- Injection well plugging (meeting the requirements of 40 CFR 146.92);
- Post-injection site care and site closure (meeting the requirements of 40 CFR 146.93);
- Emergency and remedial response (meeting the requirements of 40 CFR 146.94).

During the active life of the geologic sequestration project, 1PointFive will adjust the cost estimate for inflation within 60 days prior to the anniversary date of the establishment of the financial instrument(s) and provide this adjustment to the Director in an electronic format. 1PointFive will also provide to the Director written updates of adjustments to the cost estimate in an electronic format within 60 days of any amendments to the Project Plans that address the cost items covered in the financial assurance plan.

1PointFive shall provide notification to meet the requirements of 40 CFR 146.85 and the conditions of this permit.

- Whenever the current cost estimate increases to an amount greater than the face amount of a financial instrument currently in use, 1PointFive will, within 60 days after the increase, either 1) cause the face amount to be increased to an amount at least equal to the current cost estimate and submit evidence of such an increase to the Director or 2) obtain other financial responsibility instruments to cover the increase. Whenever the current cost estimate decreases, the face amount of the financial assurance instrument may be reduced to the amount of the current cost estimate only after 1Pointfive has received written approval from the Director.

- 1PointFive must notify the Director by certified mail and in an electronic format of adverse financial conditions, such as bankruptcy, that may affect the ability to carry out injection well plugging, post-injection site care and site closure, and any applicable ongoing actions under the Corrective Action and/or Emergency and Remedial Response.
  - If 1PointFive or third-party provider of a financial responsibility instrument is going through a bankruptcy, 1PointFive must notify the Director by certified mail and in an electronic format of the commencement of voluntary or involuntary proceedings under Title 11 (Bankruptcy), U.S. Code, which names 1PointFive as the debtor within 10 days after commencement of the proceeding.
  - A guarantor of a corporate guarantee must make such a notification, if he or she is named as debtor, as required under the terms of the guarantee.
  - A permittee who fulfills the requirements of financial assurance by obtaining a trust fund, surety bond, letter of credit, escrow account, or insurance policy will be deemed to be without the required financial assurance in the event of bankruptcy of the trustee (or issuing institution) or suspension/revocation of the authority of the trustee institution to act as trustee of the institution issuing the trust fund, surety bond, letter of credit, escrow account, or insurance policy.

1PointFive must establish other financial assurance or liability coverage, acceptable to the Director, within 60 days of a change to the Area of Review and Corrective Action Plan.

Financial Responsibility GSDT Submissions
GSDT Module: Financial Responsibility Demonstration ***Tab(s):*** Cost Estimate tab and all applicable financial instrument tabs Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☒ Demonstration of financial responsibility ***[40 CFR 146.82(a)(14) and 146.85]***

5.0 Injection Well Construction

The Becerra_CCS_01_01 injection well is designed in accordance with all applicable regulations and best available practices for drilling and well construction (see Figure NAR-14). The operational parameters and material selection are aimed to maximize mechanical integrity in the system and to optimize operations during the life of the project.

The Becerra_CCS_01_01 well design includes three main sections: conductor casing, surface casing, and long string casing to cover the USDW, provide integrity while drilling the injection zone, acquire formation data, isolate the target formation, and provide mechanical support to run the upper completion.

[redacted]

Figure NAR-14: Becerra_CCS_01_01 injection Well Proposed Schematic

5.1 Proposed Stimulation Program [40 CFR 146.82(a)(9)]

Stimulations to enhance the injectivity potential of the [redacted] in the Becerra_CCS_01_01 well may include but are not limited to: coil tubing cleanouts, stick pipe cleanouts, acid stimulation, and freshwater flushes. The need for stimulation will be determined after the characterization data from the South Texas Sequestration Project wells are available and have been fully interpreted and evaluated (i.e., results of geophysical logs, core analyses, and hydrogeologic testing). 1PointFive will notify and submit proposed stimulation procedures in writing to the Director at least 30 days in advance of performing the stimulation in accordance to 40 C.F.R. § 146.91(d)(2). 1PointFive will carry out the stimulation according to the EPA-approved procedures. The procedures will describe all fluids being pumped and demonstrate that there will be no loss of containment due to the stimulation.

5.2 Construction Procedures [40 CFR 146.82(a)(12)]

The [redacted] inch vertical wellbore will be drilled to [redacted] ft to cover base of the USDW, estimated at [redacted] ft, and to provide mechanical integrity on the surface shoe to continue drilling to the next section. A deviation survey will be taken every [redacted] ft while drilling and this section will be drilled with [redacted]. Once the final depth is reached, the well will be circulated and conditioned to run open hole electric logs according to the testing program. Then, [redacted]-inch casing will be run and cemented to surface via circulation with conventional [redacted]. If there are no cement returns to the surface, the Project Manager will inform the EPA Director, determine the top of cement with a temperature log or equivalent, and complete the annular cement program with a top job procedure after approval by the Director. After the tail cement reaches at least [redacted] psi compressive strength, the rig will install Section A of the wellhead and blowout preventor (BOP) equipment. The rig will then test the BOP and casing and pick up the drilling assembly. After drilling out the shoe track, an additional [redacted] ft of new formation will be drilled to execute a Formation Integrity Test (FIT).

A [redacted] inch vertical wellbore will be drilled from [redacted] ft to total depth (TD) while taking deviation surveys every [redacted] ft and getting cutting samples to describe the formation characteristics. The well will be drilled with [redacted]. During the drilling of the long string section, it is not envisioned to acquire any full core and only sidewall cores will be collected as per hole conditions and according to the testing program. After being fully evaluated and interpreted, the data obtained from the full core collected in the [redacted] will be used to establish the condition of the site-based geology. Once TD is reached, the well will be circulated and conditioned to run open hole electric logs and acquire samples based on the testing program. During this run, CBL-VDL casing logs will be acquired over the previously set [redacted]-inch surface casing. Then, the long string of [redacted]-inch casing will be deployed with the [redacted]. The casing will be cemented to the surface via circulation with a combination of [redacted] cement slurries. Based on simulations, a stage tool will be used to perform a two-stage cementing job to ensure good cement from the bottom to the surface. The depth of the stage tool or cementing stage tool will be adjusted based on actual conditions of the well after drilled.

After the tail slurry cement develops a minimum compressive strength of [redacted] psi, Section B of the wellhead will be installed, and the [redacted] cable will be threaded through the slips and pack off. The team will install the rest of the wellhead to prepare for completions operations.

During the completion operations, the rig will test the casing to [redacted] psi, condition the long string with a bit and scraper, run CBL-VDL-USIT-CCL and Casing Inspection logs to evaluate cement bonding and casing conditions, perforate the injection zone, and run the upper completion. The [redacted]-inch tubing and packer completion will be run to approximately [redacted] ft, in conjunction with the electric cable and pressure and temperature gauges. The fluid in the well will be displaced with packer fluid and the packer will be set. Once the packer is set, an annular pressure test will be performed to [redacted] psi on the surface to validate the mechanical seal and integrity in the annular space between the tubing and casing. A pulse neutron log will be run through tubing to set a baseline for future surveys. The well will be tested for injectivity with Step Rate Test, Injectivity Test, and Fall Off test procedures before starting injection.

5.2.1 Casing and Cementing

Specific details on the proposed casing properties and cementing program are found in section 4.0 of the Injection Well Construction Plan document of this permit.

6.0 Pre-Operational Logging and Testing

The CO_2 injector well testing program includes a combination of advanced logging, sidewall coring, fluid sampling, and formation hydrogeologic testing. This program is complemented with an extensive data acquisition program in the stratigraphic test wells, [redacted] and [redacted], as well as the data acquisition planned in the additional monitoring wells.

The pre-operational testing program will determine or verify the [redacted] information of the injection zone, overlying confining zone, and other relevant geologic formations. This data acquisition program also will be used to confirm or modify the injection well construction requirements and establish accurate baseline data for future monitoring activities.

Specific details on the proposed pre-operational logging and testing program are found in the Pre-Operational Testing Plan document of this permit.

Pre-Operational Logging and Testing GSDT Submissions
GSDT Module: Pre-Operational Testing ***Tab(s):*** Welcome tab Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☒ Proposed pre-operational testing program ***[40 CFR 146.82(a)(8) and 146.87]***

7.0 Well Operation

The well was designed to maximize the rate of injection as well as reduce the surface pressure and friction alongside the tubing, while maintaining the bottomhole pressure less than 90% of the frac pressure. The selected design provides enough clearance to deploy the pressure and temperature gauges on tubing for continuous surveillance of external integrity and conformance through the external fiber optic cable.

7.1 Operational Procedures [40 CFR 146.82(a)(10)]

The operational procedures detailed below describe how the 1PointFive will initiate injection and conduct startup-specific monitoring of the Becerra_CCS_01_01 at the Kleberg Hub.

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.

During the startup period, the permittee will submit a daily report summarizing and interpreting the operational data. At the request of the EPA, the permittee may be required to schedule a daily conference call to discuss this information. A series of successfully higher injection rates, controlled with variable frequency drive pumps, will be performed. The elapsed time and pressure values will be read and recorded for each rate and time step. Safety shutdowns will be in place to ensure that at no point during any operation will the injection pressure be allowed to exceed the maximum injection pressure of [redacted] psig measured at the wellhead. The injection rate will be measured and recorded using an orifice flow meter on the injection pipeline.

Table NAR-2 details the key parameters that will control the injection process during start up and normal operations. The parameters in Table NAR-2 may be amended as additional site data is acquired, evaluated, and interpreted.

Table NAR-2—Injection Well Operating Conditions

Parameter/Condition	Limitation or Permitted Value	Units
Maximum Injection Rate	[redacted]	
Operating Injection Rate		
Maximum Surface Wellhead Injection Pressure		
Maximum bottom hole pressure @Downhole Gauge (90% of frac gradient [redacted] psi/ft)		
Minimum Annulus Pressure		
Minimum Annulus Pressure/Tubing Differential		

Automatic alarms and automatic shut-off systems will be installed and maintained. Successful function of the alarm system and shut-off system will be demonstrated prior to injection and once every twelfth month after last approved demonstration.

7.2 Proposed Carbon Dioxide Stream [40 CFR 146.82(a)(7)(iii) and (iv)]

The project has developed a standard CO_2 specification, defining the maximum variation in the impurities and delivery conditions at the site, as shown in Table NAR-3. These standard CO_2 specifications will be enforced to the CO_2 sources and distribution channels to control the quality of the CO_2 injected at the wells. The project will install a gas analyzer at the custody transfer meter located in the sequestration site to monitor CO_2 quality continuously before it is distributed to each well to detect any major deviation from the contractual specifications.

Table NAR-3—CO_2 Stream Specification

Component	Specification
[redacted]	

7.3 Reporting and Record Keeping

Electronic reports, submittals, notifications, and records made and maintained by the 1PointFive under this permit must be in electronic format approved by the EPA. The permittee shall electronically submit all required reports to the Director.

- 1PointFive shall submit semi-annual reports containing:
- Any changes to the physical, chemical, and other relevant characteristics of the CO_2 stream from the proposed operating data;
- Monthly average, maximum, and minimum values for injection pressure; flow rate and daily volume; temperature; and annular pressure;
- A description of any event that exceeds operating parameters for the annulus or injection pressure specified in the permit;

- A description of any event that triggers the required shut-off systems and the responses taken;
- The monthly volume and/or mass of the CO_2 stream injected over the reporting period and volume and/or mass injected cumulatively over the life of the project;
- Monthly annulus fluid volume added or produced; and
- Results of the continuous monitoring required including:
  - A tabulation of the (1) daily maximum injection pressure, (2) daily minimum annulus pressure, (3) daily minimum value of the difference between simultaneous measurements of annulus and injection pressure, (4) daily volume, (5) daily maximum flow rate, and (6) average annulus tank fluid level; and
  - Graph(s) of the continuous monitoring required or of daily average values of these parameters. The injection pressure, injection volume and flow rate, annulus fluid level, annulus pressure, and temperature shall be submitted on one or more graphs, using contrasting symbols or colors, or in another manner approved by the Director; and
- Results of any additional monitoring identified in the Testing and Monitoring Plan.

Permit non-compliance shall be reported to the Director within 24 hours as described below:

- 1PointFive shall report to the Director any permit non-compliancethat endangers human health or the environment, and/or any events that require implementation of actions in the Emergency and Remedial Response Plan. Any information shall be provided orally within 24 hours from the time the permittee becomes aware of the circumstances. Such verbal reports shall include, but not be limited to, the following information:
  - Any evidence that the injected CO_2 stream or associated pressure front may have caused an endangerment to an USDW or any monitoring or other information, which indicates that any contaminant may have caused endangerment to an USDW;
  - Any noncompliance with a permit condition or malfunction of the injection system, which may have caused fluid migration into or between USDWs;
  - Any triggering of the shut-off system;
  - Any failure to maintain mechanical integrity;
  - Pursuant to compliance with the requirement at 40 CFR 146.90 (h) for surface air/soil gas monitoring or other monitoring technologies, if required by the Director, any unanticipated release of CO_2 from the injection well to the atmosphere or biosphere; and
  - Actions taken to implement appropriate protocols outlined in the Emergency and Remedial Response Plan document of this permit.
- A written submission shall be provided to the Director in electronic format within five (5) days of the time 1PointFive becomes aware of the circumstances. The submission shall contain a description of the noncompliance and its cause; the period of noncompliance (including the exact dates and times); and if the noncompliance has not been corrected,

then the anticipated time it is expected to continue, as well as actions taken to implement appropriate protocols outlined in the Emergency and Remedial Response Plan document of this permit. This submission should also include the steps taken or planned to reduce, eliminate, and prevent recurrence of the noncompliance.

Within 30 days, the permittee will report to the Director the results of periodic tests of mechanical integrity; any well workover, including stimulation; any other test of the injection well conducted by the permittee, if required by the Director; and any test of any monitoring well required by this permit.

The following items require advance notification from the permittee to the Director:

- Well Tests – 1PointFive shall give at least 30 days advance written notice to the Director in an electronic format of any planned workover, stimulation, or other well test.
- Planned Changes – 1PointFive shall give written notice to the Director in electronic format, as soon as possible, of any planned physical alterations or additions to the permitted injection facility other than minor repair/replacement or maintenance activities. An analysis of any new injection fluid shall be submitted to the Director for review and written approval at least 30 days prior to injection. This approval may result in a permit modification.
- Anticipated Non-compliance –1PointFive shall give at least 14 days advance written notice to the Director in an electronic format of any planned changes in the permitted facility or activity that may result in noncompliance with the permit requirements.

The following are some other reporting requirements:

- Compliance Schedules – Reports of compliance or noncompliance with, or any progress reports on, interim and final requirements contained in any compliance schedule of this permit, shall be submitted in electronic format by 1PointFive no later than 30 days following each schedule date.
- Transfer of Permits – This permit is not transferable to any person except after notice is sent to the Director in electronic format at least 30 days prior to the transfer and requirements of 40 CFR 144.38 (a) have been met. Pursuant to the requirements at 40 CFR 144.38 (a), the Director will require modification or revocation and reissuance of the permit to change the name of the permittee and incorporate such other requirements as may be necessary under the SDWA.
- Other Noncompliance – 1PointFive shall report in electronic format all other instances of noncompliance not otherwise reported in the next monitoring report. The reports shall contain the information previously listed in Section N (3)(b) of this permit.
- Other Information – When 1PointFive becomes aware of a failure to submit any relevant facts in the permit application or incorrect information has been submitted in a permit application or in any report to the Director, the permittee shall submit such facts or

corrected information in electronic format, within 10 days in accordance with 40 CFR 144.51 (l)(8).

- Report on Permit Review – Within 30 days of receipt of this permit, 1PointFive shall certify to the Director in electronic format that he or she has read and is personally familiar with all terms and conditions of this permit.

The following guidelines are provided for record keeping:

- 1PointFive shall retain records and all monitoring information, including all calibration and maintenance records and original chart recordings for continuous monitoring instrumentation, and copies of all reports required by this permit (including records from pre-injection, active injection, and post-injection phases) for a period of at least 10 years from collection.
- 1PointFive shall maintain records of all data required to complete the permit application form for this permit and any supplemental information (e.g., modeling inputs for AoR delineations and re-evaluations and plan modifications) submitted under 40 CFR 144.27, 144.31, 144.39, and 144.41 for a period of at least 10 years after site closure.
- 1PointFive shall retain records concerning the nature and composition of all injected fluids until 10 years after site closure.
- The retention periods may be extended at any time by a request of the Director. 1PointFive shall continue to retain records after the specified retention period of this permit, or any requested extension thereof expires, unless the permittee delivers the records to the Director or obtains written approval from the Director to discard the records.
- Records of monitoring information shall include:
  - The date, exact place, and time of sampling or measurements;
  - The name(s) of the individual(s) who performed the sampling or measurements;
  - A precise description of both the sampling methodology and handling of samples;
  - The date(s) analyses were performed;
  - The name(s) of the individual(s) who performed the analyses;
  - The analytical techniques or methods used; and
  - The results of such analyses.

8.0 Testing and Monitoring

This Testing and Monitoring Plan describes how 1PointFive will monitor the Kleberg Hub site pursuant to 40 CFR 146.90. In addition to demonstrating that the well is operating as planned, the carbon dioxide plume and pressure front are moving as predicted, and that there is no endangerment to USDWs, the monitoring data will be used to validate and adjust the geological models used to predict the distribution of the CO_2 within the storage

Results of the testing and monitoring activities described below may trigger action according to the Emergency and Remedial Response Plan.

8.1 Mechanical Integrity

Other than during periods of well workover or maintenance approved by the Director, in which the sealed tubing-casing annulus is disassembled for maintenance or corrective procedures, the injection well must have and maintain mechanical integrity consistent with 40 CFR 146.89. To meet these requirements, mechanical integrity tests/demonstrations must be witnessed by the Director, or an authorized representative of the Director, unless prior approval has been granted by the Director to run an un-witnessed test. In order to conduct testing without an EPA representative, the following procedures must be followed.

- The permittee must submit prior notification in electronic format, including the information that no EPA representative was available, and permission was received from the Director to proceed;
- The test must be performed in accordance with the Testing and Monitoring Plan document of this permit and documented by using either a mechanical or digital device that records the value of the parameter of interest;
- A final report, including any additional interpretation necessary for the evaluation of the testing, must be submitted in electronic format.

1PointFive shall conduct a casing inspection log and mechanical integrity testing as follows:

- Prior to receiving the authorization to inject, the permittee shall perform the following testing to demonstrate internal mechanical integrity pursuant to 40 CFR 146.87 (a)(4):
    - A pressure test with liquid or gas; and
    - A casing inspection log; or
    - An alternative method approved by the Director and EPA Administrator pursuant to the requirements at 40 CFR 146.89 (e).
- Prior to receiving authorization to inject, the permittee shall perform the following testing to demonstrate external mechanical integrity pursuant to 40 CFR 146.87 (a)(4):
    - A tracer survey such as an oxygen activation log; or
    - A temperature or noise log; or
    - An alternative method approved by the Director and EPA Administrator pursuant to requirements at 40 CFR 146.89 (e).
- Other than during periods of a well workover approved by the Director, in which the sealed tubing-casing annulus is disassembled for maintenance or corrective procedures, the permittee must continuously monitor injection pressure, rate, and volumes; pressure on the annulus between tubing and long string casing; and annulus fluid volume as specified in 40 CFR 146.88 (e), and 146.89 (b).

- At least once per year, the permittee must perform the following testing to demonstrate external mechanical integrity pursuant to 40 CFR 146.89 (c):
  - An Administrator-approved tracer survey such as an oxygen-activation log; or
  - A temperature or noise log. The Director may require such tests whenever the well is worked over; or
  - An alternative approved by the Director and EPA Administrator pursuant to requirements at 40 CFR 146.89 (e).
- After any workover that may compromise the internal mechanical integrity of the well, the wellbore shall be tested by means of a pressure test approved by the Director and must pass this test to demonstrate mechanical integrity.
- Prior to plugging the well, the permittee shall demonstrate external mechanical integrity of the well as described in the Injection Well Plugging Plan that meets the requirements of 40 CFR 146.92 (a).
- The Director may require the use of any other tests to demonstrate mechanical integrity, other than those listed above, with the written approval of the EPA Administrator pursuant to requirements at 40 CFR 146.89 (e).

1PointFive shall notify the Director in electronic format of his or her intent to demonstrate mechanical integrity at least 30 days prior to such demonstration. However, at the discretion of the Director, a shorter time may be allowed.

Reports of mechanical integrity demonstrations that contain logs must include an interpretation of the results by a knowledgeable log analyst. The permittee shall report in an electronic format the results of a mechanical integrity demonstration.

1PointFive shall calibrate all gauges used in mechanical integrity demonstrations and other required monitoring to an accuracy of not less than 0.5 percent of full scale, within one year prior to each required test. The date of the most recent calibration shall be noted on or near the gauge or meter. A copy of the calibration certificate shall be submitted to the Director in electronic format with the report of the test. Pressure gauge resolution shall be no greater than five (5) psi. Certain mechanical integrity and other testing may require greater accuracy and shall be identified in the procedure submitted to the Director prior to the test.

1PointFive must adhere the following guidelines regarding failure to maintain mechanical integrity:

- If the permittee or Director finds that the well fails to demonstrate mechanical integrity during a test; is unable to maintain mechanical integrity during operation; or that a loss of mechanical integrity as defined by 40 CFR 146.89 (a)(1) or (2) is suspected during operation (such as a significant unexpected change in the annulus or injection pressure), the permittee must:
  - Cease injection;

  - Take all steps reasonably necessary to determine whether there may have been a release of the injected CO_2 stream or formation fluids into any unauthorized zone. If there is evidence of USDW endangerment, the Permittee shall implement the Emergency and Remedial Response Plan document of this permit;
  - Follow the reporting requirements as directed in the Emergency and Remedial Response Plan;
  - Restore and demonstrate mechanical integrity to the satisfaction of the Director and receive written approval from the Director prior to resuming injection; and
  - Notify the Director in an electronic format when injection is expected to resume.
- If a shut-down (i.e., downhole or at the surface) is triggered, 1PointFive must immediately investigate and identify, as expeditiously as possible, the cause of the shut-down. If upon such investigation, the well appears to be lacking mechanical integrity or if monitoring required indicates that the well may be lacking mechanical integrity, the permittee must take the actions as described in the Emergency and Remedial Response Plan.
- If the well loses mechanical integrity prior to the next scheduled test date, then the well must either be plugged or repaired and retested within 30 days of losing mechanical integrity. 1PointFive shall not resume injection until the mechanical integrity is demonstrated and the Director gives written approval to recommence injection in cases where the well has lost mechanical integrity.

1PointFive shall demonstrate mechanical integrity at any time upon written notice from the Director.

Testing and Monitoring GSDT Submissions
GSDT Module: Project Plan Submissions ***Tab(s):*** Testing and Monitoring tab Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☒ Testing and Monitoring Plan ***[40 CFR 146.82(a)(15) and 146.90]***

9.0 Injection Well Plugging

Upon the end of life for the Becerra CCS 01 01, this injection well will be plugged and abandoned relevant to the requirements of Environmental Protection Agency (EPA) document 40 CFR Subpart H – Criteria and Standards Applicable to Class VI Wells. The plugging procedure and materials will be designed to prevent any unwanted fluid movement, resist the corrosive aspects of carbon dioxide (CO_2) with water mixtures, and protect any underground sources of drinking water (USDWs).

Injection Well Plugging GSDT Submissions
GSDT Module: Project Plan Submissions ***Tab(s):*** Injection Well Plugging tab Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☒ Injection Well Plugging Plan ***[40 CFR 146.82(a)(16) and 146.92(b)]***

10.0 Post-Injection Site Care (PISC) and Site Closure

This Post-Injection Site Care and Site Closure (PISC) plan describes the activities that 1PointFive will perform to meet the requirements of 40 CFR 146.93. 1PointFive will monitor ground water quality and track the position of the carbon dioxide plume and pressure front for 50 years post injection. 1PointFive may not cease post-injection monitoring until a demonstration of non-endangerment of USDWs has been approved by the UIC Program Director pursuant to 40 CFR 146.93(b)(3). Following approval for site closure, 1PointFive will plug all monitoring wells still active, restore the site in accordance with applicable law and good industry practice, and submit a site closure report and associated documentation.

PISC and Site Closure GSDT Submissions
GSDT Module: Project Plan Submissions ***Tab(s):*** PISC and Site Closure tab Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☒ PISC and Site Closure Plan ***[40 CFR 146.82(a)(17) and 146.93(a)]***
GSDT Module: Alternative PISC Timeframe Demonstration ***Tab(s):*** All tabs (only if an alternative PISC timeframe is requested) Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☐ Alternative PISC timeframe demonstration ***[40 CFR 146.82(a)(18) and 146.93(c)]***

11.0 Emergency and Remedial Response

This Emergency and Remedial Response Plan (ERRP) describes actions the 1PointFive shall take to address movement of the injection fluid or formation fluid in a manner that may endanger an underground source of drinking water (USDW) during the construction, operation, or post-injection site care periods of the Kleberg Hub.

If 1PointFive obtains evidence that the injected CO_2 stream and/or associated pressure front may cause an endangerment to a USDW, 1PointFive must perform the following actions:

1. Initiate shutdown plan for the injection well.

2. Take all steps reasonably necessary to identify and characterize any release.
3. Notify the permitting agency (UIC Program Director) of the emergency event within 24 hours as required by 40 CFR 146.94(b)(3).
4. Implement applicable portions of the approved ERRP.

Where the phrase "initiate shutdown plan" is used, 1PointFive will immediately cease injection.

Emergency and Remedial Response GSDT Submissions
GSDT Module: Project Plan Submissions ***Tab(s):*** Emergency and Remedial Response tab Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☒ Emergency and Remedial Response Plan ***[40 CFR 146.82(a)(19) and 146.94(a)]***

12.0 Injection Depth Waiver and Aquifer Exemption Expansion

Injection depth waivers are not requested in this permit application.

Injection Depth Waiver and Aquifer Exemption Expansion GSDT Submissions
GSDT Module: Injection Depth Waivers and Aquifer Exemption Expansions ***Tab(s):*** All applicable tabs Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☐ Injection Depth Waiver supplemental report ***[40 CFR 146.82(d) and 146.95(a)]*** ☐ Aquifer exemption expansion request and data ***[40 CFR 146.4(d) and 144.7(d)]***

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