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 Names: Becerra_CCS_01_01, Becerra_CCS_01_02, Becerra_CCS_02_01, Becerra_CCS_02_02, Garcias_CCS_01_01, Garcias_CCS_01_02

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

Well locations: Kleberg County, Texas

WELL_NAME	LAT_NAD27	LONG_NAD27
Becerra_CCS_01_01	[redacted]	
Becerra _CCS_01_02		
Becerra _CCS_02_01		
Becerra _CCS_02_02		
Garcias_CCS_01_01		
Garcias_CCS_01_02		

The Becerra_CCS_01_01, Becerra_CCS_01_02, Becerra_CCS_02_01, Becerra_CCS_02_02, Garcias_CCS_01_01, and Garcias_CCS_01_02 wells are part of the South Texas Sequestration Project (Kleberg Hub) being constructed by Kleberg Sequestration Hub, LLC (1PointFive)[1] 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 arrive at the storage site located in Kleberg County, Texas, where it will be injected into the [redacted] formation 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.

[1] Kleberg Sequestration Hub, LLC, is a subsidiary of 1PointFive Sequestration, LLC, which is a subsidiary of 1PointFive, LLC (collectively, "1PointFive"). 1PointFive is a wholly owned subsidiary of Oxy Low Carbon Ventures, LLC (OLCV), which is a wholly owned subsidiary of Occidental Petroleum Corporation (Oxy).

There are no known places of worship or cemeteries within a 1.3-mile buffer zone surrounding the Area of Review (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

Subsurface characterization was conducted on both regional and local scales pertinent to the Kleberg Hub, using geological, geophysical, petrophysical, and reservoir engineering data obtained from public literature, publicly available data, Oxy-licensed data, and data acquired from stratigraphic test wells drilled by 1PointFive.

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

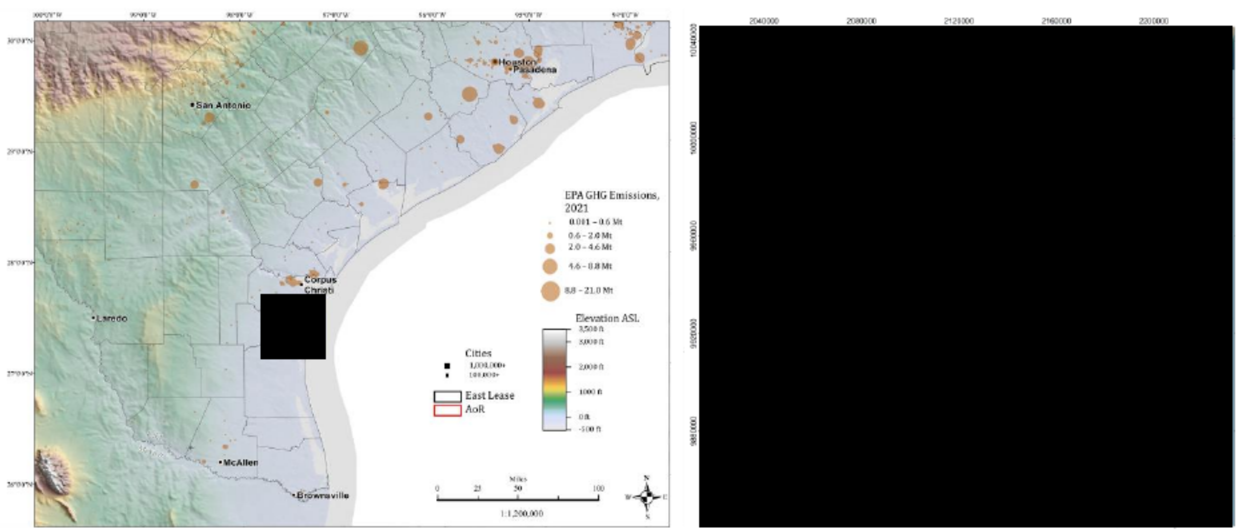

Figure NAR-1: (left) Kleberg Hub location with greenhouse gas emitters (EPA FLIGHT database from 2021) scaled by Mt/year, and (right) satellite imagery showing the leased acreage and the Area of Review.

The Kleberg Hub is strategically located near a concentration of industrial power generating plants, refineries, and 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 will also provide a source of CO_2 for sequestration (Figure NAR-1).

The Kleberg Hub site is geologically favorable for carbon sequestration due to its 1) accumulation of passive margin fluvial-deltaic and shoreface/strandplain sediments, 2) stratigraphically stacked injection targets and confining units, 3) favorable burial history in a hydrostatically pressured setting and 4) transition from freshwater to saline water above the supercritical CO_2 depth. The upper confining system is a regionally-correlatable marine shale modeled as preventing vertical migration of CO_2 into the underground source(s) of drinking water (USDW).

The site targets an area of minimal faulting within the [redacted], which developed as loading of the shelf by sediment delivered by the Oligocene Rio Grande delta system drove fault detachment in Eocene shales (Galloway, 2008). 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 may include additional Class VI permits with wells targeting both the [redacted] zones, to sequester additional CO_2 as demand for sequestration increases at the Kleberg Hub.

1PointFive (through its affiliates) has leased approximately 106,000 acres in 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 Garcias_IZM_01, Becerra_IZM_01, and Garcias_IZM_02. Log, whole core, sidewall core, pressure, formation fluid, and geomechanical data collected in these wells was used to refine and update the extant models of pore space, injectivity, and plume and pressure front migration as included in this permit application.

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 (USGS 2013). The site currently targets nearly [redacted] 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 (Figure AoR-5, Figure NAR-2, Bureau of Economic Geology [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 comprises the [redacted] injection target (Galloway, 2000, 2008). 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]. The Upper Oligocene wedge comprises part of the larger prograding Cenozoic deposition in the Gulf of Mexico (Figure NAR-3).

Era	Period		Epoch	Age	[redacted]
Cenozoic	Quaternary		Holocene		
			Pleistocene	Calabrian	
	Tertiary	Neogene	Pliocene	Piacenzian	
				Zanclean	
			Miocene	Messinian	
				Tortonian	
				Serravalian	
				Langhian	
				Burdigalian	
				Aquitanian	
		Paleogene	Oligocene	Chattian	
				Rupelian	
			Eocene	Priabonian	
				Bartonian	
				Lutetian	
				Ypresian	
			Paleocene	Thanetian	
				Selandian	
				Danian	

Figure NAR-2: Geological stratigraphic chart showing project storage complex, stratigraphic, and hydrogeologic units (after USGS, 2013; Shi and Boghici, 2023; Brown et al, 2004; Witrock, 2017).

Along the Gulf Margin, Cenozoic strata exhibit an overall progradational geometry resulting from sediment shed from the Laramide uplift and delivered to the Gulf by continent-scale river systems. Structural highs directed these river systems to the Rio Grande, Houston, and Mississippi embayments (Galloway et al. 2000; Galloway 2008; Galloway et al. 2011). Deposition was focused toward the western Gulf margin during the Paleogene, but Miocene rejuvenation of the Appalachian Mountains caused the locus of deposition to swing eastward throughout the Neogene. The Kleberg Hub is located along the northwestern margin of the Gulf of Mexico basin about 40 miles north of the Rio Grande Embayment; hence the systems targeted for CO_2 sequestration are Oligocene to Miocene in age (Figure NAR-4).

The [redacted] formation injection target was deposited as part of the Rio Grande paleo river delta and strandplain system during the mid Oligocene from ~34-23 Ma (Galloway et al. 2011). Sediment derived from the southern Larmide Uplift, Rio Grande Rift, and northern Sierra Madre Occidental was delivered to the coast via the paleo Rio Grande drainage systems (Figure NAR-3). and NAR--4). Overall relief was relatively steep on this side of the Gulf of Mexico margin with source provenance including volcanic fields, rift basins, and exhumed carbonate stratigraphy. As such, the Frio composition in this area includes volcanic rock fragments (VRFs), carbonate rock fragments (CRFs), and is generally less mature than other parts of the Texas Gulf Coast. Lithologies are mainly feldspathic litharenite to lithic arkose (Galloway et al. 2011; Loucks et al. 1984). Composition, rock fabric, burial history, and diagenetic processes result in expected porosity values of [redacted] ft of burial depth based on literature. Core measurements from the three stratigraphic test wells drilled by 1PointFive in late 2023 are aligned with these trends. Porosity reduction occurs due to compaction and deformation of ductile grains, diagenetic processes including calcite and quartz cementation and alteration of VRFs and feldspars to clays.

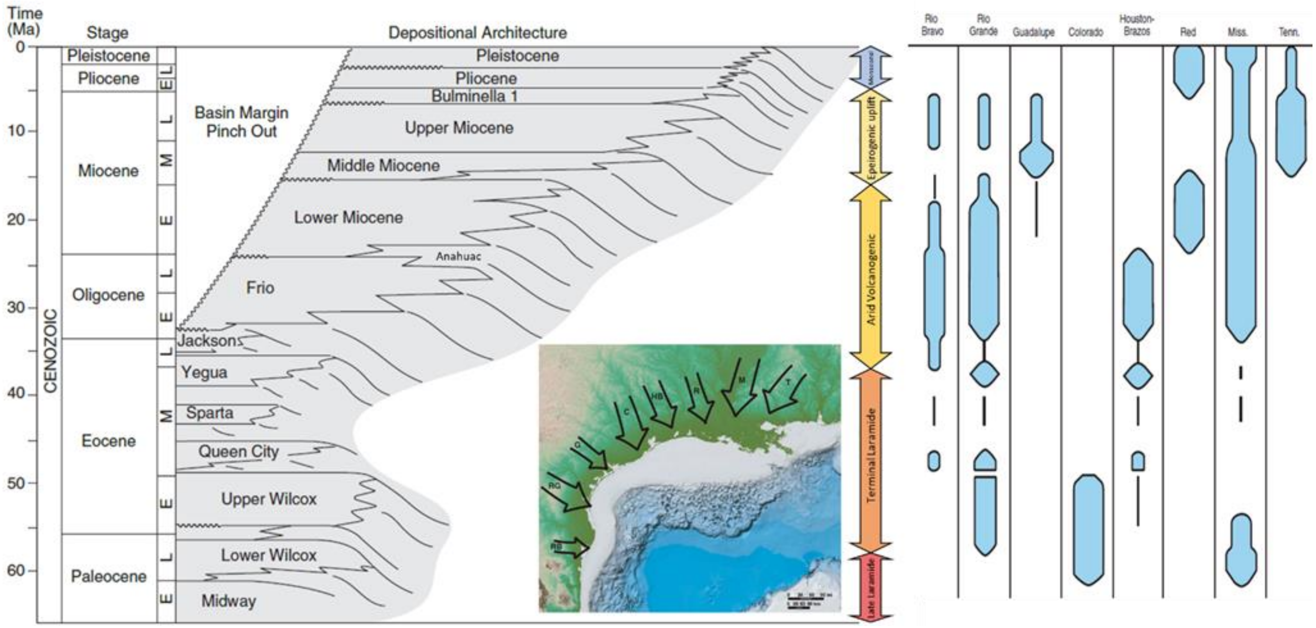

Figure NAR-3: Cenozoic stratigraphic column, river axis position, tectono-climatic events, and fluvial activity through time from Galloway et al. (2011). The Kleberg Hub is north of the Rio Grande depocenter and targets deltaic and shallow marine stratigraphy of the [redacted] formations.

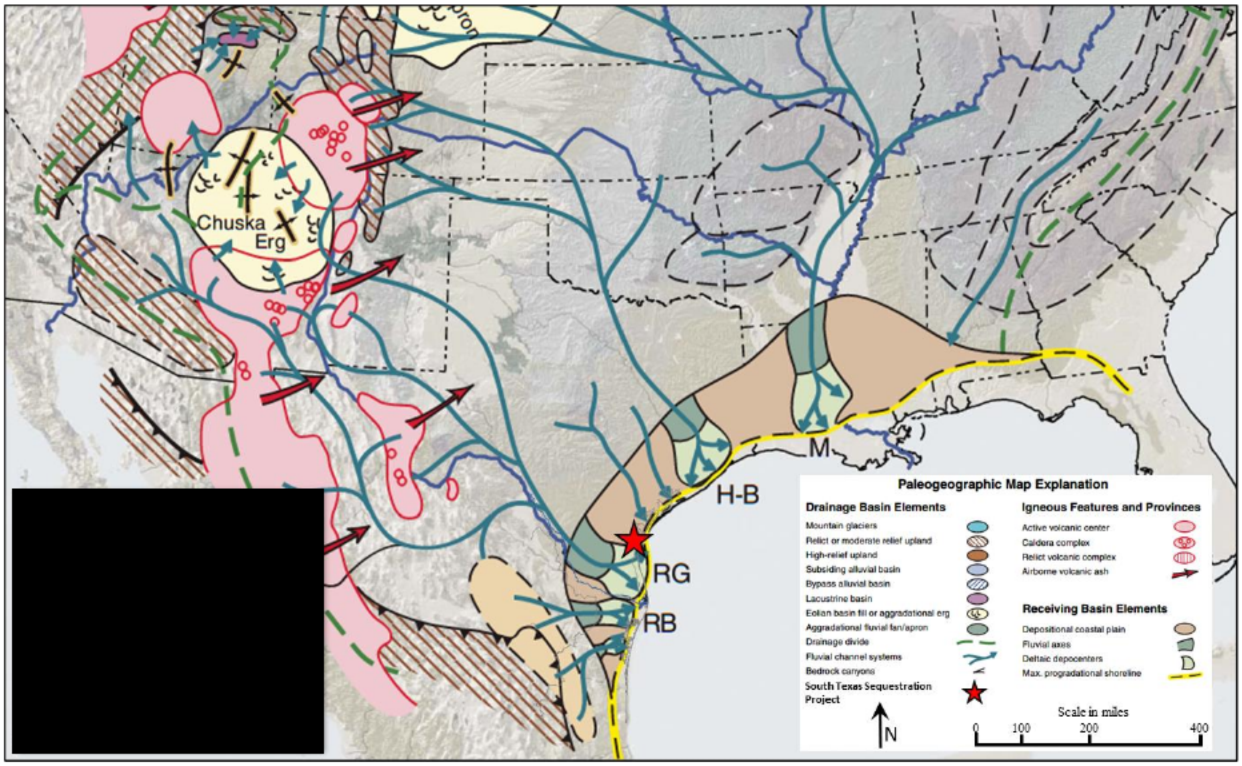

Figure NAR-4: Oligocene Frio paleogeography after Galloway et al. (2011). Sequestration hub is located on the northern edge of the Norias delta. Ternary diagram in lower left of figure shows grain composition from 121 samples from Kleberg and Kenedy counties published by Loucks et al. (1984).

The [redacted] clastic wedge prograded over the underlying [redacted], which locally is a prodelta shale, and was transgressed by the overlying late Oligocene-Lower Miocene Anahuac Shale, a regionally extensive marine shale that constitutes the upper confining system. Numerous publications interpret the [redacted] in the Kleberg Hub area as being deposited in a wave-dominated delta system, based on well log correlations, observations of sedimentary structures, and ichnologic associations (Galloway et al. 1982; Olariu et al. 2013). Sediment delivered to the shelf via the Norias (Rio Grande) delta system was transported northwest via longshore currents and reworked by wave and storm processes into the Greta barrier island/strandplain system (see Figure NAR-5).

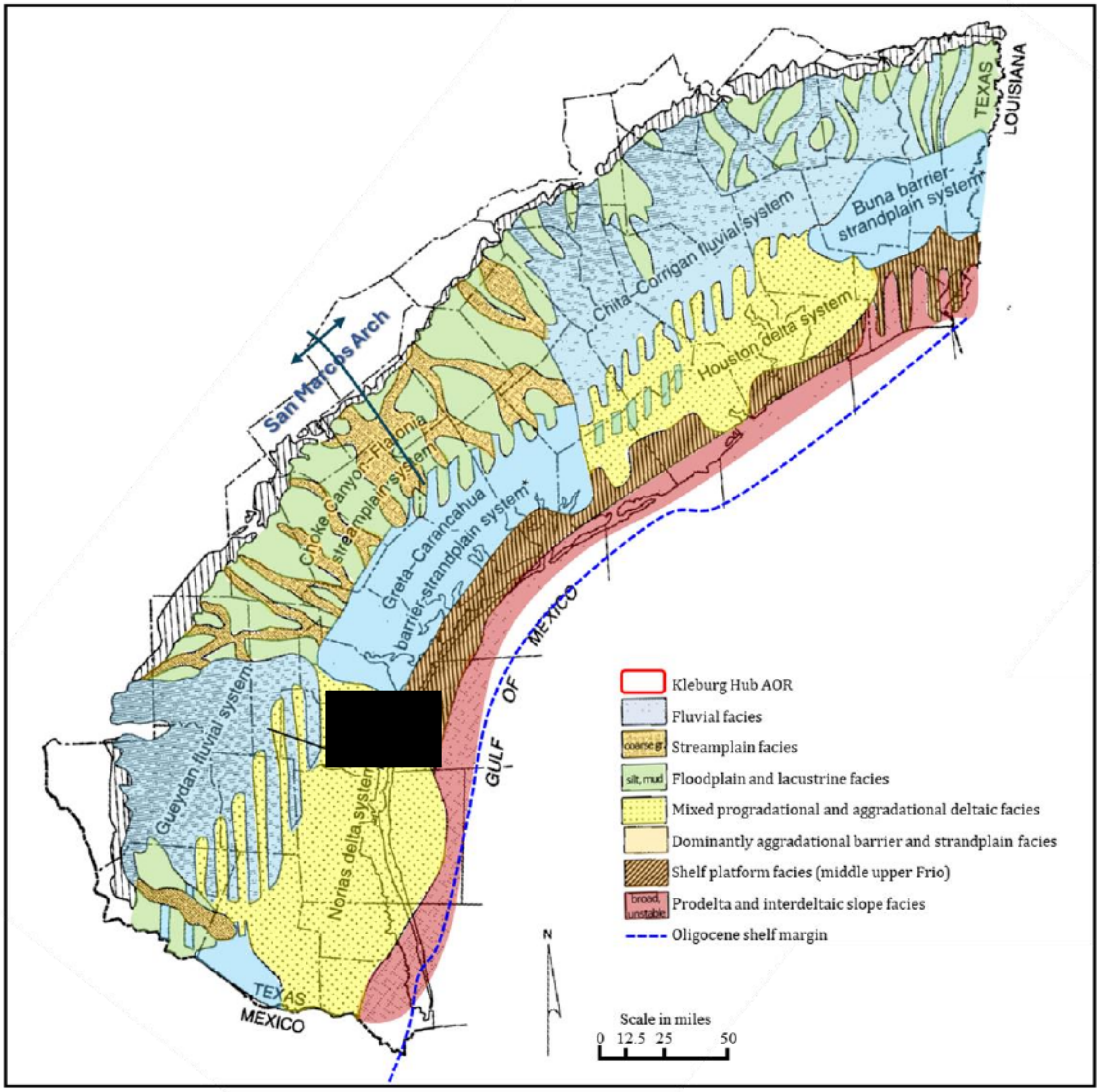

Figure NAR-5: Detailed Oligocene Frio paleogeographic map showing the position of the Norias (Rio Grande) delta system relative to basement high San Marcos Arch, and the shore-parallel nature of the Norias wave-dominated delta (Plate 13, BEG 1982).

As prograding clastic wedges were deposited, loading 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 (Ewing 1986; Diegel et al. 1995) (Figure NAR-6). These growth faults both accommodated and influenced deposition: just north of the Kleberg 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 Kleberg Hub is modeled to fall in between [redacted]. Regional dip is to the east, but within the fault blocks dip is gently down to the south-southeast. CO_2 plume migration due to buoyancy forces is therefore to the north-northeast. This also follows sand distribution patterns observed in seismic attribute extractions, which show distributary systems oriented subparallel to faults.

[redacted]

Figure NAR-6: Interpreted composite 2D seismic dip line shows progradational nature of Cenozoic deposition and linked updip extensional-downdip compressional system. Note detachment faults sole into Eocene shales to the northwest, and into allochthonous salt/weld to the southeast. The AoR within Kleberg County is positioned between major faults (see Figure NAR-9). Inset map from Galloway (2008) shows location of 2D line as it traverses structural domains.

Sediment loading of the margin drove the development of large listric growth fault systems that strike parallel to the margin and sole into mobile substrate. The Kleberg Hub area includes overpressured Eocene shales and allochthonous, now-deflated salt canopies (Ewing, 1986; Diegel et al. 1995; Galloway 2008.). T[redacted] trend in western Kleberg County (Stanley, 1970; Ewing, 1986) and inboard of the Corsair fault system located in the Brazos and Mustang Island areas of offshore Texas (Vogler and Robison 1987). Both systems are composed of north-northeast-striking listric faults. Those to the west sole into Eocene-aged mobile shales while the offshore Corsair system developed from a detachment along the allochthonous salt canopy.

Faults related to the Frio fault trend extend across the Kleberg Hub. [redacted]

Figure NAR-6 illustrates growth in the [redacted] interval, through which sand-sand juxtaposition across the faults is expected. Well and seismic data suggest that both the faults and shale ridges into which they sole influenced depositional processes in this deltaic environment (Brown et al. 2004). Overall structural dip is to the east-southeast following the basin margin.

2.2 Maps and Cross Sections of the AoR

2.2.1 Surface Maps

The Kleberg Hub lies within the south Texas coastal plain physiogeographic province; surface geology is characterized within the northeastern quarter of the Monterrey geologic quadrangle (Figures NAR-07 and NAR-08). Figure NAR-7 shows the modern-day Rio Grande delta, coastal dune, and barrier island system that comprise the surface geology in the area. Holocene lagoonal/ tidal flat sand and clay, marsh silt and clay, deltaic sand, silts, and clay, and eolian clay and silt of the Beaumont formation underlie the AoR footprint (USGS 1993). The site is generally undeveloped pastureland with thick tree and shrub growth, interspersed grasslands, wetlands, and some natural and/or manmade ponds, as shown in Figure NAR-8. No structures intended for human occupancy, no State, Tribal, or Territory boundaries, no springs, no mines, and no quarries exist within the AoR. Project site elevations range from 25 to 33 ft above sea level (Figure NAR-8; Tolunay-Wong Engineers 2023).

[redacted]

Figure NAR-7: Surface geology map of Monterrey quadrangle (USGS 1993).

[redacted]

Figure NAR-8: Surface topography map of Monterrey quadrangle (USGS 1989).

2.2.2 Structure Maps and Cross Sections

Structure maps were created using both seismic and well data. Time horizons were mapped using 2D and 3D seismic data and tied to relevant geological markers. The subsurface faults were interpreted using the same data. Figure NAR-9 shows a depth-structure map of the top of the storage reservoir. Faults mapped using seismic data are overlaid and the two major bounding faults, [redacted] Fault to the west and [redacted] Fault to the east, can be seen to be beyond the bounds of the AoR. The overall dip is to the east, but, within the AoR fault block, it is down to the south. Figure NAR-10 shows a west-east cross section through the Kleberg Hub. There are no stratigraphic pinchouts within the geomodel or subregional areas; mapped and modeled zones extend many miles beyond the Kleberg Hub. Further detailed delineation of faults and stratigraphic elements within the [redacted] formations help constrain the storage complex and refine the plume distribution.

More than 40 faults were mapped using available 2D and 3D seismic coverage, although few are present in the [redacted] formation within the 1PointFive leasehold. Twelve faults were then integrated into the structural framework of the geomodel.

[redacted]

0 5000 10000ftUS

1:155648

Figure NAR-9: [redacted] formation depth structure map from seismic interpretation. Current mapped faults (brown) overlain, wells are annotated as black symbols, the AoR shown in red; geomodel extent in black; black line shows location of cross section in Figure AoR-5. Note that the AoR is bounded by major [redacted].

[redacted]

Figure NAR-10: West-east color-replaced seismic cross section showing faults and geological formations. Transect was constructed from 2D and 3D seismic coverage. Wells are shown in black. Major bounding growth faults do not intersect with the AoR.

[redacted]

Figure NAR-11: West-east subregional wells cross section in similar orientation to Figure NAR-10. Electronic log character and motifs can be used to correlate shales regionally. [redacted] confining zone, Burkeville confining unit, and Evangeline aquifer shales separate the [redacted] injection targets from the USDW. The [redacted] correspond to named faults on the structure map.

[redacted]

Figure NAR-12: North-south subregional strike cross section showing stratigraphic continuity of [redacted] and [redacted] formations. Garcias IZM-01 is the tie well with cross section in Figure NAR-11.

2.3 Faults and Fractures

Detailed mapping of 3D seismic data over the AoR yielded faults in the modeled area, but none within the AoR. Well log correlations of the subzones comprising the confining and injection zones did not indicate faults were present. In two of the stratigraphic wells, Garcias IZM-01 and Becerra IZM-01, oil-based image logs recorded borehole resistivity-based images that were analyzed for sedimentological and structural features. In both wells, no faults or fractures were observed in any of the confining zones and no faults were observed in any of the injection targets. Seven deformation bands and three fractures were observed in the [redacted]. A detailed description follows.

2.3.1 Fracture Characterization Using Oil-Based Imager

An oil-based image log was recorded in Garcias IZM 01 and in Becerra IZM 01.

Garcias IZM-01 StrataXaminer Image Log Summary

[redacted].

Stratigraphic Observations: [redacted].

Structural Characterization: No faults were observed. [redacted]

Image logs can also provide insightful data on SHmax orientation if borehole breakout or drilling-induced tensile fractures are observed. [redacted]

Presence of fractures in confining zones (Figure NAR-13):

- [redacted]
- [redacted]
- [redacted]

[redacted]

Figure NAR-13: Garcias IZM-01 image log from [redacted].

Presence of fractures in injection zones (Figure NAR-14):

[redacted]

[redacted]

[redacted]

Figure NAR-14: Garcias IZM-01 image log in [redacted]

Presence of in-situ stress indicators (borehole breakout and induced tensile fractures), Figure NAR-15:

- [redacted]

[redacted]

Figure NAR-15: Garcias IZM-01 image log in [redacted].

King Ranch Becerra IZM-01 StrataXaminer Image Log Summary

[redacted]

[redacted]

[redacted]

[redacted]

Presence of fractures in confining zones (Figure NAR-16):

- [redacted]
- [redacted]
- [redacted]

[redacted]

Figure NAR-16: Image log from Becerra IZM-01 upper confining zones, [redacted]

Presence of fractures in injection zones:

- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]

Presence of in-situ stress indicators (borehole breakout and induced tensile fractures):

[redacted]

2.3.2 Fault Reactivation Analysis

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 reservoir formation test pressure measurements. Maximum principal stress is the overburden, and least horizontal stress is defined by the closure pressure interpreted from leakoff tests performed in the bottom half of the upper confining unit. The mean pore pressure within the [redacted] and extrapolated fracture gradient pressure is [redacted]. The subsequent Mohr-Coulomb analysis estimates the magnitude of pressure change required to instigate shear slip on the bounding fault to be [redacted]. An increase in pressure of [redacted] psi would be required to drive the Mohr circle into tensile stress (Figure NAR-17).

[redacted]

Figure NAR-17: Stress model for King Ranch Alazan 321 well. Red arrows indicate depths of Mohr-Coulomb analysis. Pressure data from the Garcias IZM 01 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. Digital logs from 195 wells were interpreted with regionally correlatable tops; of those, 147 had a log suite suitable for full petrophysical interpretation. Tops picked from well logs 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 top [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 eight wells were used as a basis for the poroperm transform incorporated into the geomodel (see Figure NAR-18).

[redacted]

Figure NAR-18: Subsurface data control in the region that was used for site characterization and geomodel building. The map on the left shows seismic 2D and 3D data footprint, select wells with sonic data sufficient for time-to-depth-ties, geomodel outline, land, and AoR. The map on right shows wells inside the geomodel footprint with digital data, core used in petrophysical curve calibration, and wells used for correlation only.

Figure NAR-19 shows the petrophysical type log, Garcias IZM 01, with stratigraphic tops and geomodel zonation. Average gross petrophysical properties for the confining zones and net average properties (sand + silt) for the injection zones can be found in Figure NAR-20; these are geomodel properties averages.

[redacted]

Figure NAR-19: Garcias IZM 01, type log from Kleberg Hub shows the results from the petrophysical analysis and core data. From left to right: track 1 has the total gamma ray in green, uranium free gamma ray in blue, separation shaded in yellow; track 2 has depth with purple rectangles representing the cored intervals, along with the symbols of the data acquired; track 3 has the formation tops; track 4 has resistivity logs; track 5 has total porosity with core data; track 6 has mud log lithology; track 7 has lithology results from mineral solver application from IP (Interactive Petrophysics,) which is the software used for petrophysical interpretation; and track 8 has calculated permeability (black curve) and core permeability data.

[redacted]

Figure NAR-20: Summary of the model average properties by zone. For confining zones, properties are averaged over the entire zone. For injection zones, properties are average for sands and silts only.

Figure NAR-21 shows how petrophysical properties were modeled within the geomodel, which was then used for dynamic simulations of CO_2 plume migration.

Table NAR-1 summarizes zone depths and minimum, mean, and maximum thickness for each zone. Summary maps of the confining and injection zones showing top depth structure, extent beyond the AoR, thickness, porosity, and permeability distribution for each of the injection and confining zones are catalogued in PBI_Petrophysical Supporting Documents Maps folder. A discussion of zone characteristics follows, including summaries of the number of samples used to characterize zone properties, mineralogical data, capillary entry pressure of the confining zone, and observations from whole core on environment of deposition that speak to extent of lithofacies interpreted within each zone. PBI_Appendix_A_PetrophysicalAnalysis.pdf describes the petrophysical methodologies applied to determine zone permeability and porosity, capillary pressure details, mineralogy and petrological findings. [redacted]

Table NAR-1: Geomodel zone depths (surfaces on left) and thicknesses (zones on right)

[redacted]

[redacted]

Figure NAR-21: 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 facies, porosity, and permeability.

2.4.1 Confining Zone Characteristics

2.4.2.1 [redacted]

The [redacted] Zone is the upper, siltier portion of the [redacted]c formation and is interpreted to be middle to lower shoreface setting in a highstand systems tract based on published composite type log from the Texas Bureau of Economic Geology and interpretation of depositional setting from whole core in the [redacted] from Garcias IZM-01 (BEG, Brown et al. 2004). Within the simulation model area, it averages [redacted].

Two rotary sidewall core (RSWC) samples from the [redacted] with mercury injection capillary pressure (MICP) seal capacity analysis show that the shales within this zone have good sealing properties. Average capillary entry pressure is [redacted] psi (CO_2-saline water system), which is the equivalent of a [redacted] ft column of supercritical CO_2, assuming an average gradient of [redacted] psi/ft.

Four RSWC samples from the [redacted] with XRD data show an average of [redacted]

2.4.2.2. [redacted]

The [redacted] is the clay-rich portion of a regionally extensive marine shale; whole core from the Garcias IZM-01 is interpreted to be derived from a lower shoreface environment. XRD from whole core plugs average [redacted]

MICP seal capacity analysis from nine samples average a capillary entry pressure of [redacted] psi (calculated CO_2-saline water system), which is the equivalent of [redacted] ft column of supercritical CO_2, assuming an average gradient of [redacted] psi/ft. The maximum capillary entry pressure and column height is [redacted] psi and [redacted] ft, respectively, from sample 1-31 in Garcias IZM 01. [redacted]

2.4.2.3. [redacted]
The lower confining zone is defined by a shale-rich interval at the transition between the [redacted]. Whole core taken from this zone in the Garcias IZM-01 well contains planar horizontal laminations and burrows including those from ophiomorpha and thalassinoides, consistent with a lower shoreface environment of deposition. MICP seal capacity analysis from whole core yielded a capillary entry pressure of [redacted] psi (calculated CO_2-saline water system), which is the equivalent of [redacted] ft column of supercritical CO_2, assuming an average gradient of [redacted] psi/ft.

2.4.2 Injection Zone Characteristics

This section describes in detail the information related to the proposed injection targets, [redacted] sandstones. It describes depths, areal extents, thicknesses, mineralogy, porosity, and permeability of the injection zones, including geology changes and facies based on geological cores, well logs, names, and lithology description according to 40 CFR § 1476.82 (3)(iii).

2.4.2.1 [redacted]
The upper portion of the [redacted] formation at the Kleberg Hub is composed of fluvial-deltaic sands interpreted from regional log motifs and whole core taken from the Garcias IZM-01 well. Scoured bases of sand beds and fining-upward cycles testify to channel fill and abandonment. Routine core analysis measurements of porosity and calculated permeabilities were used to calibrate porosity and permeability values for this zone, which, in the simulation model, [redacted], respectively.

Thin sections show angular to subangular grains of fine to very fine quartz and calcareous debris with minor volcanic rock fragments (VRF), chert fragments, plagioclase and potassium feldspar, mudstone, siltstone, metamorphic rock fragments, plutonic rock fragments, glauconite, heavy mineral grains, biotite, and organic matter. Calcite/ferroan calcite is a discontinuous pore-filling cement and there is minor illite, chlorite, and quartz cement.

Figure NAR-11 shows how the sands in this zone are highest net-to-gross on the northern end of the project, and Figure NAR-12 shows the trend of decreasing amalgamation from west to east. This suggests that the input area for the delta lobes is from the northwest; sand thickness and quality is fairly consistent from north to south across the AoR, but is less on the eastern side.

2.4.2.2 [redacted]

The [redacted] is a shalier bell-shaped interval between the [redacted] that is interpreted to be off-axis fluvial deltaic. Sand and silt lithofacies in this interval in the geomodel average [redacted]

2.4.2.3 [redacted]

The [redacted] is a regionally-correlatable blocky fluvial deltaic sand that averages [redacted] permeability within the model and is the primary injection zone target due to its good porosity, permeability, and lateral connectivity. These averages are based on petrophysical interpretation of electronic logs calibrated to preliminary RCA data from core plugs taken from whole core in the Garcias IZM-01 and rotary sidewall core in the Becerra IZM-01 and Garcias IZM-02.

Whole-core sedimentary structures, fabric, and trace fossils drive an interpretation that these sands were deposited in a fluvial-deltaic proximal setting, with variable influence from fluvial and deltaic processes. Thin section inspection suggests there may be more than one input point for sediment, as some samples contain well-rounded grains and others contain angular to subangular grains. Composition is mainly quartz with variable contributions of VRFs, accessorized by potassium and plagioclase feldspars, chert, plutonic rock, mudstone, siltstone fragments, calcareous debris, foraminifera and shell debris, metamorphic rock fragments, glauconite, heavy mineral grains, biotite, and organic matter.

As shown in cross sections Figure NAR-11 and Figure NAR-12, sand thickness and extent gradually decrease from north-to-south and shows more variability in the west-to-east direction, but the sands are ubiquitous in the area.

2.4.24 [redacted]

The uppermost unit of the lower injection zone is the [redacted] zone. Whole core taken from this interval in the Garcias IZM-01 contains thin- to medium-stacked tabular beds of fine- to very-fine-grained sandstone, coarsening up, and fining-upward beds of fine- to very-fine-grained sandstone, interpreted as distributary channels in a delta lobe. The shalier nature of the interval in comparison to the overlying units, shown in Figure NAR-101 and Figure NAR-112, suggests that it was deposited in a more distal and/or off axis part of the system. Grain rounding ranges from rounded to angular, suggesting more than a single input source. Composition is majority quartz with considerable secondary VRFs, potassium feldspar, plagioclase feldspar, calcareous debris, and small amounts of chert fragments, plutonic rock fragments, mudstone, siltstone, glauconite, heavy minerals, biotite, and organic matter. Major calcite/ferroan calcite cement was observed in a few thin sections and as nodular cement in whole core. Average net porosity sands + silts in the model for [redacted]

2.4.2.5 [redacted]

Three coarsening-up to amalgamated cycles comprise the [redacted] zone. Whole core from this interval in the Garcias IZM-01 contains sedimentary structures and ichnofacies interpreted as being deposited in a shoreface environment, ranging from upper shoreface to offshore environment of deposition. Grain composition and rounding is similar to intervals described above, but calcite/ferroan calcite cement is more frequently observed in thin section and in whole core; silica cement is also observed in some thin sections.

The average net porosity sands + silts in the model for Frio Lower is [redacted]

2.4.2.6 [redacted]

The [redacted] is the deepest zone of potential injection above the base confining zone, though it is not an injection target for the proposed injectors. It consists of a coarsening-upward base that is interpreted to by fluvial-deltaic with a transgressive/muddy upper portion. A thin section from RSWC in this interval in the Garcias IZM-01 shows quartz, feldspar, and VRF grains with some carbonate cement diagenesis. The average net porosity sands + silts in the model for [redacted].

2.5 Geomechanical and Petrophysical Information

Petrophysical analysis in the stratigraphic wells was calibrated to core data. Sixteen base wells with a complete set of logs were then used in addition to the stratigraphic wells to calibrate the model to the core. For more detail, please refer to the Appendix A – Petrophysical Analysis.

In the Garcias IZM 01, [redacted] of whole core was collected and [redacted] sent for geomechanical testing (Table NAR-2). Details of the core analysis, samples selection, and analysis program are included in PBI_Appendix A – Petrophysical Analysis. [redacted]

Table NAR-2: Samples sent for geomechanical testing in Garcias IZM 01.

Sample ID	Core Number	Requested Depth (ft)	Formation Tops	Geomechanical Testing
[redacted]				

The oil-based images acquired in Garicas IZM 01 and Becerra IZM 01 show no fractures or faults in any of the confining zones (please see Section 2.3.1 of this report for details). For the injection zones in Becerra IZM 01, three fractures are observed. For more details on location of these fractures, see Section 2.3.1 of this report.

To understand average ductility, rock strength, and consistency of these, core testing is underway at [redacted] laboratories. Testing will make estimates of dynamic and static elastic and poroelastic properties (Young's modulus, Poisson's ratio, and Biot's coefficient) from velocities and strain measurements. Testing provides qualitative characterization of plastic deformation and is incorporated into stress characterization analytically. These measurements will be used to calibrate rock property models that are inputs to the linear poroelastic stress model and understand the implication of elastic and plastic deformation on stress. Unconfined Compressive Strength (UCS) tests are also underway to measure the shear strength of each sample.

The stress model is provided as input to injection pressure models and is used explicitly in critical stress analysis (fault stability analysis). A detailed review is provided in AOR section 2.10. Mohr-Coulomb stress analysis for the [redacted] shows that a pressure increase of [redacted] psi is required for fault slip, and [redacted] psi is required for matrix failure (Figure AOR-32). Mohr-Coulomb stress analysis in the [redacted] shows [redacted] psi is required for fault slip and [redacted] psi is required for tensile matrix failure (Figure AOR-33). Modeled injection results in a maximum pressure increase of [redacted] psi within the AoR; the critical pressure front is defined by a pressure increase of [redacted] psi (e.g. Figure AoR-40). These values are far below the deltaP required for fault or matrix failure.

Anomalies and uncertainties always exist in the data and, once received, will be addressed in preoperational testing via uncertainty analysis; additional analysis will be conducted if necessary.

Pore pressure measurements from reservoir description tool (RDT) were taken above and below the [redacted] confining zone in the Garcias IZM-01 (See Section AOR 2.10 and Figure AOR-31 for details). A pore pressure curve interpreted between these points gives values ranging from [redacted] psi from the top to the base of the Anahuac Lower. In the Becerra IZM-01, which encountered stratigraphy downdip/deeper, these projected pressures range from ~[redacted] psi.

2.6 Seismic History

Regional earthquakes were identified using the USGS online database and cross-checked against the BEG's TEXNET database to determine the location of events (Figure NAR-22). Two recorded events of Magnitude 3 were identified within 50 miles of the Kleberg Hub 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-23) indicates that this area is at relatively low risk for natural earthquake activity.

Seismometer stations were identified via the Incorporated Research Institute for Seismology's database (Figure NAR-22). There is one station identified within a 50-mile radius of the Kleberg Hub. Nine stations are identified within a 75-mile radius of the Kleberg Hub, two of which are permanently installed.

A risk assessment conducted by 1PointFive of potential induced seismicity due to injection activities is presented in Figure NAR-**24** through Figure NAR-26. The probability of induced seismicity related to injection activity is medium, while the assessed consequence of an event is classified as high. Oxy's planned mitigation measures, including installing additional seismometers and planned 2D and 3D seismic data acquisition, will lower the probability level to low (see Testing and Monitoring Plan attachment).

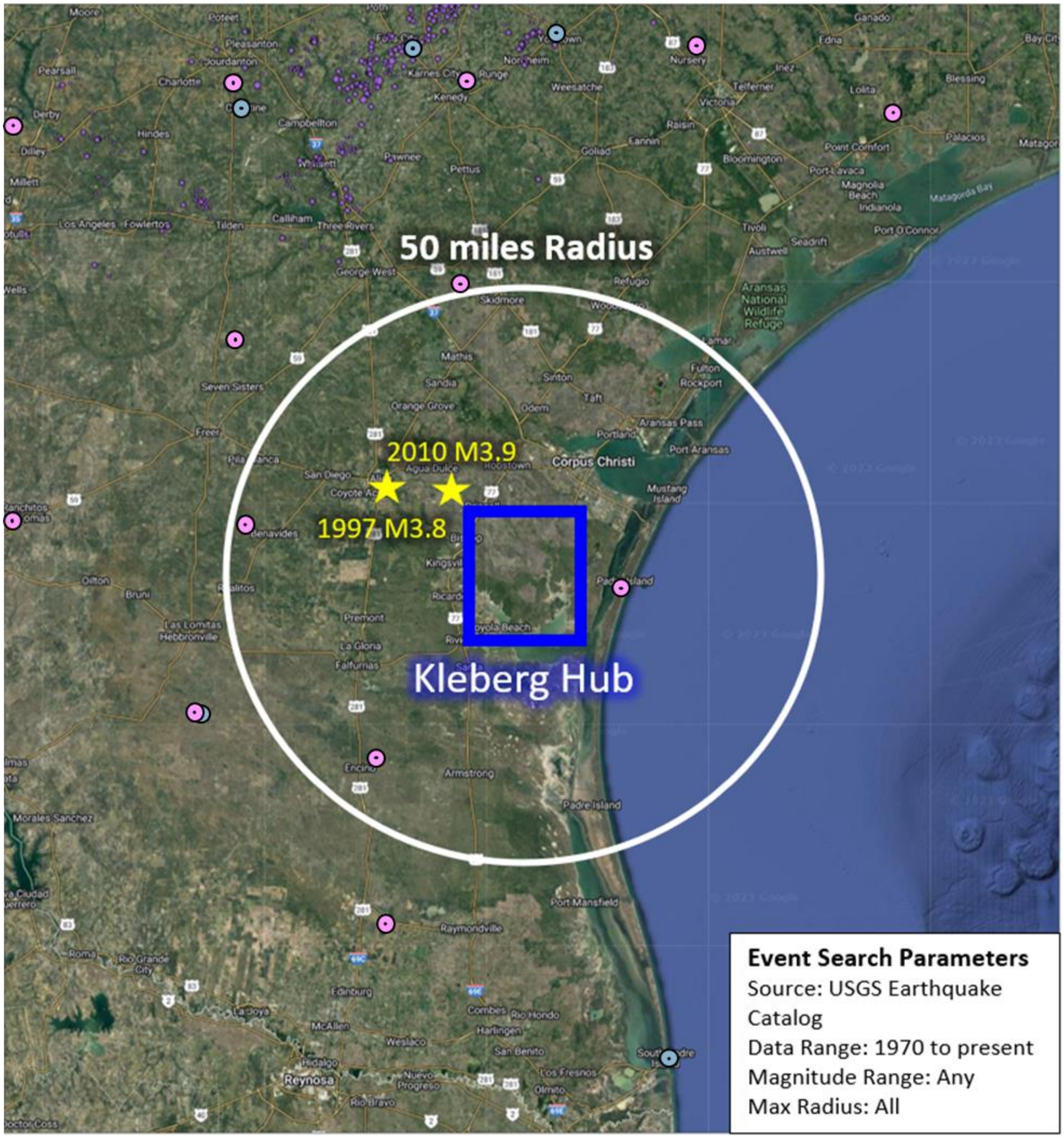

Figure NAR-22: Seismometer stations (pink and blue circles) and historic seismic activity (yellow stars) from BEG TEXNET and IRIS databases.

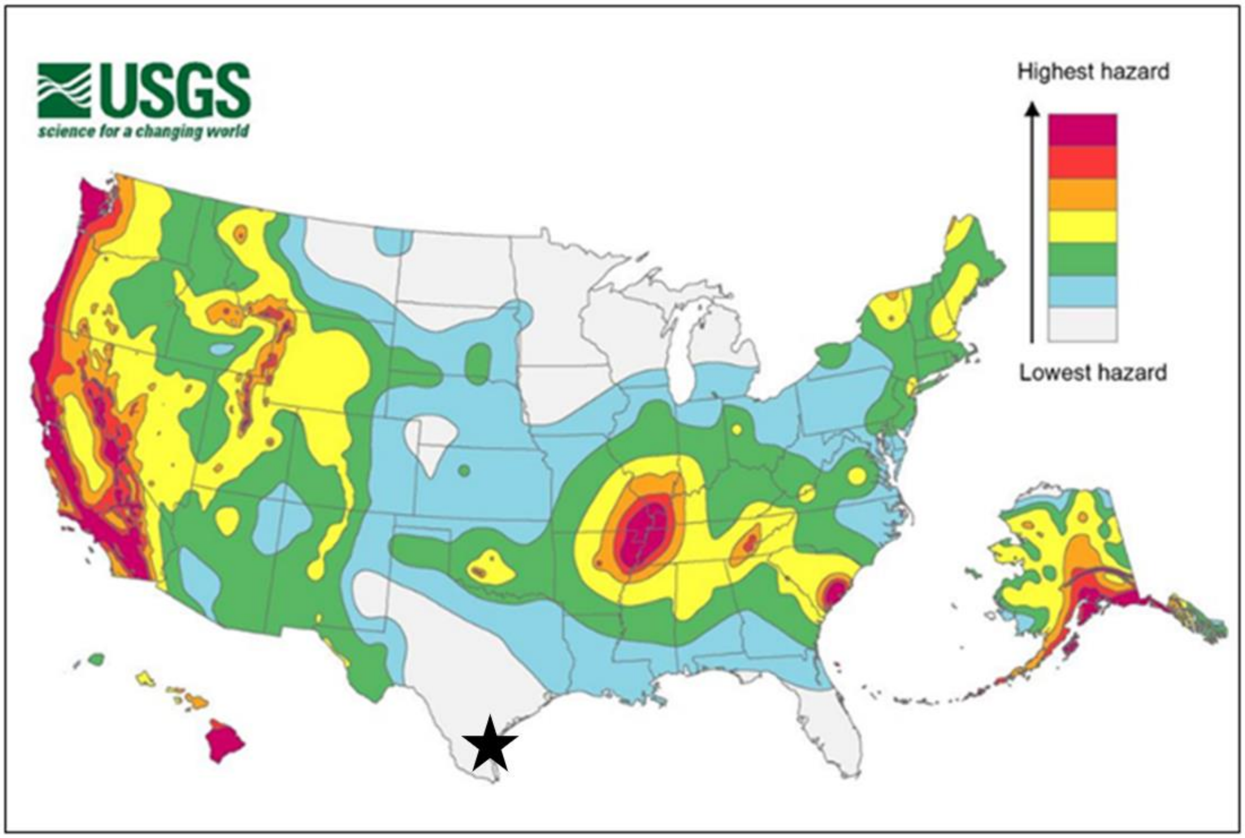

Figure NAR-23: Seismic hazard map showing that peak ground accelerations have a 2% probability of being exceeded in 50 years from USGS 2018 Long-Term National Seismic Hazard Map (USGS, 2018). Seismic hazard potential in the study area is one of the lowest in the U.S.

Probability

Probability of a Seismic Event	Historic Seismicity	Seis-mometer Coverage	Seismic Coverage	Basement Faulting (proximity to a fault of concern)	Injection Zone's Proximity to Basement	Injection Rate	Count
High (3)	✓	✓					11/18 8/18 (red)
Medium (2)			✓				
Low (1)		✓ (red)	✓ (red)	✓	✓	✓	

Figure NAR-24: Assessed probability of a seismic event. Historic Seismicity: two seismic events have been recorded within a 50-mile radius of the Kleberg Hub site. Seismometer Coverage: no current seismometer coverage is within 50 miles of the Kleberg Hub project, and only three stations have been active in the past to record events within the same radius. Section 7.3 in the Testing and Monitoring Plan attachment discusses 1PointFive's plan for deploying a new seismometer monitoring network. Seismic Coverage: proprietary 3D seismic is available over majority of the AoR. Note that the planned 3D seismic acquisition program (discussed in section 6.1.1 in the Testing and Monitoring Plan attachment) over the Geologic Sequestration project will reduce the risk from medium (currently) to low. Basement Faulting: all basement faults proximal to the Kleberg Hub are observed to detach within the Wilcox (more than 10,000 ft above the estimated basement depth). Basement Proximity: the proposed injection zone is more than 20,000 ft above the estimated basement depth. Injection Rate: fault reactivation pressures were modeled for the greater Kleberg Hub area, and all faults required a delta-P of >1000 PSI to reactivate. Modeled injection pressures for the Kleberg Hub program do not exceed 300 psi. Black marks are current results, while red marks show results with planned mitigation measures.

Consequence

Consequence of a Seismic Event	Public Impact / Tolerance	Proximity to Critical Infrastructure (e.g. Dams)	Seismicity Regulatory Regime	Impact on Development	Final
High (3)	✓		✓	✓	11/12
Medium (2)		✓			
Low (1)					

Figure NAR-25: Assessed consequence of a seismic event. Public Impact/Tolerance: Public tolerance for induced seismicity is fragile in Texas, and media exposure of induced seismic events related to CCS activity is predicted to be high. Proximity to Critical Infrastructure: Kleberg Hub is located within 20 miles of the Corpus Christi Ship Channel. Seismic Regulatory Regime: local seismicity monitoring is required for CCS operations. Impact on Development: significant seismic events have the potential to stop project advancement.

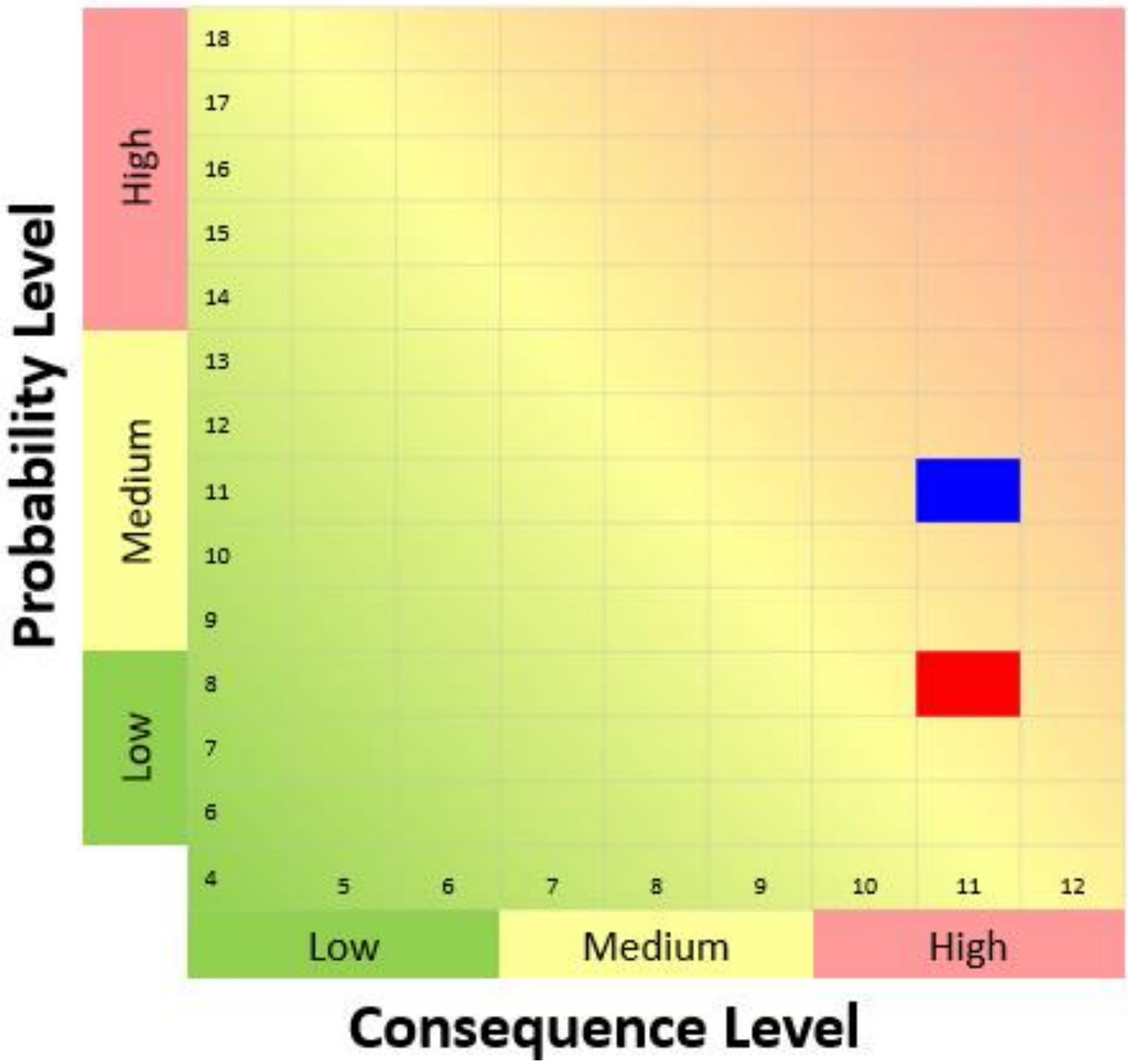

Figure NAR-26: Assessed risk matrix for induced seismicity at the Kleberg Hub site. The probability of induced seismicity related to injection activity is medium, while the assessed consequence of an event is classified as high. Note that planned mitigation measures would lower the probability level to low (red box).

Table NAR-3: Consequence matrix criteria used for risk matrix assessment analysis.

Consequence Matrix Criteria Definition

Consequence of a Seismic Event	**Public Impact / Tolerance** **How close is the project to a population center? Note the concern here is not just response to damaging earthquakes, but also nuisance earthquakes that are felt but may not cause damage**	**Proximity to Critical Infrastructure (e.g. Dams)** **How close is the project to various public or private critical infrastructure? Examples: Dams, Mines, CCS sites, Hazardous Waste Sites, etc**	**Seismicity Regulatory Regime** **What is the current regulatory regime for the project area. Considering regulatory agencies, and requirements associated with certification groups/entities**	**Impact on Development** **Impact of future seismicity on the project's future. Possible scenarios include: temporary halt to injection (impact to disposal/production), change to completion (impact to production/reserves), or sterilization of regions from future activity (impact to reserves)**
High	Close to population center (town/city). Events almost certainly felt by large number of public (nuisance). Some of the public has expressed concern and/or events have been highlighted in the news	Close (<10 miles) to critical infrastructure or landforms that could be impacted by earthquakes	Local seismicity monitoring required. Regulatory agency (or similar) has contacted operators about seismicity in the area e.g. Current/recent Regulatory Mandated Area (e.g. SIR)	Significant events have the potential to stop project advancement, halt future drilling and/or shut-in adjacent wells/units. Triggers economic impact assessment
Medium	Moderate distance to population center (town/city) Events may be felt by some of the public, but with little concern for the events themselves (i.e. not concerned)	Moderate distance (between 10 & 50 miles) to critical infrastructure or landforms that could be impacted by earthquakes	Local seismicity monitoring not currently required, but could be in the near future	Seismicity could have some impact to future development plans, but may be adaptable (e.g. change completion design) or could result in temporary lost production (e.g. ESP shutdown)
Low	Large distance to population center (town/city) Events unlikely to be felt by much of the public	Long distance (>50 miles) from critical infrastructure or landforms that could be impacted by earthquakes	No seismicity monitoring requirements and none expected in the near future	Seismicity is not expected to have significant impact on the future development (e.g. last well/pad in program)

Table NAR-4: Probability matrix criteria used for risk matrix assessment analysis.

Probability Matrix Criteria Definition

Probability of a Seismic Event	Historic Seismicity Sources including TexNet and WTX , USGS and historical catalogues	Seis-mometer Coverage Intends to capture the data availability aspect associated with these risks	Seismic Coverage Because no data does not imply no risk, this is intended to capture the data availability aspect associated with these risks	Basement Faulting Proximity to a fault of concern	Injection Zone's Proximity to Basement	Injection Rate
High	High levels of local seismicity in the immediate project area detected (e.g., USGS, TexNet, WTX, etc.) or from prior microseismic monitoring. Magnitudes above M2.0 common (i.e., multiple times per year) **and/or** magnitudes above M3.5 have been detected or area with Injection Induced Events	No local historical or current seismicity monitoring in the area. Local Mc with existing arrays ≥ M3.0. No seismometers with 12 miles of project site	No seismic data covering the area or sparse 2D coverage	Mapped faults at injection zone that continue into basement at critical orientations relative to S_{Hmax}. Modeling shows fault critically stressed and close to slip currently or with project parameters as defined (e.g. injection rates). Fault may be observed (linear cluster) from earthquake data in areas with poor/no seismic coverage	Injection zone is < 3,000 ft (TVD) of basement	Injection rates > 15,000 bpd
Medium	Moderate levels of local seismicity in the immediate project area detected (e.g. USGS, TexNet, WTX, etc.) or from prior microseismic monitoring. Magnitudes above M2.0 rare (i.e., 1 per year or less) **and** no magnitudes above M3.5	Seismicity monitoring in the area currently but with high Mc (≥ M1.5), high event location uncertainty (>1.5 miles) and/or short history (e.g. ≤6 months). No seismometers within 6 miles of project site	Either poor quality 3D seismic data or good quality 2D seismic data with reasonable line density and data quality for mapping of critical faults	Mapped faults are ambiguous in extent (connection between injection zone and basement) or are present but oriented >45 degrees from S_{Hmax}. Modeling shows no significant increase in FSP from pre-project conditions	Injection zone is 3,000 – 6,000 ft (TVD) of basement	Injection rates between 10,000 bpd and 15,000 bpd
Low	No local seismicity in the immediate project area detected (e.g., USGS, TexNet, WTX, etc.) or from prior microseismic monitoring (no M>0.0)	Seismicity monitoring with long history (>2 years), low event location uncertainty and low Mc (>1.5). Seismometers within 6 miles	High quality 3D seismic data covering area of interest	Seismic data shows **no** faulting connecting injection zone to basement. Modeling show no increase in the potential of fault slip	Injection zone is > 6,000 ft (TVD) of basement	Injection rates < 10,000 bpd

Table NAR-5: Probability ranking definition matrix criteria.

Probability Ranking Definition

Probability of a Seismic Event	Historic Seismicity	Seismometer Coverage	Seismic Coverage	Basement Faulting (proximity to a fault of concern)	Injection Zone's Proximity to Basement	Injection Rate*	Final Probability Level
High	3	3	3	3	3	3	**High Probability Level if Total >12**
Medium	2	2	2	2	2	2	**Moderate Probability Level if Total 7≤X≤12**
Low	1	1	1	1	1	1	**Low Probability Level if Total =6**

2.7 Hydrologic and Hydrogeologic Information

The Gulf Coast Aquifer is the only major aquifer in the region of the Kleberg Hub AoR. Groundwater salinity in the Kleberg Hub AoR was interpreted using 42 geophysical logs, resulting in base USDW ranges from [redacted] feet total vertical depth subsea (TVDSS). Fluid analysis from stratigraphic test wells and newly completed water wells were also used to support base USDW. Detailed review provided in PBI_03_AOR_CA_Kleberg Sections 2.2.4, 2.25, and 2.2.6

2.8 Geochemistry

Two geochemical modeling studies were performed: (1) batch reactions with detailed geochemical equilibrium simulations and (2) reactive-transport and the multiphase flow simulations using the full-field model. Current reactive-transport simulation runs suggest calcite and kaolinite precipitation coinciding with plagioclase dissolution are the most important geochemical considerations for CO_2 injection. Additional reactive-transport simulation runs are being conducted to refine the geochemical model. Detailed review provided in PBI_03_AOR_CA_Kleberg Section 4.3

2.9 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.

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

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 analyzing 218 wells with electronic logs and eight 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-6 using a basis of a one square mile unit area.

Table NAR-6: 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/ft³)	P10 G_{CO_2} (tonne/ mi²) $E_{saline} = 0.005$	P50 G_{CO_2} (tonne/ mi²) $E_{saline} = 0.02$	P90 G_{CO_2} (tonne/ mi²) $E_{saline} = 0.054$
[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 106,000 acres (165.6 mi^2), the total storage capacity of the Kleberg Hub 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 Model Domain

A static geologic model was constructed covering an area of 249,091 acres over the injection site, a portion of which was extracted for simulation. The modeled interval includes ~4,500' of gross rock characterizing the [redacted] formations. Figure NAR-27 displays the 147 wells with quality logs and reservoir tops data that were used, in conjunction with 2D and 3D seismic data, to construct reservoir top surfaces. The wells shown in Figure NAR-27 had the appropriate digital logs to be petrophysically analyzed and used in building the petrophysical property models. Detailed information of these wells is tabulated in PBI_Appendix C – Well List Inventory, Tables C-1 and C-2. Isochores from well logs were used in addition to depth information derived from well tops and depth converted seismic surfaces to establish a structural and stratigraphic framework. Additionally, 12 fault planes interpreted from seismic were included in the structural modeling Figure AoR-17 and Figure AOR-18 of the Area of Review and Corrective Action Plan Document. The static model was built using the volume-based modeling processes in Petrel. Prior to creating the volume-based model, a Pillar Grid model was constructed to allow for increased editing capabilities unavailable in volume-based modeling. After the initial pillar grid model was constructed, surfaces and faults were exported from this model and used as inputs for the final volume-based model that was populated with reservoir properties.

[redacted]

Figure NAR-27: Well location map inside the Geomodel polygon, color coded by data available, thick green outline highlight the stratigraphic wells and thick blue outline highlight wells used as based wells in the petrophysical analysis.

3.1 AoR and Corrective Action

The Area of Review and Corrective Action Plan document meets the requirements of the Environmental Protection Agency (EPA) 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 USDWs, and implementing corrective action on existing wells within the AoR. The document describes the subsurface characterization, computational modeling, current AoR delineation, corrective action plan and schedule, wells requiring corrective action, and future AoR reevaluation plan and schedule.

The plan delineates the AoR and provides any corrective action 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.

The AOR defined in the Area of Review and Corrective Action document was defined by modeling six injection wells located on three pads. [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

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 application. The financial instrument(s) will 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 the Director with 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 will provide notification to meet the requirements of 40 CFR 146.85 and the conditions of this permit, including the following:

- 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 perform 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 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, Becerra_CCS_01_02, Becerra_CCS_02_01, Becerra_CCS_02_02, Garcias_CCS_01_01, and Garcias_CCS_01_02 injection wells are designed in accordance with all applicable regulations and industry standards for drilling and well construction (see Figures NAR-28 through NAR-33). The operational parameters and material selection are intended to maximize mechanical integrity in the system and to optimize operations during the life of the project.

The well design for the Becerra_CCS_01_01, Becerra_CCS_01_02, Becerra_CCS_02_01, Becerra_CCS_02_02, Garcias_CCS_01_01, and Garcias_CCS_01_02 includes three main sections: conductor casing, surface casing, and long string casing to protect 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-28: Becerra_CCS_01_01 Injection Well Proposed Schematic

[redacted]

Figure NAR-29: Becerra_CCS_01_02 Injection Well Proposed Schematic

[redacted]

Figure NAR-30: Becerra_CCS_02_01 Injection Well Proposed Schematic

[redacted]

Figure NAR-31: Becerra_CCS_02_02 Injection Well Proposed Schematic

[redacted]

Figure NAR-32: Garcias_CCS_01_01 Injection Well Proposed Schematic

[redacted]

Figure NAR-33: Garcias_CCS_01_02 Injection Well Proposed Schematic

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

Stimulations to enhance the injectivity potential of the Frio Sandstone in the Becerra_CCS_01_01, Becerra_CCS_01_02, Becerra_CCS_02_01, Becerra_CCS_02_02, Garcias_CCS_01_01, and Garcias_CCS_01_02 wells may include but are not limited to [redacted]. 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 with 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)]

Conductor

The [redacted] in. wellbore for the conductor casing will be drilled via auger to a depth approximately of [redacted] ft. The wellbore will be cased with a [redacted] in. line pipe and cemented with a mixture of concrete to surface. This section will be used to provide support for the surface section operations only and will be preset before the start of drilling operations and during the construction of the cellar and mouse hole installation. Due to the shallow depth of this section, no logging or testing is planned.

Surface Section

The [redacted]-inch vertical wellbore will be drilled to 3,000 ft to cover the base of the USDW, estimated at [redacted] ft for the six injectors, and to provide mechanical integrity on the surface shoe to continue drilling to the next section. A deviation survey will be taken every 100 ft while drilling. This section will be drilled with freshwater mud. 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 a 13⅜-inch casing will be run and cemented to the surface via circulation with a [redacted]. If no cement returns to the surface, the Project Manager will inform the EPA UIC Director and Texas regulators, determine the top of cement with a temperature log or equivalent, and after approval by the Director, complete the annular cement program with a top job procedure. After the tail cement reaches at least 500 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 10 to 15 ft of new formation will be drilled to execute a Formation Integrity Test (FIT).

Long String Section

A [redacted] in. directional wellbore will be drilled from 3,000 ft to total depth (TD) while taking deviation surveys every 100 ft and collecting cutting samples to describe the formation characteristics. The well in this section will be drilled with synthetic-based mud. Once TD is reached, the well will be circulated and conditioned to run open-hole electric logs and acquire side wall cores (SWC) and water samples according to the Pre-Operational Formation Testing Plan. Once testing is complete, the long string of [redacted]-in. casing will be deployed with the distributed temperature sensing (DTS)/distributed acoustical sensing (DAS) fiber optic cable attached to the exterior of the casing. The casing will be cemented to the surface via circulation with a combination of [redacted] Based on simulations, a stage tool will be used to perform a two-stage cementing job to establish good cement from the bottom to the surface. The stage tool or cementing stage tool depth will be adjusted based on actual conditions of the well after it is drilled.

After the cementing is complete, Section B of the wellhead will be installed and the DTS/DAS cable will be threaded through the slips and pack off. The team will then install the rest of the wellhead to prepare for completion operations.

During completion operations, the rig crew will test the casing to 1,000 psi, condition the long string with a bit and scraper, and run cement bond and casing inspection logs to evaluate cement bonding and casing conditions.

The [redacted]-in. tubing and packer completion will vary by injector, but will be set between [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 1,000 psi on the surface to validate the mechanical seal and integrity in the annular space between the tubing and casing. The pulse neutron log will be run through tubing to set a baseline for future surveys.

The crew will proceed to perforate the injection zone through tubing and initiate the well testing. The well will be tested for injectivity with step rate test, injectivity test, and falloff test procedures before starting CO_2 injection.

5.2.1 Casing and Cementing

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

6.0 Preoperational 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, Garcias IZM 01, Garcias IZM 02, and Becerra IZM 01, as well as the data acquisition planned in the additional monitoring wells.

The preoperational testing program will determine or verify the depth, fluid salinity, thickness, mineralogy, lithology, porosity, and permeability 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 preoperational logging and testing program are found in the Preoperational Testing Plan document of this permit.

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

7.0 Well Operation

The wells were 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 well designs provide enough clearance to deploy the pressure and temperature gauges on the 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, Becerra_CCS_01_02, Becerra_CCS_02_01, Becerra_CCS_02_02, Garcias_CCS_01_01, and Garcias_CCS_01_02 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 a flowmeter on the injection pipeline.

Table NAR-7 details the key parameters that will control the injection process during startup and normal operations. The parameters in Table NAR-7 may be amended as additional site data is acquired, evaluated, and interpreted.

Table NAR-7: Injection Well Operating Conditions.

Parameter/Condition	Limitation or Permitted Value	Units
[redacted]		

*Operating Injection Rate and Maximum Bottomhole Pressure are well dependent. See specific well operations document for specific details.

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 every twelfth month after last approved demonstration.

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

The project will receive two streams of CO_2 with different specifications defining the maximum variation in the impurities and delivery conditions to the site. The [redacted] (Table NAR-9). 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-8: CO_2 Stream Specification A.

[redacted]

Table NAR-9: CO_2 Specification Stream B

[redacted]

7.3 Reporting and Recordkeeping

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

1PointFive will submit semi-annual reports containing:

- Any changes to the physical, chemical, or 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 shutoff systems and the responses taken;
- The monthly volume and/or mass of the CO_2 stream injected during 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 noncompliance shall be reported to the Director within 24 hours as described below:

- 1PointFive shall report to the Director any permit noncompliance that endangers human health or the environment or any events that require notification to the Director within 24 hours 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 a USDW or any monitoring or other information that indicates that any contaminant may have caused endangerment to a USDW;
  - Any noncompliance with a permit condition or malfunction of the injection system that may have caused fluid migration into or between USDWs;
  - Any triggering of the shutoff 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; and
  - Actions taken to implement appropriate protocols outlined in the Emergency and Remedial Response Plan document of this permit.
- A written submission will be provided to the Director in electronic format within five 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.

1PointFive will report to the Director the results of periodic tests of mechanical integrity; any well workover, including stimulation; any other test of the injection or monitoring wells conducted by the permittee within 30 days of the work completion if required by the Director.

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, 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 Noncompliance –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 additional 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 scheduled date.
- Transfer of Permits – This permit is not transferable to any person or entity 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 may 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.
- Other Information – When 1PointFive becomes aware of a failure to submit any relevant facts in the permit application or that incorrect information has been submitted in a permit application or in any report to the Director, 1PointFive will 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 issuing a permit to construct, 1PointFive will certify to the Director in electronic format that the Project Manager has read and is personally familiar with all terms and conditions of the permit.

The following guidelines are provided for recordkeeping:

- 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 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 pursuant to 40 CFR 146.90. In addition to demonstrating that the wells are operating as planned, the CO_2 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 wells 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 unwitnessed test. 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 that 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, 1PointFive will continuously monitor injection pressure, rate, and volumes; pressure on the annulus between tubing and long string casing; and the annulus fluid volume as specified in 40 CFR 146.88 (e), and 146.89 (b).
- At least once per year, 1PointFive wil perform the following testing to demonstrate external mechanical integrity pursuant to 40 CFR 146.89 (c):
    - An EPA Administrator-approved tracer survey such as an oxygen-activation log; or
    - A temperature or noise log. The Director may require such tests whenever a 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 a 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 a well, 1PointFive will 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 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 an 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. 1PointFive will report the results of a mechanical integrity demonstration in an electronic format.

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 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 to the following guidelines regarding failure to maintain mechanical integrity:

- If 1PointFive or the Director finds that a well fails to demonstrate mechanical integrity during a test, is unable to maintain mechanical integrity during operation, or is suspected of a loss of mechanical integrity as defined by 40 CFR 146.89 (a)(1) or (2) 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 CO2 stream or formation fluids into any unauthorized zone. If there is evidence of USDW endangerment, 1PointFive shall implement applicable actions included in 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 shutdown (*i.e*., downhole or at the surface) is triggered, 1PointFive must immediately investigate and identify, as expeditiously as possible, the cause of the shutdown. If, upon such investigation, a well appears to be lacking mechanical integrity or if required monitoring indicates that a well may be lacking mechanical integrity, the permittee must take the actions as described in the Emergency and Remedial Response Plan.
- If a 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 of the Becerra_CCS_01_01, Becerra_CCS_01_02, Becerra_CCS_02_01, Becerra_CCS_02_02, Garcias_CCS_01_01, and Garcias_CCS_01_02 injection wells, the wells will be plugged and abandoned relevant to the requirements of EPA 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 CO_2 with water mixtures, and protect any 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 groundwater quality and track the position of the carbon dioxide plume and pressure front for 50 years post injection, unless earlier approved by the Director. 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

The 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 a 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 of the injection wells.
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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