For assistance in accessing this document, please contact ghgreporting@epa.gov.

Subpart RR Monitoring, Reporting, and Verification (MRV) Plan
Cotton Cove CCS 1

NW Tarrant County, Texas

Prepared by

BKV dCarbon Ventures, LLC

Version 3.0

February 19, 2025

TABLE OF CONTENTS

1 – INTRODUCTION

BKV dCarbon Ventures, LLC (dCarbon), a subsidiary of BKV Corporation (BKV), is authorized by the Texas Railroad Commission (TRRC) to inject up to 4.0 million standard cubic feet per day (MMscfd), equivalent to approximately 75,744 metric tons per year (MT/yr), of carbon dioxide (CO_2) into the proposed Cotton Cove CCS 1 injection well in Tarrant County, Texas. The permit issued by the TRRC allows injection into the Ellenburger Group at a depth of 8,806 feet to 11,250 feet with a maximum allowable surface pressure of 2,500 pounds per square inch gauge (psig).

dCarbon currently intends to dispose of CO_2, into the Cotton Cove CCS 1 injection well (CCS 1). produced by the nearby Cotton Cove Gas Plant (Gas Plant), operated by BKV Midstream, LLC (TCEQ CN604046912) which is a separate, pre-existing facility. The CCS 1 and the Gas Plant are not under common ownership or common control, and the Gas Plant has a function separate and distinct from the injection well source category, making them separate and distinct facilities under 40 CFR 98.6. The project site is located approximately four miles east-northeast of Azle, Texas, as shown in **Figure 1**. dCarbon anticipates drilling the Cotton Cove CCS 1 well in Q1 2025 and completing and beginning injection operations in 2026. The Cotton Cove CCS 1 has an approved W-14 injection permit (permit number 17534) and an approved W-1 drilling permit (permit number 902971) with the TRRC (UIC number 000126822, API number 42-439-37356). Copies of the approved W-1 and W-14 are included as Attachment A.

Although dCarbon intends to initiate injection with lower volumes, all calculations in this document have been performed assuming close to the maximum injection amount allowed by the TRRC permit (75,744 MT/yr). dCarbon plans to inject for approximately 12 years.

dCarbon submits this Monitoring, Reporting, and Verification (MRV) plan for approval by the Environmental Protection Agency (EPA) in accordance with 40 CFR § 98.440-449, Subpart RR, of the Greenhouse Gas Reporting Program (GHGRP).

dCarbon’s TRRC operator number is 100589.

dCarbon’s Environmental Protection Agency Identification (EPA ID) number is 110071343305.

The Cotton Cove CCS 1 well’s Greenhouse Gas Reporting Program Identification (GHGRP ID) number is 589741. All aspects of this MRV plan refer to this well and this GHGRP ID number.

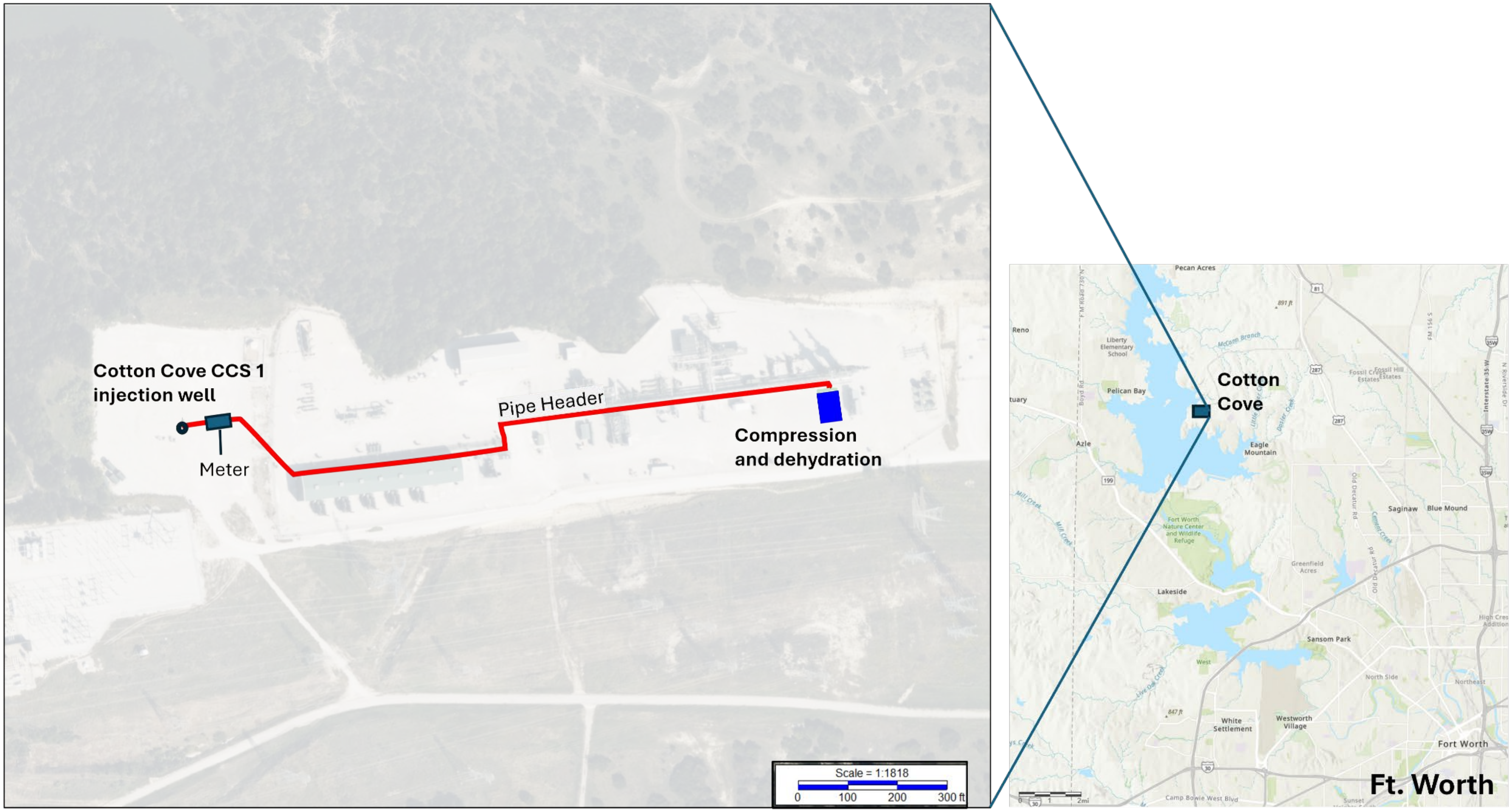


Figure 1. Location map for the Cotton Cove CCS 1 well in Tarrant County Texas. The well is planned to be drilled immediately west of the Cotton Cove Gas Plant that captures the CO_2 to be injected. North is up.

2 – FACILITY INFORMATION

Facility Name:

Cotton Cove Gas Plant (TCEQ CN604046912)

Address: 10055 Morris Dido Newark Road, Fort Worth, TX 76179

Latitude: 32.90927778

Longitude: -97.46976667

GHGRP ID number: 526203

FRS ID: 110040511256

NAICS Code: 211111

Reporting structure: Currently reporting under Subpart C, Subpart W, and Subpart RR.

Underground Injection Control (UIC) Permit Class:

The Oil and Gas Division of the Texas Railroad Commission (TRRC) regulates oil and gas activity in Texas and has primacy to implement the Underground Injection Control (UIC) Class II program for injection wells. The TRRC has permitted the Cotton Cove CCS 1 well as a UIC Class II well. The Class II permit was issued to dCarbon in accordance with Statewide Rule 9.

Injection Well:

Cotton Cove CCS 1

API number: 42-439-37356

UIC number: 000126822

Cotton Cove CCS 1, GHGRP ID: 589741

The Cotton Cove CCS 1 well will be disposing of CO_2 from the Cotton Cove Gas Plant. All aspects of this MRV plan refer to the Cotton Cove CCS 1 well and GHGRP 589741.

3.1 Overview of Geology

The proposed injection site lies in the northwestern part of Tarrant County, where the Barnett Shale, Viola Group, Simpson Group, and Ellenburger Group dip and thicken to the east toward the Muenster Arch, as seen in the west to east cross section of **Figure 2**. The north to south cross section of **Figure 2** shows the Ellenburger and overlying formations dipping down to the north. One inference from these cross sections is that any CO_2 injected may exhibit the tendency to move up dip due to buoyancy, meaning the anticipated plume movement will be westward and southward, which is towards the Bend Arch. The dip direction is further represented in the structure contour map of the Ellenburger Group top (Pollastro, 2007) in **Figure 2**.

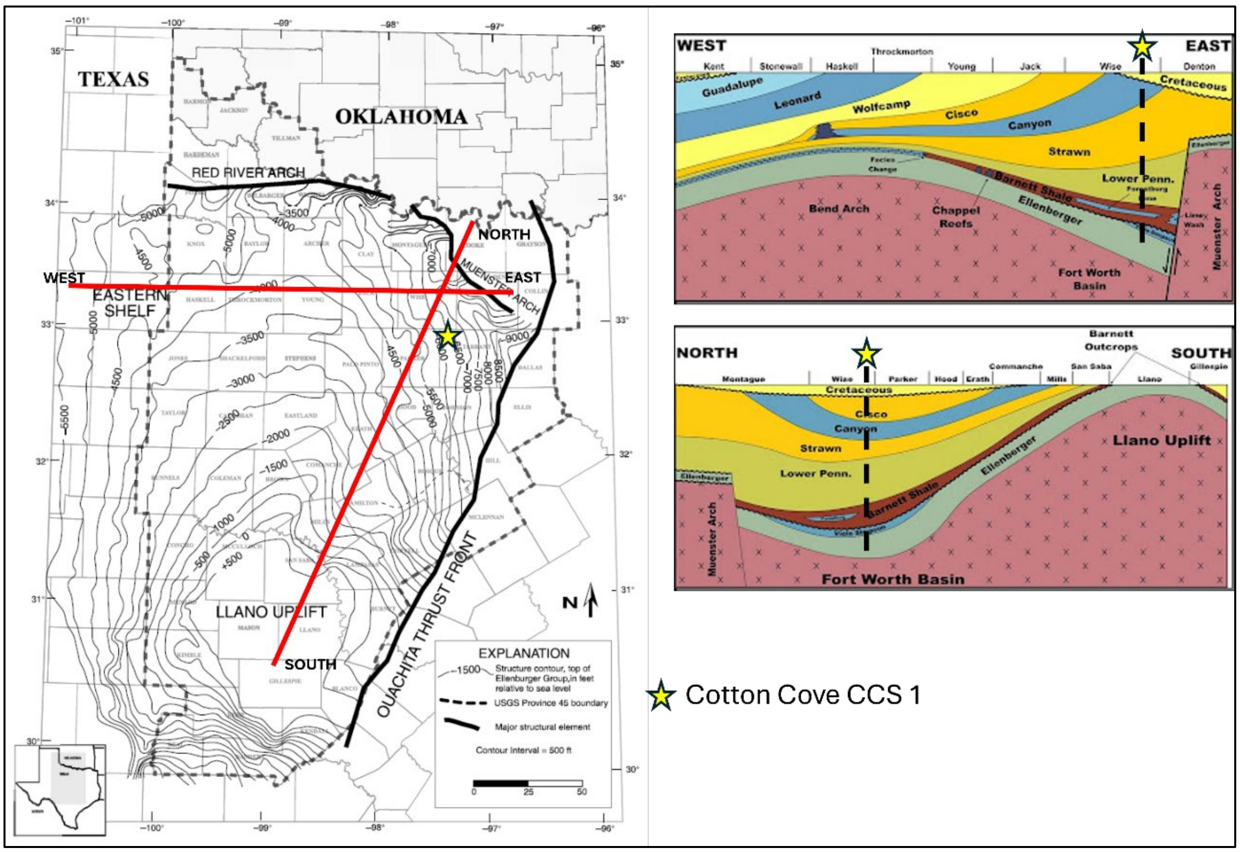


Figure 2. (*Left*) Ellenburger structure map modified from Jarvie *et al.* (2007) showing the regional structures within and bounding the Fort Worth Basin. The Ellenburger structural contours are depicted in feet True Vertical Depth Subsea (TVDSS) at an interval of 500 feet and the final Cotton Cove CCS 1 location is shown by a yellow star. (*Right*) Cross sections from W-E (top right) and N-S (middle right) show the regional dip of the sedimentary units in the Fort Worth Basin modified from Bruner *et. al.*, (2011), also with a yellow star and dashed black line indicating the position of the Cotton Cove CCS 1 well.

The Fort Worth Basin sedimentary succession began with the deposition of locally abundant Cambrian clastics in the southern section of the basin that unconformably overlie the uneven Precambrian basement (**Table 1**). Ordovician age Ellenburger platform carbonates were deposited next on a passive margin and are up to 4,000 feet thick in the Fort Worth Basin. The Ellenburger platform carbonates underwent multiple episodes of regional exposure causing dolomitization and karsting in several subunits of the Ellenburger. Ordovician Viola and Simpson Groups overlie the Ellenburger Group and are found in the northern section of the basin near the Muenster Arch. A major erosive episode occurred during the Mississippian, eroding down to the Ordovician. Later deposition of the Barnett Shale unconformably overlies the variably present Viola Limestone, Simpson Group, and the Ellenburger Group (Gao, 2021). Overlying the Barnett Shale is a thick section of mostly Pennsylvanian and Permian carbonates and clastics (Bend, Strawn, and Canyon Groups). **Figure 2** indicates the general regional stratigraphy. Although there are multiple storage-confining unit systems that could be evaluated for injection, the focus was on the Mississippian-Ordovician section that consists of the Barnett Shale and the Ellenburger Formation. The Ellenburger Group directly overlies the basement rock and is considered the main injection target.

Table 1. Regional Stratigraphy at Cotton Cove CCS 1 Site in North Texas.

<table>
<tr><th>SYSTEM</th><th>SERIES</th><th>STAGE</th><th colspan="2">GROUP OR FORMATION</th></tr>
<tr><td>Cretaceous</td><td>Lower</td><td>Comanchean</td><td colspan="2">Trinity Group</td></tr>
<tr><td rowspan="13">Pennsylvanian</td><td>Upper</td><td>Missourian</td><td>Canyon Group</td><td>Jasper Creek Formation</td></tr>
<tr><td rowspan="8">Middle</td><td rowspan="6">Desmonesian</td><td rowspan="3">Strawn Group</td><td>Willow Point Formation</td></tr>
<tr><td>Lone Camp Formation</td></tr>
<tr><td>Millsap Lake Formation</td></tr>
<tr><td rowspan="3">Kickapoo Group</td><td>Ratville Formation</td></tr>
<tr><td>Parks Formation</td></tr>
<tr><td>Caddo Pool Formation</td></tr>
<tr><td rowspan="4">Atokan</td><td rowspan="6">Bend Group</td><td>Caddo Formation</td></tr>
<tr><td>Smithwick Shale</td></tr>
<tr><td rowspan="4">Lower</td><td>Pregnant Shale</td></tr>
<tr><td>Big Saline Formation</td></tr>
<tr><td rowspan="2">Morrowan</td><td>Marble Falls Limestone</td></tr>
<tr><td>Comyn Formation</td></tr>
<tr><td rowspan="3">Mississippian</td><td colspan="2" rowspan="2">Chesterian – Meramecian</td><td rowspan="3">Barnett</td><td>Upper Barnett Shale</td></tr>
<tr><td>Forestburg Limestone</td></tr>
<tr><td colspan="2">Osagean</td><td>Lower Barnett Shale</td></tr>
<tr><td rowspan="3">Ordovician</td><td colspan="2" rowspan="2">Upper</td><td colspan="2">Viola Group</td></tr>
<tr><td colspan="2">Simpson Group</td></tr>
<tr><td colspan="2">Lower</td><td colspan="2">Ellenburger Group</td></tr>
<tr><td>Precambrian</td><td colspan="2"></td><td colspan="2">Basement</td></tr>
</table>

3 – PROJECT DESCRIPTION

This Project Description discusses the geologic setting, the planned injection and confining intervals or zones (terms interval and zone used interchangeably), the planned injection volumes and process, and the reservoir modeling performed for the proposed Cotton Cove CCS 1 Class II injection well. dCarbon has prepared this MRV plan to support the storage of CO_2 in Tarrant County, Texas.

3.2 Bedrock Geology

3.2.1 Basin Description

The Fort Worth Basin is a flexural basin that formed in the foreland of the advancing Ouachita orogenic belt during the Late Mississippian through Pennsylvanian Epochs. As illustrated in **Figure 2**, the Fort Worth Basin is bounded to the east by the Ouachita fold and thrust belt and to the north by the Muenster Arch and Red River Arch. These arches are characterized by a series of high angle reverse faults. The basin is deepest in the northeast, with as much as approximately 12,000 feet of sediment infill where the Ouachita thrust front meets the Muenster Arch and is shallowest in the south.

3.2.2 Stratigraphy

The Ellenburger Group in the Fort Worth Basin contains alternating limestone and dolostone lithologies, consistent with regional descriptions of the Ellenburger. Vertical changes in properties throughout the Ellenburger were used to divide the unit into eight subunits (A-G), in agreement with a similar approach demonstrated by Smye *et al.* (2019). The main target storage reservoir, Ellenburger Subunit E, was identified based on the dominant dolostone lithology, gross and net reservoir thicknesses, porosity values, and permeability values. The Ellenburger Subunit B and the stratigraphic top portion of Ellenburger Subunit C were identified as the caprock based on the dominant limestone lithology, thickness, porosity, and permeability values. Below this interval, there are layers of tighter limestone throughout Ellenburger Subunits C, C2, and D that would also act as sealing units to the underlying Ellenburger Subunit E storage interval.

The Barnett RDC 1 well (API number 42-497-38108), located approximately 27 miles northwest of the proposed Cotton Cove CCS 1 injection well, was used to calibrate well-log-based petrophysical properties since it has modern well logs and core data (**Figure 3**). The Tarrant North SWD 1 well (API number 42-439-31228), located approximately six miles to the northeast, was also used in well correlations and thickness calculations because of its closer proximity. Dominant lithologies were determined by comparing the photoelectric factor log curve and the separation of the density and neutron porosity curves in the Tarrant North SWD 1 well with the volume of clay, sand, lime, dolomite, gas, and free water calculated in the Barnett RDC 1 well. Gross reservoir thickness was determined for each Ellenburger subunit by adding the footage from the top to the bottom of the subunit.

Figure 3 shows the correlation of the Barnett RDC 1 to the Cotton Cove CCS 1 site, including the Tarrant North SWD 1, as noted by the well names posted on the map and at the base of the well logs in the cross section. Ellenburger Subunits A through F are present and appear to be contiguous in the project area. The thickness of Ellenburger Subunits B-D is approximately 2,000 feet while Ellenburger Subunit E thickness varies across the cross-sections. It is estimated there is at least 2,000 feet of Ellenburger Subunits B-D and 1,000 feet of Ellenburger Subunit E at the Cotton Cove CCS 1 proposed location.

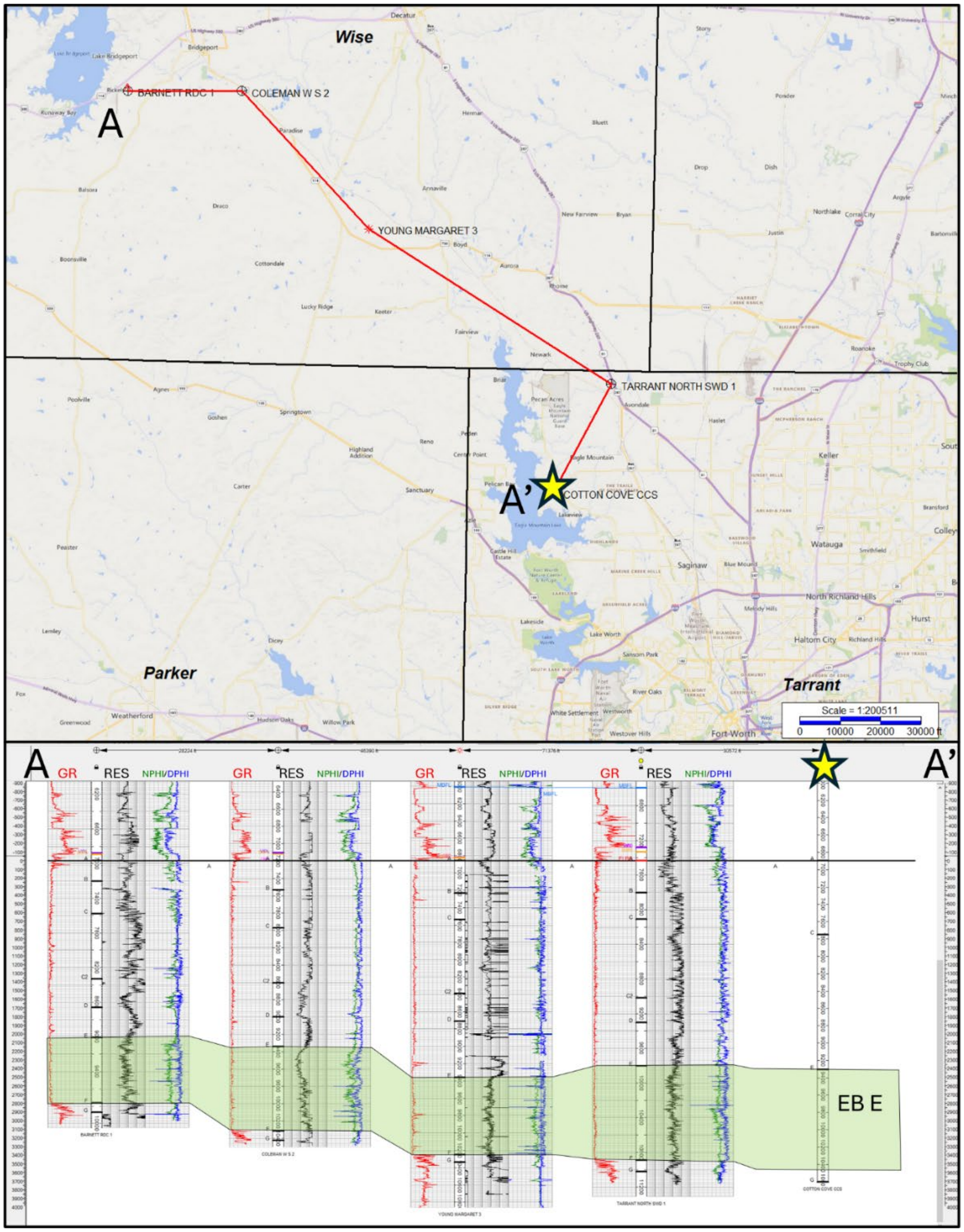


Figure 3. (*Top*) Map of north Texas, including Wise and Tarrant Counties, with the Cotton Cove CCS 1 (yellow star) and a NW-SE stratigraphic cross section (A-A'). North is up. (*Bottom*) Cross section, datumed on the top of the Ellenburger Subunit A, showing Gamma Ray (GR), Resistivity (RES), Neutron Porosity (NPHI), and Density Porosity (DPHI) from the Barnett RDC 1 well to the Tarrant North SWD 1 well. Ellenburger Subunit E (EB E) is the storage interval.

3.2.3 Faulting

Faults within the Fort Worth Basin are generally northeast-trending, high-angle normal faults with most of the faults rooting into the Precambrian crystalline basement (**Figure 4**). A secondary set of east-west faults appear to connect these major trends. The mechanism for deformation that produced these faults has been attributed to flexure generated by the Ouachita orogenic belt. Deep seated faults that root into the Precambrian crystalline basement generally terminate in the base of the Pennsylvanian age strata and do not continue into the overlying Cretaceous strata where present, suggesting that faults have not experienced significant movement since their formation (Wood, 2015). Karsting in the region has resulted in small-scale, concentric faults that originate from the collapse of karst features predominantly within the Ellenburger Formation.

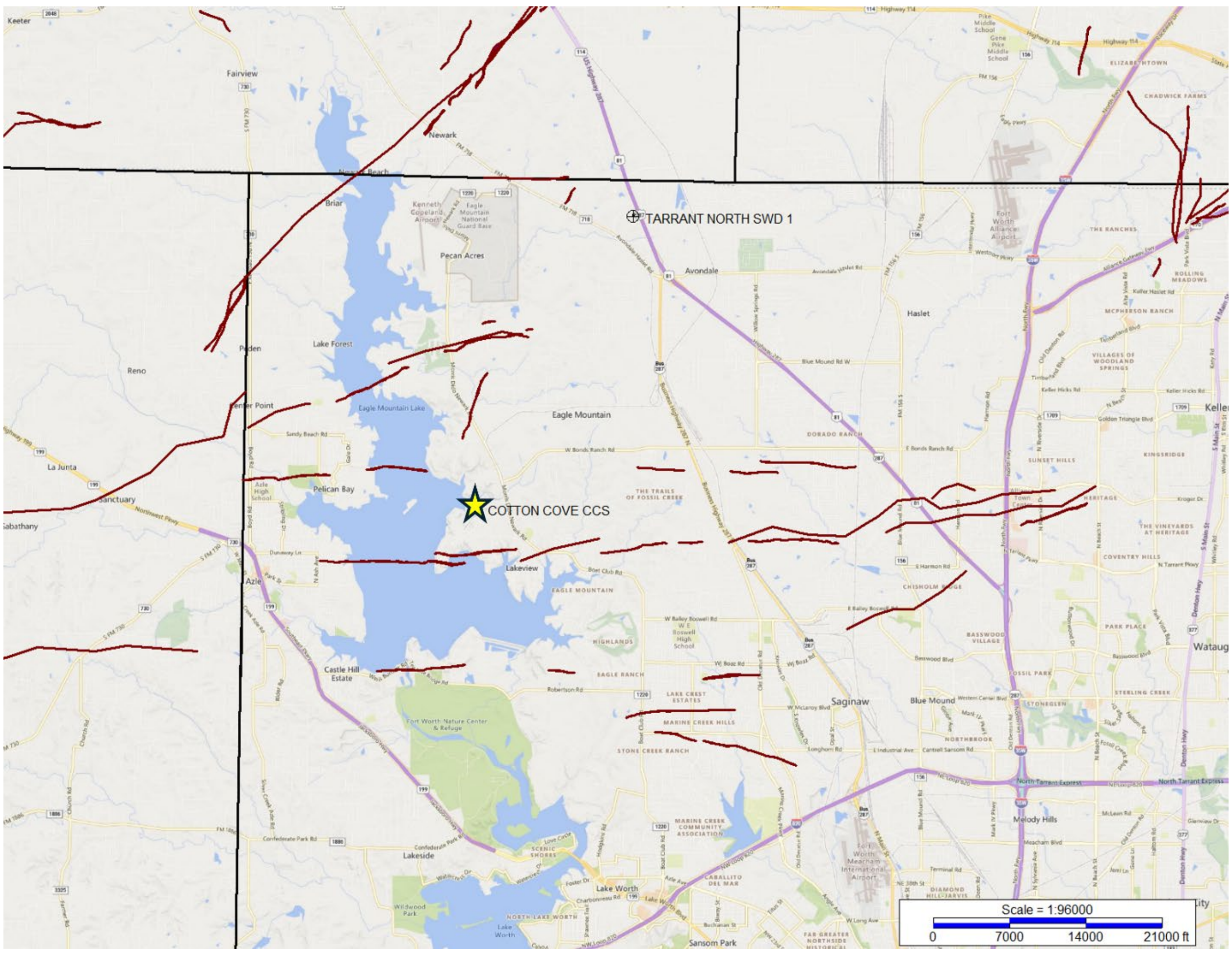


Figure 4. Mapped faults (brown lines) at the top Ellenburger level, near the proposed injection well, from Wood (2015) and internal mapping. North is up.

3.3 Lithological and Reservoir Characterizations

Smye *et al*. (2019) provided a detailed description of regional stratigraphy as well as petrophysical attributes of multiple units within the Upper Cambrian to Ordovician. Prior to understanding the petrophysical properties of these subunits and assessing their storage reservoir or confining layer potential, it is important to understand the overall lithology. Literature suggests the Ellenburger interval is mostly composed of calcite, dolomite, quartz, and clay. The carbonate intervals are mostly clean with less than 10% clay by volume. However, the top of the Ordovician section was shown to have an increased clay content (about 40% by volume). This also coincided with an increase in siliciclastic materials (quartz and clay). Porosity in clean carbonate intervals is approximately 5%, while that in siliciclastic intervals may reach 20%. The basement lithology was identified as granite wash with hematite contents ranging between 5-10% by volume. **Figure 5** shows the general stratigraphy in the area.

To better understand local stratigraphy and petrophysics, lithological characterization was focused on the strata highlighted by red dashed box in **Figure 5**. The Viola and Simpson Groups are expected to overlie Ellenburger Subunit A at the Cotton Cove CCS 1 site as depicted on the right side of the highlighted column.

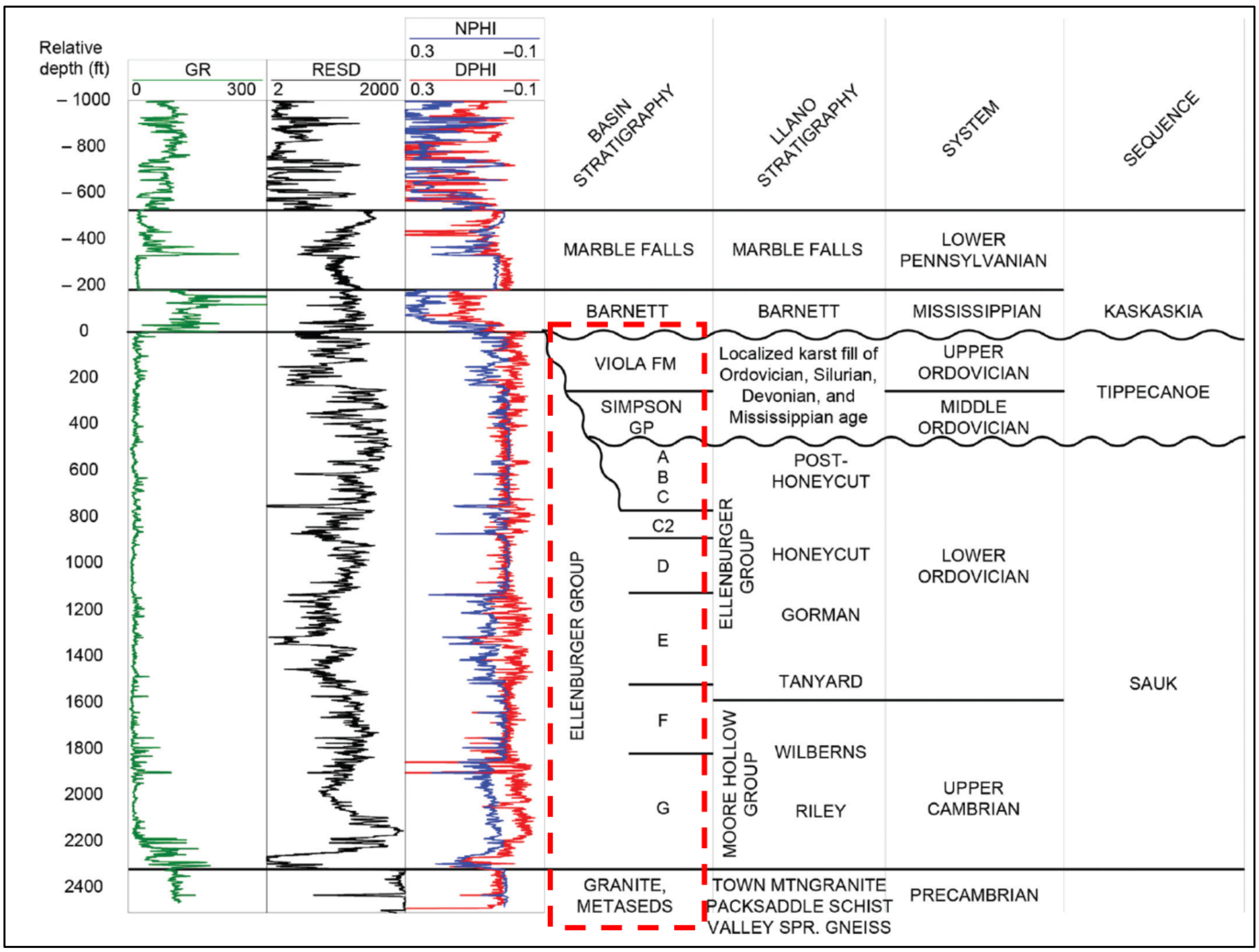


Figure 5. Regional stratigraphy at Cotton Cove CCS 1 site in north Texas (modified from Smye *et al.,* 2019). Red dashed box highlights the section of focus for the lithological characterization.

The Simpson and Viola Groups are anticipated to serve as the secondary confining interval at the Cotton Cove CCS 1 location. The Barnett Shale, located above the Viola Group, is a source rock and an unconventional reservoir that is extensively drilled in the Fort Worth Basin. The porosities and permeabilities in the Barnett Shale range from 4-6% and 7-50 nanodarcies, respectively. These low porosities and permeabilities are characteristic of conventional seals and, as such, the Barnett serves as an additional confining interval. The wells in the project area produce unconventional gas from the Barnett Shale.

Underlying the Viola and Simpson Groups are the informal Ellenburger lettered units defined by Smye *et al.*, 2019, which contains both the anticipated storage and confining intervals. The Ellenburger was divided into eight lithostratigraphic units starting with Ellenburger Subunit A at the top to Ellenburger Subunit G at the bottom which sits on top of the crystalline basement. Ellenburger Subunit G is not seen on well logs sufficiently to confirm that it is present in the area. Ellenburger Subunit F may sit on the crystalline basement in the area and serves as the lower seal for the reservoir. Core data from the Barnett RDC 1 showed Ellenburger Subunit F had porosities below 2% and permeabilities below 0.005 millidarcies (mD), making it an excellent lower seal. Ellenburger Subunit E will serve as the storage interval. It is characterized as a clean dolomitic reservoir with 49% dolomite by volume and approximately 4% matrix porosity. Ellenburger Subunits B and C were found to have lower matrix porosities compared to Ellenburger Subunit E, which should provide vertical confinement or impediment to CO_2 movement. Ellenburger Subunit A has been proven to have reservoir characteristics with multiple saltwater disposal wells completed in Ellenburger Subunit A. Karsting features at the top of the Ellenburger imply there is some potential for hydraulic communication between Ellenburger Subunit A and the overlying Barnett. **Figure 6** illustrates the log response and petrophysical properties of Ellenburger Subunits A-G.

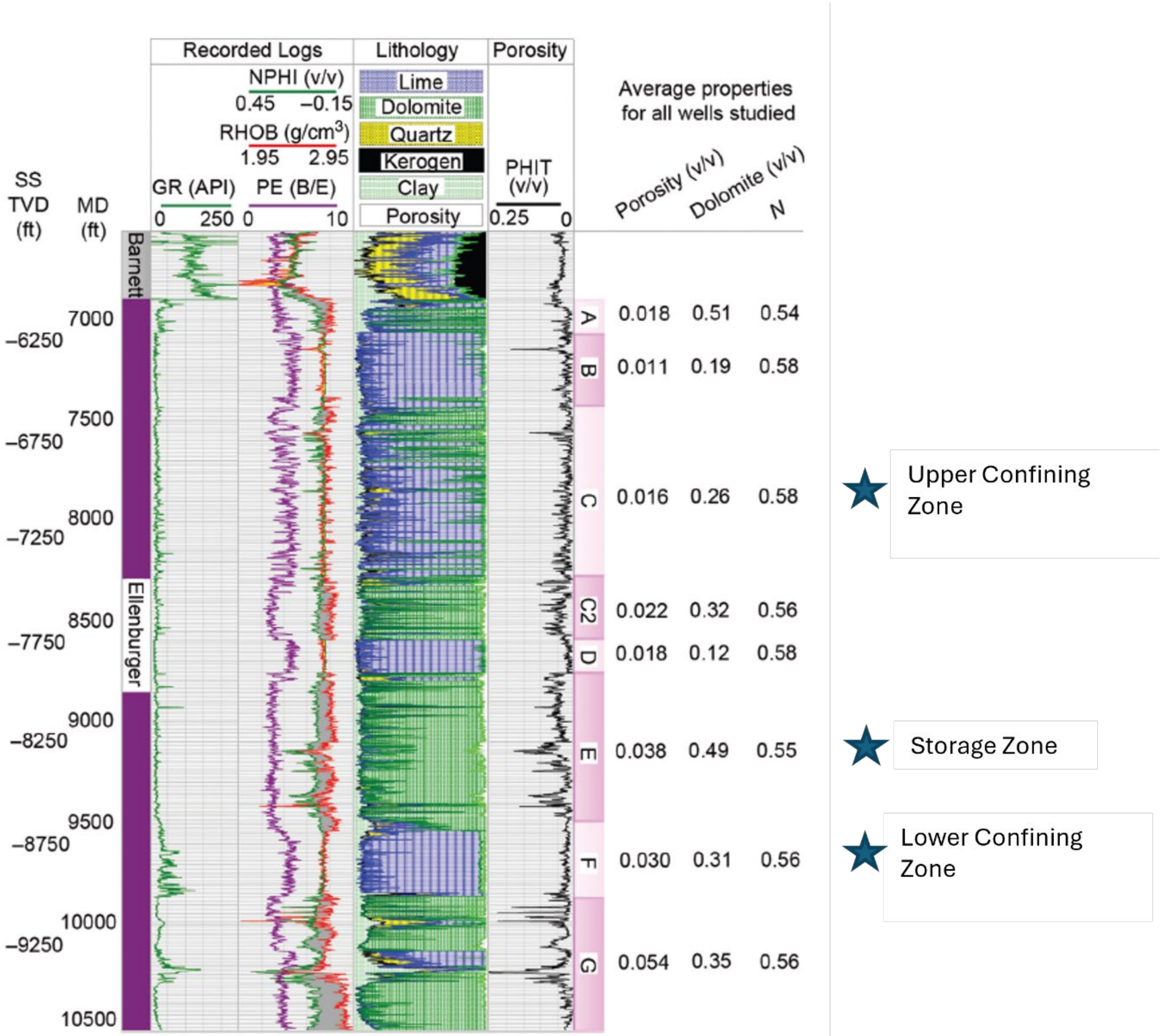


Figure 6. General properties of Ellenburger Subunits A-G in the project area (modified from Smye *et al.*, 2015).

The Barnett RDC 1 injection well located approximately 27 miles northwest of the proposed injection site also contains Ellenburger Subunits A through F, as shown below in **Figure 7**. Drilling at the proposed site should result in reservoir and seal intervals like those shown in both **Figures 6 and 7**.

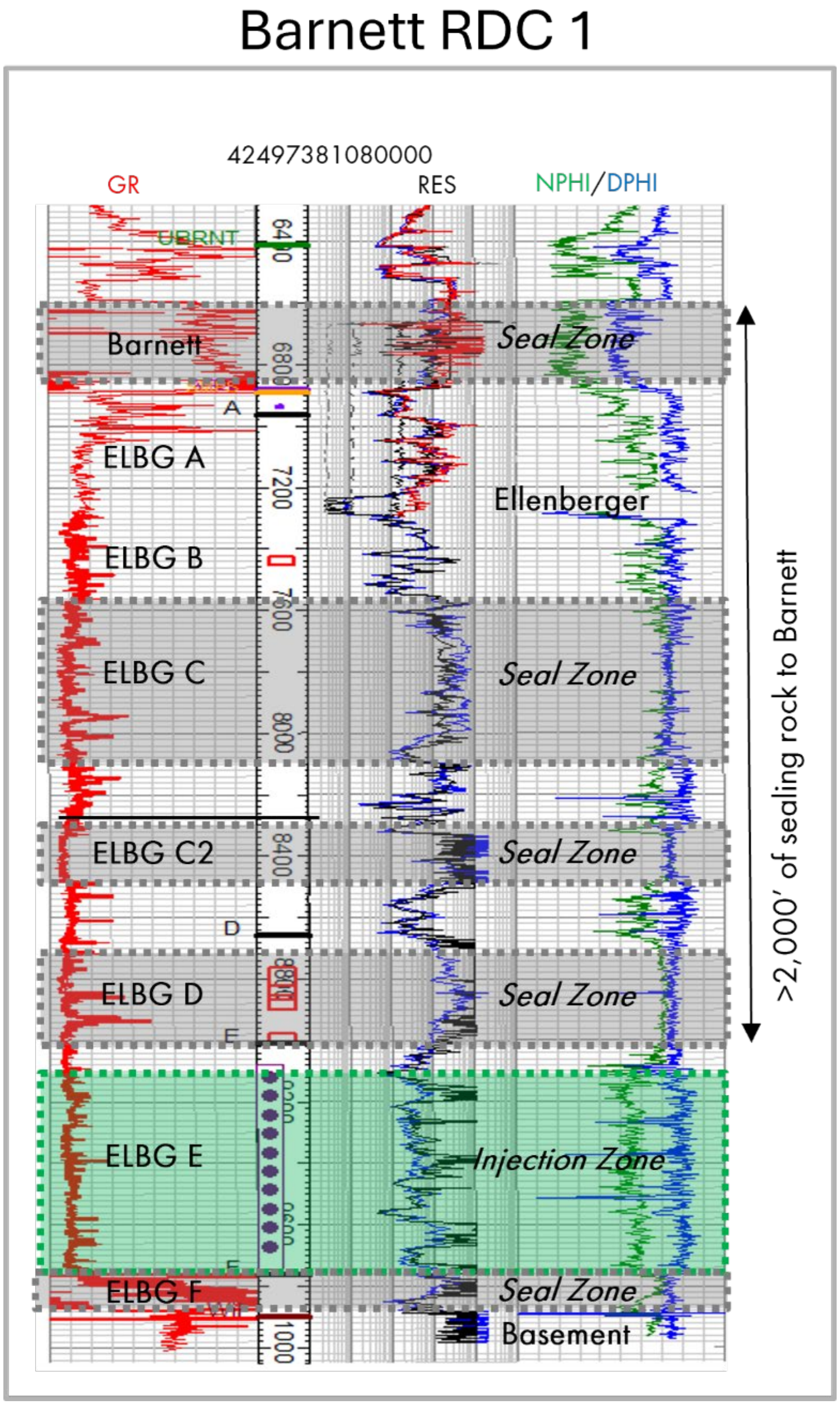


Figure 7. Barnett RDC 1 well log interpretation; Ellenburger Subunits A through F are shown on the log image.

Net reservoir thickness was determined for each subunit of the Ellenburger by summing the footage where the average porosity (PHIA) curve was greater than 2%. It is important to note that such a low matrix porosity value was chosen as the cut-off because fractures greatly enhance permeability and improve Ellenburger reservoir quality even in intervals with very low matrix porosity.

Saltwater disposal into analogous Ellenburger intervals with low porosity lend support to the premise that a low log porosity could still result in realizable CO_2 storage potential (*e.g.*, Tarrant North SWD 1). A net-to-gross ratio was determined for each subunit by dividing the net reservoir thickness by the gross reservoir thickness. Average porosity was calculated for each subunit of the Ellenburger by averaging the average porosity (PHIA) curve from the top to the bottom of the subunit. These reservoir interval properties were subsequently used to derive preliminary storage resource estimates. **Table 2** lists average petrophysical properties in the Ellenburger as seen in the Tarrant North SWD 1 well.

Table 2. Ellenburger Group properties assessed at the project area.

<table>
<tr><th>Ellenburger Subunit</th><th>Dominant Lithology</th><th>Gross Reservoir Thickness (feet)</th><th>Net Reservoir Thickness (feet [>2% PHIA])</th><th>Net-to-Gross Ratio</th><th>Average Reservoir Porosity (%)</th><th></th></tr>
<tr><td>A</td><td>Dolostone</td><td>372</td><td>160</td><td>0.43</td><td>3.3</td><td></td></tr>
<tr><td>B</td><td>Limestone</td><td>307</td><td>25</td><td>0.08</td><td>1.3</td><td rowspan="4">Upper Confining Interval</td></tr>
<tr><td>C</td><td>Limestone</td><td>906</td><td>284</td><td>0.31</td><td>2.4</td></tr>
<tr><td>C2</td><td>Dolostone</td><td>281</td><td>88</td><td>0.31</td><td>2.5</td></tr>
<tr><td>D</td><td>Limestone</td><td>502</td><td>288</td><td>0.57</td><td>3.5</td></tr>
<tr><td>E</td><td>Dolostone</td><td>1087</td><td>700</td><td>0.64</td><td>4.2</td><td>Storage Interval</td></tr>
<tr><td>F</td><td>Limestone</td><td>136</td><td>4</td><td>0.03</td><td>1.1</td><td>Lower Confining Interval</td></tr>
<tr><td>G</td><td>Dolostone</td><td>N/A</td><td>N/A</td><td>N/A</td><td>N/A</td><td></td></tr>
</table>

Permeability data in individual Ellenburger subunits was obtained from literature and informed by the core data from the Barnett RDC 1 well. Regional hydrostatic pressure gradient in the Ellenburger was assumed to be 0.5 pounds per square inch (psi) per foot, while the geothermal gradient in the Fort Worth Basin was estimated at 1.25°F per 100 feet using the well logs from the Tarrant North SWD 1.

3.4 Formation Fluid Chemistry

Through a review of chemical analyses of oil-field brines from the U.S. Geological Survey National Produced Waters Geochemical Database v3.0, five wells within in the Fort Worth Basin were identified with water samples from the Ellenburger as shown in **Figure 8**.

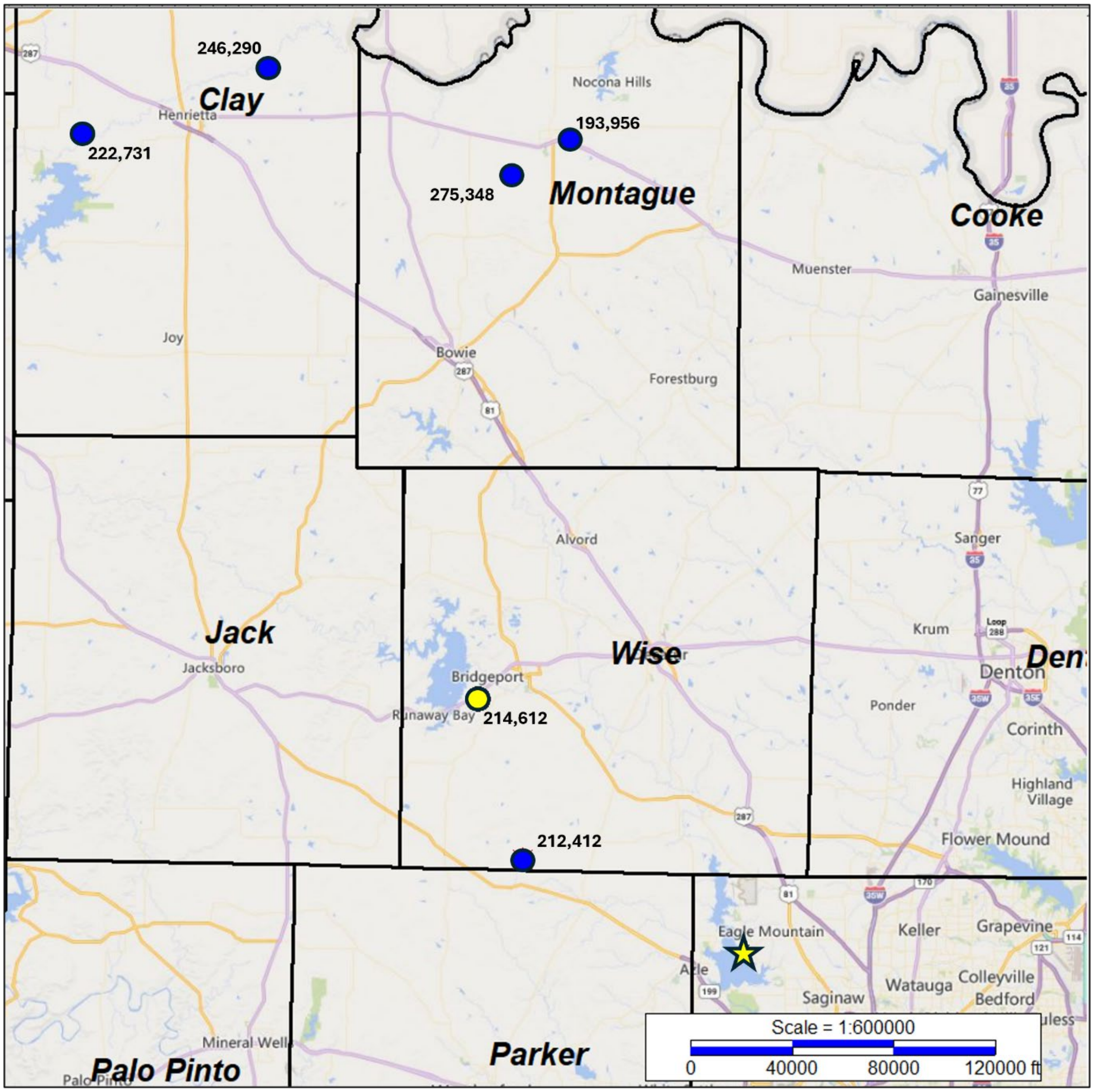


Figure 8. Map showing the location of wells used in the formation fluid chemistry analysis. The blue circles are wells from the USGS Produced Waters Database v3.0 while the yellow circle is the Barnett RDC 1. TDS values in mg/L are annotated. The Cotton Cove CCS 1 location is shown with the yellow star. North is up.

The Ellenburger Group is not productive of oil and gas within the immediate area surrounding the proposed injection well and consequently formation fluid chemical analyses for the Ellenburger Group are from a basin-wide review. The USGS database indicates that Ellenburger fluids have greater than 190,000 parts per million (ppm) total dissolved solids (TDS) within the Fort Worth Basin as reported in **Table 3**. The average of the five samples available in the USGS database is similar to the TDS value that dCarbon obtained from the Barnett RDC 1 well. The Barnett RDC 1 well sample had 214,612 mg/L TDS, an Na concentration of 54,465 ppm, a Ca concentration of 22,269 ppm, and a Cl concentration of 128,819 ppm.

Table 3. Ellenburger Formation fluid chemistry. These values are derived from the five wells depicted in Figure 8.

	TDS (mg/L)	Na (ppm)	Ca (ppm)	Cl (ppm)
AVG	230,147	63,363	20,635	142,168
LOW	193,956	55,352	15,352	118,405
HIGH	275,348	77,094	23,443	169,720

3.5 Potential of Induced Seismicity – Ellenburger Formation

An analysis of historical seismic events within 100 square miles surrounding the proposed Class II well injection site shows seismic activity dating back to 1900, according to the U.S. Geological Survey (USGS) Earthquake Catalog (**Figure 9**). Of the nine earthquakes above magnitude 3.0 shown on the map, three fall within the 100 square-mile area. All but one of the nine earthquakes appear to be part of the Azle-Reno earthquake swarm, documented by Hornbach, *et al*. (2015) (**Figure 10**). The Azle-Reno swarm earthquakes were mapped back to an NNE-SSW basement-rooted fault and its antithetic fault via data from a local earthquake network and advanced hypocenter location techniques. It is likely that the wide scatter in the mapped earthquake locations seen in the USGS catalog is a function of the location uncertainty due to the sparse recording array rather than actual separation of earthquake hypocenters.

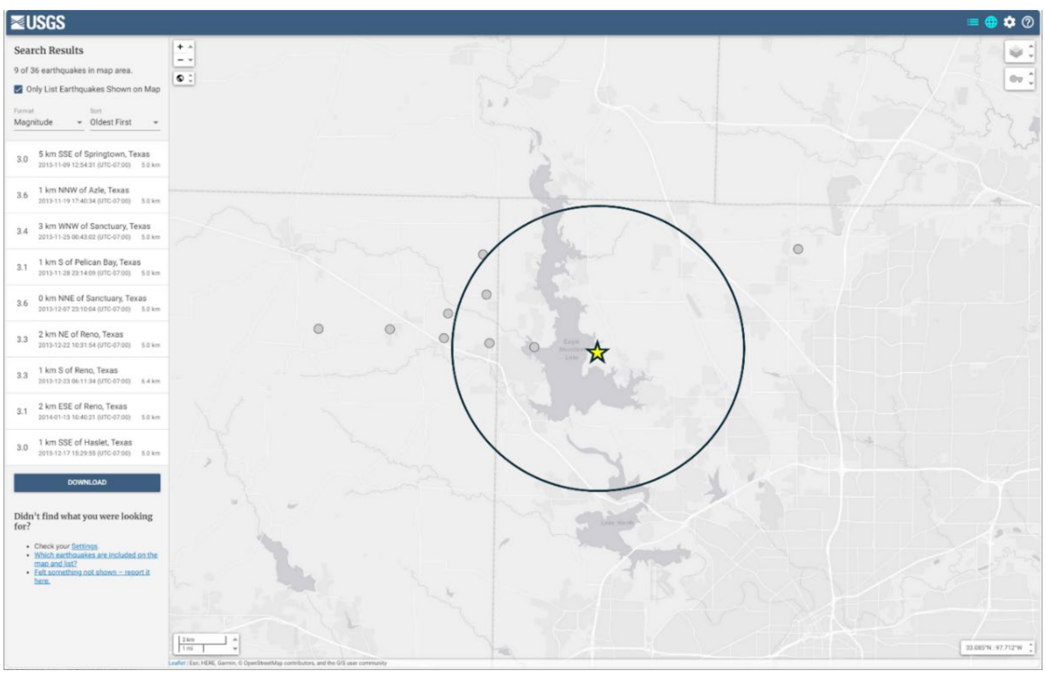
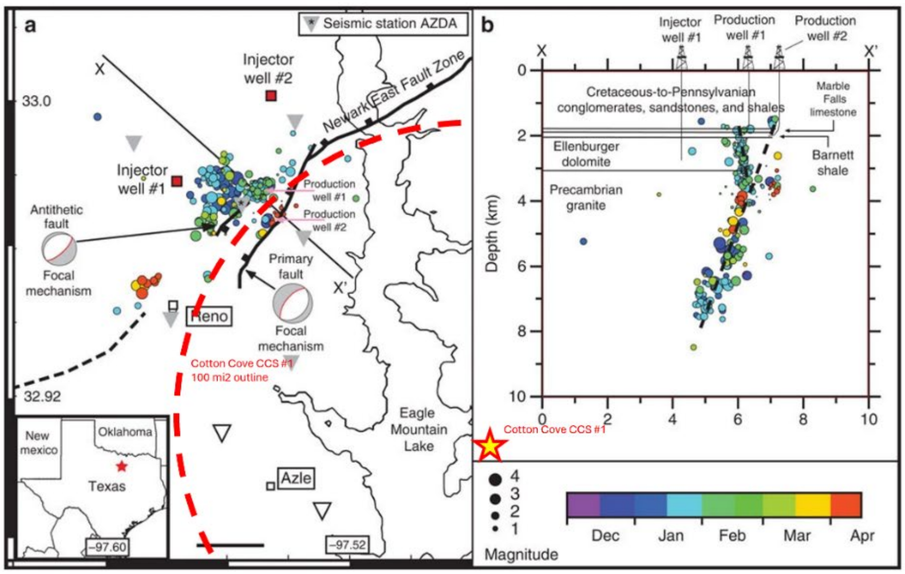


Figure 9. Screenshot from the USGS Earthquake Catalog showing historical seismic activity at or above Magnitude 3.0 in the surrounding 100 square miles to the proposed Cotton Cove CCS 1 site. Three seismic events meet these criteria in the USGS catalog. North is up.

Fault slip potential of mapped faults within the Fort Worth Basin was assessed through a literature survey (Hennings, *et al.*, 2019). Current findings show that steeply dipping faults that strike north-northeast have the highest fault slip potential. These results are consistent with the orientation of the faults that produced the Azle-Reno swarm. No additional earthquakes have been reported since 2015 despite several saltwater disposal wells that inject in the Ellenburger Group continuing to operate in the area. Beginning in August 2023, BKV began operating a local earthquake network covering portions of Wise, Denton, Parker and Tarrant Counties in Texas (**Figure 11**). No earthquakes have been detected within the 100 square-mile area surrounding the Cotton Cove CCS 1 location with this array since it began recording.



Map showing the location of NEFZ (black) at the top of the Ellenburger formation, inferred faults (dashed) at the top of the Ellenburger formation, injection wells (red squares), two production wells (API 36734045 and 36734139) with significant brine production near the faults (pink arrows) and earthquake epicentres (coloured circles) recorded by the temporary seismic network (triangles) (**a**). The red star in the inset of **a** shows the map location. The black scale bar in **a** is 2 km. Grey (white) triangles indicate the locations of active (inactive) seismic stations. Line X–X′ in **a** shows the location of the cross-section shown in (**b**). We interpret two faults based on earthquake location and consistent with industry interpretations: a primary normal fault and a shallower antithetic normal fault.

Figure 10. Modified from a map from Hornbach *et.al.*, 2015. Earthquake hypocenters for the 2013-14 Azle-Reno swarm were located using a local array of seismometers resulting in reduced location uncertainty. Earthquakes were clustered along a northwest-dipping normal fault and it's southeast-dipping antithetic fault. These earthquakes cluster just outside of the line marking the surrounding 100 square miles to the proposed Cotton Cove CCS 1 site. North is up.

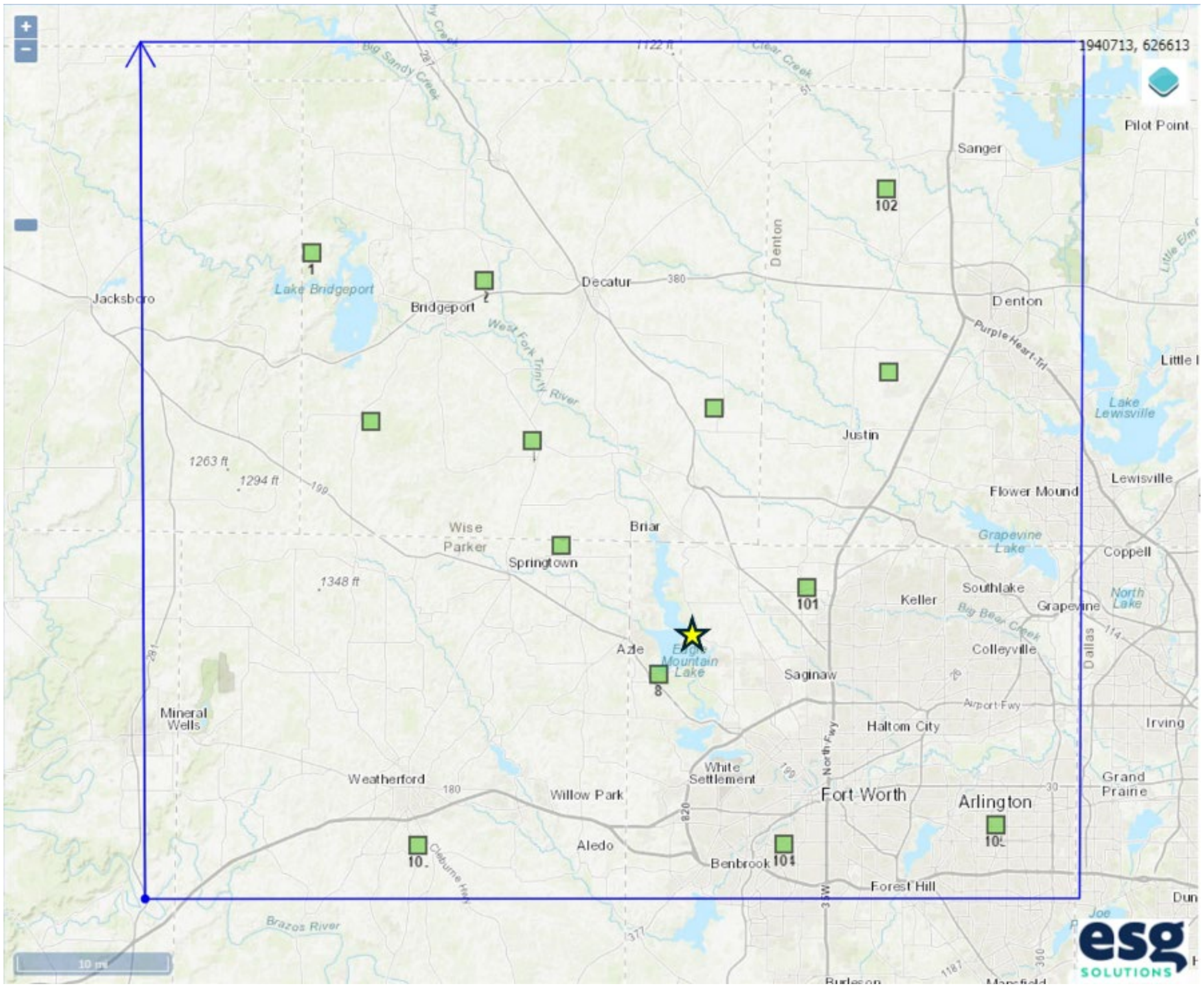


Figure 11. Map of the local seismic array monitoring the area of the Cotton Cove CCS 1. The yellow star marks the location of the Cotton Cove CCS 1. Seismic stations contributing data to the BKV seismic analysis are shown with the green squares. Stations 1-8 are operated by BKV while Stations 101-105 are operated by either TexNet or the USGS and their data are used in the hypocenter locations. North is up.

3.6 Groundwater Hydrology in MMA

Tarrant County falls within the Northern Trinity Groundwater Conservation District as mapped by the Texas Water Development Board (**Figure 12**). One aquifer is within the vicinity of the proposed injection site: the Trinity Group Aquifer. The Lower Cretaceous Trinity Group is classified as a major aquifer and serves as an important source of groundwater for a portion of northern Texas, including Tarrant County, Texas. The Trinity Group Aquifer outcrops at the Cotton Cove CCS 1 site and across a large swath of Wise and Parker Counties and the northwestern corner of Tarrant County.

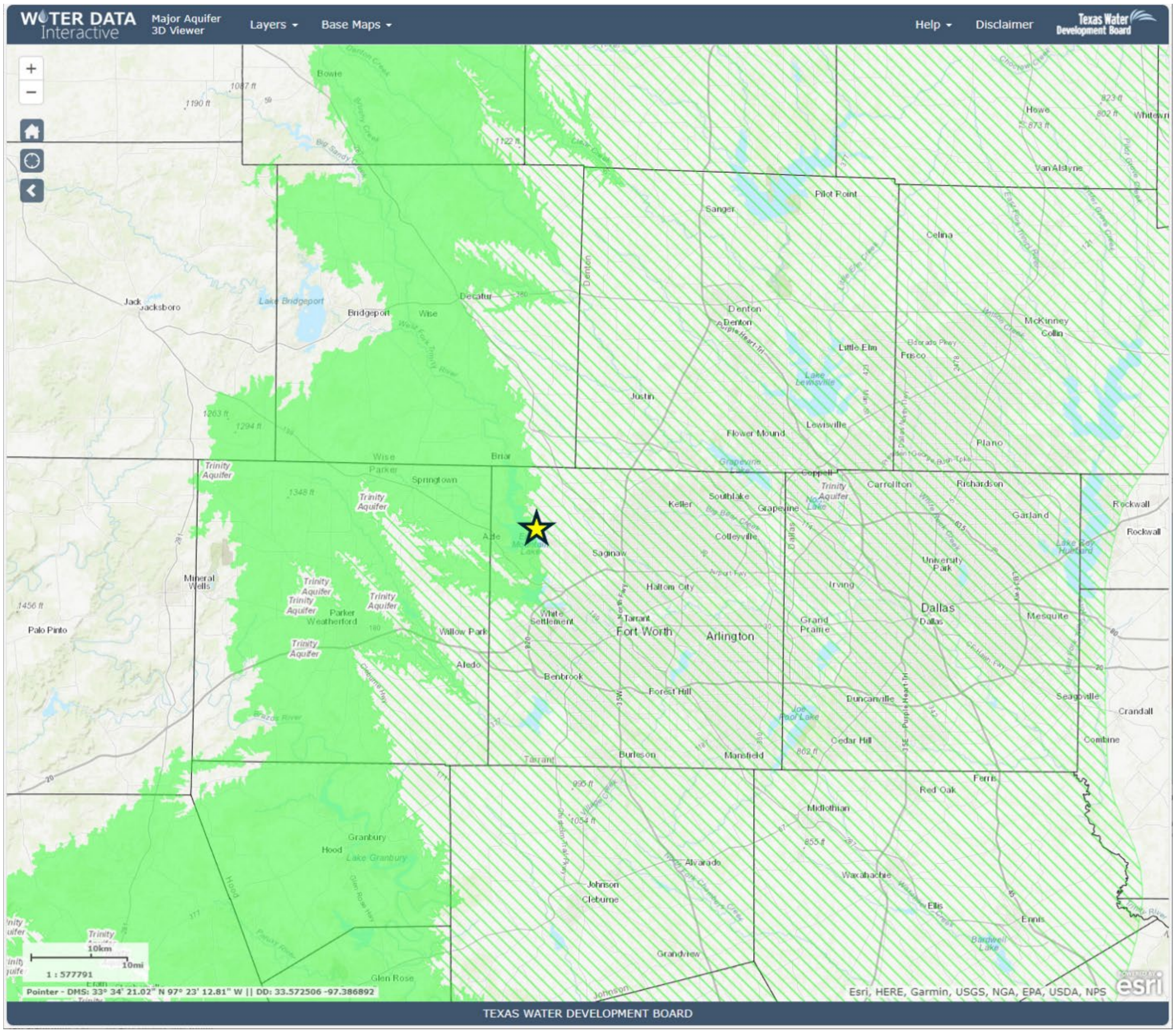


Figure 12. Map of the Trinity Major Aquifer extent within northcentral Texas, from the Texas Water Development Board Interactive Viewer. The location of the proposed Cotton Cove CCS 1 is shown with a yellow star. North is up.

The Trinty Group Aquifer is unconfined west of the project site and confined east of the site (**Figure 12**). Water in the Trinity Group Aquifer is considered fresh but hard, with TDS values in the project area of less than 1,000 mg/L. The overall stratigraphic column contains numerous barriers to vertical flow (or aquitards) that are expected to prevent CO_2 injected into the Ellenburger Subunit E from reaching the surface or near surface location of the Trinity Group Aquifer (**Figure 13**).

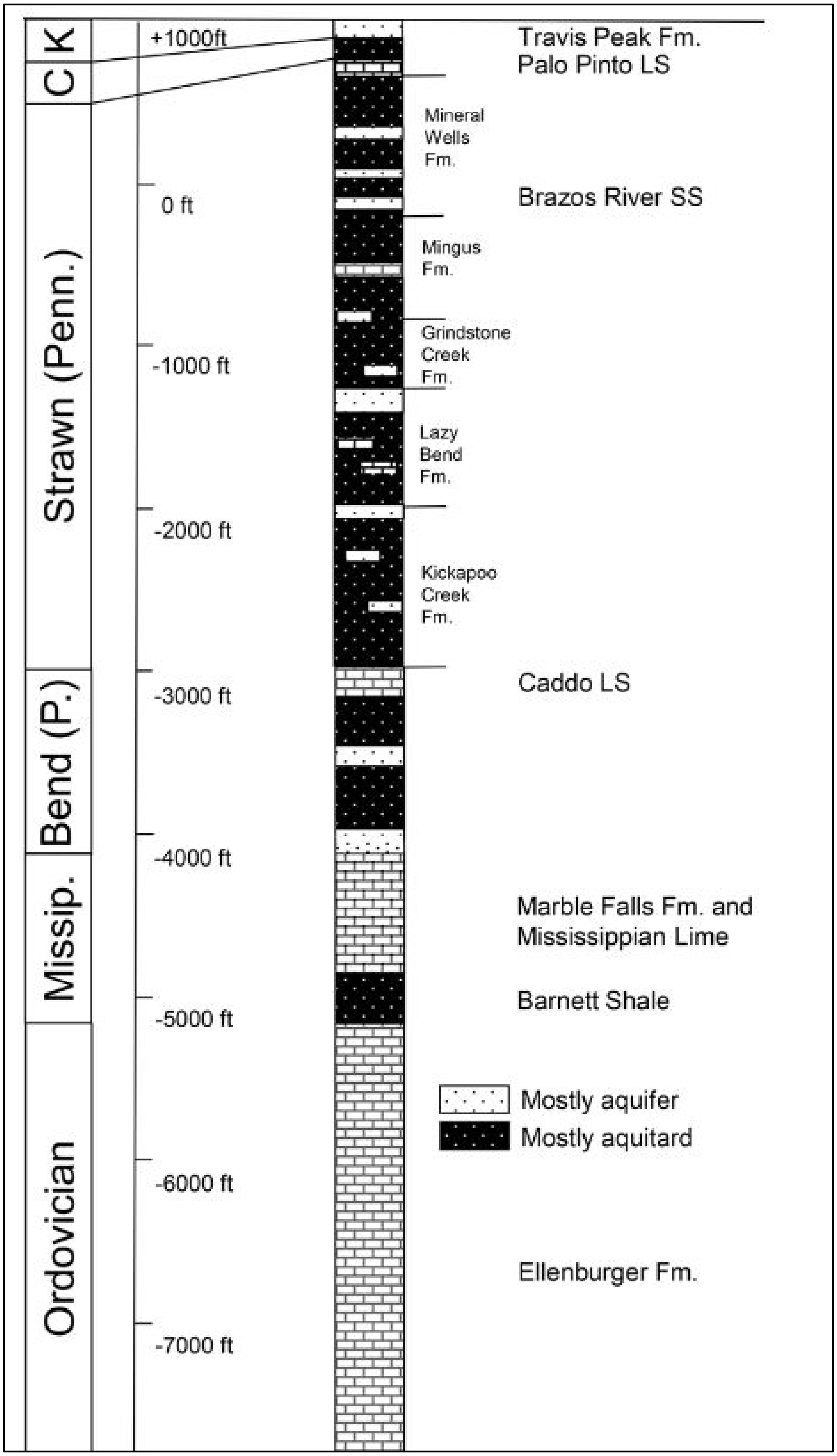


Figure 13. Stratigraphic column showing aquifers and aquitards, modified from Nicot *et al*., (2011)

There are 107 freshwater wells within a two-mile radius and 34 wells within a one-mile radius of the proposed injection well, according to the Texas Water Development Board Groundwater Data Viewer, as shown in **Figure 14** and listed in **Table 4**.

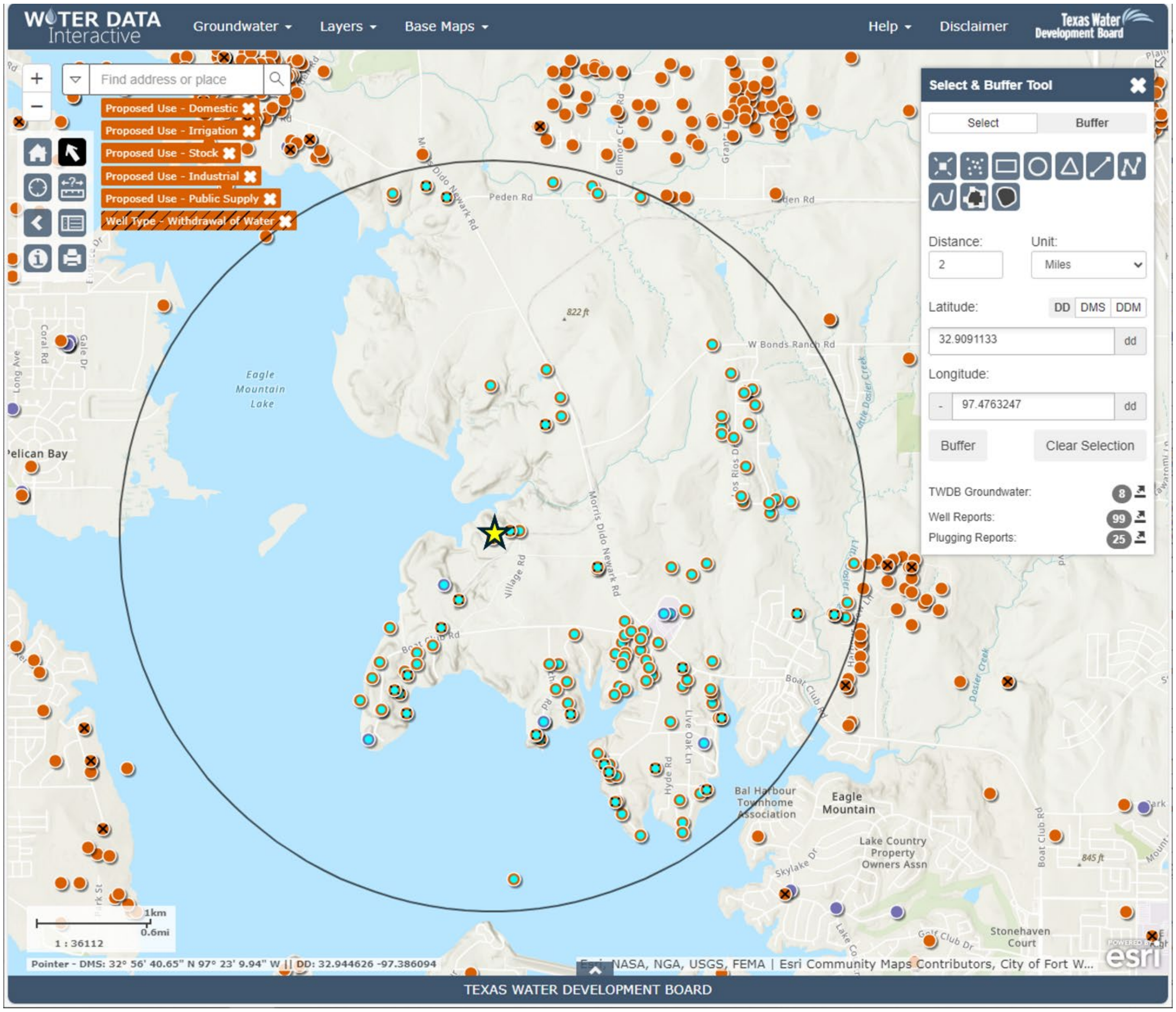


Figure 14. Water wells within two miles from the proposed injection site, data from the Texas Water Development Board Interactive Viewer. North is up.

Table 4. Groundwater wells in project area.

Well Report Tracking Number	Latitude (DD)	Longitude (DD)	Borehole Depth (feet)
4945	32.8825	-97.474444	200
8105	32.886945	-97.458889	140
8162	32.888611	-97.459167	140
9201	32.899167	-97.483334	205
23976	32.896389	-97.488611	340
23981	32.916667	-97.454167	355

Well Report Tracking Number	Latitude (DD)	Longitude (DD)	Borehole Depth (feet)
24611	32.902778	-97.443889	330
27215	32.921667	-97.454445	377
27217	32.9175	-97.455278	380
27266	32.914445	-97.453056	340
27268	32.916944	-97.455278	380
27269	32.918333	-97.455278	340
27270	32.920278	-97.453056	350
27271	32.920278	-97.453056	350
27273	32.917778	-97.452778	380
27274	32.919167	-97.452223	335
30454	32.936111	-97.467222	355
37395	32.891945	-97.466389	238
45494	32.902778	-97.443889	320
57105	32.935556	-97.466667	942
80342	32.923889	-97.456112	220
86272	32.889167	-97.457223	140
104755	32.908889	-97.476389	266
123923	32.900278	-97.462778	200
123929	32.899445	-97.462223	200
126757	32.901945	-97.485834	180
156542	32.898334	-97.461667	253
161948	32.901667	-97.462501	280
190665	32.892222	-97.466667	266
194317	32.903334	-97.458612	180
196988	32.900834	-97.464445	260
196990	32.899722	-97.464167	260
197152	32.935278	-97.462778	280
197159	32.936389	-97.470833	280
202905	32.909445	-97.473889	738
204320	32.902501	-97.464167	180
204322	32.900834	-97.461112	180
210501	32.901389	-97.464167	140
210511	32.906112	-97.458056	380
210912	32.896111	-97.469444	200
234675	32.894722	-97.460001	140
255591	32.899167	-97.464445	286
257427	32.901667	-97.463612	200
257473	32.901112	-97.462778	200
257476	32.898611	-97.484445	180
267624	32.898889	-97.461945	210

Well Report Tracking Number	Latitude (DD)	Longitude (DD)	Borehole Depth (feet)
268343	32.899167	-97.470278	235
306601	32.899167	-97.471111	200
317205	32.896111	-97.456112	200
323205	32.921944	-97.471389	294
324408	32.895	-97.455556	180
330547	32.898056	-97.4875	172
364478	32.900001	-97.483334	224
365834	32.906945	-97.456667	260
367478	32.911667	-97.453334	297
373975	32.910834	-97.450834	297
377943	32.911667	-97.448889	320
386419	32.935278	-97.485556	240
387615	32.886111	-97.458889	200
389582	32.891389	-97.465556	280
392805	32.935556	-97.485556	220
395997	32.897222	-97.470555	200
396019	32.906945	-97.443056	300
403825	32.911945	-97.450278	297
407372	32.895556	-97.486667	320
407944	32.899286	-97.486792	210
412976	32.906531	-97.466806	802
415271	32.897861	-97.462194	260
438110	32.897417	-97.464733	160
458834	32.900585	-97.481922	320
463887	32.912167	-97.453444	347
469393	32.896937	-97.456209	200
508639	32.897211	-97.456264	200
513027	32.90004	-97.46411	200
520574	32.890422	-97.465485	220
527005	32.88756	-97.46444	140
532284	32.91165	-97.45088	322
534258	32.90395	-97.44367	372
535973	32.8994	-97.45613	180
545467	32.895599	-97.486566	281
550851	32.920408	-97.452453	400
557415	32.89743	-97.45887	260
562605	32.897185	-97.464191	200
573642	32.897149	-97.485324	200
579758	32.885889	-97.462765	180
583511	32.906633	-97.4599	220

Well Report Tracking Number	Latitude (DD)	Longitude (DD)	Borehole Depth (feet)
585719	32.89795	-97.45848	220
587677	32.897767	-97.469483	240
634201	32.901472	-97.468833	160
641548	32.888573	-97.464852	222
644810	32.89678	-97.46515	278
648844	32.89053	-97.46497	280
649674	32.91975	-97.47009	170
654239	32.90302	-97.44504	360
662127	32.9183	-97.47005	335
667007	32.89999	-97.46504	265
667223	32.89999	-97.46504	265
677269	32.9207	-97.47656	313
677560	32.920123	-97.45321	420
State Well Number	**Latitude (DD)**	**Longitude (DD)**	**Borehole Depth (feet)**
3205701	32.894722	-97.471667	273
3205702	32.894722	-97.471667	261
3205703	32.905278	-97.480833	196
3205704	32.893334	-97.487778	656
3205705	32.903056	-97.460001	194
3205706	32.903056	-97.460556	320
3205804	32.889445	-97.456945	233
3205805	32.893056	-97.456945	220

3.7 DESCRIPTION OF CO_2 PROJECT FACILITIES

dCarbon will accept CO_2 from by the Cotton Cove Gas Plant (**Figure 1**). The temperature, pressure, composition, and quantity of CO_2 will be measured and metered according to industry standards, with an orifice meter, Coriolis meter, or similar device. dCarbon will dehydrate and compress the CO_2 to a supercritical physical state and transport it to the Cotton Cove CCS 1 injection site. The CO_2 stream will be metered to verify quantity. The CO_2 will then be injected into the Ellenburger Subunit E as previously described. This formation is deeper than other formations known to be productive of oil and gas in the area. A gas analysis of the CO_2 stream is shown in **Table 5**. Although the industry-standard sampling of the CO_2 stream is expected to be representative of the composition of the gas, it is possible that the composition will vary slightly over time.

Table 5. CO_2 stream analysis for the Cotton Cove CCS 1 site.

Name	Normalized Weight Percent	Normalized Mole Percent	Normalized Liquid Volume Percent
Nitrogen	0.007	0.011	0.007
Carbon Dioxide	99.8514	99.665	99.8514
Methane	0.095	0.261	0.095
Ethane	0.013	0.019	0.013
Propane	0.002	0.002	0.002
Isobutane	0.008	0.006	0.008
N-butane	0.001	0.001	0.001
Isopentane	0.003	0.002	0.003
N-pentane	0.000	0.000	0.000
Hexanes	0.006	0.003	0.006
Heptanes	0.000	0.000	0.000
Octanes	0.000	0.000	0.000
Nonanes	0.000	0.000	0.000
Decanes plus	0.000	0.000	0.000
BTEX	0.002	0.000	0.002
H_2S	0.000	0.000	0.000
H2O	0.012	0.030	0.012
Total	100	100	100
Total Sample Properties			
Property	Value		
BTU (Gross)	3.15		
Density (lbs/gal)	4.09		
Molecular weight	43.93		
Specific gravity (Air=1)	1.5167		

3.8. Reservoir Characterization Modeling

A regional subsurface model was created in Schlumberger's Petrel software. The model utilizes structural and petrophysical interpretations made from available well and seismic data as primary inputs. The resulting static earth model (SEM) was then used for fluid flow simulations. Well tops and petrophysical data required to populate the model were sourced from digital logs available for the Barnett RDC 1 well (approximately 27 miles northwest of Cotton Cove CCS 1, as discussed in previous sections) and other deep wells. The reservoir is characterized by low matrix porosities and permeabilities that are significantly enhanced by naturally existing high porosity and permeability fractures in dolomitic intervals, that contribute to overall higher fluid flow. For the current assessment, a single porosity, single permeability distribution model was deemed appropriate for the model given the uniformity of natural fracture distribution within the Ellenburger Subunit E. This assumption is supported by consistent saltwater disposal rates and injection volumes into the Ellenburger Group in nearby counties. These assumptions will be examined and verified using a pressure fall-off test (PFOT) that will be conducted during the construction of the Cotton Cove CCS 1 well. If PFOT and logging programs detect deviations from anticipated reservoir behavior, dCarbon will use the new data to update reservoir models, as well as injection forecasts and the MRV plan if appropriate.

The primary objectives of the simulation model were to:

1. Estimate the maximum areal extent of the injectate plume and its migration post injection
2. Determine the ability of the target formation to handle the required injection rate
3. Characterize potential interaction between the injected CO_2 and any nearby potential leakage pathways
4. Quantify the increase in pore pressure dues to CO_2 injection spatially within the reservoir

The CO_2 storage complex is confined to the Ellenburger Group. The Ellenburger Subunit E is modeled as the reservoir interval and the Ellenburger Subunits B-D are modeled as the primary seal to impede vertical fluid flow. The lower confining interval for the reservoir is modeled as the Ellenburger Subunit F.

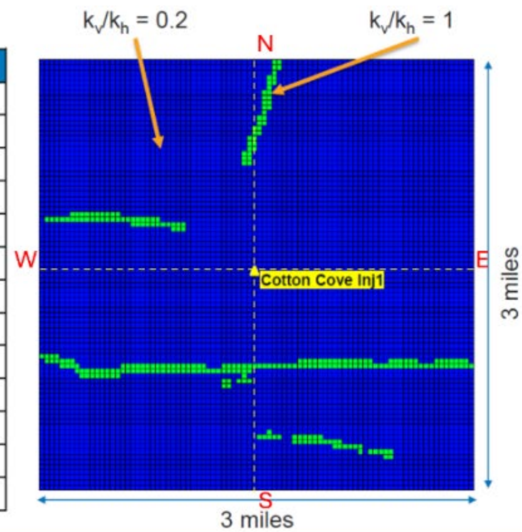
An SEM with the dimensions of 8.8 miles by 6.4 miles by 2.3 miles (X, Y, and Z) was constructed from elevation grids and faults derived from 3D seismic data and well log information (**Figure 15**) in Schlumberger's Petrel software. A 4-mile by 4-mile tartan grid was generated and then exported to Rock Fluid Dynamics's tNavigator simulator to account for fully implicit multiphase compositional fluid flow. This simulation was constructed to model other transport and mixing phenomena, i.e., relative permeability, diffusion, aqueous solubility, and buoyancy to accurately predict the plume movement. The reservoir is modeled to be a completely saline aquifer. The salinity of the formation, estimated to be 200,000 ppm TDS, is typical of the Ellenburger Group in the project area. The injected gas stream is assumed to be fully composed of CO_2. **Figure 15** illustrates the vertical layering of the model with relationship to the simulated CO_2 saturation profile. The injection rate modeled was 75,000 MT/year for 12 years followed by 100 years of post-injection simulation to fully document the movement of CO_2. **Figure 15** also depicts the initial model conditions and a map view of permeability enhancements in the model due to mapped faults.

The methodologies employed for static and dynamic models were based on established techniques in literature. Specifically, the reservoir relative permeability model was calculated from capillary pressure data from the Barnett RDC 1 using the Brooks and Corey (1966) model. The relative permeability curves for sealing layers were obtained from Bennion and Bachu (2007). The initial reservoir conditions were developed using gradients derived from Barnett RDC 1 well data. Mapped and inferred faults were given enhanced permeability in the simulation model of 400 mD and a 1:1 vertical to horizontal permeability. Ellenburger Group interpreted as affected by karsting, primarily in the Ellenburger Subunit A, was given the same enhanced permeability in the simulation model as the mapped faults.

While the top of the Ellenburger Subunit E reservoir interval was modeled at 8,920 feet at the injection well, the top of the perforated interval was chosen to be at 10,140 feet to force the CO_2 to first migrate vertically in the reservoir before hitting the seal at the Ellenburger Subunit D.

Using the aforementioned methodology to develop model estimates, the pressure gradient was assumed to be 0.5 psi per foot, which resulted in an estimated reservoir pressure of 5,070 psi at the top of the injection interval. The temperature gradient was assumed to be 1.25°F per 100 feet, resulting in an estimated temperature of 200°F at the top of the injection interval. Fracture pressures were estimated at 0.7 psi per foot. To ensure CO_2 injection does not induce fractures within the Ellenburger, injection well bottom hole pressure (BHP) was constrained to 90% of calculated fracture pressure, thereby applying a safety factor of 10%. This resulted in a maximum bottom hole injection pressure constraint of 6,388 psi. There are no active wells injecting or producing from the injection interval in the project area. Therefore, no additional wells other than injector were included in the fluid flow simulation model.

Input	Specifications
Total Number of Grid Blocks	1,732,470
N_x, N_y, N_z	64, 64, 199
D_x, D_y	250 ft * 250 ft
Injection Formation top	EB E ~ 8,180 ft TVDSS (8,920 ft MD)
k_v/k_h (matrix)	0.2
k_v/k_h (faults and karst)	1
Pressure Gradient	0.5 psi/ft
Temperature Gradient	1.25 deg F/100 ft + 70 deg F Surface
Injection rate	75 ktpa
Water saturation	100%
Fracture pressure Gradient	0.7 psi/ft
Maximum allowable pressure	90% of Fracture pressure
Salinity	200,000 ppm



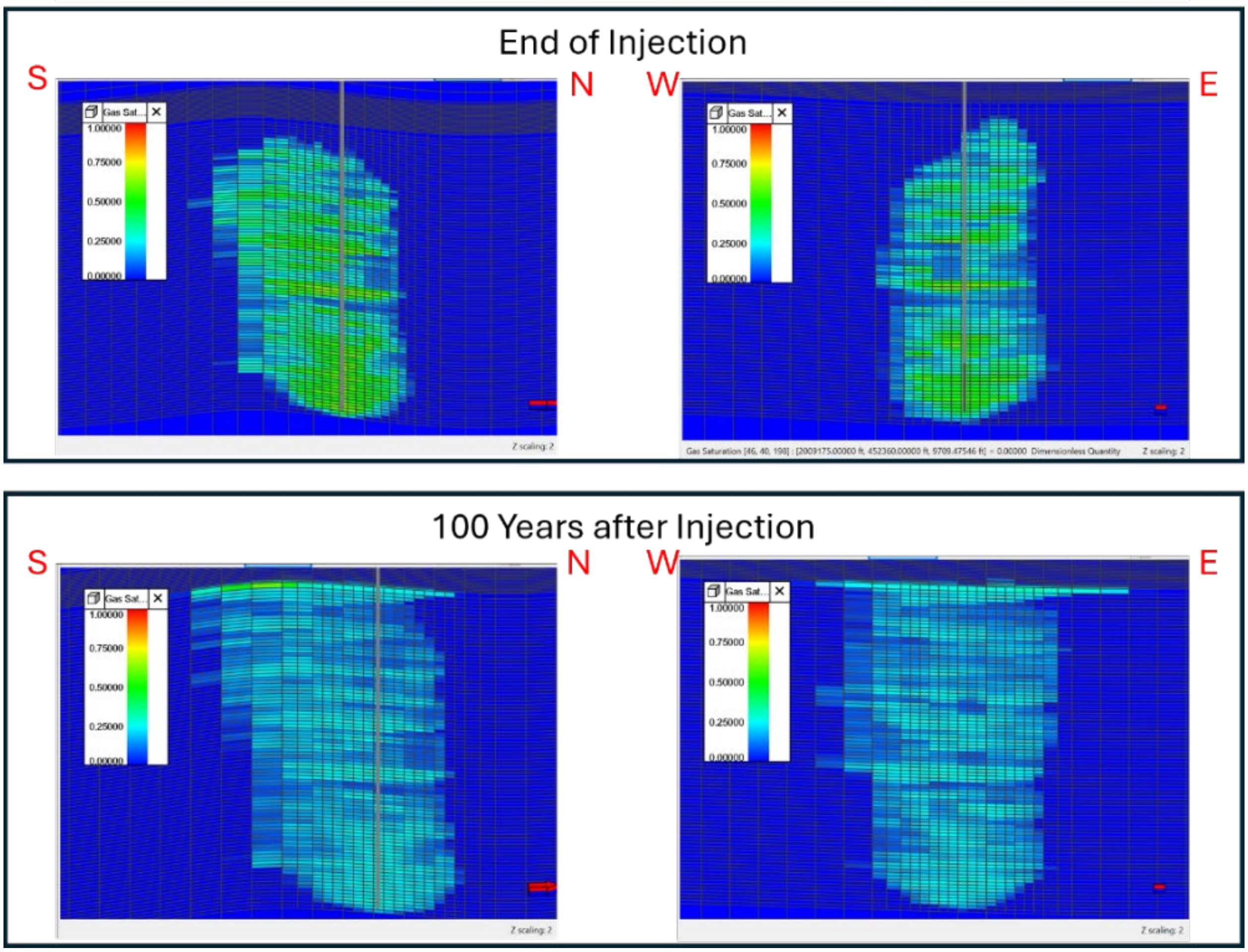


Figure 15. (Upper left table): Simulation conditions employed in the tNavigator model for the Cotton Cove CCS 1 well. (Middle and lower images): Depiction of the end of injection and 100 years after injection modeling results. The color bar in all images indicates modeled CO_2 gas saturation. (Upper right image): The map depicts the enhancement of permeability in certain areas of the model due to mapped faults.

As mentioned earlier, injection was modeled at 75,000 MT/year. The model simulated 12 years of active injection followed by 100 years without injection to determine when plume migration stops. Plume migration ceased after 94 years post injection, which is determined to be the maximum extent of the CO_2 plume. **Figure 16** shows the CO_2 plume at the end of injection (green) compared to 94 years post injection (cyan). Injected CO_2 flows generally west, which is the regional up dip direction. The enhanced permeability areas in the model representing faults and karsts were not reached by CO_2 during the simulation. While the final CO_2 plume stabilizes in a position where the western end is under Eagle Mountain Lake, there are no natural leak pathways that allow CO_2 to reach the lake. A more detailed discussion of potential leak pathways is presented in Section 5.

Figure 16. Simulation results showing CO_2 Plumes (end of injection = green and after 100 years of injection = cyan). Cotton Cove CCS 1 injection wells is shown by as the yellow star. North is up.

Figure 17 illustrates bottom hole pressure at the Cotton Cove CCS 1 well as modeled. The bottom hole pressure remained well under the bottom hole pressure constraint. The maximum bottom hole pressure reached is ~5,630 psi (758 psi lower than the BHP constraint), which occurs at the start of injection. This maximum pressure is reached early and is anticipated to be a result of near wellbore effects arising from CO_2 forcing its way into the brine-filled porous media. Upon reaching a critical mass, the flow transitions from capillary-driven to advection-driven flow and the BHP starts to decline until the end of injection while keeping the injection rate constant. The BHP then falls to roughly 5,092 psi until the end of injection.

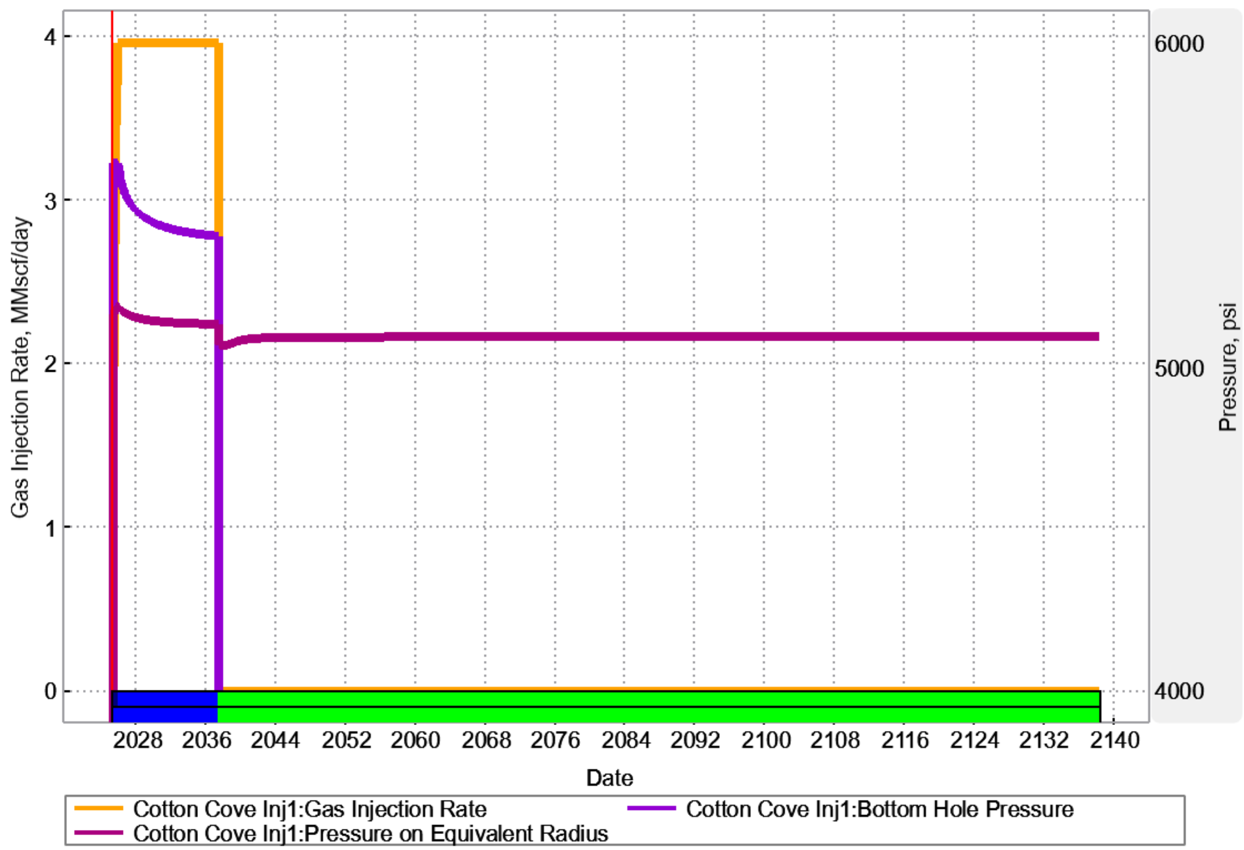


Figure 17. Modeled injection profile at Cotton Cove CCS 1 well. Gas injection rate shown in MMscf/day on the left Y axis and bottom hole pressure and pressure on equivalent radius shown in psi on the right Y axis. The blue bar along the X axis indicates the 12-year injection period and the green bar indicates the 100-year post-injection period.

4 – DELINEATION OF MONITORING AREA

4.1 Maximum Monitoring Area (MMA)

The MMA is defined as equal to or greater than the area expected to contain the free-phase CO_2 plume until the CO_2 plume has stabilized plus an all-around buffer of at least one-half mile. The numerical simulation using tNavigator as discussed above was used to estimate the size and migration of the CO_2 plume. We modeled injection of CO_2 into the Ellenburger Subunit E for 12 years followed by 100 years of post-injection modeling. Results indicated that the plume ceased to migrate after 94 years post injection. For more information on the simulation construction and setup, please see the discussion in Section 3.8. A 5% cutoff of gas saturation was used to determine the boundary of the CO_2 plume. The area of the MMA was determined to be 3.07 square miles with the greatest extent reaching 1.5 miles from the injector. **Figure 18** shows the End of Injection (EOI) plume (green), the 94-year post-injection plume (black solid), and the MMA using a 0.5 mi buffer (black dashed).

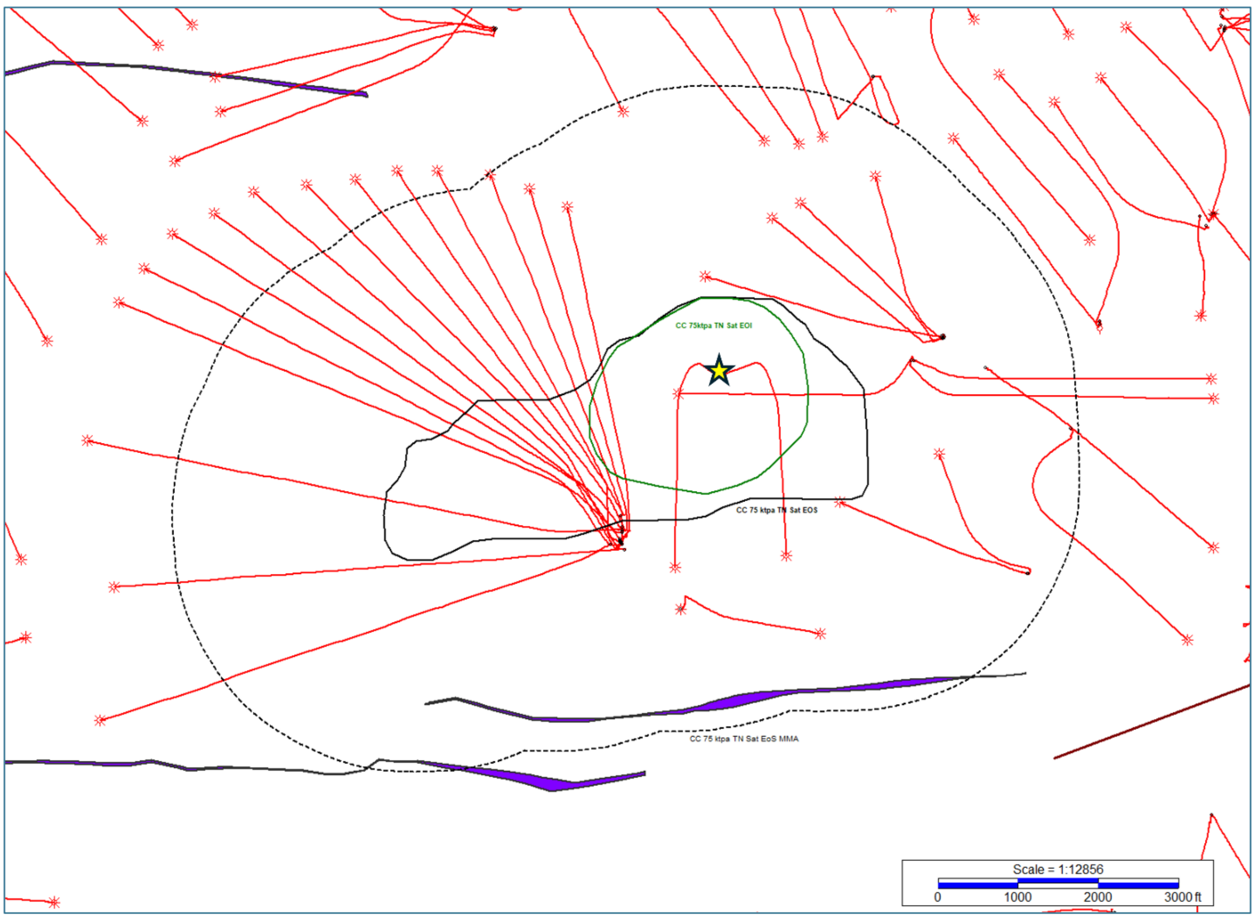


Figure 18. MMA (black dashed), EOI plume (green), and 100-year post injection plume outlines (black solid) as modeled at the Cotton Cove CCS 1 well (yellow star). Barnett gas wells are shown as red lines with the well symbol at the bottomhole location. Thin purple polygons are faults at the top of the Ellenburger Group. North is up.

4.2. Active Monitoring Area (AMA)

As discussed in Section 3, there are no structural or geological features mapped within the project area that could cause the unintended migration of the CO_2 plume through natural pathways to the USDW. The mapped faulting in the area does not extend shallower than the top of the Mississippian Marble Falls Formation, leaving more than 5,000 feet of mostly Pennsylvanian shales between the top of the faults and the USDW. The only potential leakage pathways that exist are well penetrations and the surface equipment. Leakage from groundwater wells, faults and fractures, leakage through the confining layer, and seismicity events are expected to be highly improbable. That said, these leakage pathways have been considered and options to monitor them are discussed in Sections 4 and 5. Sufficient care and consideration will be provided to monitoring these pathways, if any, and simulation models will be calibrated with new data as appropriate.

dCarbon adhered to the definition of Active Monitoring Area (AMA) provided in 40 CFR 98.449 to delineate the AMA for this project. As noted in Section 6, dCarbon proposes to monitor the injection site from year one through year 12, which is projected to be the EOI. Based on the definitions in 40 CFR § 98.449 and an initial time interval of t=12, we defined our AMA by superimposing the following:

(1) The area projected to contain the free phase CO_2 plume at the end of year 12, plus an all-around buffer of one-half mile or greater if known leakage pathways extend laterally more than one-half mile.

(2) The area projected to contain the free phase CO_2 plume at the end of year 17.

As noted in Section 4.1, dCarbon utilized the plume area after 94 years of post-injection plus a one-half mile buffer to determine the MMA, which far exceeds the definition of AMA set forth in 40 CFR § 98.449. Therefore, the AMA is proposed to have the same boundary as the MMA, which adequately covers the area that is required by 40 CFR § 98.449. **Figure 18** shows the MMA, which is the same as the AMA. **Figure 19** indicates the AMA/MMA (black dashed) and currently existing oil and/or gas wells within this area. None of these wells were found to penetrate the Ellenburger within the project area. Water wells in the region are shallow with drilled depths up to 802 feet from surface. Additional discussion on well infrastructure within the project area can be found in later sections of this document.

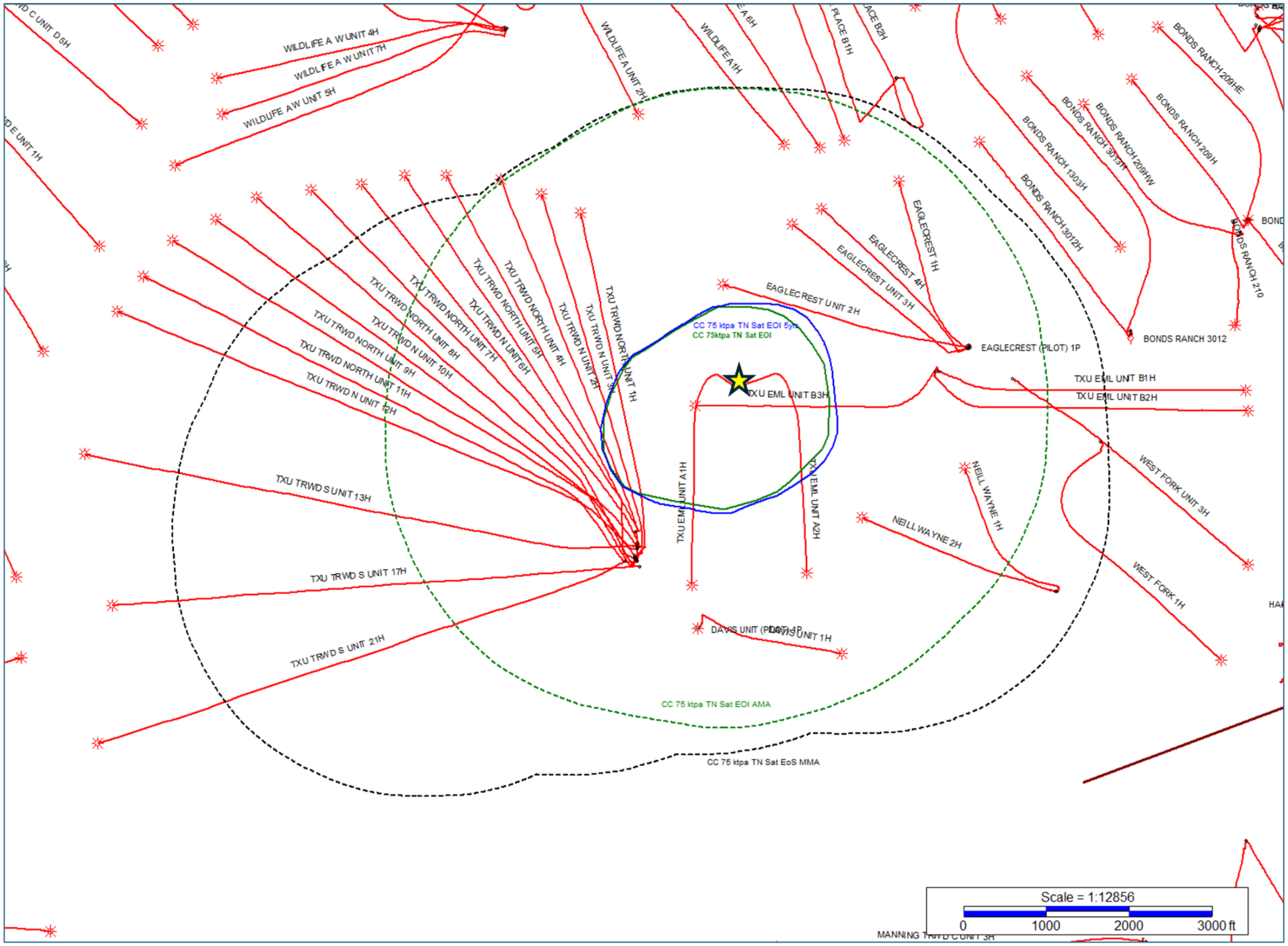


Figure 19. The calculated AMA (green dashed) and existing wells within the project AMA/MMA. The solid green and blue outlines show the extent of the CO_2 plume at EOI and five years post-injection respectively. The MMA is shown as the black dashed line for comparison. The Cotton Cove CCS 1 is shown as a yellow star. Barnett gas wells are shown as red lines with the well symbol at the bottomhole location. North is up.

5 – IDENTIFICATION AND EVALUATION OF POTENTIAL LEAKAGE PATHWAYS TO SURFACE

dCarbon has assessed each of the discussed potential leakage pathways for likelihood, potential timing, and magnitude. The framework of this assessment is based upon the California Air and Resources Board's CCS Protocol Section C.2.2(d). **Table 6** describes the basis for event likelihood and **Table 7** provides the details of the leakage likelihood, timing of occurrence, and estimated magnitude of leakage for each type of leak risk.

Table 6. Risk likelihood matrix (developed based on comparable projects).

Risk Factor for Probability		Description
1	Improbable	<1% chance of occurring*
2	Unlikely	1-5% chance of occurring*
3	Possible	> 5% chance of occurring*
*During the life of the project or 100 years after project closure, whichever is shorter		

Table 7. Description of leakage likelihood, timing, and magnitude.

Leakage Pathway	Likelihood	Timing	Magnitude
Potential Leakage from Surface Equipment	**Possible**	Anytime during project operations, but most likely during start-up / transition or maintenance periods	**<100 MT per event** (100 MT represents approximately 12 hours of full permitted flow facility release)
Leakage from Approved, Not Yet Drilled Wells	**Improbable**, as there are no approved not yet drilled wells	After new wells are permitted and drilled	**<1 MT per event**
Leakage from Existing wells	**Unlikely**, as there are several thousand feet of impermeable rock between the injection zone and the total depth of existing wells.	When the CO_2 plume expands to the lateral locations of conductive fractures, then travels up faults to the Barnett Shale, and then appears in the production stream of the Barnett Shale wells.	**<1 MT per event** due to natural dispersion of CO_2 within the Ellenburger Subunit E before it would laterally reach an existing well combined with thickness and low porosity / permeability of upper confining zone
Potential Leakage from Fractures and Faults	**Improbable**, as there are several thousand feet of impermeable rock between the injection zone and surface or USDW that would need to be compromised and there are no mapped faults within the MMA that reach shallow enough to serve as a conduit to the USDW or the surface.	Anytime during operation	**<100 MT per event**, due to natural dispersion of CO_2 within the Ellenburger Subunit E before it would laterally reach a fault or fracture significant enough to cause leakage
Leakage Through Confining Layers	**Improbable**, as the upper confining zone is nearly 2,000 feet thick and very low porosity and permeability	Anytime during operations	**<100 MT per event**, due to natural dispersion of CO_2 within the Ellenburger Subunit E and thickness/properties of upper confining zone
Leakage from Natural or Induced Seismicity	**Improbable**, as there are a couple thousand feet of impermeable rock between the injection zone and surface or USDW that would need to be compromised and there are no mapped faults within the MMA that extend shallow enough to reach the USDW or the surface.	Anytime during operations	**<100 MT per event**, due to natural dispersion of CO_2 within the Ellenburger Subunit E before it would laterally reach a fault or fracture significant enough to cause leakage
Leakage from Lateral Migration	**Improbable**, as the Ellenburger is a very thick and laterally continuous formation with the closest well penetration 5.8 miles downdip.	More likely late in life as plume expands	**<1 MT per event** due to natural dispersion of CO_2 within the Ellenburger Subunit E and continuity / thickness of upper confining zone

5.1 Potential Leakage from Surface Equipment

dCarbon's surface facilities at the Cotton Cove Gas Plant and at the injection well site are specifically designed for injecting the CO_2 stream described in **Table 5**. The facilities minimize leakage points such as valves and flanges by following industry standards and best practices. This includes but is not limited to automatic detection of CO_2 and lack of O_2 detection in specifically designated locations. All BKV and dCarbon field personnel are required to wear gas monitors that detect four or five gases, including H_2S and O_2. A shut-in valve is located at the wellhead in case of emergency. The compressor will also have emergency shut down switches that can be activated automatically in case of unexpected standard operating conditions such as a loss of line pressure.

Additionally, the compressor facility, pipe header, and injection well locations will all be subjected to Auditory, Visual, and Olfactory (AVO) and CO_2 leak detection per BKV and dCarbon safety and operations standards. These recurring monthly inspections, which are standard for detecting leaks and malfunctioning equipment in the gas production industry, will aid in the rapid detection of any potential leaks that may occur. As a part of these inspections, operations personnel are frequently able to repair leaks immediately by tightening valves, flanges, or similar equipment. Any leaks that are detected will be analyzed to determine the amount of CO_2 that may have leaked. These leakage quantities, if any exist, will be included in recurring reporting. BKV Midstream, LLC or dCarbon personnel are expected to visit the site daily.

5.2 Leakage from Approved, Not Yet Drilled Wells

There are no approved, not yet drilled well permits within the MMA other than the Cotton Cove CCS 1 well.

5.3 Leakage from Existing Wells

There are 34 existing wells within the MMA. Of these 34 wells, one had a pilot borehole for the subsequent horizontal well (**Table 8)**. The 34 wells all have active status. However, all these wells are shallower than the proposed disposal interval from this project. In fact, the targeted injection interval (which is greater than 8,800 feet) is approximately 2,000 feet deeper and separated by several impermeable intervals from the existing wells in the MMA. All 34 wells were drilled shallower than the target Ellenburger formation.

Additionally, the wellbore design of the injection well contains three layers of steel casing, two of which run to the surface to ensure complete isolation of wellbore fluids. Each of these three casing strings will be cemented over their entirety and inspected with cement bond logs to ensure wellbore integrity. Finally, all injection into the well will occur through a final steel tubing string that is secured in place with a permanent packer. All these aspects of wellbore construction are designed to ensure that all CO_2 is injected into the target formation and that there are no leakage pathways from the wellbore directly into shallower formations.

The primary potential leakage pathway for CO_2 through the existing wells would be for CO_2 to travel via faults in the Ellenburger to the Barnett Shale. The Barnett Shale is expected to be under pressured due to depletion from gas production. Injected CO_2 entering the Barnett Shale could be produced in the gas stream of these wells. While this is considered improbable due to the reservoir simulation modeling showing no CO_2 reaching the enhanced permeability areas of the model, dCarbon will consider this potential pathway specifically in its monitoring program. In addition, no wells in the AMA/MMA are located within Eagle Mountain Lake. No leak pathways are present that are expected to allow injected CO2 to reach the area of Eagle Mountain Lake.

Table 8. Existing oil and gas wells in MMA with TRRC records.

Well Name	Well Number	UWI	Latitude	Longitude	Operator Current	Operator Original	Total Depth(f)	Status
LAKE PLACE	B1H	424393102900	32.9191420	-97.4698666	BKV NORTH TEXAS LLC	ANTERO RESOURCES INC LP	8650	Gas Well
WILDLIFE	A1H	424393119200	32.9239294	-97.4838481	BKV NORTH TEXAS LLC	XTO ENERGY INC	10435	Gas Well
WILDLIFE A UNIT	2H	424393119600	32.9240571	-97.4837859	BKV NORTH TEXAS LLC	XTO ENERGY INC	8567	Gas Well
EAGLECREST	1H	424393124000	32.9102136	-97.4670317	BKV NORTH TEXAS LLC	XTO ENERGY INC	8641	Gas Well
EAGLECREST (PILOT)	1P	424393124077	32.9102136	-97.4670317	BKV NORTH TEXAS LLC	XTO ENERGY INC	6924	Location Only
EAGLECREST UNIT	2H	424393124400	32.9101730	-97.4670195	BKV NORTH TEXAS LLC	XTO ENERGY INC	9045	Gas Well
DAVIS UNIT	1H	424393137300	32.9008732	-97.4776844	BKV NORTH TEXAS LLC	XTO ENERGY INC	8227	Gas Well
DAVIS UNIT (PILOT)	1P	424393137377	32.9008732	-97.4776844	XTO ENERGY INC	XTO ENERGY INC	7158	Gas Well
NEILL WAYNE	1H	424393138400	32.9020862	-97.4635819	BKV NORTH TEXAS LLC	XTO ENERGY INC	8472	Gas Well
NEILL WAYNE	2H	424393138500	32.9020931	-97.4635666	BKV NORTH TEXAS LLC	XTO ENERGY INC	8889	Gas Well
WEST FORK	1H	424393162800	32.9070608	-97.4618388	BKV NORTH TEXAS LLC	SULLIVAN HOLLIS R INC	10163	Gas Well
LAKE PLACE	B2H	424393204200	32.9191465	-97.4698521	BKV NORTH TEXAS LLC	XTO ENERGY INC	9088	Gas Well
TXU TRWD N UNIT	6H	424393221100	32.9035759	-97.4800683	BKV NORTH TEXAS LLC	XTO ENERGY INC	11683	Gas Well
TXU TRWD N UNIT	2H	424393221200	32.9040765	-97.4801342	BKV NORTH TEXAS LLC	XTO ENERGY INC	11025	Gas Well
TXU TRWD N UNIT	10H	424393223000	32.9035352	-97.4800689	BKV NORTH TEXAS LLC	XTO ENERGY INC	12585	Gas Well
TXU TRWD S UNIT	17H	424393223600	32.9029178	-97.4799856	BKV NORTH TEXAS LLC	XTO ENERGY INC	12845	Gas Well
TXU EML UNIT	A1H	424393245100	32.9089106	-97.4761473	BKV NORTH TEXAS LLC	XTO ENERGY INC	9164	Gas Well
TXU EML UNIT	A2H	424393262300	32.9089049	-97.4760521	BKV NORTH TEXAS LLC	XTO ENERGY INC	9062	Gas Well
TXU TRWD S UNIT	13H	424393338100	32.9037054	-97.4800853	BKV NORTH TEXAS LLC	XTO ENERGY INC	13056	Gas Well

TXU TRWD S UNIT	21H	424393345100	32.9031007	-97.4805575	BKV NORTH TEXAS LLC	XTO ENERGY INC	13064	Gas Well
TXU TRWD N UNIT	12H	424393354600	32.9035061	-97.4800683	BKV NORTH TEXAS LLC	XTO ENERGY INC	13163	Gas Well
TXU EML UNIT	B1H	424393365600	32.9094039	-97.4683171	BKV NORTH TEXAS LLC	XTO ENERGY INC	10200	Gas Well
TXU EML UNIT	B2H	424393365800	32.9093921	-97.4683110	BKV NORTH TEXAS LLC	XTO ENERGY INC	10500	Gas Well
TXU EML UNIT	B3H	424393423300	32.9093969	-97.4682044	BKV NORTH TEXAS LLC	XTO ENERGY INC	9535	Gas Well
WEST FORK UNIT	3H	424393526800	32.9091561	-97.4652839	BKV NORTH TEXAS LLC	XTO ENERGY INC	9298	Gas Well
TXU TRWD NORTH UNIT	1H	424393598400	32.9032790	-97.4801794	BKV NORTH TEXAS LLC	XTO ENERGY INC	10350	Gas Well
TXU TRWD N UNIT	3H	424393598500	32.9032457	-97.4801754	BKV NORTH TEXAS LLC	XTO ENERGY INC	10694	Gas Well
TXU TRWD NORTH UNIT	5H	424393601000	32.9031750	-97.4801698	BKV NORTH TEXAS LLC	XTO ENERGY INC	11009	Gas Well
TXU TRWD NORTH UNIT	4H	424393603300	32.9032055	-97.4801726	BKV NORTH TEXAS LLC	XTO ENERGY INC	10765	Gas Well
TXU TRWD NORTH UNIT	7H	424393605300	32.9031776	-97.4801011	BKV NORTH TEXAS LLC	XTO ENERGY INC	11485	Gas Well
TXU TRWD NORTH UNIT	8H	424393605400	32.9031436	-97.4800911	BKV NORTH TEXAS LLC	XTO ENERGY INC	11846	Gas Well
TXU TRWD NORTH UNIT	9H	424393605500	32.9031212	-97.4800893	BKV NORTH TEXAS LLC	XTO ENERGY INC	12258	Gas Well
TXU TRWD NORTH UNIT	11H	424393605600	32.9030873	-97.4800851	BKV NORTH TEXAS LLC	XTO ENERGY INC	12522	Gas Well
LAKE PLACE	A7H	424393628200	32.9310611	-97.4774402	BKV NORTH TEXAS LLC	XTO ENERGY INC	11739	Gas Well
LAKE PLACE	A6H	424393628300	32.9310939	-97.4774460	BKV NORTH TEXAS LLC	XTO ENERGY INC	11470	Gas Well
EAGLECREST	4H	424393655400	32.9102140	-97.4670370	BKV NORTH TEXAS LLC	XTO ENERGY INC	8989	Gas Well
EAGLECREST UNIT	3H	424393655700	32.9101702	-97.4670211	BKV NORTH TEXAS LLC	XTO ENERGY INC	8975	Gas Well

5.4 Potential Leakage from Fractures and Faults

Several episodes of fault formation took place in the Fort Worth Basin, based on 3D seismic data interpretation conducted by dCarbon. The oldest set of faults displaced Ordovician rocks but did not displace Mississippian rocks such as the Barnett Shale. A younger set of faults displaced Mississippian and older rocks and appear to be related to the Ouachita orogenic belt collision. These faults show displacement up into the base of the Pennsylvanian rocks. These larger, younger faults have greater displacement but are relatively sparce.

An east-west fault is interpreted at the south edge of the MMA, south of the Cotton Cove CCS 1 based on available subsurface data including 3D seismic data (**Figure 4**). A second, east-west fault may exist north of the MMA. These faults were included in the dynamic reservoir model as areas of enhanced permeability. Dynamic modeling indicates that the CO_2 plume will not intersect any mapped faults, based on dCarbon's existing 3D seismic interpretations. These faults terminate at the top of the Mississippian strata at roughly 6000 feet TVDSS, leaving roughly 6,000 feet of unfaulted Pennsylvanian shales and sands to serve as yet another secondary confining system. It is highly improbable that injected CO_2 would migrate up faults to the USDW or to the surface through faults. As there are no natural leak pathways that traverse this secondary confining system, we assess it as improbable that CO2 would reach the surface under Eagle Mountain Lake.

Karst development is present in some areas at the top of the Ellenburger. Karsting is often developed in the upper several hundred feet of an exposed carbonate (in this case, the Ellenburger Subunit A), where fresh water enters the shallow subsurface through fractures and dissolves the rock, creating underground caves with a thin roof (**Figure 20**). Subsequent loading of sediment can cause the thin cave roof to collapse, allowing the overlying sediment to fill the void (Zeng, 2011). These karsted sections of the Ellenburger were given enhanced permeability in the model as described earlier. We applied the enhanced permeability to the upper 500 feet of the Ellenburger, where karsted, as a conservative modeling assumption.

Karsting does not appear to affect any subunit of the Ellenburger below Ellenburger Subunit A, including Ellenburger Subunits B-D or the injection interval, Ellenburger Subunit E. This suggests that the Ellenburger Subunits B-D will remain a continuous upper seal for the injection interval even in karst areas. There are interpreted Ellenburger Subunit A karst features south and north of the Cotton Cove CCS 1, but the CO_2 plume does not intersect them, based on the dynamic modeling. Small karst features sitting at the northern edge of the MMA seem to have only impacted the upper 200 feet of the Ellenburger, leaving 2,000 feet of Ellenburger apparently unaffected as shown in the type log in **Figure 20**.

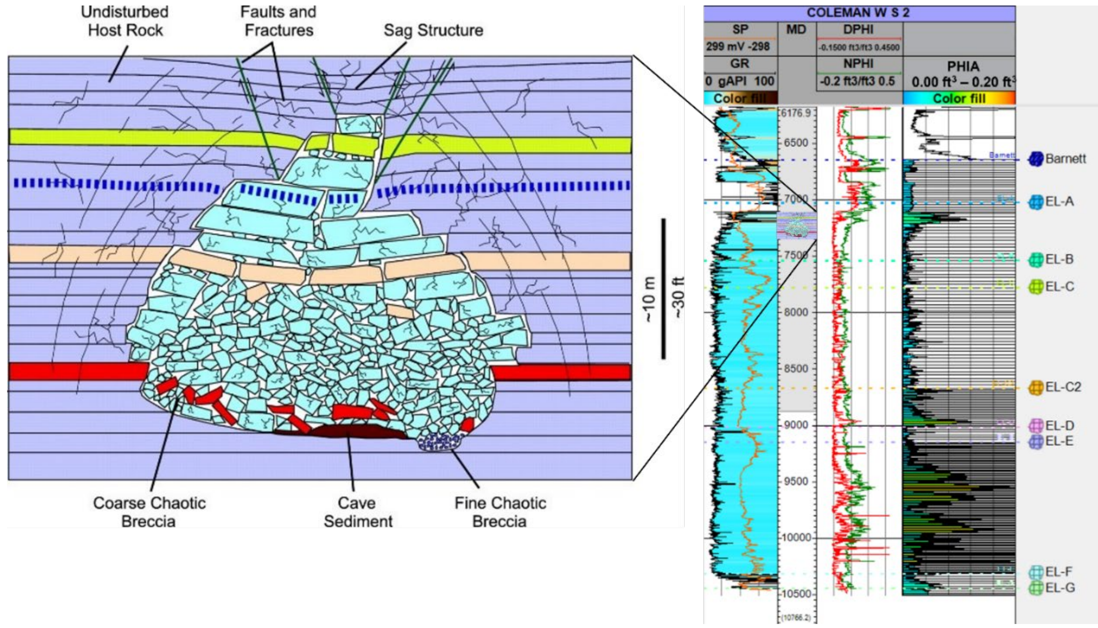


Figure 20. A schematic diagram showing the geometry and component facies of a single cave passage buried in deeper subsurface where collapse and extensive brecciation occurred (modified from Zeng *et al.*, 2011). The typical scale of the karst features is shown on the right placing the feature on the Coleman 1 well log. Note that the interpreted karst features are only observed in the upper portion of the Ellenburger, above the confining Ellenburger Subunits B-D and not in the modeled plume area.

5.5 Leakage Through Confining Layers

The Ellenburger Subunit E injection interval is bound above by the competent confining intervals of the Ellenburger Subunits B-D and below by the competent confining Ellenburger Subunit F. Secondary seals above the injection interval include the Barnett Shale, Marble Falls Limestone, and the Atoka shales. Overall, there is an excess of 2,000 feet of impermeable rock between the injection interval and the deepest well penetrations, making vertical migration past the primary and secondary confining intervals unlikely. While unlikely, dCarbon proposes monitoring to look for injected CO_2 in the gas stream of the Barnett Shale wells located above the MMA as described in Section 5.3.

5.6 Leakage from Natural or Induced Seismicity

The Cotton Cove CCS 1 well location is in an area of the Fort Worth Basin that has experienced seismic activity historically, as described in Section 3.5. The occurrence of injection-induced earthquakes in the Fort Worth Basin makes this a hazard that dCarbon will monitor.

Since no faults are mapped that cut from the injection interval through the sealing limestones and shales of the Pennsylvanian, no leakage is expected due to induced seismic activity. However, dCarbon also plans several operational procedures to monitor injection-induced seismicity and to immediately identify any minor or major seismic events in the area. Before initiating injection into the well, dCarbon will be installing surface pressure gauges, so that reservoir pressure and injection pressure can be modeled and monitored. Additionally, consistent with TRRC guidelines and permit conditions, dCarbon plans to maintain bottomhole injection pressure below formation fracture pressure and maintain surface pressure below 0.25 psi per foot gradient when measured from the top of the injection interval. Finally, dCarbon plans to perform periodic pressure fall-off tests (PFOT) to determine and monitor reservoir pressure to ensure unexpected static pressure increases are not observed. These measures are designed to prevent induced fracturing of the formation and reduce the likelihood of induced seismicity. Should any unexpected increase in formation pressure be detected, dCarbon can perform Fault Slip Potential (FSP) analysis (Walsh, *et al.,* 2017) to evaluate the risk of induced seismicity on the closest mapped faults. dCarbon plans to build this model based on geologic data collected during drilling the Cotton Cove CCS 1 well. If there is a concern related to abnormal pressures or seismicity related to operations at the well, dCarbon will report required information to the regulator per their injection permit conditions and investigate further.

Furthermore, dCarbon installed new ground seismic monitoring stations near the injection site that are designed to detect any seismic events in the area, natural or induced. Any seismic events detected in the area will have their hypocenters located and analyzed to determine their origin and if they may have potential impacts on the injection program or confining layers. Additionally, the TexNet seismic monitoring program will also be monitored to ensure any material seismic events in the area are investigated. Since its installation in 2023, the dCarbon seismic network has not detected any earthquakes in the 100 square mile area around the Cotton Cove Project.

5.7 Leakage from Lateral Migration

The structural dip of the Ellenburger Group in the vicinity of the Cotton Cove CCS 1 injection site is about two degrees up to the west (200 feet/mile), shown in **Figure 21**. The closest well that penetrates the Ellenburger Subunit E injection interval is down dip to the northeast approximately 5.8 miles (Tarrant North SWD 1).

Dynamic modeling of the CO_2 plume has the maximum extent of the plume traveling less than 1.5 miles, with the maximum distance traveled to the west. Given that the distance to the next penetration of the injection interval is four times the distance the plume is expected to travel, no leakage from lateral migration is expected.

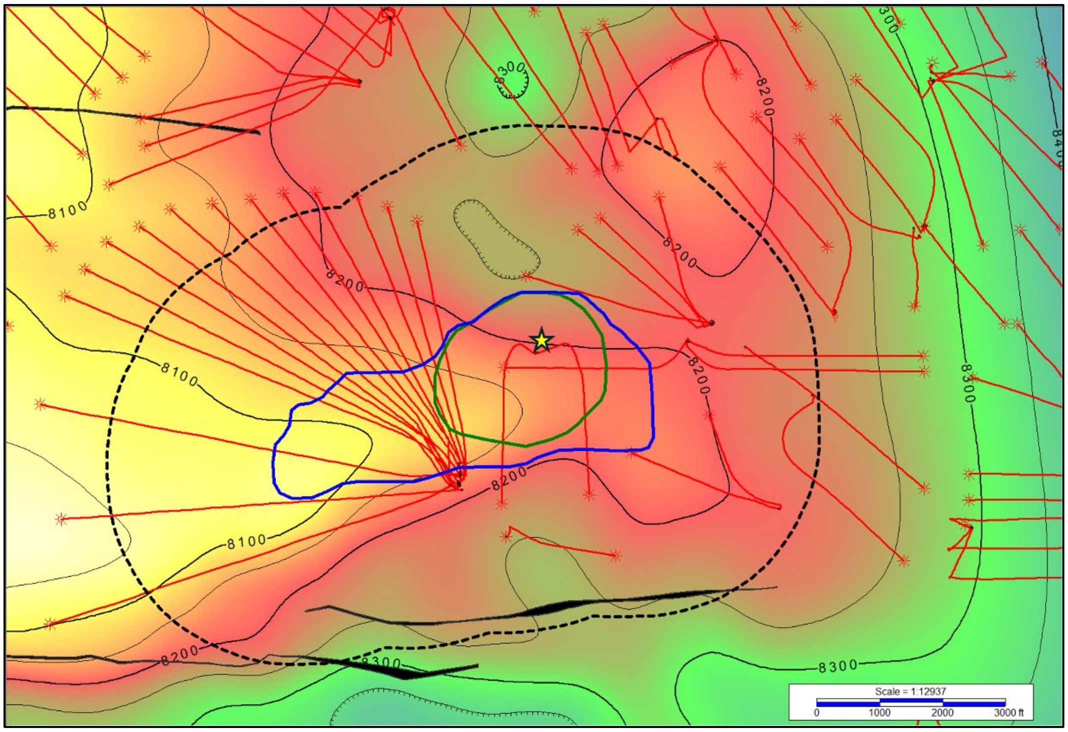


Figure 21. The Cotton Cove CCS 1 well location (yellow star) posted on a map of the top Ellenburger Subunit E depth structural contours in feet TVDSS with a contour interval of 500 feet from the simulation model. The CO_2 plume size at the end of injection (green) and 100 years post-injection and AMA/MMA are also shown as solid blue and dashed black outlines, respectively, from Figure 18. Mapped faults are shown in black.

6 – PLAN OF ACTION FOR DETECTING AND QUANTIFYING SURFACE LEAKAGE OF CO_2

This section discusses the strategy that dCarbon will employ for detecting and quantifying surface leakage of CO_2 through the pathways identified in previous sections to meet the requirements of 40 CFR § 98.448(a)(3). This section summarizes the monitoring of potential leakage pathways to the surface, and the methods for quantifying leakage should it occur.

6.1 Leakage from Surface Equipment

Monitoring will occur during the planned 12-year injection period, or until the cessation of operations. dCarbon will use the existing Supervisory Control and Data Acquisition (SCADA) monitoring systems to identify changes from the expected performance that may indicate leakage of CO_2. As the CO_2 compressor station, pipe header, and injection well are all designed to handle expected concentrations, temperatures, and pressures of CO_2, any leakage from surface equipment will be quickly detected and addressed. The facility is designed to minimize potential leakage points by following the American Society of Mechanical Engineers (ASME) standards, American Petroleum Institute (API) standards, and other industry standards, including standards pertaining to material selection and construction. Additionally, connections are designed to minimize corrosion and leakage points.

Periodic inspections will be conducted by field personnel at the compressor facility and the injection well. These inspections will aid with identifying and addressing issues in a timely fashion to minimize the possibility of leakage. If any issues are identified, such as vapor clouds, ice formations, or abnormal AVO observations, corrective actions will be taken to address such issues.

Any leakage would be detected and managed as per Texas regulations and dCarbon's safety and operations plans. Continuous monitoring systems would trigger an alarm upon a release. The mass of the CO_2 released would be calculated for the operating conditions at the time, including pressure, flow rate, size of the leak point opening, and duration of the leak. This method is consistent with 40 CFR § 98.448(a)(5), allowing the operator to calculate site-specific variables used in the mass balance equation.

Additionally, CO_2 for injection will be metered with a Coriolis meter at the injection well site, immediately upstream of the injection wellhead itself (**Figure 22**). The injection stream will also be sampled and analyzed periodically with a gas chromatograph to determine final composition. The meter will each be calibrated to industry standards. Any discrepancies in CO_2 throughput at the meter will be investigated and reconciled. Any CO_2 that is determined to have leaked or not been received at the injection wellhead will be quantified using the procedures specified in subpart W of the GHGRP, reported as specified in 40 CFR § 98.448(a)(5), and subtracted from reported injection volumes. Gas samples will be taken and analyzed per the manufacturer's recommendations to confirm stream composition and calibrate or recalibrate meters, if necessary. At a minimum, these samples will be taken quarterly. Minimal variation of concentration and composition are expected but will be included in regulatory filings as appropriate.

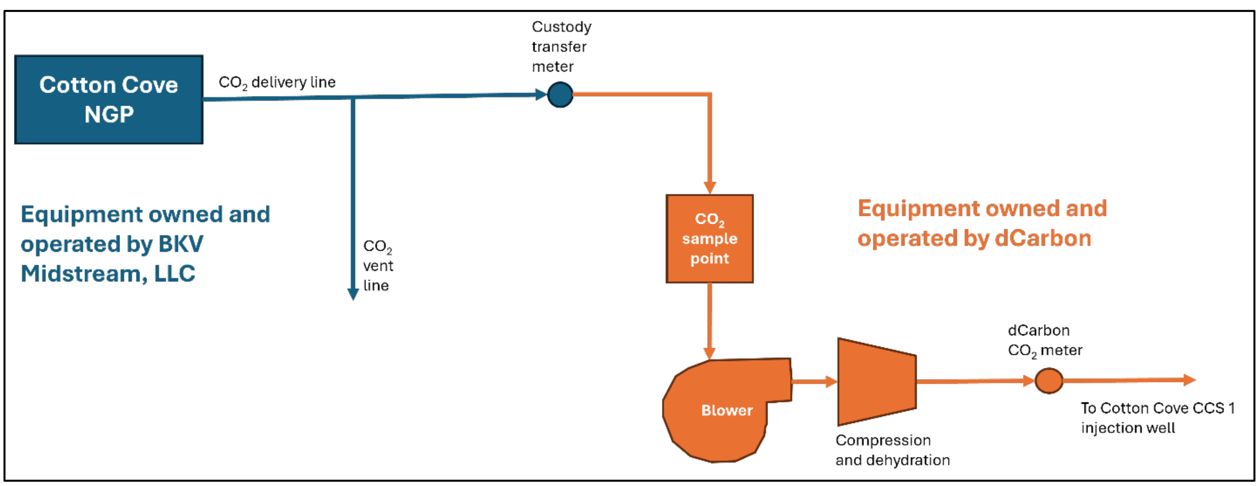


Figure 22. Project conceptual diagram with metering locations. Equipment and pipe headers in Blue are owned and operated by BKV Midstream, LLC while equipment and pipe headers in orange are owned and operated by dCarbon.

6.2 Leakage from Existing and Future Wells within the Monitoring Area

As previously discussed, there are no wells in the MMA currently existing, approved, or pending that penetrate as deep as the Ellenburger injection interval. However, dCarbon will reverify the status and public information for all proposed and approved drilling permits within the MMA quarterly. If any wells are proposed, permitted, or drilled within the MMA, dCarbon will investigate the proposal and determine if any additional risks are introduced through the new well proposal. Additionally, dCarbon will monitor and collect injection volumes, pressures, temperatures, and gas composition data for the injection well. This data will be reviewed by qualified personnel and will follow response and reporting procedures when data is outside acceptable performance limits. Finally, dCarbon will update the MRV plan if any new wells are drilled within the MMA, or if any other material change to the project occurs.

The injection well design has pressure and temperature gauges monitoring the injection stream at the wellhead in addition to pressure sensors for each annulus of the well. Annual bottomhole pressure and temperature measurements will be made to calibrate the surface readings to bottom hole. A change of pressure on the annulus would indicate the presence of a possible leak requiring remediation. Mechanical Integrity Tests (MITs) performed annually would also indicate the presence of a leak. Upon a negative MIT, the well would immediately be isolated, and the leak mitigated.

In the unlikely event that any CO_2 leaks occur into existing or future wells in the monitoring area, dCarbon will endeavor to work with the operator(s) of those wells and/or midstream providers to take gas samples quarterly to quantify variations or increases of CO_2 compared with historical or baseline CO_2 concentrations. Any measurable increases in CO_2 which may be confidently attributed to injection volumes from the Cotton Cove CCS 1 well will be calculated using standard engineering procedures for estimating potential well leakage determined to be appropriate for the situation. These volumes will be documented and reported in the annual monitoring report and subtracted from reported injection volumes. Additionally, dCarbon will evaluate and execute any additional downhole remediations (*e.g.*, well workovers, such as adding plugs, remedial cement jobs) that could address leakage from the injection well to the existing and future wells in the area if necessary and practical.

6.3 Leakage from Faults and Fractures

No faults or fractures have been identified that would allow CO_2 to migrate vertically to intervals with USDWs or to the surface. In the unlikely event that such leakage from faults or fractures occurs, dCarbon will determine which standard engineering techniques for estimating potential leakage from the faults and fractures is appropriate for the situation to estimate any leakage from faults and fractures, and report such leakage estimates and the methodology employed in the annual monitoring report.

6.4 Leakage through Confining Layers

Leakage through confining layers to the surface or to the USDW is improbable, given the number and thickness of competent layers between the injection interval and the USDW. Sampling of the produced gas stream from the Barnett Shale gas wells within the MMA is the primary tool for detecting CO_2 that has bypassed the primary confining system. These producing gas wells are not expected to produce any of the CO_2 injected into the Ellenburger Subunit E and will act as above zone monitoring wells. dCarbon plans to inject a small amount of chemical tracer with the CO_2 downstream of the volumetric flow meter. Thie chemical tracer will serve as confirmation that any increase in CO_2 detected in the produced gas stream from the Barnett Shale wells in the AMA/MMA is from the sequestration reservoir.

Groundwater sampling would be the primary tool for quantifying CO_2 leakage up through the multiple layers of the primary and secondary confining systems. The chemical tracer injected with the CO_2 can also be analyzed for in the groundwater sampling.

As with any CO_2 leakage, however, should it occur, dCarbon will determine which standard engineering techniques for estimating potential leakage is appropriate for the situation to estimate any leakage, and report such leakage estimates and the methodology employed in the annual monitoring report.

6.5 Leakage through Natural or Induced Seismicity

While the likelihood of a natural or induced seismicity event is low, dCarbon operates a proprietary seismic monitoring array in the general area of the Cotton Cove CCS 1 well. This monitoring array augments the TexNet Seismic Monitoring system. If a seismic event of 3.0 magnitude or greater is detected, dCarbon will review the injection volumes and pressures at the Cotton Cove CCS 1 well to determine if any significant changes occurred that would indicate potential leakage. Leakage due to natural or induced seismicity would require that earthquakes activate faults that penetrate through the confining intervals, a situation that is very unlikely based on the location of mapped faults and the extent of the modeled plume.

In the unlikely event CO_2 leakage occurs due to natural or induced seismicity, dCarbon will determine which standard engineering techniques for estimating potential leakage is appropriate for the situation and report such leakage estimates and the methodology employed in the annual monitoring report.

6.6 Leakage through Lateral Migration

The distances to the closest penetration of the Ellenburger injection interval are more than four times the expected plume radius at the end of injection. As such, leakage through lateral migration is not expected. In addition, the only wells that penetrate the injection interval are saltwater disposal wells. Injection into these wells would be expected to raise the reservoir pressure locally near the well, further limiting the ability of the CO_2 to access the saltwater injector well bore.

In the unlikely event CO_2 leakage occurs due lateral migration, like leakage through confining layers, dCarbon will determine which standard engineering techniques for estimating potential leakage is appropriate for the situation, and report such leakage estimates and the methodology employed in the annual monitoring report.

6.7 Quantification of Leakage

In the unlikely event that CO_2 moves vertically past the primary and secondary confining layers as described earlier in Section 6, there are several methods dCarbon may utilize to quantify leakage depending on the nature and severity of the leak. dCarbon will consider additional standard and specialized engineering methods to quantify leaks as appropriate. dCarbon's methodology to characterize, monitor, detect, and isolate leaks for quantification is described below.

As a primary monitoring and quantification strategy, dCarbon plans to sample the gas stream from the gas wells in the MMA. These wells should intercept CO_2 that might traverse the primary sealing interval before it bypasses the secondary seals. Noting the increase in CO_2 concentration in the produced gas stream along with the presence of the chemical tracer, will be a trigger for dCarbon to investigate and quantify possible leakage through the primary confining layers. dCarbon will document the methods used to calculate the volume of CO_2 leakage in its annual monitoring report.

dCarbon has access to a deep groundwater monitoring well at the Cotton Cove Gas Plant that will be used to monitor the USDW. This well will be deeper than any active groundwater wells in the area that typically draw water from shallow drinking water intervals. dCarbon also plans to periodically sample the well to monitor for chemical composition. If dCarbon notices an increase in groundwater CO_2 concentration compared to baseline measurements, the increase in concentration will be analyzed volumetrically to provide a preliminary estimate of CO_2 leakage. dCarbon will conduct baseline sampling of available water wells within the MMA prior to injection to establish a basis for comparison to later samples.

Any leakage that did extend to the surface could be characterized and quantified through surface surveillance in the project area paired with direct pressure, volume, and temperature (PVT) measurements. Currently available (and continuously improving) atmospheric sensing technology could be used to establish a baseline of ambient CO_2 concentration in the project area and identify any fluctuations. Deviations from baseline concentration along with understanding of the distance from potential leak sources can then be coupled with temporally matched meteorological data to semi-quantitatively determine leak attribution and rate. Based on the size of leak, these qualified or quantified leak rates can be compared with spatiotemporally monitored PVT data to co-index or further refine leaked volumes from likely point sources.

Any diffuse leak or leak without an obvious single point source may require additional identification and quantification methods. dCarbon works with environmental services and data companies that specialize in monitoring and quantifying gas leaks in various industrial settings. One such quantification method involves utilizing fixed monitoring systems to detect CO_2. Additional system capabilities may also include the deployment of an unmanned aerial vehicle (UAV), which is outfitted with high-fidelity CO_2 sensors capable of measuring concentrations as little as parts per billion (ppb). The UAV mobile surveillance platform possesses the ability to be flown on a programmable and highly replicable pattern across the MMA in both the X and Y axes (longitude + latitude) as well as the Z axis (height). Depending on the system's ability to obtain a reliable baseline across the MMA, areal deviation in CO_2 concentration could be measured, and diffuse leak sources could potentially be identified, provided the emissions reach a sufficient threshold. dCarbon will also consider similar technologies with less spatial resolution or fidelity such as fixed wing flyovers and/or improving satellite data with UAV technology to screen for and support diffuse emissions identification and investigation.

Depending on the applicability and monitoring needs, dCarbon will also consider other monitoring quantification methods such as the Eddy Covariance Method (ECM) (Korre, 2011). This method utilizes gas fluxes and ambient meteorological conditions to detect and quantify leaks, although the ability to detect smaller leaks may be limited. Additionally, long open path tunable diode lasers could be used to measure distance averaged concentrations of CO_2 in the air, which could help quantify a leak of CO_2. This system could be paired with an array of short, closed path detectors (*e.g.*, gas chromatographs) that are typically placed around a suspected leak or leak area to monitor point-source CO_2 concentration increases and to quantify leakage. dCarbon may also evaluate other emerging technologies for quantifying CO_2 leakage such as Non-Dispersive Infra-Red (NDIR) CO_2 sensors and soil flux detectors. dCarbon may also utilize three-dimensional reservoir models that factor in faults and surface topography to predict CO_2 leakage locations, quantity, and timing. The applicability of such models in predicting and quantifying gas leaks has been tested and documented at the Leroy natural gas storage site in Wyoming, USA (Chen, 2013).

As the technology and equipment to quantify CO_2 leakage is rapidly evolving and expected to improve over time, dCarbon will continue to update its leak detection and quantification plans as appropriate. If dCarbon detects a leak associated with CO_2 injection at the Cotton Cove CCS 1 well, all methods discussed in this section will be considered in addition to emerging technologies to determine the most applicable and effective method of quantification.

7 – BASELINE DETERMINATIONS

This section identifies the strategies that dCarbon will undertake to establish the expected baselines for monitoring CO_2 surface leakage per § 98.448(a)(4). There are three primary monitoring baselines that dCarbon will establish as part of this project.

Baseline groundwater quality and properties will be determined and monitored through the sampling of one or more groundwater wells near the injection well site. Samples will be taken and analyzed by a third-party laboratory to establish the baseline properties of the groundwater in the area.

Baseline gas composition, including CO_2, will be established from the producing Barnett Shale wells within the MMA that are acting as above-zone monitoring wells. Gas samples will be taken and analyzed by a third-party laboratory.

Baseline seismicity in the area near the Cotton Cove CCS 1 has been determined through the historical data from USGS and TexNet seismic array data. This information is augmented by additional data from dCarbon's proprietary seismic monitoring array, operating since 2023.

8 – SITE SPECIFIC CONSIDERATIONS FOR DETERMINING THE MASS OF CO_2 SEQUESTERED

This section identifies how dCarbon will calculate the mass of CO_2 injected, emitted, and sequestered. This also includes site-specific variables for calculating the CO_2 emissions from equipment leaks and vented emissions of CO_2 between the injection flow meter and the injection well, per 40 CFR § 98.448(a)(5).

8.1 MASS OF CO_2 RECEIVED

Per 40 CFR § 98.443, the mass of CO_2 received must be calculated using the specified CO_2 received equations "unless you follow the procedures in 40 CFR §98.444(a)(4)." 40 CFR § 98.444(a)(4) states that "if the CO_2 you receive is wholly injected and is not mixed with any other supply of CO_2, you may report the annual mass of CO_2 injected that you determined following the requirements under paragraph (b) of this section as the total annual mass of CO_2 received instead of using Equation RR-1 or RR-2 of this subpart to calculate CO_2 received."

The CO_2 received by dCarbon for injection into the Cotton Cove CCS 1 injection well will be wholly injected and not mixed with any other supply and the annual mass of CO_2 injected will equal the amount received. Any future streams will be metered separately before being combined into the calculated stream.

8.2 MASS OF CO_2 INJECTED

Per 40 CFR § 98.444(b), since the flow rate of CO_2 injected will be measured with a volumetric flow meter, the total annual mass of CO_2, in metric tons, will be calculated by multiplying the volumetric flow at standard conditions by the CO_2 concentration in the flow and the density of CO_2 at standard conditions, according to Subpart RR Equation 5:

$$CO_{2,u} = \sum_{p=1}^{4} Q_{p,u} * D * C_{CO_{2,p,u}}$$

Where:

$CO_{2,u}$	=	Annual CO_2 mass injected (metric tons) as measured by flow meter u
$Q_{p,u}$	=	Quarterly volumetric flow rate measurement for flow meter u in quarter p at standard conditions (standard cubic meters per quarter)
D	=	Density of CO_2 at standard conditions (metric tons per standard cubic meter): 0.0018682
$C_{CO2,p,u}$	=	CO_2 concentration measurement in flow for flow meter u in quarter p (vol. percent CO_2, expressed as a decimal fraction)
p	=	Quarter of the year

u = Flow meter

8.3 Mass of CO_2 Produced

The Cotton Cove CCS 1 injection well will receive CO_2 produced from the nearby Cotton Cove Gas Plant and will be used for injection only. No CO_2 will be produced from this well. Additionally, the injection well is not part of an enhanced oil recovery project, and therefore, no CO_2 will be produced.

Should it be determined that CO_2 has bypassed the primary confining system and reached the Barnett Shale wells within the MMA, dCarbon will modify this MRV plan to use 40 CFR Part 98, Subpart RR Eq.-11 to calculate the total mass of CO_2 sequestered at the facility.

8.4 Mass of CO_2 Emitted by Surface Leakage

Mass of CO_2 emitted by surface leakage and equipment leaks will not be measured directly. Any leakage would be detected and managed as a major upset event. Gas detectors and continuous monitoring systems would trigger an alarm upon a release. The mass of the CO_2 released would be calculated for the operating conditions at the time, including pressure, flow rate, size of the leak point opening, and duration of the leak. This method is consistent with 40 CFR § 98.448(a)(5), allowing the operator to calculate site-specific variables used in the mass balance equation.

In the unlikely event that CO_2 was released because of surface leakage, the mass emitted would be calculated for each surface pathway according to methods outlined in the plan and totaled using 40 CFR Part 98-Subpart RR Equation 10 as follows:

$$CO_{2,E} = \sum_{x=1}^{X} CO_{2,x}$$

Where:

$CO_{2,E}$ = Total annual mass emitted by surface leakage (metric tons) in the reporting year
$CO_{2,x}$ = Annual CO_2 mass emitted (metric tons) at leakage pathway x in the reporting year
X = Leakage pathway

Annual mass of CO_2 emitted (in metric tons) from any equipment leaks and vented emissions of CO_2 from equipment located on the surface between the flowmeter used to measure injection quantity and injection wellhead will comply with the calculation and quality assurance/quality control requirement proposed in Part 98, Subpart W and will be reconciled with the annual data collected through the monitoring plan.

8.5 Mass of CO_2 Sequestered

The mass of CO_2 sequestered in the subsurface geologic formations will be calculated based on 40 CFR Part 98, Subpart RR Equation 12, as this well will not actively produce any oil or natural gas or any other fluids, as follows:

$$CO_2 = CO_{2I} - CO_{2E} - CO_{2FI}$$

Where:

CO_2	=	Total annual CO_2 mass sequestered in subsurface geologic formations (metric tons) at the facility in the reporting year.
$CO_{2,I}$	=	Total annual CO_2 mass injected (metric tons) in the well or group of wells covered by this source category in the reporting year.
$CO_{2,E}$	=	Total annual CO_2 mass emitted (metric tons) by surface leakage in the reporting year.
CO_{2FI}	=	Total annual CO_2 mass emitted (metric tons) from equipment leaks and vented emissions of CO_2 from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead, for which a calculation procedure is provided in Subpart W of Part 98.

Should it be determined that CO_2 has bypassed the primary confining system and reached the Barnett Shale wells within the MMA, dCarbon will modify this MRV plan to use 40 CFR Part 98, Subpart RR Eq.-11 to calculate the total mass of CO_2 sequestered at the facility.

9 – ESTIMATED SCHEDULE FOR IMPLEMENTATION OF MRV PLAN

The injection well is expected to begin operation in 2026 and that will be the date that data to calculate the total volume of CO_2 sequestered will begin to be collected. Baseline monitoring data will be collected beginning in 2025 and the MRV plan will be implemented upon receiving EPA MRV plan approval. The exception to the monitoring baseline data is the seismicity baseline data which began in 2017 with the TexNet monitoring system.

10 – QUALITY ASSURANCE

10.1 CO_2 Injected

- The flow rate of the CO_2 being injected will be measured with a volumetric flow meter, consistent with industry best practices. These flow rates will be compiled quarterly.
- The composition of the CO_2 stream will be measured upstream of the volumetric flow meter with a gas composition analyzer or representative sampling consistent with industry best practices.
- The gas composition measurements of the injected stream will be reported quarterly.
- The CO_2 measurement equipment will be calibrated according to manufacturer specifications.

10.2 CO_2 Emissions from Leaks and Vented Emissions

- Gas detectors, if employed, will be operated continuously, except for maintenance and calibration.
- Gas detectors, if employed, will be calibrated according to manufacturer recommendations and API standards.
- Calculation methods from Subpart W will be used to calculate CO_2 emissions from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead.

10.3 Measurement Devices

- Flow meters will be continuously operated except for maintenance and calibration.
- Flow meters will be calibrated according to the requirements in 40 CFR § 98.3(i).
- Flow meters will be operated per an appropriate standard method as published by a consensus-based standards organization.
- Flow meter calibrations will be traceable to the National Institute of Standards and Technology (NIST).

All measured volumes of CO_2 will be converted to standard cubic feet at a temperature of 60 degrees Fahrenheit and an absolute pressure of 1.0 atmosphere.

10.4 Missing Data

In accordance with 40 CFR § 98.445, dCarbon will use the following procedures to estimate missing data if unable to collect the data needed for the mass balance calculations:

- If a quarterly quantity of CO_2 injected is missing, the amount will be estimated using a representative quantity of CO_2 injected from the most recent previous period of time at a similar injection pressure.
- Fugitive CO_2 emissions from equipment leaks from facility surface equipment will be estimated and reported per the procedures specified in Subpart W of 40 CFR § 98.

11 – RECORDS RETENTION

dCarbon will retain records as required by 40 CFR § 98.3(g). These records will be retained for at least five years and include:

- Quarterly records of the CO_2 injected.
- Volumetric flow at standard conditions.
- Volumetric flow at operating conditions.
- Operating temperature and pressure.
- Concentration of the CO_2 stream.
- Annual records of the information used to calculate the CO_2 emitted by surface leakage from leakage pathways.
- Annual records of information used to calculate CO_2 emitted from equipment leaks and vented emissions of CO_2 from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead.

12 – REFERENCES

Bennion, D.B., and Bachu, S., 2007, Permeability and Relative Permeability Measurements at Reservoir Conditions for CO_2-Water Systems in Ultra Low Permeability Confining Caprocks, SPE Paper # 106995.

Brooks, R. H., and Corey, A. T., 1966, Properties of porous media affecting fluid flow, J. Irrig. Drain. Div., v. 6, p. 61-90.

Bruner, K.R. and Smosna, R., 2011, A Comparative Study of the Mississippian Barnett Shale, Fort Worth Basin, and Devonian Marcellus Shale, Appalachian Basin, DEO/NETL-2011/1478.

Chen, M., *et al.*, 2013, Analysis of fault leakage from Leroy underground natural gas storage facility, Wyoming, USA, Hydrogeology, v. 21, p. 1429–1445.

Gao, S. *et al*., 2021, Low pressure buildup with large disposal volumes of oil field water: A flow model of the Ellenburger Group, Fort Worth Basin, North Central Texas, American Association of Petroleum Geologists Bulletin v. 105, no.12, p. 2575-2593.

Hennings, P.H., *et al*., 2019, Injection-Induced Seismicity and Fault-Slip Potential in the Fort Worth Basin, Texas. Bulletin of the Seismological Society of America, v.109, no. 5, p. 1615-1634.

Hornbach, M., DeShon, H., Ellsworth, W. *et al*., 2015, Causal factors for seismicity near Azle, Texas, Nature Communications v. 6, no. 6728, https://doi.org/10.1038/ncomms7728

Horne, E. A. *et al*.., 2021, Basement-rooted faults of the Delaware Basin and Central Basin Platform, Permian Basin, West Texas and southeastern New Mexico, *in* Callahan, O. A., and Eichhubl, P., eds., The geologic basement of Texas: a volume in honor of Peter T. Flawn: The University of Texas, Bureau of Economic Geology Report of Investigations No. 286, doi:10.23867/RI0286C6.

Jarvie, D.M., *et al.*, 2007, Unconventional shale-gas systems: The Mississippian Barnett Shale of North Central Texas as one model for thermogenic shale-gas assessment, American Association of Petroleum Geologists Bulletin, v. 91, no. 4, p. 475-499.

Korre, A., *et al.*, 2011, Quantification techniques for potential CO_2 leakage from geologic sites, Energy Procedia, v. 4, p. 3143-3420.

Nicot, J, *et al*., 2011, Methane occurrences in aquifers in the Barnett Shale area with a focus on Parker County, Texas, University of Texas, https://deepblue.lib.umich.edu/bitstream/handle/2027.42/137724/gwat12508-sup-0001-supinfo.pdf?sequence=1.

Pollastro, R.M., 2007, Geologic framework of the Mississippian Barnett Shale, Barnett-Paleozoic total petroleum system, Bend Arch-Fort Worth Basin, American Association of Petroleum Geologists Bulletin, v. 91, no.4, p. 405-436.

Smye, K.M. *et al*., 2019, Stratigraphic Architecture and Petrophysical Characterization of Formations for Deep Disposal in the Fort Worth Basin, TX, Interpretation no. 7, p. 1-52, 10.1190/int-2018-0195.1.

Texas Water Development Board Interactive Viewer, 2024, https://www3.twdb.texas.gov/apps/waterdatainteractive/groundwaterdataviewer.

Walsh, F.R.I. *et al*., 2017, FSP 1.0: A Program for Probabilistic Estimation of Fault Slip Potential Resulting from Fluid Injection, available at: https://scits.stanford.edu/software.

Wood, V., 2015, Reservoir Characterization and Depositional System of the Atokan Grant Sand, Fort Worth Basin, Texas. University of Arkansas Thesis, 90 p.

Zeng, H., 2011, Characterizing seismic bright spots in deeply buried, Ordovician Paleokarst strata, Central Tabei Uplift, Tarim Basin, Western China, Geophysics, v. 76, p. B127-B137.

Zeng, H., *et al*., 2011, Three-dimensional seismic geomorphology and analysis of the Ordovician paleokarst drainage system in the Central Tabei Uplift, Northern Tarim Basin, Western China, American Association of Petroleum Geologists Bulletin, v. 95, no.12, p. 2061–2083.

Attachment A

Copies of W-14, W-1, Drilling Permit