# RED TRAIL ENERGY SUBPART RR MONITORING, REPORTING, AND VERIFICATION (MRV) PLAN

**Class VI Well**

Reporting Number: 530977

North Dakota Storage Facility Permit: Order No. 31453–31455

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Within the text of this monitoring, reporting, and verification plan, the Red Trail Energy storage facility permit is designated as follows:

**Reference 1: Red Trail Energy Carbon Dioxide Geologic Storage Facility Permit**

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# 1.0 PROJECT DESCRIPTION

## 1.1 Project Characteristics

The Red Trail Energy (RTE) facility is a North Dakota-based, investor-owned 64-million-gallon dry mill ethanol production plant, which has been in operation since January 2007. The RTE facility, located about a mile east of Richardton, North Dakota (Figure 1-1), emits an average of 180,000 metric tons annually of high-purity carbon dioxide ($CO_2$) (>99% $CO_2$ dry) from the fermentation process during ethanol production. The RTE carbon capture and storage (CCS) project is currently constructing a $CO_2$ capture facility (mainly dehydration and compression) adjacent to the RTE ethanol plant to capture all $CO_2$ from fermentation. RTE plans to inject the resulting 180,000-metric-ton-per-year $CO_2$ stream into the Broom Creek Formation via the RTE-10 injection well located on RTE property (Figure 1-1) for permanent geologic $CO_2$ storage.

RTE received formal approval of its North Dakota $CO_2$ storage facility permit (SFP) on October 19, 2021. This approval by the North Dakota Industrial Commission (NDIC) authorizes the geologic storage of $CO_2$ from the RTE ethanol facility in the amalgamated storage reservoir pore space of the Broom Creek Formation (NDIC Order Nos. 31453 and 31454). North Dakota has the authority to regulate the geologic storage of $CO_2$ and primacy to administer the North Dakota Underground Injection Control (UIC) Class VI Program (83 Federal Register 17758, 40 Code of Federal Regulations [CFR] 147). No other geologic storage project exists or is planned at or near the RTE CCS project.

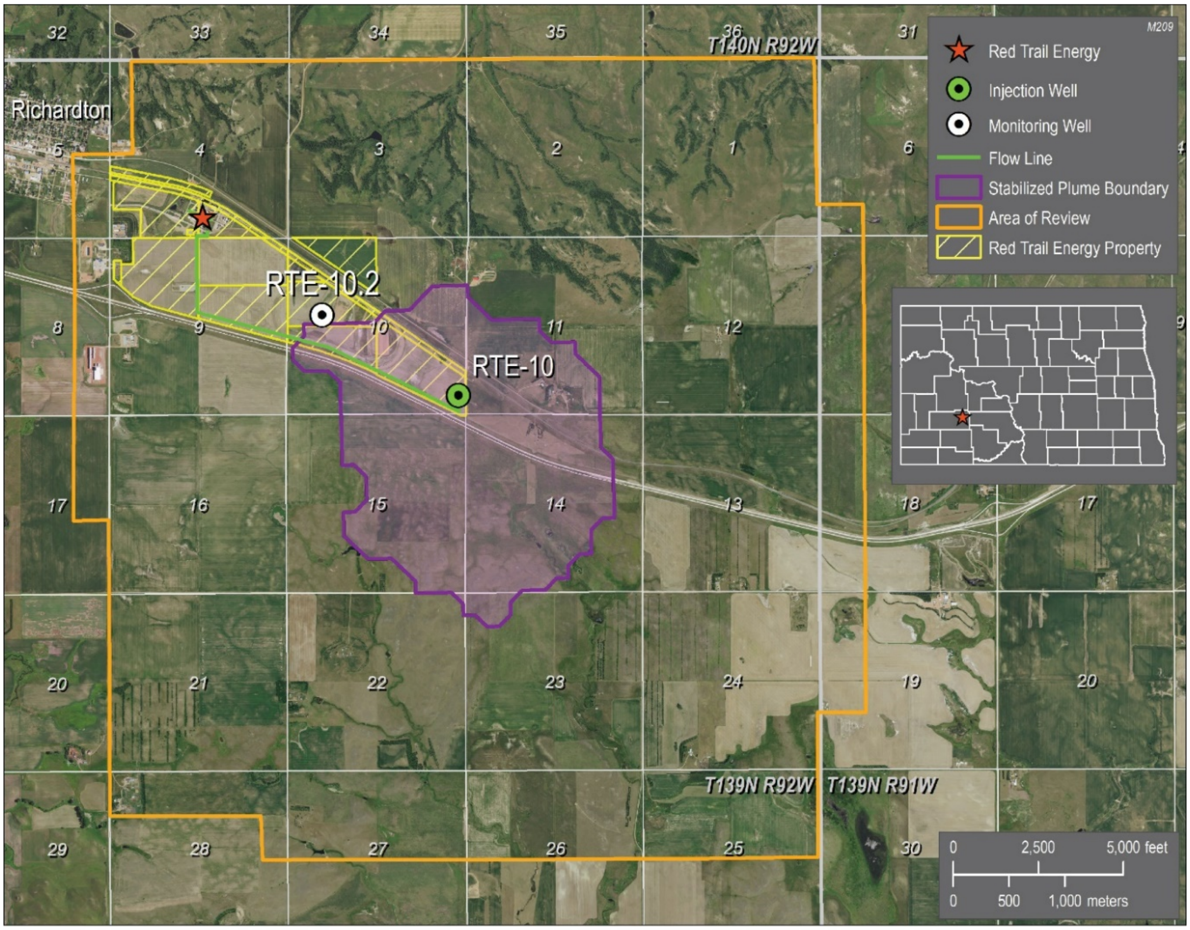


Figure 1-1. Location of the RTE facility, RTE-10 injection well, RTE-10.2 monitoring well, and $CO_2$ flowline. Also shown is the town of Richardton, with a population of about 850 people, the stabilized plume boundary, and the area of review (AOR).

### 1.2 Environmental Setting

The RTE CCS project site is on the southern flank of the Williston Basin, a sedimentary intracratonic basin covering approximately 150,000 square miles, with its depocenter near Watford City, North Dakota. Figure 1-2 shows the geographic distribution of oil fields in North Dakota (i.e., western Williston Basin) and demonstrates there has been no exploration for, and development of, hydrocarbon resources within the stabilized plume boundary (Reference 1, Section 2.6). The Rummel-State 1 (NDIC No. 6797), a dry hole drilled to the Red River Formation (below the Broom Creek Formation) in 1978, is located within the southwestern edge of the AOR (see Section 3.2 of this MRV plan for more information on the Rummel-State 1).

A generalized stratigraphic column of the Williston Basin for the Richardton area is provided in Figure 1-3. The target $CO_2$ storage reservoir for the RTE CCS project is the Broom Creek Formation, a predominantly sandstone interval lying about 6,380 feet below the RTE facility

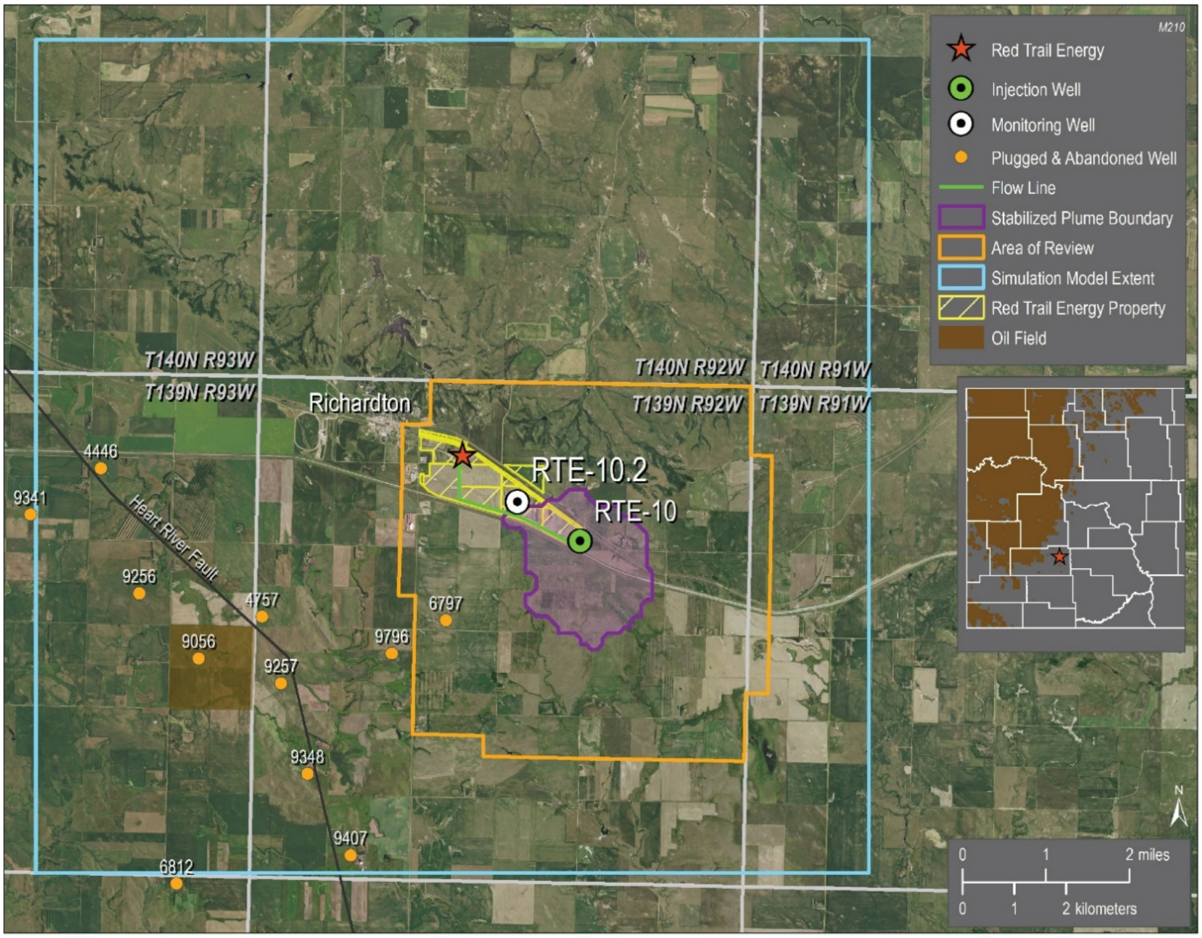


Figure 1-2. Map showing the AOR, stabilized plume boundary, RTE ethanol facility, RTE-10 injection well, RTE-10.2 monitoring well, town of Richardton, and oil and gas wells immediately outside of or within the simulation model extents. Also shown is an inset map identifying the geographic distribution of oil fields in North Dakota (i.e., western portion of the Williston Basin) and the Heart River Fault. The oil field in T139N-R93W is the Taylor Field. Wells 9056 and 9341 produced some hydrocarbons from the Winnipeg Formation (see Figure 1-3 for stratigraphic reference), but all other wildcat wells shown on the map were classified as dry holes.

(Reference 1, Section 2.3). Mudstones, siltstones, and interbedded evaporites of the Opeche Formation unconformably overlie the Broom Creek and serve as the primary confining zone (Reference 1, Section 2.4.1). The Amsden Formation (dolostone, limestone, and anhydrite) unconformably underlies the Broom Creek Formation and serves as the lower confining zone (Reference 1, Section 2.4.3). Together, the Opeche, Broom Creek, and Amsden comprise the $CO_2$ storage complex. In addition to the Opeche Formation, there is about 1,200 feet of impermeable rock formations between the Broom Creek Formation and the next overlying porous zone, the Inyan Kara Formation (Reference 1, Section 2.4.2). An additional 3,000 feet of impermeable intervals separates the Inyan Kara and the lowest underground source of drinking water (USDW), the Fox Hills Formation.

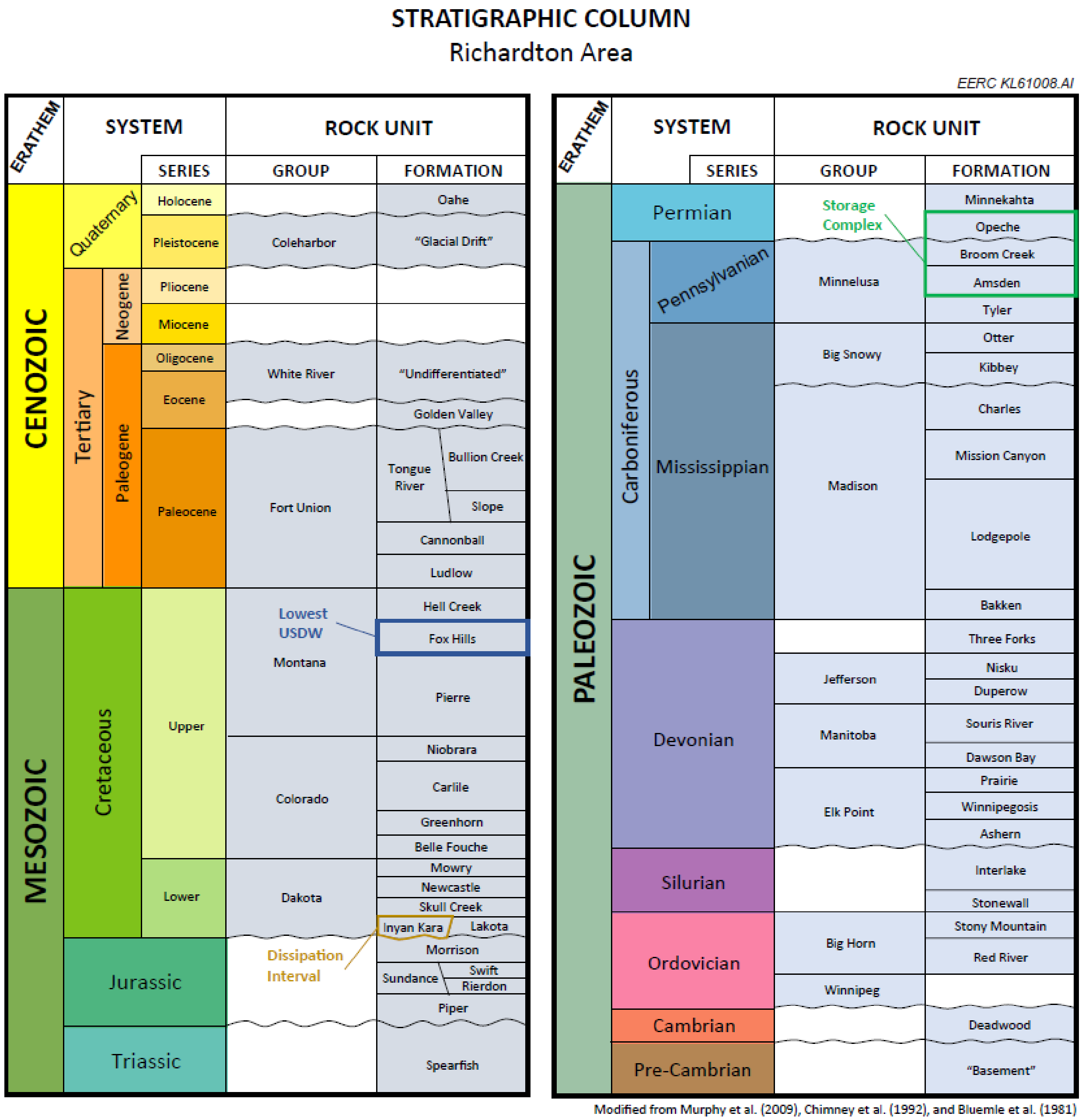


Figure 1-3. Generalized stratigraphic column of the Williston Basin for the Richardton area, identifying the storage complex (i.e., storage reservoir and primary confining zones) as well as the dissipation interval and lowest USDW underlying the RTE CCS project site.

## 1.3 Description of $CO_2$ Project Facilities and Injection Process

RTE plans to capture and store 180,000 metric tons per year over the course of 20 years of injection, followed by at least 10 years of post-injection site care. Figure 1-4 shows integration of

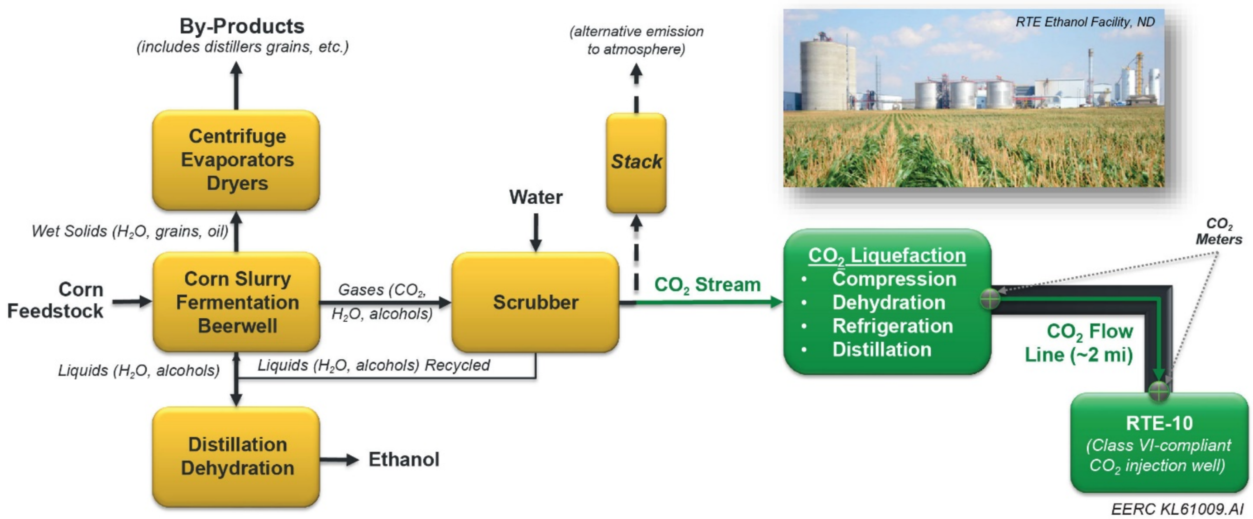


Figure 1-4. Flow diagram of the RTE CCS process, showing major CCS components and the path of the $CO_2$ stream from the capture facility to the RTE-10 injection well.

major CCS components with the existing RTE ethanol facility. The capture–liquefaction facility was designed to capture the $CO_2$ currently produced during RTE's fermentation process (following the scrubber prior to stack emission), compress the gaseous $CO_2$ stream to approximately 350 pounds per square inch, dehydrate the stream, and then liquefy the $CO_2$ using a closed-loop ammonia ($NH_3$) refrigeration process. A conventional distillation column would distill the liquid $CO_2$ to remove oxygen in addition to other noncondensable gases. The final liquid $CO_2$ stream would flow to the RTE-10 injection well for geologic storage into the Broom Creek Formation; an underground flowline is installed on RTE property to connect the capture plant to the RTE-10 injection well.

# 2.0 DELINEATION OF MONITORING AREA AND TIME FRAMES

## 2.1 Active Monitoring Area: RTE AOR Delineation in Accordance with U.S. Environmental Protection Agency (EPA) and North Dakota Rules

RTE proposes that because the AOR, as delineated in Reference 1, Section 3 and Appendix A, exceeds the requirements of the active monitoring area (AMA) under Title 40, CFR § 98.449 (Subpart RR), the AOR will serve as AMA for the RTE CCS project (Figure 2-1).

The AOR is defined as the "region surrounding the geologic sequestration project where underground sources of drinking water may be endangered by the injection activity" (North Dakota Administrative Code [NDAC] § 43-05-01-01). The NDAC requires the operator to develop an AOR and corrective action plan using the geologic model, simulated operating assumptions, and site characterization data on which the model is based (NDAC § 43-05-01-5.1). Further, the NDAC requires a technical evaluation of the storage facility area plus a minimum buffer of 1 mile (NDAC § 43-05-01-05). The storage facility boundaries must be defined to include the areal extent of the $CO_2$ plume plus a buffer area to allow operations to occur safely and as proposed by the applicant (North Dakota Century Code [NDCC] § 38-22-08). Therefore, RTE elected to permit the storage facility area boundaries based on the reservoir model output discussed in Reference 1, Section 3 and Appendix A, and then, added a 1-mile buffer, rounding out to the nearest 40-acre tract.

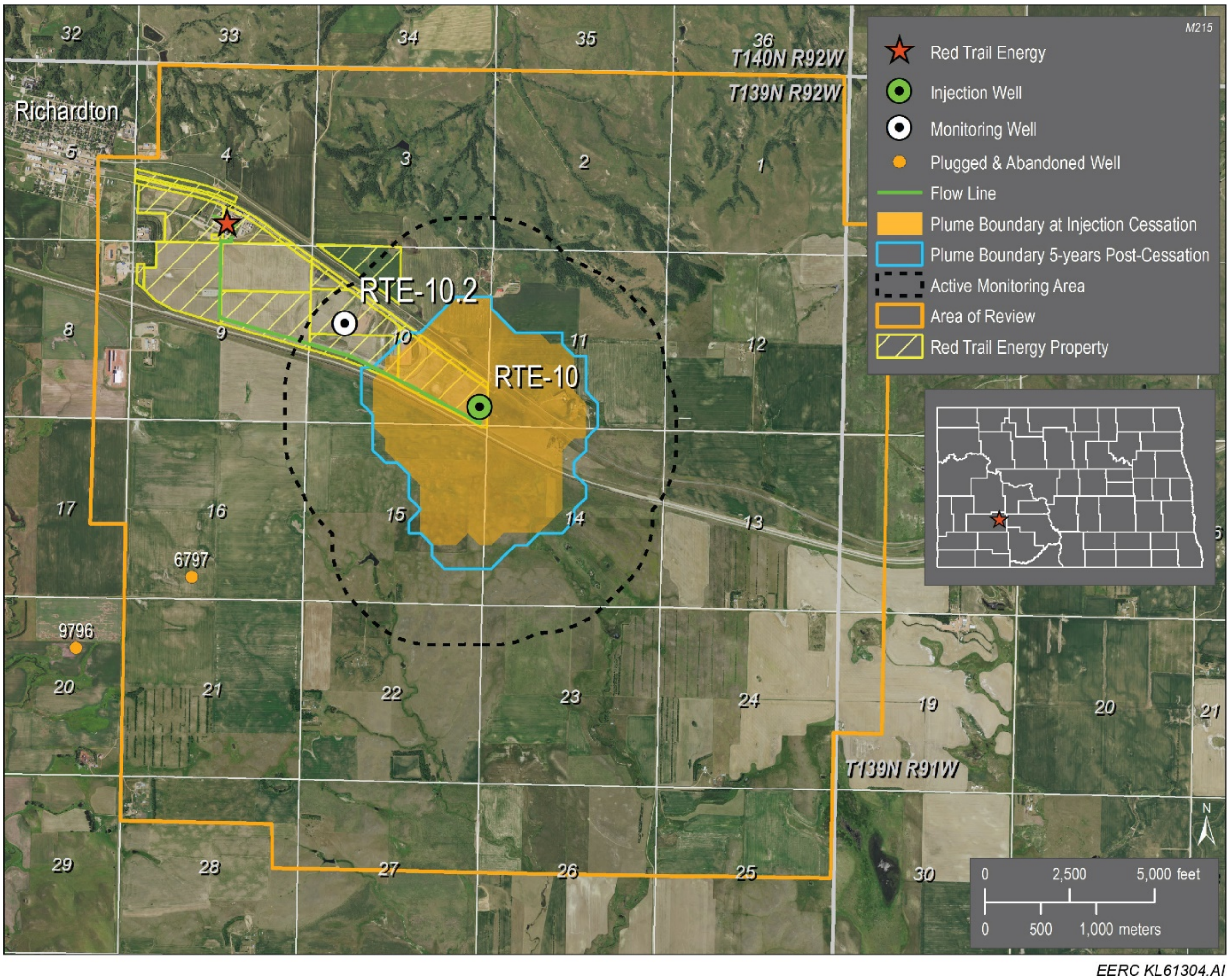


Figure 2-1. Map showing the AOR relative to the AMA boundaries calculated, as prescribed under 40 CFR § 98.449 (Subpart RR), with "t" set equal to injection cessation (20 years). The AOR subsumes the AMA and exceeds requirements for the AMA; therefore, the AOR serves as the AMA for the RTE CCS project.

## 2.2 Maximum Monitoring Area

RTE proposes that the delineated AOR and proposed AMA from Figure 2-1 also serve as the maximum monitoring area (MMA) for the RTE CCS project (Figure 2-2), as it also exceeds the requirements for delineating the MMA under 40 CFR § 98.449 (Subpart RR).

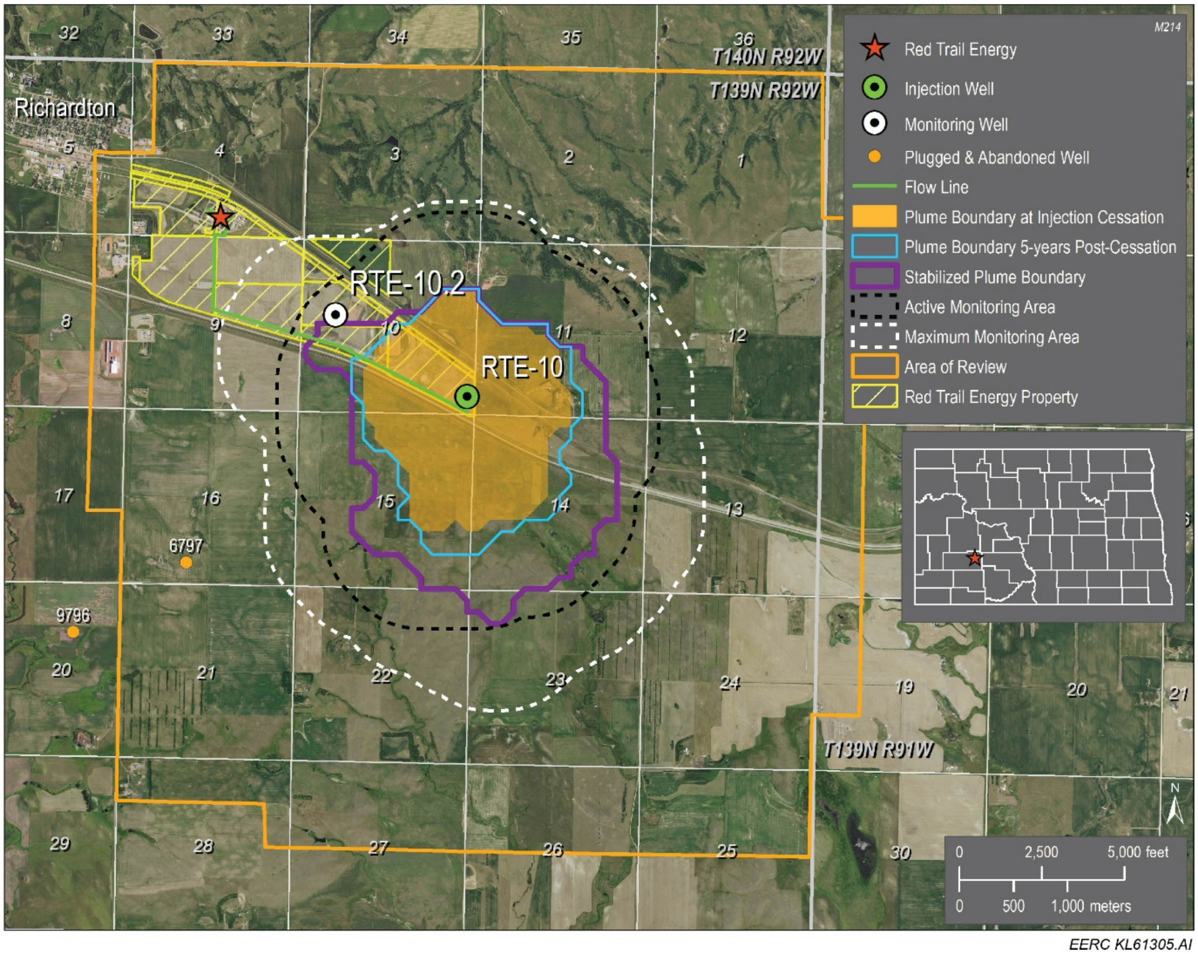


Figure 2-2. Map showing the AOR relative to the calculated MMA and AMA boundaries calculated, as prescribed under 40 CFR § 98.449 (Subpart RR). The AOR subsumes the calculated AMA and MMA and exceeds requirements for both AMA and MMA; therefore, the AOR serves as both the AMA and MMA for the RTE CCS project.

## 2.3 Monitoring Time Frames

The monitoring program for the geologic storage of $CO_2$ (Reference 1, Section 4.4) comprises three distinct periods: 1) pre-operational (pre-injection of $CO_2$) baseline monitoring, 2) operational ($CO_2$ injection) monitoring, and 3) post-operational (post-injection of $CO_2$) monitoring. These monitoring periods therefore encompass the entire life cycle of the project. For purposes of this monitoring, reporting, and verification (MRV) plan, it is expected that reporting will be initiated during the operational period and continue through the post-injection period.

The storage system parameters that are monitored during each period are essentially identical; however, the duration of the monitoring period of the measurements performed varies. A brief description of the purpose of each of these monitoring periods and their duration is provided below.

The pre-operational baseline monitoring establishes the pre-$CO_2$ injection conditions of the storage system and uncertainty associated with the measurement of each of the key storage system parameters. An understanding of the repeatability and variability of each measurement is key to successfully determining the movement of $CO_2$ that is contained in the formation at any given time.

The operational injection period is focused on validating and updating numerical models of the storage system to ensure that the geologic storage project is operating safely and protecting all USDWs. Lastly, the purpose of the post-operational monitoring is to verify the stability of the $CO_2$ plume location and assess the integrity of all decommissioned wells. The duration of these monitoring periods is a minimum of 20 and 10 years, respectively.

## 3.0 EVALUATION OF POTENTIAL LEAKAGE PATHWAYS

An evaluation of potential subsurface leakage pathways and surface equipment failures during implementation of the project was informed by a screening-level risk assessment (SLRA), which was performed in accordance with the International Organization for Standardization's (ISO's) risk management standard ISO 31000 (Leroux and others, 2017). The SLRA was conducted through a series of work group sessions involving Energy & Environmental Research Center subject matter experts. During these meetings, factors and equipment that could lead to potential leakage pathways were identified and evaluated for the following:

1. Surface components (flowline and wellhead)
2. Abandoned oil and gas wells
3. Faults, fractures, bedding plane partings, and seismicity
4. Injection well or monitoring well
5. Confining zone limitations

This leakage assessment determined none of the pathways required corrective action and the probability of leakage is unlikely. However, a robust monitoring program, described in Reference 1, Section 4.4 and summarized in Table 4-1, was developed to form the basis of this MRV plan.

### 3.1 Surface Components

Surface equipment components present potential leakage pathways during the operational injection period for the RTE CCS project site. Surface equipment can be subject to deterioration due to normal aging throughout its functional life. Corrosion, lack of maintenance, and deviation from operational parameters may cause loss of mechanical integrity in these assets.

The RTE CCS system includes a 4-inch flowline buried a minimum of 6 feet to transport $CO_2$ from the capture facility to the storage site (2 miles). The flowline will be connected to a metering station at the wellhead and located contiguous with the south side of the well pad. Distributed temperature-sensing/distributed acoustic-sensing (DTS/DAS) fiber optics are installed along the flowline as part of the leak detection program and mechanical integrity protocol. Flowmeters and temperatureand pressure transducers will be installed at each metering station.

Shutoff devices will be installed at each end of the flowline to control any potential release and send alarms to the automated system. Pressure gauges will be installed on the wellhead to monitor annular pressure between tubing and casing.

Surface components of the injection system, including the $CO_2$ transport flowline and wellhead, will be monitored using $CO_2$ leak detection equipment. Routine visual inspections will be conducted, and real-time operating parameters tracked through an automated system for alarm notification and process management.

The risk of leakage via surface equipment is mitigated through:

- Adhering to regulatory requirements for construction and operation of the site.
- Implementing highest standards on material selection and construction processes for the flowline and wells.
- Implementing best practices and a robust mechanical integrity program as well as operating procedures.
- Monitoring continuously via an automated system and integrated databases.

The risk of leakage through surface equipment (under normal operating conditions) is unlikely, and the magnitude will vary according to the failure observed. A potential leakage event from instrumentation or valves could represent a few pounds of $CO_2$ released during several hours, while a puncture in the flowline could potentially represent several tons of $CO_2$ released underground until the shutoff device stops the injection automatically or the operator ceases the $CO_2$ supply. Note that should a potential shutoff situation occur, the RTE facility will revert to current operations, emitting $CO_2$ under existing permits maintained through the North Dakota Department of Environmental Quality.

This risk of leakage through surface equipment reduces to almost zero during the post-injection site care period. At cessation of the injection period, the injector wells will be properly plugged and abandoned following NDIC protocols and facility equipment decommissioned according to regulatory requirements. The only remaining surface equipment leakage path will be the monitoring well, RTE-10.2, identified as a potential leakage pathway at the wellhead valves or in the instrumentation.

### 3.2 Abandoned Oil and Gas Wells

The Rummel-State 1 (NDIC No. 6797) well spudded in December 1978 to a depth of 11,270 feet into the Red River Formation and was plugged and abandoned in February 1979. Multiple drillstem tests were conducted in several stratigraphic intervals, but the well encountered no commercial accumulations of hydrocarbons. The Rummel-State 1 was evaluated as part of the risk assessment for the RTE CCS project and is the only oil and gas well within the AOR. It was determined that no corrective action was needed, as the $CO_2$ plume does not come into contact with the well (Reference 1, Section 3.1.2).

## 3.3 Faults, Fractures, Bedding Plane Partings, and Seismicity

No known or suspected regional faults, fractures, or bedding plane partings with sufficient permeability and vertical extent to allow fluid movement between formations have been identified within the AOR through site-specific characterization activities, prior studies, or previous oil and gas exploration activities (Reference 1, Section 2.5).

### *3.3.1 Heart River Fault*

The Heart River Fault, located 3.2 miles southwest of the RTE plant and 1.4 miles from the outer edge of the AOR for the RTE project (Figure 1-2), is a high-angle reverse fault that originates in the Precambrian basement. Through the interpretation of seismic data, the offset of the Heart River Fault is interpreted to be less than 400 feet in rocks up through the Stony Mountain, Stonewall, and lower Interlake Formations, well below the Broom Creek Formation (Reference 1, Section 2.5.1). Formations between the lower Interlake Formation and the Niobrara show some flexure from the fault but have no apparent offset (see Figure 1-3 for stratigraphic reference).

### *3.3.2 Natural or Induced Seismicity*

The history of seismicity relative to regional fault interpretation in North Dakota demonstrates low probability that natural seismicity will interfere with containment (Reference 1 Section 2.5.3). Between 1870 and 2015, 13 seismic events were detected within the North Dakota portion of the Williston Basin (Anderson, 2016). The seismic event recorded closest to the RTE CCS project occurred 21.6 miles from Richardton, North Dakota, with a magnitude of 3.2 (Reference 1, Section 2.5.3).

Studies completed by the U.S. Geological Survey (USGS) indicate there is a low probability of damaging seismic events occurring in North Dakota, with less than two such events predicted to occur over a 10,000-year period (U.S. Geological Survey, 2019). Through the risk assessment process, potential leakage resulting from natural or induced seismicity was shown to be very unlikely.

## 3.4 Injection Well and Monitoring Well

### *3.4.1 RTE-10 (NDIC No. 37229)*

The RTE-10 well spudded in March 2020 as a stratigraphic test well to a depth of 6,900 feet into the Amsden Formation. This well was drilled specifically to gather geologic data to support the development of a $CO_2$ SFP and as the RTE CCS project's future injector well. The RTE-10 will be monitored in real time with external downhole pressure and temperature gauges set in the injection interval and the dissipation interval to detect any potential mechanical integrity issues associated with potential leakage. Additionally, fiber optic cable, which is capable of collecting temperature and acoustic information, will monitor from the top of the injection interval to the base of the confining layer above the dissipation interval during injection. Once the injection period ceases, the RTE-10 will be properly plugged and abandoned following NDIC protocols. A complete description of the RTE-10 wellbore construction can be found in Reference 1, Section

4.5.1 (Well Casing and Cementing Program). An evaluation of RTE-10 for determining the likelihood, magnitude, and timing of potential surface leakage was conducted by a professional engineer and determined there is no significant risk of a potential leakage pathway to the surface (Reference 1, Section 3.1.1)

### *3.4.2 RTE-10.2 (NDIC No. 37858)*

The RTE-10.2 well spudded in October 2020 as a stratigraphic test well and future monitoring well for the injected $CO_2$ of the RTE project. The well was drilled to a depth of 6,770 feet into the Amsden Formation. The RTE-10.2 will monitor the Broom Creek Formation in real time with external downhole pressure and temperature gauges set in the injection interval and the dissipation interval to detect any potential mechanical integrity issues associated with potential leakage. Additionally, fiber optic cable, which is capable of collecting temperature and acoustic information, will monitor from the top of the injection interval to the base of the confining layer above the dissipation interval during injection. Once the injection period ceases, RTE-10.2 will be properly plugged and abandoned following NDIC protocols. A complete description of the RTE-10.2 wellbore construction can be found in Reference 1, Section 4.5.2 (Well Casing and Cementing Program). An evaluation of RTE-10.2 for determining the likelihood, magnitude, and timing of potential surface leakage was conducted by a professional engineer and determined there is no significant risk of a potential leakage pathway to the surface (Reference 1, Section 3.1.1)

## 3.5 Confining Zone Limitations

### *3.5.1 Lateral Migration*

For the RTE CCS project, the initial mechanism for geologic confinement of $CO_2$ injected into the Broom Creek Formation will be the cap rock (Opeche Formation), which will contain the initially buoyant $CO_2$ under the effects of relative permeability and capillary pressure (Reference 1, Section 2.3.2). The Opeche Formation is a laterally extensive formation that is 6,276 feet below the surface and 103 feet thick at the RTE CCS project site (Reference 1, Section 2.4.1). Lateral movement of the injected $CO_2$ will be restricted by residual gas trapping (relative permeability) and solubility trapping (dissolution of the $CO_2$ into the native formation brine).

### *3.5.2 Seal Diffusivity*

Several additional formations provide additional confinement above the Opeche Formation (Reference 1, Section 2.4.2). Impermeable rocks above the primary seal, the Opeche Formation, include the Minnekahta, Spearfish, Piper, and Swift Formations, which make up the first additional group of confining formations. Together with the Opeche, these formations are 1,200 feet thick and will isolate Broom Creek Formation fluids from migrating upward to the next permeable interval, the Inyan Kara Formation. Above the Inyan Kara Formation, 3,000 feet of impermeable rock acts as an additional seal between the Inyan Kara and the lowermost USDW, the Fox Hills Formation. Confining layers above the Inyan Kara include the Skull Creek, Mowry, Belle Fourche, Greenhorn, Carlile, Niobrara, and Pierre Formations (see Figure 1-3 for stratigraphic reference).

The possibility of fluid migration through 1,200 and 3,000 feet of overlying confining layers presents a very low risk to the RTE CCS project site. The thick impermeable layers and laterally extensive formations drastically reduce potential leakage pathways through geologic formations.

#### *3.5.3 Drilling Through the $CO_2$ Area*

There has been no historic hydrocarbon exploration or production from formations below the Broom Creek Formation within the stabilized $CO_2$ plume boundary. Although there was some historical oil and gas production from deeper formations along the nearby Heart River Fault trend, there are no known commercial accumulations of hydrocarbons in the AOR (Reference 1, Section 2.6). With no known commercial ventures drilling near the RTE CCS project area, there is very little chance of drilling through the storage complex at this time. Any future endeavors to explore for, or produce, hydrocarbons could avoid the $CO_2$ plume using horizontal drilling techniques.

### 3.6 Monitoring, Response, and Reporting Plan for $CO_2$ Loss

RTE proposes a detailed emergency remedial and response plan (Reference 1, Section 4.1) that covers the actions to be implemented from detection, verification, analysis, remediation, and reporting for each risk. RTE also proposes a robust monitoring program based on the detailed risk assessment performed during the application for the storage facility and UIC Class VI permit. The program covers a corrosion and mechanical integrity protocol (Reference 1, Section 4.4.2); continuous, real-time surveillance of injection performance (Reference 1, Sections 4.4.3 and 4.4.4); monitoring of near-surface conditions (Reference 1, Sections 4.4.5–4.4.7); and direct and indirect monitoring of the $CO_2$ plume (Reference 1, Sections 4.4.8.1 and 4.4.8.2).

### 3.7 Summary

In an unlikely scenario of potential leakage through any pathway, response and remediation would be performed in accordance with the emergency and remedial response plan. Estimating volumetric losses of $CO_2$ would require consideration of the potential leakage event facts and circumstances, e.g., magnitude and timing of the $CO_2$ leak and pathway characteristics (fault or fracture permeability, geometry extension, and location). Based upon the presenting facts and circumstances, modeling to estimate the $CO_2$ loss would be performed and volumetric accounting would follow industry standards as applicable.

## 4.0 STRATEGY FOR DETECTING AND QUANTIFYING POTENTIAL SURFACE LEAKAGE OF $CO_2$

Table 4-1 summarizes the monitoring frequency for each of the three project periods, and Table 4-2 summarizes the potential leakage pathway covered by each technique. These methodologies target early detection of any potential abnormalities in operating parameters or deviations from the baseline and threshold established for the project. These methodologies will lead to a verification process to validate if a potential leak has occurred or if the system has lost mechanical integrity. The data collected during monitoring are also used to calibrate the numerical model and improve the prediction for the injectivity, $CO_2$ plume, and pressure front.

## Table 4-1. Summary of RTE's CCS Monitoring Strategy

| Method (target area/structure) | Pre-Injection (Baseline – 1 year) | Injection Period (20 years) | Post-Injection (10 years) |
|---|---|---|---|
| $CO_2$ Stream Analysis (capture) | Start-up | Real-time | NA[1] |
| Surface Pressure Gauges and Temperature Sensors (RTE-10, RTE-10.2, and flowline) | NA | Real-time | NA |
| Mass/Volume Flowmeters (RTE-10 and flowline) | NA | Real-time | NA |
| Downhole Pressure Gauges and Temperature Sensors (RTE-10 and RTE-10.2) | NA | Real-time | Real-time until plume stabilization is demonstrated |
| DTS/DAS Fiber (RTE-10 and RTE 10.2, dedicated Fox Hills monitoring wells, and flowline) | NA | Real-time | Real-time DTS until well plugging and site reclamation |
| Visual Inspections (flowline) | Start-up | Quarterly | Quarterly |
| Corrosion Coupons (flowline) | NA | Quarterly | NA |
| SCADA[2] Automated Remote System (surface facilities) | Start-up | Real time | NA |
| Soil Gas Analysis (AOR) | Three to four seasonal samples adjacent to each RTE well | Three to four seasonal samples per year adjacent to each well | Three to four seasonal samples every 3 years adjacent to each well |
| Water Analysis: Shallow Aquifers (AOR) | Three to four seasonal sample events per water wells closest to RTE-10 | Once per year during years 1 through 3 and 5, then every 5 years thereafter. Other water wells may be phased in based on $CO_2$ plume migration. | Three to four sample events at cessation of injection and before site closure |
| Water Analysis: Lowest USDW (AOR) | Three to four sample events per dedicated Fox Hills monitoring well adjacent to each RTE well | Once per year during years 1 through 3 and 5, then every 5 years thereafter | Three to four sample events at cessation of injection and before site closure |
| Cement Bond Logs (RTE-10 and RTE-10.2) | After cementing | If needed | Prior to P&A[3] |

Continued . . .

**Table 4-2. Summary of RTE's CCS Monitoring Strategy (continued)**

| Method (target area/structure) | **Pre-Injection (Baseline – 1 year)** | **Injection Period (20 years)** | **Post-Injection (10 years)** |
|---|---|---|---|
| Annular Pressure Test (RTE-10 and RTE-10.2) | Prior injection | Perform during workovers but not more than once every 5 years | Perform during workovers but not more than once every 5 years |
| Pulsed-Neutron Logs (RTE-10 and RTE-10.2) | Baseline | Every 5 years in RTE-10.2 and as needed in RTE-10 | Every 5 years in RTE-10.2 and as needed in RTE-10 |
| Ultrasonic Imager Logs (RTE-10 and RTE-10.2) | Baseline | Perform during workovers but not more than once every 5 years | Perform during workovers but not more than once every 5 years |
| Pressure Falloff Test (RTE-10) | Prior to injection | Every 5 years | Prior to P&A |
| Time-Lapsed Seismic Surveys (AOR) | Baseline | Every 5 years | Every 5 years |
| Surface Seismometers (AOR) | Baseline | Real-time | Real-time |
| InSAR[4] (AOR)* | Baseline | Real-time | Real-time |
| Gravity Surveys (AOR)* | Baseline | TBD[5] – repeat survey at least once | TBD |

* If feasible.
[1] Not applicable.
[2] Supervisory control and data acquisition.
[3] Plugged and abandoned.
[4] Interferometric synthetic aperture radar.
[5] To be determined.

**Table 4-3. Monitoring Strategies for Detecting Changes in the Storage Reservoir Associated with $CO_2$ Injection**

| Monitoring Strategy (target area) / Potential Leakage Pathway | Wellbores | Faults and Fractures | Natural and Induced Seismicity | Flowline and Surface Equipment | Vertical Migration | Lateral Migration | Diffuse Leakage Through Seal |
|---|---|---|---|---|---|---|---|
| $CO_2$ Stream Analysis (capture) | X | | | X | X | | X |
| Surface Pressure Gauges and Temperature Sensors (RTE-10, RTE-10.2, and flowline) | X | | | X | X | X | |
| Mass / Volume Flowmeters (RTE-10 and flowline) | | | | X | X | | |
| Downhole Pressure Gauges and Temperature Sensors (RTE-10 and RTE-10.2) | X | | | X | X | X | X |
| DTS/DAS Fiber (RTE-10, RTE-10.2, dedicated Fox Hills monitoring wells, and flowline) | X | X | X | X | X | X | X |
| Visual Inspections (flowline) | X | | | X | X | | |
| Corrosion Coupons (flowline) | | | | X | X | | |
| SCADA Automated Remote System (surface facilities) | | | X | X | X | | |
| Soil Gas Analysis (AOR) | X | | | | X | | X |
| Protected Groundwater Zone: Shallow Aquifers (AOR) | | X | | | X | | X |
| Protected Groundwater Zone: Lowest USDW (AOR) | X | | | | X | | X |
| Cement Bond Logs (RTE-10 and RTE-10.2) | | | | | X | | |
| Annular Pressure Test (RTE-10 and RTE-10.2) | | | | X | X | | |
| Pulsed-Neutron Logs (RTE-10 and RTE-10.2) | X | | | | X | X | X |
| Ultrasonic Imager Logs (RTE-10 and RTE-10.2) | | | | | X | | |
| Pressure Falloff Test (RTE-10) | X | | | | X | X | |
| Time-Lapsed Seismic Surveys (AOR) | X | X | | X | X | X | X |
| Surface Seismometers (AOR) | | X | X | | | | X |
| InSAR (AOR)* | X | X | | X | | X | X |
| Gravity Surveys (AOR)* | | | | | | X | |

* If feasible.

### 4.1 Potential Leak Verification

RTE will monitor injection wells through continuous, automated pressure and temperature monitoring in the injection zone, monitoring of the annular pressure in wellheads, DTS alongside the casing, and routine maintenance and inspection.

As part of the surveillance protocol, RTE will use reservoir simulation modeling, based on history-matched data obtained from the monitoring system, to compare the initial numerical model with the real development of the plume and pressure front. The model will be continuously calibrated with the acquisition of real-time data. Every 5 years, a formal AOR review will be submitted, and the monitoring plan revised and modified if needed.

The model history match allows the project operator and owner to identify conditions that differ from those proposed by the numerical model and deviations in the operating conditions from the originals. For example, the injection well will be monitored, and if the injection pressure, temperature, or rate measurements deviate significantly from the specified set points, then a data flag will be automatically triggered by the automated system and field personnel will investigate the excursion. These excursions will be reviewed to determine if potential $CO_2$ leakage is occurring. Excursions are not necessarily indicators of potential leaks; rather, they indicate that injection rates, temperatures, and pressures are not conforming to the expected pattern of the injection plan. In many cases, problems are straightforward and easy to fix (e.g., a meter needs to be recalibrated) and there is no indication that potential $CO_2$ leakage has occurred. In the case of issues that are not readily resolved, a more detailed investigation will be initiated. If further investigation indicates a potential leak has occurred, efforts will be made to quantify its magnitude.

The model history-matching in combination with the mechanical integrity data, geophysical surveys, and near-surface monitoring form a powerful tool to appropriately follow changes in $CO_2$ concentration at the surface. Many variations of $CO_2$ concentration detected on the surface are the result of natural processes or external events not related to the $CO_2$ storage complex.

Because a potential $CO_2$ surface leak is of lower temperature than ambient conditions, it will often lead to the formation of bright white clouds and ice that are easily visually observed. With this understanding, RTE will also rely on a routine visual inspection process to detect unexpected releases from wellbores of the RTE CCS project.

Response plan actions and activities will depend upon the circumstances and severity of the event. RTE will address an event immediately and, if warranted, communicate the event to the UIC program director within 24 hours of discovery.

If an event triggers cessation of injection and remedial actions, RTE will demonstrate the efficacy of the response/remedial actions to the satisfaction of the UIC program director before resuming injection operations. Injection operations will only resume upon receipt of written authorization of the UIC program director.

## 4.2 Quantification of Potential Leakage

As discussed above, the potential pathways for leakage include failure or issue in surface equipment or subsurface equipment (wellbores), faults or induced fractures, and competency of the seal to contain the $CO_2$ in the storage reservoir.

Given the uncertainty concerning the nature and characteristics of any potential leaks that may be encountered, the most appropriate methods to quantify the volume of $CO_2$ will be determined on a case-by-case basis. Any volume of $CO_2$ detected as potentially leaking to the surface will be quantified using acceptable emission factors, engineering estimates of potential leak amount based on subsurface measurements, numerical models, history-matching of the reservoir performance, detailed analysis of the collected monitoring parameters, and delineation of the affected area, among others. Potential leaks will be documented, evaluated, and addressed in a timely manner. Records of potential leakage events will be retained in an electronic central database.

# 5.0 DETERMINATION OF BASELINES

RTE will establish pre-injection baselines by implementing a monitoring program prior to any $CO_2$ injection and during each of the four primary seasonal ranges. This baseline will be created by monitoring the targeted surface, near-surface, and deep subsurface. The baseline will contain information on the characteristics of a range of environmental media such as surface water, soil gas in the vadose zone, shallow groundwater, and storage reservoir formation water.

These baselines provide a basis for determining if potential $CO_2$ leaks are occurring by providing a foundation against which characteristics of these same media during $CO_2$ injection can be compared and evaluated. For example, changes in concentrations or levels of certain parameters in these media during injection might suggest that they have been impacted by potentially leaking $CO_2$.

Determinations of these baselines are a critical component of a Class VI SFP. A detailed description of these baselines for both the surface and subsurface for the RTE CCS project area is provided in Reference 1, Section 4.4.6.

## 5.1 Surface Baselines

A baseline sampling program has been completed for the RTE CCS project. Baseline data were obtained from 11 soil gas-sampling locations and three existing groundwater wells in the northwestern portion of the AOR. In addition, two dedicated monitoring wells were drilled in the Fox Hills Formation and placed near the RTE injection and monitoring wells. For additional information regarding surface baselines, refer to Reference 1, Sections 4.4.5–4.4.7.

### 5.2 Subsurface Baselines

Pre-operational baseline data will be collected in the injection and monitoring wells using pulsed-neutron logs. These time-lapse saturation data will be used as an assurance-monitoring technique for $CO_2$ in the formation directly above the storage reservoir, otherwise known as the above-zone monitoring interval.

Indirect monitoring methods will also track the extent of the $CO_2$ plume within the storage reservoir and can be accomplished by performing time-lapse geophysical surveys of the AOR. A 3D seismic survey was conducted to establish baseline conditions in the storage reservoir.

Feasibility studies for monitoring surface deformation with InSAR and detecting changes in mass with gravity methods will be performed prior to injection to justify application of the technologies at the RTE CCS site. For more information on what these technologies measure and how RTE plans to implement them, refer to Reference 1, Section 4.4.8 and Table 4-11 in Section 4.4.8.2, respectively.

For passive seismicity monitoring, the project will install seismometer stations sufficient to confidently measure baseline seismicity from the injection area 1 year prior to injection. For additional information regarding subsurface baselines, refer to Reference 1, Section 4.4.8.

## 6.0 DETERMINATION OF SEQUESTRATION VOLUMES USING MASS BALANCE EQUATIONS

The RTE CCS project area is a $CO_2$ storage site in a saline aquifer with no production associated from the storage complex. The proposed main metering station for mass balance calculation is identified as the first metering station placed at the wellhead, using the station at the flow line as a backup/duplicate.

To calculate the annual mass of $CO_2$ that is stored in the storage complex, the project will use Equation RR-12 from 40 CFR Part 98, Subpart RR (Equation 1):

$$CO_2 = CO_{2I} - CO_{2E} - CO_{2FI} \qquad \text{[Eq. 1]}$$

Where:

$CO_2$ = Total annual $CO_2$ mass stored in subsurface geologic formations (metric tons) at the facility.

$CO_{2I}$ = Total annual $CO_2$ mass injected (metric tons) in the well or group of wells.

$CO_{2E}$ = Total annual $CO_2$ mass emitted (metric tons) by potential surface leakage.

$CO_{2FI}$ = Total annual $CO_2$ mass emitted (metric tons) from potential equipment leaks and vented emissions of $CO_2$ from equipment located on the surface between the flowmeter used to measure injection quantity and the injection wellhead, for which a calculation procedure is provided in Subpart W of Part 98.

Mass of $CO_2$ Injected ($CO_{2I}$):

RTE will use volumetric flow metering to measure the flow of the injected $CO_2$ stream and will calculate annually the total mass of $CO_2$ (in metric tons) in the $CO_2$ stream injected each year in metric tons 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 Equation RR-5 from 40 CFR Part 98-Subpart RR (Equation 2):

$$CO_{2,u} = \sum_{p=1}^{4} Q_{p,u} * D * C_{CO_2,p,u} \qquad \text{[Eq. 2]}$$

Where:

$CO_{2,u}$ = Annual $CO_2$ mass injected (metric tons) as measured by Flowmeter u.

$Q_{p,u}$ = Quarterly volumetric flow rate measurement for Flowmeter 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.

$C_{CO2,p,u}$ = Quarterly $CO_2$ concentration measurement in flow for Flowmeter u in Quarter p (weight percent $CO_2$, expressed as a decimal fraction).

p = Quarter of the year.

u = Flowmeter.

Mass of $CO_2$ Emitted by Potential Surface Leakage ($CO_{2E}$):

RTE characterized, in detail, potential leakage paths on the surface and subsurface, concluding that the probability is very low in each scenario. However, a detailed monitoring and surveillance plan is proposed in Reference 1, Section 4.4, to detect any potential leak and defined a baseline for monitoring.

If the monitoring and surveillance plan detects a deviation from the threshold established for each method, the project will conduct a detailed analysis based on technology available and type of potential leak to quantify the $CO_2$ volume to the best of its capabilities. The process for quantifying potential leakage could entail using best engineering principles, emission factors, advanced geophysical methods, delineation of the potential leak, and numerical and predictive models among others.

RTE will calculate the total annual mass of $CO_2$ emitted from all potential leakage pathways in accordance with the procedure specified in Equation RR-10 from 40 CFR Part 98-Subpart RR (Equation 3):

$$CO_{2E} = \sum_{x=1}^{X} CO_{2,x} \qquad \text{[Eq. 3]}$$

Where:

$CO_{2E}$ = Total annual $CO_2$ mass emitted by potential surface leakage (metric tons) in the reporting year.

$CO_{2,x}$ = Annual $CO_2$ mass emitted (metric tons) at potential leakage pathway x in the reporting year.

x = Potential leakage pathway.

Mass of $CO_2$ Emitted by Potential Equipment Leaks and Vented Emissions ($CO_{2FI}$)
Annual mass of $CO_2$ emitted (in metric tons) from potential 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 ($CO_{2FI}$) 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 and surveillance plan proposed in Reference 1, Section 4.4.

## 7.0 MRV PLAN IMPLEMENTATION SCHEDULE

This MRV plan will be implemented starting April 2022 or within 90 days of EPA approval, whichever occurs later. Other greenhouse gas (GHG) reports are filed on April 30 of the year after the reporting year, and it is anticipated that the Annual Subpart RR report will be filed at the same time. It is anticipated that the MRV program will be in effect during the period of 30 years (20 years injection and 10 years post-injection) from April 2022 to April 2052, during which time the RTE CCS project will be operated.

## 8.0 QUALITY ASSURANCE PROGRAM

A detailed quality assurance procedure for RTE monitoring techniques and data management is provided in the quality assurance and surveillance plan found in Reference 1, Section 4.4.9.

RTE will ensure compliance with the quality assurance requirement in 40 CFR § 98.444:

$CO_2$ received:
- The quarterly flow rate of $CO_2$ will be reported from continuous measurement at a receiving meter on the injection well pad.
- The quarterly $CO_2$ concentration will be reported from near-continuous measurement upstream of the receiving meter on the injection well pad.

Flowmeter provision:
- Operated continuously, except as necessary for maintenance and calibration.
- Operated using calibration and accuracy requirements in 40 CFR § 98.3(i).
- Operated in conformance with consensus-based standards organizations including, but not limited to, the American Society for Testing and Materials International, the American National Standards Institute, the American Gas Association, the American Society of Mechanical Engineers, the American Petroleum Institute, and the North American Energy Standards Board.

## 9.0 RECORDS RETENTION

RTE will follow the record retention requirements specified by 40 CFR § 98.3(g). In addition, it will follow the requirements in Subpart RR 40 CFR § 98.447-Subpart RR by maintaining the following records for at least 3 years:

- Quarterly records of $CO_2$ received at standard conditions and operating conditions, operating temperature and pressure, and concentration of the streams.
- Quarterly records of injected $CO_2$, including volumetric flow at standard conditions and operating conditions, operating temperature and pressure, and concentration of the streams.
- Annual records of information used to calculate the $CO_2$ emitted by surface leakage from leakage pathways.
- Annual records of information used to calculate the $CO_2$ emitted from potential equipment leaks and vented emissions of $CO_2$ from equipment located on the surface between the flowmeter used to measure injection quantity and the injection wellhead.

These data will be collected, generated, and aggregated as required for reporting purposes.

## 10.0 REFERENCES

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