OFFICE OF ATMOSPHERIC PROTECTION
WASHINGTON, D.C. 20460

July 14, 2025

Mr. James Schramski
Riverside Energy Holdings, LLC
10691 East Carter Road
Traverse City, Michigan 49684

Re: Monitoring, Reporting and Verification (MRV) Plan for Chester 21-29N-02W

Dear Mr. Schramski:

The United States Environmental Protection Agency (EPA) has reviewed the Monitoring, Reporting and Verification (MRV) Plan submitted for Chester 21-29N-02W, as required by 40 CFR Part 98, Subpart RR of the Greenhouse Gas Reporting Program. The EPA is approving the MRV Plan submitted by Chester 21-29N-02W on February 6, 2025, as the final MRV plan. The MRV Plan Approval Number is 1015227-1. This decision is effective five days after the signature date below and is appealable to the EPA's Environmental Appeals Board under 40 CFR Part 78. In conjunction with this MRV plan approval, we recommend reviewing the Subpart PP regulations to determine whether your facility is required to report data as a supplier of carbon dioxide. Furthermore, this decision is applicable only to the MRV plan and does not constitute an EPA endorsement of the project, technologies, or parties involved.

If you have any questions regarding this determination, please contact me or the Greenhouse Gas Reporting Program Helpdesk at ghgreporting@epa.gov.

Sincerely,

SHARYN LIE Digitally signed by SHARYN LIE
Date: 2025.07.14 18:20:27 -04'00'

Sharyn Lie
Director, Climate Change Division

Technical Review of Subpart RR MRV Plan for Chester 21-29N-02W

April 2025

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Appendices

This document summarizes the U.S. Environmental Protection Agency's (EPA's) technical evaluation of the Greenhouse Gas Reporting Program (GHGRP) subpart RR Monitoring, Reporting, and Verification (MRV) plan submitted by Riverside Energy Michigan, LLC for the Chester 21-29N-02W Storage Facility (Chester) located in Otsego County, Michigan. Note that this evaluation pertains only to the Subpart RR MRV plan, and does not in any way replace, remove, or affect Underground Injection Control (UIC) permitting obligations. Furthermore, this decision is applicable only to the MRV plan and does not constitute an EPA endorsement of the project, technologies, or parties involved.

1 Overview of Project

Section 1 of the MRV plan states that Riverside Energy Michigan, LLC (REM) is developing the Chester facility located in Otsego County, Michigan, approximately 9 miles southeast of the town of Gaylord, Michigan. The plan explains that the project would securely store the CO_2 emissions captured from the processing of natural gas produced from the Antrim Shale biogenic gas play in the northern Michigan Basin. The captured CO_2 will be injected into the Niagaran Pinnacle Reef.

According to the MRV plan, the Devonian age Antrim Shale Formation, from which the CO_2 originates, is produced regionally from a subsurface depth of approximately 1,000 to 2,000 ft. The Silurian age Niagaran reef that constitutes the storage formation is approximately 6,000 to 7,000 ft and has neither unplugged wells nor hydrocarbon production associated with it. The MRV plan states it is the explicit purpose and design of this project to sequester and dispose of CO_2 and not to facilitate any additional production from the Storage Facility.

The CO_2 injection well (Smith 3-21) will be operated by Riverside Energy Michigan, LLC, permitted as a UIC Class II well, and regulated by Michigan Department of Environment, Great Lakes, and Energy (Michigan-EGLE) Geologic Resources Management Division (GRMD). The UIC Class II permit for the proposed Smith 3-21 injection well was issued by Michigan-EGLE GRMD.

Section 2 of the MRV plan provides the project description and general geologic settings. The Chester Field is a Northern Niagaran Pinnacle Reef Trend (NNPRT) located in Sections 21 and 22 of Township 29 North, Range 2 West, Otsego County, Michigan. The NNPRT in the Michigan Basin features several hundred highly compartmentalized pinnacle reefs found at an average dept of about 6,000 ft below the ground surface. These reefs are separated from one another by distances as little as hundreds of feet to as much as several miles. The NNPRT originated from coral reefs formed during the Silurian Period 420 to 440 million years ago in tropical sea environments. Individual reefs typically range in area from 50 to 500 acres and have vertical heights between 100 to 700 ft in the subsurface.

The MRV plan states the reservoir facies primarily consist of porous and permeable dolomite and limestone. Reef porosity values can be as high as 35%, but typically average 3 to 12%. Net pay intervals can total from only a few feet to several hundred feet. The most productive reef reservoirs are characterized by dolomitized reef facies with well-developed inter-crystalline and vuggy porosity.

Secondary porosity is present and can enhance permeability, which typically averages 3 to 10 millidarcies.

The Niagara and A1 Carbonate Formations of the early Silurian Niagara Group contain the main reservoir units within the reefs. The base of the Niagara Formation, referred to as the "Lockport" or "White Niagaran" is typically a partially dolomitized to dolomitized crinoidal wackestone. Overlying the Lockport, the Guelph Formation is comprised of units commonly referred to as the "Gray" and "Brown" Niagaran. The Gray Niagaran and Lockport are typically characterized by very low porosity. The Brown Niagaran comprises the core of the reef reservoir and pinnacle reef buildup. The A1 Carbonate and Brown Niagaran Formations are encased by a sequence of evaporites and salt-plugged carbonates, comprising the seal for the reefs. The A1 Evaporite is typically thin or not present at the crest of the reef but forms a seal of the Brown Niagaran at reef flanks.

According to the MRV plan A2 Evaporite Formation rests directly on top of the A1 Carbonate Formation and serves as the primary seal for the Storage Facility. The A2 Evaporite is characterized by non-porous and impermeable anhydrite at the reef crest, which transitions to halite dominated facies off the structure of the reef. Above the 120 ft thick A2 Evaporite Formation is a 1,300 ft thick series of massive evaporite deposits and interbedded shale and limestone deposits that make up the bulk of the Salina Group.

The description of the project provides the necessary information for 40 CFR 98.448(a)(6).

2 Evaluation of the Delineation of the Maximum Monitoring Area (MMA) and Active Monitoring Area (AMA)

As part of the MRV plan, the reporter must identify and delineate both the maximum monitoring area (MMA) and active monitoring area (AMA), pursuant to 40 CFR 98.448(a)(1). Subpart RR defines the maximum monitoring area as "the area that must be monitored under this regulation and 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 zone of at least one-half mile." Subpart RR defines the active monitoring area as "the area that will be monitored over a specific time interval from the first year of the period (n) to the last year in the period (t). The boundary of the active monitoring area is established by superimposing two areas: (1) the area projected to contain the free phase CO_2 plume at the end of year t, plus an all-around buffer zone 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 t + 5." See 40 CFR 98.449.

A geologic model was developed to complete computation injection simulations and evaluate the dynamic storage capacity of the Chester facility. The model was generated from 2D seismic and well log information in IHS' *Petra®* software. Computer Modeling Group's *GEM™* reservoir simulation software was used to complete injection simulation. The reef reservoir is modeled as a closed system with all model boundaries closed and initialized with depleted gas, oil, and water saturations at 300 psi. The simulation was run for 15 years. For the model, the injection rate was set at 12,000 Mcfd based on basin experience from CO_2 injection in other Niagaran reef projects. The maximum bottomhole pressure was limited to 4,345 psi. After approximately 4 years, the model showed that the maximum bottomhole pressure limit was reached, limiting further injection. The simulation injected 16.7 billion cubic feet of CO_2 or approximately 880,000 metric tons of CO_2 after 5 years.

According to the MRV plan, REM plans to inject CO_2 at a rate of 12,000 Mcfd or approximately 230,000 metric tons of CO_2 per year. Injection will continue until the reef pressure increases to the maximum bottomhole pressure of 4,345 psi. Once additional injection is constrained by bottomhole pressure limit, injection will stop. Based on the mass balance and injection simulation work described in the storage reservoir is expected to fill up after approximately 5 years at an average injection rate of 12,000 Mcfd.

The MRV plan states that the Chester facility is defining the time period of the AMA to be 10 years in order to span the expected injection period and provide incorporated buffer time for any maintenance, downtime, or unexpected delays. To concur with the regulation that the AMA is defined as the area projected to contain the free phase CO_2 plume at the end of year t + 5 plus a one-half mile all around buffer, Riverside has delineated the AMA boundary as the extent of the CO_2 plume at the end of year 15 plus a one-half mile buffer zone. The compartmentalized nature of the Niagaran reef creates conditions where the plume is limited to the shape and the volume of reef structure. Per the modelling, the free phase CO_2 plume is projected to remain within the Reef Structure. Therefore, REM defines the MMA as the same as the AMA since the plume is constrained to the reef structure.

The delineations of the MMA and AMA are acceptable per the requirements in 40 CFR 98.448(a)(1). The MMA and AMA described in the MRV plan are clearly delineated in the plan and are consistent with the definitions in 40 CFR 98.449.

3 Identification of Potential Surface Leakage Pathways

As part of the MRV plan, the reporter must identify potential surface leakage pathways for CO_2 in the MMA and the likelihood, magnitude, and duration of surface leakage of CO_2 through these pathways pursuant to 40 CFR 98.448(a)(2). REM identified the following as potential leakage pathways in Section 5 of their MRV plan that required consideration:

- Surface equipment
- Existing wellbores
- Wells not yet drilled
- Injection Wellbore
- Existing faults and fractures
- Natural / Induced seismicity
- Confining layers
- Lateral migration

3.1 Potential Leakage from Surface Equipment

The MRV plans states that the potential leakage pathways from surface equipment are limited to the mass flow meter, the injection wellhead, the short flowline between the two, and any pipe fittings or valves installed along the flowline or wellhead. REM states that the likelihood of leakage from these surface components is low. To further mitigate leakage REM is locating the CO_2 received and injection mass flow meter near the wellhead to minimize opportunities for potential leakage from surface equipment. Furthermore, REM states they are adhering to high material selection and construction standards when designing and constructing the wellhead and flowline. The MRV plan also states the wellhead and mass flow meter will be continuously monitored with the supervisory control and data acquisition (SCADA) systems. Additionally, personnel will routinely conduct audible, visual, and olfactory (AVO) inspections of the surface equipment for leaks along with quarterly monitoring of surface equipment with Optical Gas Imaging (OGI) technology. Therefore, REM estimates the magnitude of potential leakage from these surface components is small with any leaked volume likely limited to the volume of CO_2 in the flowline or wellhead components. The timing of leakage spans from the start of injection until the well is plugged and abandoned.

Thus, the MRV plan provides an acceptable characterization of CO_2 leakage that could be expected from surface equipment.

3.2 Potential Leakage from Existing Wellbores

The MRV plan describes seven boreholes that penetrate the A2 confining layers. These boreholes are both inside and outside of the reef structure.

Inside the Reef

The MRV plans states there are four boreholes that penetrate the A2 Evaporite confining layer within the Reef Structure. Three of these boreholes have been plugged and abandoned according to State of Michigan standards and determined by REM to be an unlikely pathway for CO_2 migration above the confining interval. REM has determined that a cement plug has been placed within the boreholes that span the A2 Evaporite confining layer, as well as within several overlying intervals. Therefore, leakage through these legacy wellbores is unlikely. The fourth borehole that penetrates the A2 Evaporite confining layer is an active brine disposal well. The MRV plan states the well was reworked into a brine disposal well by plugging back and completing the well within the Dundee formation at approximately 2,450 ft. The well continues to pass mechanical integrity tests (MITs) in accordance with State of Michigan standards. REM has determined that the State Chester 2-22 well is a low risk for CO_2 leakage because it has been properly plugged downhole and recompleted above.

Outside the Reef

The MRV plan states that two boreholes within the ½ mile buffer of the AMA and MMA penetrate the A2 Evaporite confining layer. One additional borehole surface location is located within the AMA and MMA, however, it’s bottomhole location and penetration of the A2 Evaporite confining layer are located outside of the Project’s AMA and MMA. These three wellbores have been plugged and abandoned according to State of Michigan standards. The likelihood of leakage from these wells is very low as they do not intersect the Reef Structure and the projected free-phase CO_2 plume.

The MRV plan states there are 21 wellbores within the AMA and MMA that do not penetrate the A2 Evaporite confining layer. The likelihood of CO_2 leakage through any of these wellbores is assessed to be very low because the bottom of each of these boreholes is at least 3,350 vertical feet above the top of the A2 Evaporite confining layer. Furthermore, the geologic formations within this minimum 3,350 feet of vertical separation consists primarily of regionally deposited evaporites and tight carbonates with characteristically low vertical permeability.

Thus, the MRV plan provides an acceptable characterization of the likelihood of CO_2 leakage that could be expected through existing wells.

3.3 Potential Leakage from Wells not yet Drilled

The MRV plan states wellbores drilled in the future through the Reef Structure may be a potential leakage pathway for CO_2 but the likelihood of leakage from wells not yet drilled is low. REM states hydrocarbon production from the A1 Carbonate and Brown Niagaran formations in the Chester Facility Reef Structure will not be possible after injection of CO_2 begins. Additionally, there are no known hydrocarbon producing formations below the Brown Niagaran in the AMA and MMA. The MRV plan states future wells drilled outside of the Reef Structure but within the AMA and MMA will not interact with the free-phase CO_2 plume and all well records and injection data will be shared with Michigan-EGLE to ensure that potential drillers are aware of the Project for the indefinite future. Lastly, the MRV plan states Michigan Admin. Code R. 324.413 regulates the drilling of wellbores to strata beneath gas storage reservoirs. While this rule applies to natural gas storage projects (not CO_2 storage projects), Michigan-EGLE already has experience in protecting and regulating the drilling of new wells through gas storage reservoirs. Therefore, it is unlikely that any future wells will be drilled through the A2 Evaporite confining layer within the Reef Structure and projected free-phase CO_2 plume. The magnitude of potential leakage from wells not yet drilled is low.

Thus, the MRV plan provides an acceptable characterization of the likelihood of CO_2 leakage that could be expected from wells not yet drilled.

3.4 Potential Leakage from the Injection Wellbore

Only one well, Smith 3-21 will be permitted and constructed as a Class II oil field waste disposal well with Michigan-EGLE. The MRV plan states that the well will be constructed more rigorously than Michigan Class II standards. Prior to injection, a cement bond log and MIT will be run to ensure proper well construction. Chester will perform a MIT at least every five 5 years per Michigan-EGLE requirements. Chester states they will monitor annular fluid volume quarterly, and surface pressure of the tubing and annular space will be continuously monitored by a SCADA system. Additionally, Chester will monitor surface components with OGI technology quarterly. Once injection is complete the injection well will be plugged and abandoned with cement plugs placed to prevent any future leakage of CO_2. The MRV plan states leakage from the injection wellbore is unlikely due to the constant monitoring of the wellbore and periodic mechanical integrity testing. The magnitude of leakage from the injection wellbore is small. It is unlikely that a blowdown of the wellbore would be necessary, but if one occurs, the leaked CO_2 would be limited to the volume contained in the wellbore and could be easily quantified using volume, pressure, and temperature data. The timing of leakage risk from the injection wellbore occurs from the beginning of injection until proper plugging and abandonment.

Thus, the MRV plan provides an acceptable characterization of the likelihood of CO_2 leakage that could be expected through the injection wellbore.

3.5 Potential Leakage from Existing Faults and Fractures

REM's evaluation of 2D seismic data did not reveal any faults or fractures in the Reef Structure, and there are no known faults or fractures through the A2 Evaporite confining layer in the AMA and MMA that would allow CO_2 movement into overlying formations. The risk of leakage of CO_2 from an unknown fault or fracture is very low because hydrocarbons were sealed within the Reef Structure throughout geological time.

Thus, the MRV plan provides an acceptable characterization of the likelihood of CO_2 leakage that could be expected through existing faults and fractures.

3.6 Potential Leakage from Natural or Induced Seismicity.

The MRV plan states the Michigan Basin is structurally stable with few major structural features. No naturally occurring earthquakes greater than magnitude 2.5 have originated within 100 miles of the Storage Facility since 1900. To date, REM is unaware of any induced seismicity issues associated with natural gas storage in Niagaran reefs. The planned maximum bottomhole pressure for the Storage Facility is 4,345 psi (6,036 ft depth * 0.8 psi/ft fracture gradient * 0.9 safety factor). The MRV plan states the likelihood of leakage from induced seismicity is low and the risk would be limited to the active injection period because the reservoir pressure will be highest during the injection period.

Thus, the MRV plan provides an acceptable characterization of the likelihood of CO_2 leakage that could be expected from natural of induced seismicity.

3.7 Potential Leakage through Confining Layers

The MRV plan states the primary seal of the Project is the A2 Evaporite confining layer. The A2 Evaporite is comprised of anhydrite which has extremely limited porosity and permeability. Above the A2 Evaporite confining layer, additional evaporite and low-permeability carbonate sequences are present that further reduce the risk of upward movement of CO_2 through overlying strata. The MRV plan states likelihood of leakage through confining layers is very low, because the A2 Evaporite confining layer's sealing capacity has been proven by the previous trapping of hydrocarbons throughout geologic time.

Thus, the MRV plan provides an acceptable characterization of the likelihood of CO_2 leakage that could be expected through confining layers.

3.8 Potential Leakage from Lateral Migration

REM states the Reef Structure is fully compartmentalized due to the unique formation of the pinnacle reef and subsequent deposition of overlying strata. The Reef Structure is encased in a tight carbonate and non-porous evaporate seal that prevents the vertical and lateral migration of fluids. The MRV plan states the likelihood of leakage from lateral migration of CO_2 is very low as demonstrated by the production history The magnitude of any potential leakage is low due to the closed structure of the reef.

Thus, the MRV plan provides an acceptable characterization of the likelihood of CO_2 leakage that could be expected from lateral migration.

4 Strategy for Detection and Quantifying Surface Leakage of CO_2 and for Establishing Expected Baseline for Monitoring

40 CFR 98.448(a)(3) requires that an MRV plan contains a strategy for detecting and quantifying any surface leakage of CO_2, and 40 CFR 98.448(a)(4) requires that an MRV plan includes a strategy for establishing the expected baselines for monitoring potential CO_2 leakage. Section 5 of the MRV plan discusses the strategies that REM and the Chester facility will employ for detecting and quantifying surface leakage of CO_2 through the pathways identified in the previous section to meet the requirements of 40 CFR 98.448(a)(3).

4.1 Detecting and Quantifying Leakage from Surface Equipment

The MRV plan noted the potential leakage pathways from surface equipment are limited to the mass flow meter, injection wellhead, short flowline, and associated pipe fittings or valves. However, the likelihood of leakage is low due to several mitigation measures. The MRV plan states the CO_2 mass flow meter is located near the wellhead to minimize potential leakage risks. High-quality materials and strict construction standards are used in designing the wellhead and flowline to enhance integrity. Continuous monitoring through the SCADA system ensures real-time detection of any anomalies. Additionally, routine AVO inspections are conducted at least once per week to identify leaks, which may be detected by sound, visual distortion, or odor. Quarterly inspections using OGI technology, such as infrared or thermal imaging cameras, provide an additional layer of monitoring. The MRV plan states any potential leakage would be minimal, confined to the CO_2 volume within the flowline or wellhead components, and could occur from the start of injection until the well is permanently plugged and abandoned. The MRV plan provides adequate characterization of the Chester's facility approach to detect potential leakage from surface equipment and the injection wells as required by 40 CFR 98.448(a)(3).

4.2 Detecting and Quantifying Leakage from Existing Wells and Future Wells

The MRV plan states that REM will be conducting quarterly groundwater monitoring and OGI on the injection well pad. Pressure transducers installed in the tubing and annulus at the wellhead will be monitored by the SCADA system and bottomhole pressure and temperature surveys will occur periodically through the injection period to identify possible abnormalities in operational parameters that would indicate a subsurface leak. Riverside will conduct bottomhole pressure tests and temperature surveys every six months for the first two years and annually thereafter.

The MRV plan states if a leak is detected, its volumetric flow will be attempted to be metered if possible. If not, the latest injection data and reservoir pressure, volume and temperature data will be used to estimate a leakage volume and rate with a mass balance approach from the storage intervals. Thus, the MRV plan provides adequate characterization of the Chester facility's approach to detect potential leakage through existing and future wells as required by 40 CFR 98.448(a)(3).

4.3 Detecting and Quantifying Leakage from Injection Wellbore

Section 5.3 of the MRV plan states, multiple monitoring strategies will be deployed to detect leakage from the injection wellbore. The long string casing, injection tubing string and packer assembly are subjected to a MIT every 5 years as well as once before injection begins. Additionally, the fluid level in the annular space will be checked quarterly for any significant changes. The MRV plan states the tubing and annular pressure at the wellhead will be monitored and is tied to the SCADA system. REM will conduct bottomhole pressure tests and temperature surveys every six months for the first two years, and annually thereafter. Additionally, the quarterly OGI and weekly AVO inspections would also encompass the area around the wellbore at the surface. If a leak is determined, it will be quantified using the timing of the loss of integrity and any pertinent data from the MIT. Furthermore, if any venting of CO_2 occurs during repairs, the amount would be estimated using Subpart W procedures. Thus, the MRV plan provides adequate characterization of the Chester facility's approach to detect potential leakage from the injection wellbore as required by 40 CFR 98.448(a)(3).

4.4 Detecting and Quantifying Leakage from Existing Faults and Fractures and Natural or Induced Seismicity

As stated in the MRV plan, natural and induced seismicity are considered to be unlikely. However, leakage from existing faults or fractures or fractures created by natural or induced seismicity will be monitored by continuous monitoring of operational parameters at the wellbore, periodic reservoir pressure and temperature surveys, and quarterly groundwater monitoring near the injection well pad. REM will conduct bottomhole pressure tests and temperature surveys every six months for the first two years, and annually thereafter. The MRV plan states any abnormalities in operation and reservoir parameters will be investigated to determine if there is a subsurface leak. The latest injection data and reservoir pressure, volume and temperature data will be used with a mass balance approach to estimate a leakage volume and rate from the storage intervals. Additionally, REM will subscribe to the United States Geological Survey's Earthquake Hazards Program Earthquake Notification Service (USGS ENS) to receive notifications of any earthquakes with magnitude 2.0 or greater in Michigan and upon notification will evaluate monitoring data to determine in the storage facility was affected.

The MRV plan provides adequate characterization of the Chester facility's approach to detect potential leakage from existing faults and fractures and natural or Induced Seismicity as required by 40 CFR 98.448(a)(3).

4.5 Detecting and Quantifying Leakage through Confining Layers or Lateral Migration

The MRV plan states leakage through the confining layers or from lateral migration will be monitored by periodic groundwater monitoring and reservoir pressure tests. The water well, to be drilled at the injection well pad for drilling operations, will undergo quarterly groundwater sampling and testing, and the samples will be kept for groundwater monitoring. The MRV plan specifies if a leak is determined, the latest injection data and reservoir pressure, volume and temperature data will be used with a mass balance approach to estimate a leakage volume and rate from the storage intervals

The MRV plan provides adequate characterization of the Chester facility's approach to detect potential leakage through the confining layers or lateral migration as required by 40 CFR 98.448(a)(3).

4.7 Determination of Baselines

Section 6 of the MRV plan identifies the strategies that REM will undertake to establish the expected baselines for CO_2 surface leakage per 40 CFR 98.448(a)(4). Prior to the start of continuous injection, the MRV plan identified the following data to compare with future data to detect surface leakage:

Wellbore Integrity

Before CO_2 injection begins, the MRV plan states a MIT and annular pressure test will be conducted to confirm wellbore integrity. The initial annular fluid volume will be recorded and monitored during start-up to assess its response, with a stabilized volume noted after at least a week of continuous injection. Additionally, Injection tubing and annulus pressures at the wellhead will be recorded before injection starts and continuously monitored using the SCADA system. The MRV plan states MITs will be performed at least every five years in compliance with Michigan-EGLE requirements.

Injection Well Operating Parameters

The MRV plan states that REM has established target injection and storage rates based on experience from other operators injecting and storing fluids in other Niagaran reefs. During injection operations, REM will use site-specific data during wellbore construction and the initial injection period to update nominal injection parameters such as wellhead tubing and annulus pressures and injection flow rates.

Reservoir Conditions

The MRV plan states initial bottomhole pressure will be recorded at mid-perforations and a temperature survey with gradient stops will be completed before injection. A bottomhole pressure test and temperature survey will be conducted at least every six months for the first two years of injection and then annually thereafter. After approximately 48 hours of continuous CO_2 injection, REM will run in hole to mid-perforations to establish reservoir pressure and temperature and run a gradient on the way out of the hole while noting casing and tubing pressures at surface.

Groundwater Monitoring

The MRV plan states groundwater monitoring will be conducted from a 100-ft deep water well on the injection well pad to detect fugitive CO_2. Analyses will include field parameters (temperature, pH, conductivity, dissolved oxygen, oxidation-reduction potential, turbidity) and EPA UIC lab analyses (major ions, total iron, TDS, resistivity, specific gravity, and pH). The MRV plan added additional lab testing will measure dissolved methane, ethane, propane, and calculated dissolved CO_2. A baseline sample will be collected before injection, with quarterly sampling during injection.

Surface Equipment Monitoring

The MRV plan states before injection begins, REM will conduct a baseline OGI survey. Additionally, the MRV plan states within the first month of injection, an additional OGI survey will occur and thereafter, an OGI survey will be conducted quarterly at the injection well pad to detect surface leakage of CO_2.

Thus, the MRV plan provides an acceptable approach for detecting and quantifying leakage and for establishing expected baselines in accordance with 40 CFR 98.448(a)(3) and 40 CFR 98.448(a)(4).

5 Considerations Used Calculate Site-Specific Variables for the Mass Balance Equation

Section 7 of the MRV plan provides the equations that REM and the Chester facility will use to calculate the mass of CO_2 sequestered in subsurface geologic formations.

5.1 Calculation of Mass of CO_2 Received and Injected

Section 7.1 of the MRV plan states that REM, in accordance with 40 CFR 98.444(a)(4) will determine the annual mass of CO_2 injected as the total annual mass of CO_2 received instead of using Equation RR-1 or RR-2 to calculate CO_2 received. The CO_2 received at the Storage Facility will be wholly injected and not mixed with any other supply of CO_2. There will be no production from the Storage Facility. Equation RR-4 in 40 CFR 98.443(c) of Subpart RR will be used to calculate the mass of CO_2 received at the Storage Facility each year.

$$CO_{2,u} = \sum_{p=1}^{4} Q_{p,u} * C_{CO_{2,p,u}} \text{ (Eq. RR-4)}$$

where:

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

$Q_{p,u}$ = Quarterly mass flow rate measurement for flow meter u in quarter p (metric tons per quarter).

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

p = Quarter of the year.

u = Flow meter.

Chester provides an acceptable approach for calculating the mass of CO_2 received under Subpart RR.

5.2 Calculation of Mass of CO_2 Produced/Recycled

Section 7.2 of the MRV plan states there will be no production from the Chester facility.

Chester provides an acceptable approach for calculating the mass CO_2 produced under Subpart RR.

5.3 Calculation of Mass of CO_2 Lost through Surface Leakage

Section 7.3 of the MRV plan states Equation RR-10 will be used to calculate the annual mass of CO_2 emitted due to surface leakage from the leakage pathways identified in the plan.

$$CO_{2E} = \sum_{x=1}^{X} CO_{2,x} \quad \text{(Eq. RR-10)}$$

where:

CO_{2E} = Total annual CO_2 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.

Chester provides an acceptable approach for calculating the mass of CO_2 lost by surface leakage under Subpart RR.

5.4 Calculation of Mass of CO_2 Emitted from Equipment Leaks and Vented Emissions

Section 7.4 of the MRV plan states REM will quantify the 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 injection mass flow meter and the wellhead in accordance with the procedures provided under Subpart W of 40 CFR 98. At the Storage Facility, the injection mass flow meter is located near the wellhead, limiting the equipment to the mass flow meter, the injection wellhead, the short flowline between the two, and any pipefittings or valves installed along this flowline or wellhead.

5.5 Calculation of Mass of CO_2 Sequestered in Subsurface Geologic Formations

Since the Chester facility does not actively produce oil, natural gas, or any other fluid, the MRV plan states that Equation RR-12 will be used to calculate the total annual CO_2 mass sequestered in subsurface geologic formations.

$$CO_2 = CO_{2I} - CO_{2E} - CO_{2FI} \quad \text{(Eq. RR-12)}$$

where:

CO_2 = Total annual CO_2 mass sequestered in subsurface geologic formations (metric tons) at the facility in the reporting year.

CO_{2I} = 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_{2E} = 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 mass flow meter used to measure injection quantity and the injection wellhead, for which a calculation procedure is provided in Subpart W of 40 CFR 98.

REM provides an acceptable approach for calculating the mass of CO_2 sequestered in subsurface geologic formations under Subpart RR.

6 Summary of Findings

The Subpart RR MRV plan for the Chester 21-29N-02W Storage Facility meets the requirements of 40 CFR 98.448. The regulatory provisions of 40 CFR 98.448(a), which specifies the requirements for MRV plans, are summarized below along with a summary of relevant provisions in the Chester's MRV plan.

Subpart RR MRV Plan Requirement	Chester 21-29N-02W Plan
40 CFR 98.448(a)(1): Delineation of the maximum monitoring area (MMA) and the active monitoring areas (AMA).	Section 3 of the MRV plan delineates the MMA. The MMA is defined by the lateral extent of the Reef Structure plus a one-half mile buffer. The MRV plan defines the active monitoring area as the same area as the MMA.
40 CFR 98.448(a)(2): Identification of potential surface leakage pathways for CO_2 in the MMA and the likelihood, magnitude, and timing, of surface leakage of CO_2 through these pathways.	Section 4 of the MRV plan identifies and evaluates potential surface leakage pathways. The MRV plan identifies the following potential pathways: surface equipment, existing wells, wells not yet drilled, injection wellbore, existing faults and fractures, natural or induced seismicity, confining layers, and lateral migration. The MRV plan analyzes the likelihood, magnitude, and timing of surface leakage through these pathways.
40 CFR 98.448(a)(3): A strategy for detecting and quantifying any surface leakage of CO_2.	Section 5 of the MRV plan describe the strategy that REM and the Chester facility will use to detect and quantify potential CO_2 leakage to the surface should it occur.

40 CFR 98.448(a)(4): A strategy for establishing the expected baselines for monitoring CO_2 surface leakage.	Section 6 of the MRV plan describes the strategy for establishing baselines against which monitoring results will be compared to assess potential surface leakage. REM will collect various data to establish a baseline as the Storage Facility against which future data may be compared to detect surface leakage. The suggested data from the Chester facility includes collecting wellbore integrity data, initial injection well operating parameters, initial reservoir conditions, groundwater monitoring, and surface equipment monitoring.
40 CFR 98.448(a)(5): A summary of the considerations you intend to use to calculate site-specific variables for the mass balance equation.	Section 7 of the MRV plan describes REM and the Chester facility's approach for determining the total amount of CO_2 sequestered using the Subpart RR mass balance equations, including calculation of equipment leaks and vented emissions of CO_2.
40 CFR 98.448(a)(6): For each injection well, report the well identification number used for the UIC permit (or the permit application) and the UIC permit class.	Section 1 of the MRV plan identifies the well identification number used for the UIC permit and the UIC class for the Smith 3-21 injection well. The well is permitted as Class II and regulated by Michigan-EGLE GRMD.
40 CFR 98.448(a)(7): Proposed date to begin collecting data for calculating total amount sequestered according to equation RR-11 or RR-12 of this subpart.	Section 8 of the MRV plan states that the REM and the Chester facility will be ready to begin CO_2 injection and to begin collecting data for calculating the total amount of CO_2 sequestered by March 1, 2025.

Appendix A: Final MRV Plan

Riverside Energy Michigan, LLC Chester 21-29N-02W Storage Facility Subpart RR Monitoring, Reporting, and Verification Plan

February 6, 2025

TABLE OF CONTENTS

Abbreviations and Acronyms

°F	Degrees Fahrenheit
AMA	Active Monitoring Area
API	American Petroleum Institute
BBL	Barrel
Bcf	Billion cubic feet
BHL	Bottom hole location
cf	Cubic feet
CO_2	Carbon dioxide and other carbon oxides
EGLE	Environment, Great Lakes, and Energy
EOR	Enhanced oil recovery
EPA	United States Environmental Protection Agency
ft	Foot (feet)
GOR	Gas to oil ratio
GRMD	Geologic Resources Management Division
HMI	Human Machine Interface
IP	Initial production
KB	Kelly bushing
lbs	Pounds
Mcf	Thousand cubic feet
Mcfd	Thousand cubic feet per day
MD	Measured depth
md	Millidarcy
MIT	Mechanical integrity test
MMA	Maximum Monitoring Area
MMscf	Million standard cubic feet
MMscfd	Million standard cubic feet per day
MRV	Monitoring, Reporting, and Verification
NNPRT	Northern Niagaran Pinnacle Reef Trend
P&A	Plugged and abandoned
PBTD	Plugged back total depth
pH	Scale of acidity
psi	Pounds per square inch
SCADA	Supervisory Control and Data Acquisition
scf	Standard cubic feet
SHL	Surface hole location
SLB	Schlumberger
SWD	Salt water disposal
TD	Total depth
TDS	Total dissolved solids
TVD	True vertical depth
UIC	Underground Injection Control
USGS	United States Geologic Survey

1. STORAGE FACILITY INFORMATION

1.1 Project Overview

The Chester 21-29N-02W Storage Facility is a CO_2 acid gas disposal injection project being developed by Riverside Energy Michigan, LLC (Riverside) in Otsego County, Michigan. The purpose of the project is to securely store the CO_2 emissions captured from the processing of natural gas produced from the Antrim Shale biogenic gas play in the northern Michigan Basin. The captured CO_2 will be injected into a Niagaran Pinnacle Reef reservoir, the Chester 21-29N-02W Reef.

The Chester 21-29N-02W Reef was once a natural gas producing field but has since been depleted, plugged, and abandoned. The Niagaran reservoir at a depth of approximately 6,100 feet (ft) enables CO_2 to be stored efficiently in a critical gas phase. This Monitoring, Reporting, and Verification (MRV) plan is designed in accordance with 40 CFR 98.440-449, Subpart RR, to define and describe the Chester 21-29N-02W Storage Facility (Storage Facility).

The Chester 21-29N-02W Storage Facility spatially consists of the surface and subsurface areas contained within the active and maximum monitoring areas, defined in *Section 3*. In process terms, the Chester 21-29N-02W Storage Facility begins at the mass flow meter positioned on the CO_2 flowline immediately upstream of the injection wellhead and ends in the subsurface at the reservoir's lithofacies-controlled aerial limits. Figure 1 shows the location of the Chester 21-29N-02W Storage Facility, the separate Turtle Lake Capture Facility (Capture Facility) from where CO_2 is sourced, and the approximately 2 miles of CO_2 flowline that links the two.

The Devonian age Antrim Shale Formation, from which the CO_2 originates as a minor co-constitute of natural gas production, produces regionally from a subsurface depth of approximately 1,000 to 2,000 ft. In contrast, the Silurian age Niagaran reef reservoir that constitutes the Chester 21-29N-02W Storage Facility is approximately 6,000 to 7,000 ft deep and currently has neither unplugged wells nor hydrocarbon production associated with it. It is the explicit purpose and design of this project to sequester and dispose of CO2 and not to facilitate any additional production from the Storage Facility. As such, the Turtle Lake Capture Facility exists and operates separate from the Storage Facility and is not a part of the Storage Facility as defined in this MRV plan.

1.2 Reporter Number

Greenhouse Gas Reporting Program Identifier: 589821

Operator: Riverside Energy Michigan, LLC on behalf of Riverside Carbon Solutions, LLC

1.3 Storage Facility Location

The Storage Facility is located in Otsego County, Michigan, approximately 9 miles southeast of the town of Gaylord, Michigan.

Storage Facility location description in the Public Land Survey System:

Sections 21 and 22, T29N-R02W

Storage Facility coordinates in North American Datum of 1983 (NAD83):

Latitude: 44.896048°
Longitude: -84.547381°

1.4 Underground Injection Control Permit Class: Class II

The Michigan Department of Environment, Great Lakes, and Energy (Michigan-EGLE) Geologic Resources Management Division (GRMD) administers the Underground Injection Control (UIC) program in Michigan for all Class II injection wells, by the statutes and rules subject to Part 615, Supervisor of Wells, of the Michigan Natural Resources and Environmental Protection Act (NREPA), Public Act 451 of 1994, as amended. The CO_2 injection well (Smith 3-21) will be operated by Riverside Energy Michigan, LLC, permitted as a UIC Class II well, and regulated by Michigan-EGLE GRMD.

The UIC Class II permit for the proposed Smith 3-21 injection well was issued by Michigan-EGLE GRMD on 1/10/2025 (EGLE permit number 61818).

The unique identifer assigned to the well is API number 21-137-62019-00-00.

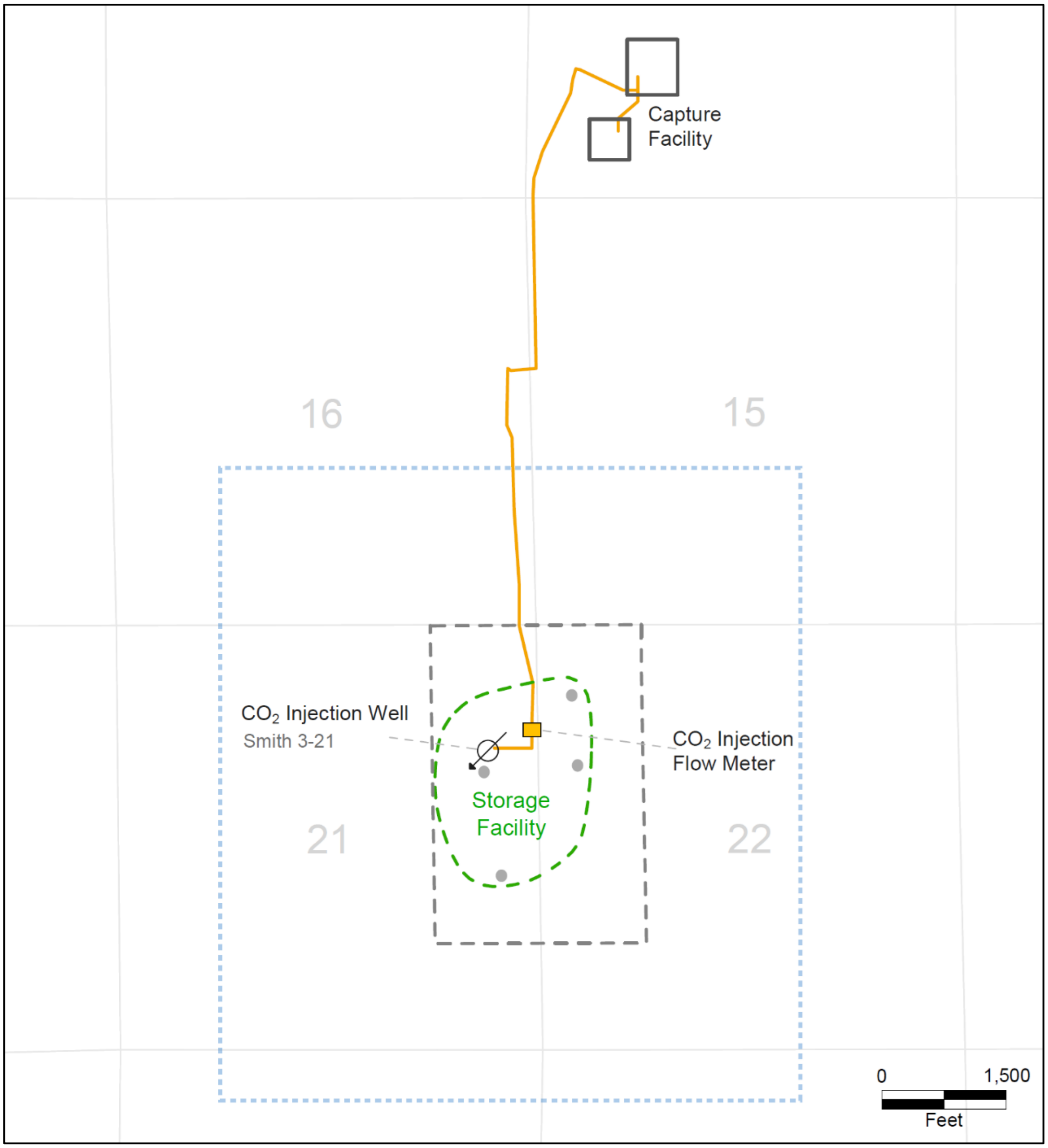

Figure 1. Map of the Chester 21-29N-02W Storage Facility (dashed green outline), showing the Capture Facility, CO_2 pipeline (orange) from the Capture Facility, Injection Unit (dashed gray rectangular outline) permitted with Michigan-EGLE, the Active and Maximum Monitoring Areas for the Storage Facility (dashed blue outline), the Smith 3-21 CO_2 Injection Well, and all plugged wells within the Storage Facility (gray circles). Section 3 and Figure 14 discuss the Active and Maximum Monitoring Areas in greater detail. The base map depicts the PLSS and shows all or portions of sections within T29N-R02W.

2. PROJECT DESCRIPTION

2.1 Regional Geology

The Northern Niagaran Pinnacle Reef Trend (NNPRT) in the Michigan Basin features several hundred highly compartmentalized pinnacle reefs found at an average dept of about 6,000 ft

below the ground surface. These reefs are separated from one another by distances as little as hundreds of feet to as much as several miles. The NNPRT originated from coral reefs formed during the Silurian Period 420 to 440 million years ago in tropical sea environments (Figure 2).

The reefs were subsequently buried by sediments deposited around and above the reefs encasing them within mostly impermeable layers of evaporitic and carbonate rocks. These impermeable evaporitic and carbonate rocks are responsible for trapping and sealing prolific quantities of oil and gas within these reefs.

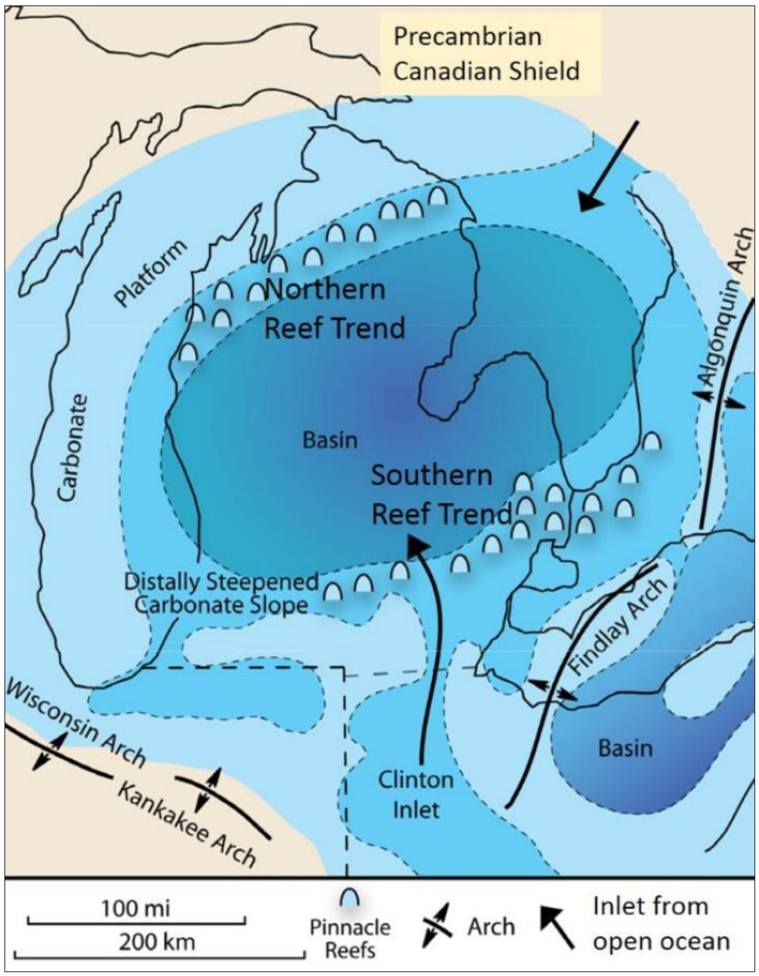

Figure 2. Map of the Michigan Basin and interpreted paleogeography during the Silurian Period, depicting the Northern Niagaran Reef Trend amongst regional environments. Ritter (2008) modified after Briggs and Briggs (1974).

The NNPRT forms a part of a broader shallow shelf carbonate depositional system that partially encircles the Michigan Basin. The NNPRT is positioned along the margin of the system's carbonate platform. Individual reefs typically range in area from 50 to 500 acres and have vertical heights between 100 to 700 ft in the subsurface.

The reservoir facies primarily consist of porous and permeable dolomite and limestone. Some reefs are completely dolomitized, while others are essentially all limestones. Dolomitization of the reefs, which helps enhance porosity, increases as the reefs become shallower. Salt and anhydrite plugging of porosity occurs in the deeper reefs (Gill 1979). Reef porosity values can be as high as 35%, but typically average 3 to 12%. Net pay intervals can total from only a few feet to several hundred feet. The most productive reef reservoirs are characterized by dolomitized reef facies with well-developed inter-crystalline and vuggy porosity. Secondary porosity is present and can enhance permeability, which typically averages 3 to 10 millidarcies.

The Niagara and A1 Carbonate Formations of the early Silurian Niagara Group contain the main reservoir units within the reefs, shown in the stratigraphic column in Figure 3. The base of the Niagara Formation, referred to as the "Lockport" or "White Niagaran" is typically a partially dolomitized to dolomitized crinoidal wackestone, (Charbonneau, 1990). Overlying the Lockport, the Guelph Formation is comprised of units commonly referred to as the "Gray" and "Brown" Niagaran. The Gray Niagaran and Lockport are typically characterized by very low porosity. The Brown Niagaran comprises the core of the reef reservoir and pinnacle reef buildup. It is characterized by dolomite and limestone skeletal wackestones and boundstones, (Huh, 1973).

The A1 Carbonate overlies the Brown Niagaran at the reef crest and is sometimes referred to as the "Ruff" Formation. The A1 Carbonate is considered a reservoir unit in the crest of some reefs but grades into tight, low porosity dolomitic mudstone near the reef flanks, (Huh, 1973).

The A1 Carbonate and Brown Niagaran Formations are encased by a sequence of evaporites and salt-plugged carbonates, comprising the seal for the reefs. The A1 Evaporite is typically thin or not present at the crest of the reef but forms a seal of the Brown Niagaran at reef flanks. Overlying the A1 Carbonate and providing the primary seal for the Storage Facility is the A2-Evaporite, Figure 3. The A2 Evaporite is characterized by non-porous and impermeable anhydrite at the reef crest. It transitions to halite dominated facies off the structure of the reef. Further overlying the A2 Evaporite are hundreds of feet of non-porous evaporite and low porosity carbonate and shale sequences that comprise the Salina Group.

The lithostratigraphy and internal reef structure are visualized in Figure 4. Reef formation began surrounding a carbonate bioherm in warm, shallow waters, (Rine, 2017). The reef core grew upwards as sea level in the Michigan Basin rose. When sea level fell, the reefs became exposed and evaporite deposition encased the reefs.

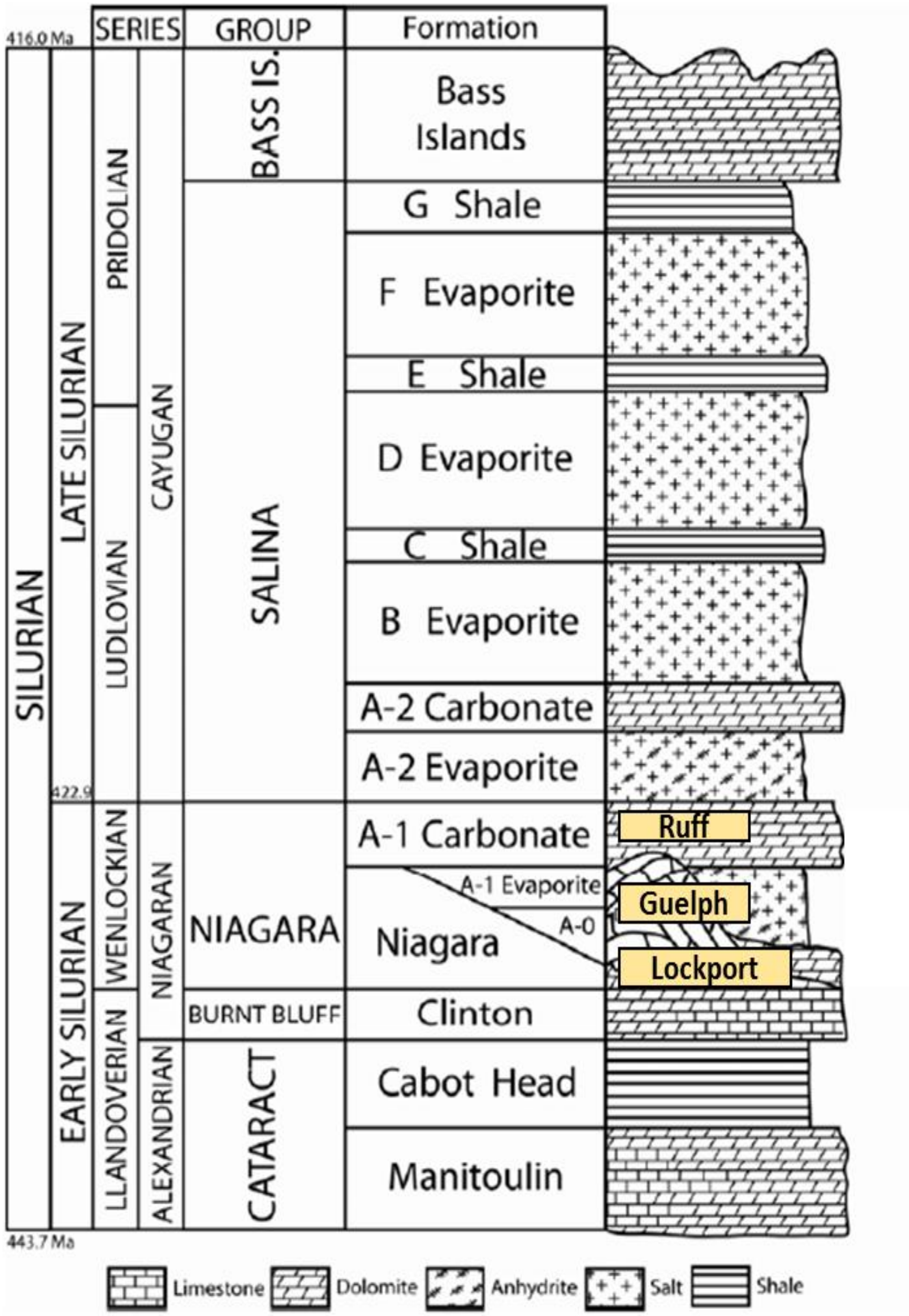

Figure 3. Generalized stratigraphic column for Silurian period deposits in the Michigan Basin, with emphasis on Niagaran reefs (Ritter, 2008).

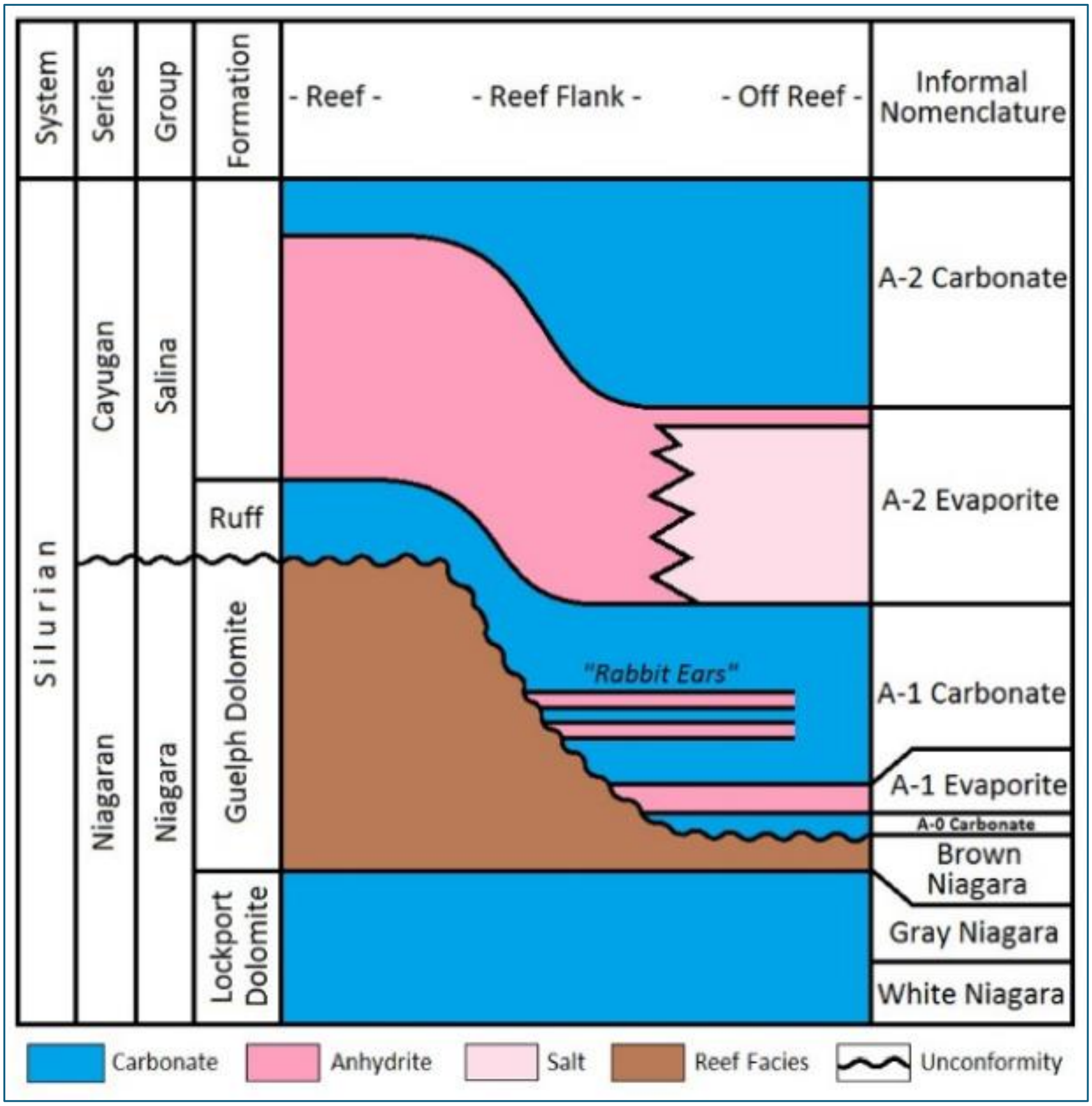

Figure 4. Lithostratigraphy visualization of a Niagaran reef interval, (Gupta et al., 2020 modified from Gill 1979 and Huh 1973).

2.2 Site Characterization

The Chester 21-29N-02W Field is a Northern Niagaran Pinnacle Reef located in Sections 21 and 22 of Township 29 North, Range 2 West, Otsego County, Michigan. The Field has a footprint of approximately 90 acres and is buried to a depth of 6,710 ft TVD (-5,472 ft subsea TVD) at its base to 6,160 ft (-4,921 ft subsea TVD) at its top.

While the reef structure itself is 550 ft tall and consists of the Brown Niagaran Formation, an additional 60 ft of A1 Carbonate Formation rests directly on top of the Brown Niagaran Formation and serves as a vertical extension of the physical reservoir observed in the Niagaran interval. Porosity of the A1 Carbonate and Brown Niagaran reservoir intervals derived from wireline logs ranges from 1 to 16% and averages 5.4%. Unless otherwise specified, all subsequent mentions

in this document of the Reef, Reef Structure, or Field will mean to refer to the total interval that includes both the Brown Niagaran Formation and the A1 Carbonate Formation.

The A2 Evaporite Formation rests directly on top of the A1 Carbonate Formation and serves as the primary seal for the Storage Facility. Above the 120 ft thick A2 Evaporite Formation is a 1,300 ft thick series of massive evaporite deposits and interbedded shale and limestone deposits that make up the bulk of the Salina Group.

The following geologic data was compiled for the Chester 21-29N-02W Reef and surrounding area:

- Well data from historic wellbores including wireline logs, drillers reports, and state curated well files.
- 2D seismic data, composed of 5 lines that each traverse the Reef Structure and adjacent surrounding area.
- Oil and gas production histories as reported to the State of Michigan.

Figure 5 shows the shot point locations of 2D seismic lines used to interpret the Reef Structure at the Storage Facility. Figure 6 is a stratigraphic cross section of well logs through the Storage Facility and Figure 7 is the cross-section reference map.

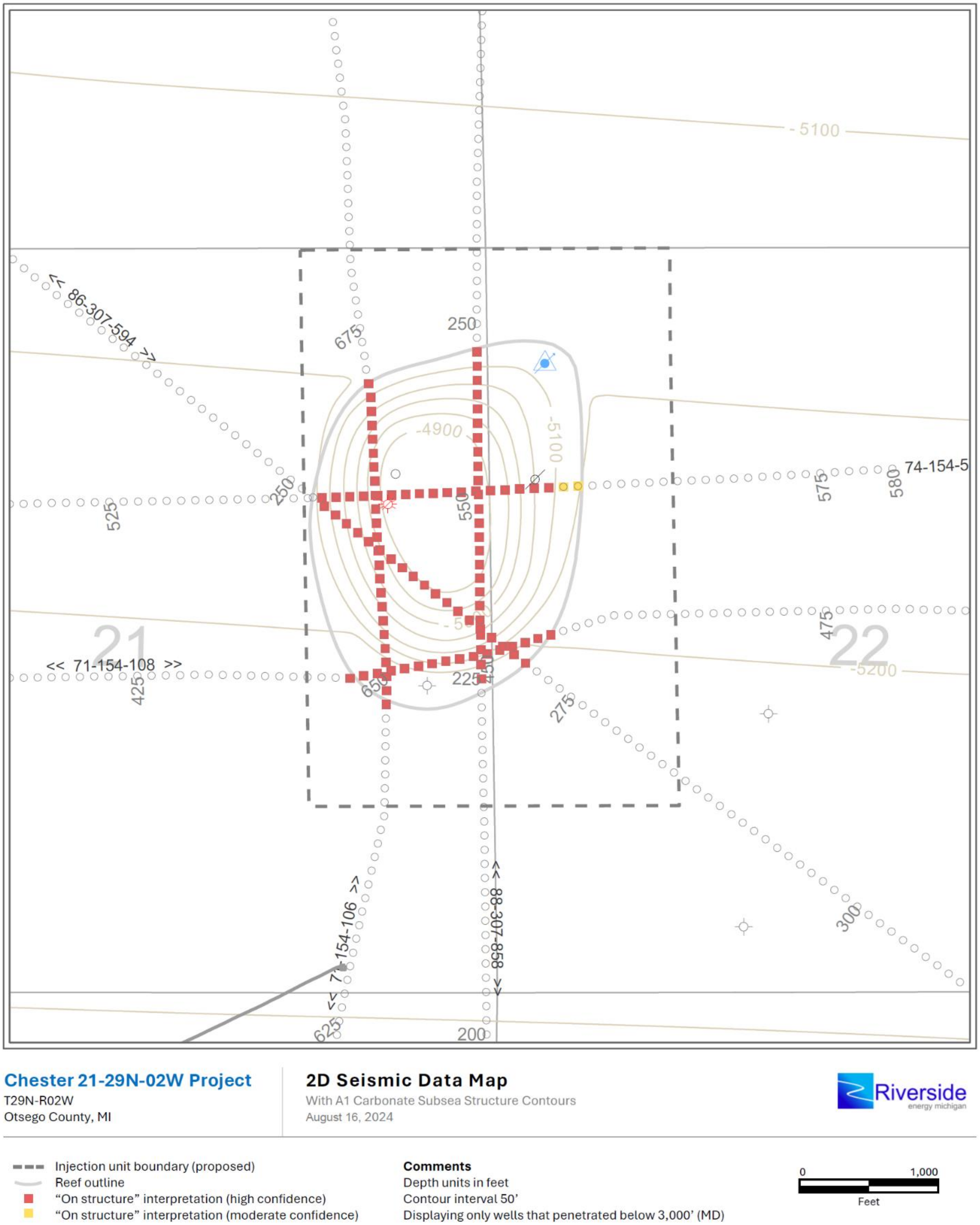

Figure 5. 2D seismic shot point locations used to determine the position of the Chester 21-29N-02W Reef Structure.

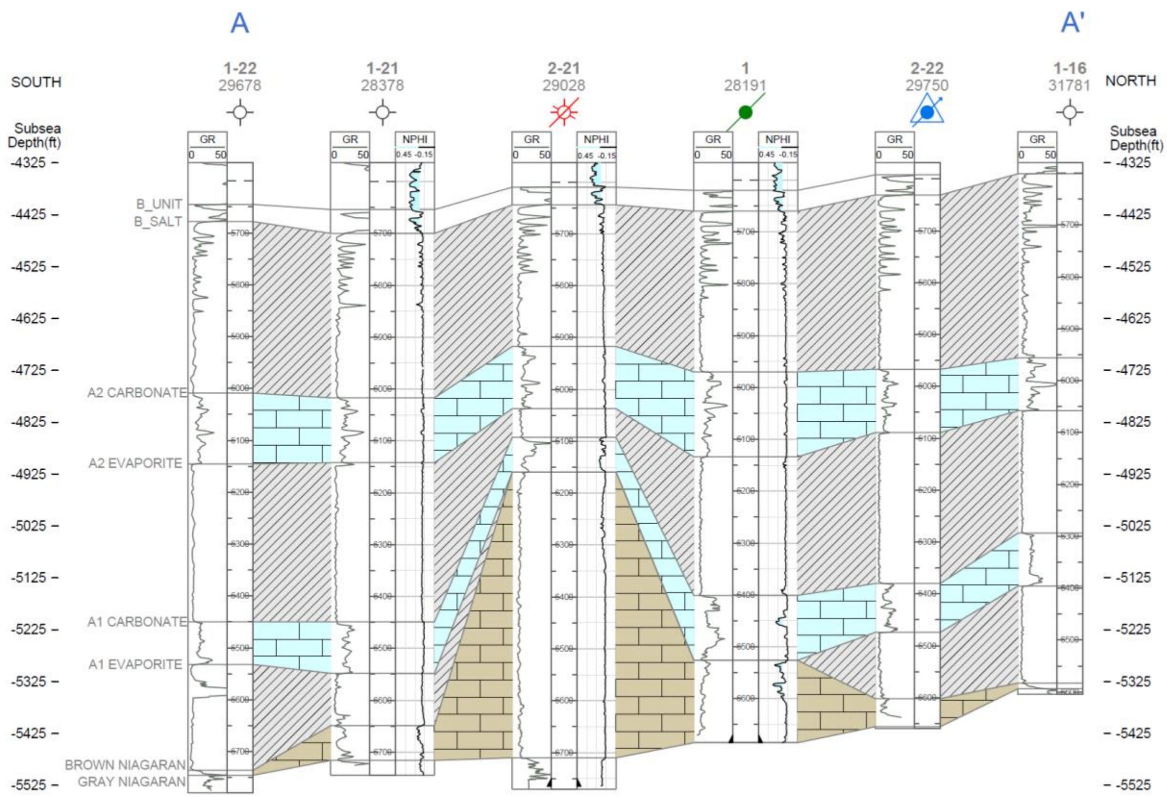

Figure 6. Stratigraphic-structural cross-section of Niagaran reef interval at the Chester 21-29N-02W Storage Facility and surrounding area. Wireline log tracks include Gamma Ray log response (“GR”, scale 0 to 50 API) left of each wellbore, and where available Neutron Porosity log response (“NPHI”, 0.45 to -0.15%) right of wellbore.

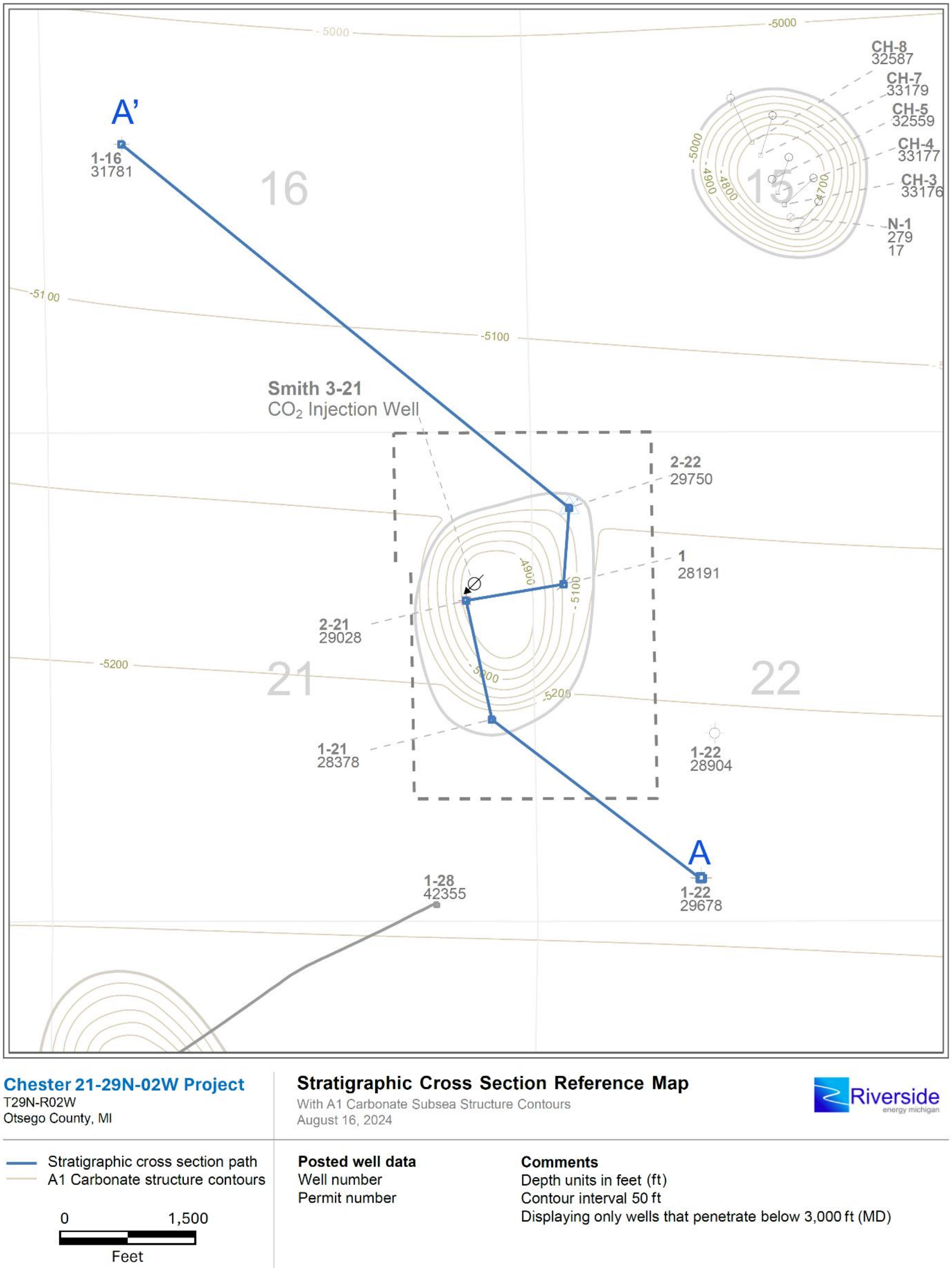

Figure 7. Reference map for the stratigraphic cross-section in Figure 6.

2.3 Operational History of the Chester 21-29N-02W Reef and Existing Wells

The Chester 21-29N-02W Reef was discovered in 1970 by Great Lakes Exploration that developed a single discovery well for oil production. The drilling of three additional wells was attempted between 1971 and 1974, resulting in one gas producing well and two dry holes. One of these dry holes, the State Chester 2-22, has been converted into a brine disposal well into the shallower Dundee Formation, disposing of water produced from Antrim Shale gas production. This well was recompleted with a cement plug within the Niagaran below. These four wells are the only wells ever drilled into the Chester 21-29N-02W Reef and summarized in Table 1.

Table 1. List of wellbore penetrations within the Reef Structure.

Well Name	Marshall, Glen	Underwood, N M & Knapp C A	Leacock Hubbard Underwood	State Chester
Well No.	1	1-21	2-21	2-22
API	21137281910000	21137283780000	21137290280000	21137297500000
MI Permit No.	28191	28378	29028	29750
Well Status	P&A	P&A	P&A	Active PBTD SWD
Well Designation	Oil	Dry Hole	Gas	Initially a Dry Hole, now PBTD SWD
First Operator	Great Lakes Exploration	Miller Brothers	Miller Brothers	Reef Petroleum Corporation
Last Operator	ANR Pipeline	Miller Brothers	Saba Energy of Texas	VCP Michigan
Formation at TD	Gray Niagaran	Gray Niagaran	Gray Niagaran	Gray Niagaran
TD (MD, TVD per KB)	6,685	6,744	6,770	6,660
Datum Elevation (KB)	1,242	1,239	1,238	1,244
SHL Latitude	44.89582	44.89186	44.89537	44.89806
SHL Longitude	-84.54549	-84.54850	-84.54952	-84.54523
BHL Latitude	44.89582	44.89186	44.89537	44.89806
BHL Longitude	-84.54549	-84.54850	-84.54952	-84.54523
Note				PBTD 4,215 ft MD
Producing Formation	Brown Niagaran	-	Brown Niagaran	-
IP oil (BBL/day)	480	-	NA	-
IP gas (Mcf/day)	NA	-	20,000	-
Cumulative oil (BBL)	25,483	-	162,238	-
Cumulative gas (Mcf)	520,175	-	9,951,270	-
Cumulative water (BBL)	Unknown	-	Unknown	-
Permit date	9/24/1970	3/23/1971	9/14/1972	5/13/1974
Well spud date	11/20/1970	4/22/1971	12/9/1972	5/23/1974
Completion date	1/25/1971	5/26/1971	2/26/1973	6/19/1974
Abandonment date	11/21/1990	5/29/1971	6/8/2002	

Table 2 summarizes the additional wells that exist within the active and maximum monitoring areas of the Storage Facility but do not penetrate the Reef Structure. The majority of these wells targeted the Antrim Shale Formation for natural gas production and typically only penetrate in depth to approximately -250 ft to -950 ft (subsea), whereas the Primary Seal and Storage

Reservoir each exceed -4,500 ft (subsea) throughout the Active and Maximum Monitoring Areas. See *Section 3* for the definition and map of the Active and Maximum Monitoring Areas.

Table 2. List of wellbore penetrations within Active and Maximum Monitoring Areas.

Evaluation Group	API	Well Name	Well No.	TD (subsea ft)	Well Type	Well Status
This Project's Pending CO2 injection well	TBD	Smith	3-21	-5,250	CO2 Injection	Permit pending
Penetrations into the Reef Structure	21-137-29028-0000	Leacock Hubbard Underwood Knapp	2-21	-5,532	Gas	P&A
	21-137-28378-0000	Underwood, N M & Knapp	1-21	-5,505	Dry Hole	P&A
	21-137-28191-0000	Marshall, Glen	1	-5,443	Oil	P&A
	21-137-29750-0000	State Chester	2-22	-5,416	SWD	Active
Penetrations depth equivalent to, but not into, the Reef Structure	21-137-28904-0000	Underwood & Knapp & Ashland Farms	1-22	-5,541	Dry Hole	P&A
	21-137-29678-0000	Underwood, Nellie M, & Knapp	1-22	-5,540	Dry Hole	P&A
	21-137-42355-0000	State Chester	1-28	-5,371	Gas	P&A
Penetrations at least 3,350 ft above Primary Seal	21-137-46107-0000	Campbell et al.	1-22	-1,454	SWD	Active
	21-137-55872-0000	State Chester	A3-28	-938	Gas	Producing
	21-137-55871-0000	State Chester	A1-27	-937	Gas	Producing
	21-137-50566-0000	State Chester	24-21	-840	Gas	P&A
	21-137-50567-0000	State Chester	23-21	-772	Gas	Producing
	21-137-55327-0000	Jaeger	D4-21	-718	Gas	Producing
	21-137-55326-0000	Jaeger	C4-21	-704	Gas	Producing
	21-137-55399-0000	Wright	B3-21	-692	Gas	Producing
	21-137-44259-0000	State Chester Venture	51	-633	Gas	Producing
	21-137-45622-0000	Campbell et al.	14-22	-604	Gas	Producing
	21-137-45588-0000	Campbell et al.	13-22	-600	Gas	Producing
	21-137-45536-0000	Campbell et al.	23-22	-593	Gas	Producing
	21-137-45537-0000	Marshall	12-22	-592	Gas	Producing
	21-137-45589-0000	Campbell et al.	24-22	-585	Gas	Producing
	21-137-44261-0000	State Chester Venture	52	-544	Gas	Producing
	21-137-40014-0000	State Chester Venture	31	-400	Gas	Producing
	21-137-39042-0000	State Chester Venture	22	-370	Gas	Producing
	21-137-41430-0000	State Chester	47	-348	Gas	Producing
	21-137-42229-0000	State Chester Venture	54	-329	Gas	Producing
	21-137-41432-0000	State Chester	45	-312	Gas	Producing
	21-137-27029-0000	State Chester	13	-260	Gas	Producing

In total, the Chester 21-29N-02W Field has produced 10,583,601 Mcf of natural gas, 203,105 barrels of oil, and an unknown volume of water. The production totals are summarized in Table 3. The Leacock Hubbard Underwood & Knapp #2-21 tested at an initial reservoir pressure of 3,227 psi at approximately 6,300 ft (0.51 psi per foot gradient) with a temperature of 114°F. It is believed the reservoir was depleted to a current pressure of approximately 300 psi or less. The Marshal, Glen #1 well was plugged and abandoned in 1990, and the Leacock Hubbard Underwood & Knapp #2-21 well was the final well at the Reef Structure to be plugged and abandoned in 2002.

Table 3. Summary of production from Chester 21-29N-02W Field.

Well Name	Date of First Production	Total Production		
		BO	Mcf	GOR
Marshall, Glen #1	1/19/1971	41,062	529,169	12,887
Leacock Hubbard Underwood & Knapp #2-21	2/6/1973	162,043	10,054,432	62,048
Total		203,105	10,583,601	52,109

As there are no longer any producing wells into the Reef Structure and as the structure is laterally limited, there will be no production associated with the Storage Facility. The Smith 3-21 UIC Class II CO_2 injection well will be the only wellbore penetrating the Reef Structure.

2.4 Mass Balance Estimate of Storage Resources

A mass balance approach using natural gas production data was used to estimate approximately 1 million metric tons of CO_2 storage resources at the Storage Facility. This mass balance approach does not consider produced water or oil that may provide additional accessible pore volume for storage. This mass balance approach does not consider a storage efficiency factor.

Determining the accessible reservoir pore volume:

> 10.5 Bcf produced natural gas
> Formation volume gas factor Bg = 0.0042 cf/scf at 114°F and 3,168 psi
> 1/Bg = 238 scf/cf
> Reservoir pore volume = 10,500,000,000 scf / 238 scf/cf = 44,100,000 cf

Determining the storage resources of the accessible reservoir pore volume for CO_2:

> Confining interval top depth = 6,035 ft
> Fracture pressure (estimate) = 0.80 psi/ft
> Current reservoir pressure (estimated) = 300 psi
> Injection pressure limit = 6,035 ft * 0.80 psi/ft * .90 safety factor = 4,345 psi
> CO_2 density @ 4,345 psi = 55 lbs/cf
> Storage resource given 44,100,000 cf of accessible pore space = 1,080,000 metric tons of CO_2

2.5 Reservoir Modelling and Injection Simulation

A simple geologic model was developed to complete computational injection simulations and evaluate the dynamic storage capacity of the Storage Facility. The model was generated from 2D seismic (structure) and well log information (top depths and porosity) in IHS' *Petra*® software. Computer Modeling Group's *GEM*™ reservoir simulation software was used to complete injection simulation.

Figure 8 shows the 3D view of the initial gridded model of the Chester 21-29N-02W Reef used for injection simulation with the position of the injection well entering the top of the reef. The model covers a 3,430 by 3,640 ft (0.65 by 0.69 miles) area and contains the approximate 90-acre (0.14 square mile) Chester 21-29N-02W Reef Structure within it. Porosity of the A1 Carbonate and Brown Niagaran reservoir intervals ranges from 2 to 9%. Permeability of the reservoir intervals ranges from 1 to 5 millidarcies and was derived from basin-wide Niagaran reef porosity-permeability cross plots by Gupta et al. (2020).

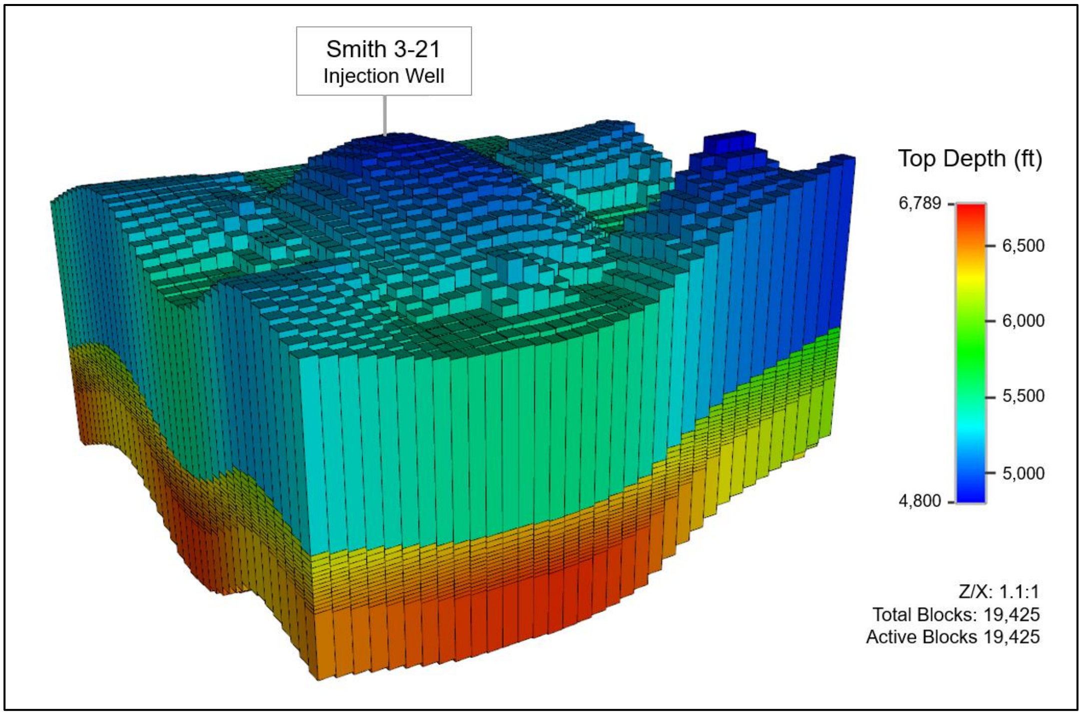

Figure 8. Gridded Model of the Chester 21-29N-02W Area Used for Injection Simulation. Also shown is the approximate location of the Smith 3-21 injection well.

The reef reservoir is modeled as a closed system with all model boundaries closed. The reef reservoir was initialized with depleted gas, oil, and water saturations at 300 psi. Injection rate was set at 12,000 Mcfd based on basin experience from CO_2 injection in other Niagaran reef projects. The maximum bottomhole pressure was limited to 4,345 psi (6,036 ft depth * 0.8 psi/ft fracture gradient * 0.9 safety factor).

The simulation was run for 15 years. After approximately 4 years, the maximum bottomhole pressure limit was reached, limiting further injection. Nearly no CO_2 was injected after 5 years. The simulation injected 16.7 Bcf of CO_2 or approximately 880,000 metric tons of CO_2 after 5 years. Figure 9 shows the development of the CO_2 plume within the Reef Structure over time. The CO_2 is limited to the 90-acre Reef Structure and contained within the dashed green Reef Structure boundary shown in Figure 14. Figure 10 shows the average Reef Structure pressure over time. Figure 11 reports the daily CO_2 injection rate and cumulative CO_2 injection totals over 5 years of injection.

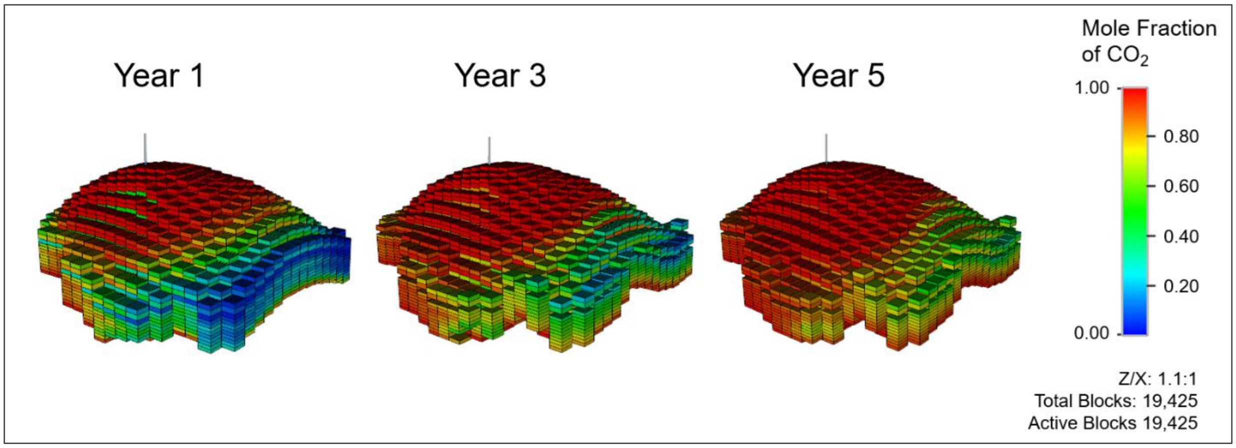

Figure 9. CO_2 plume development in the Reef Structure over 5 years of injection (Mole fraction of CO_2 in reservoir blocks). Also shown is the approximate location of the Smith 3-21 injection well where it enters the Reef Structure.

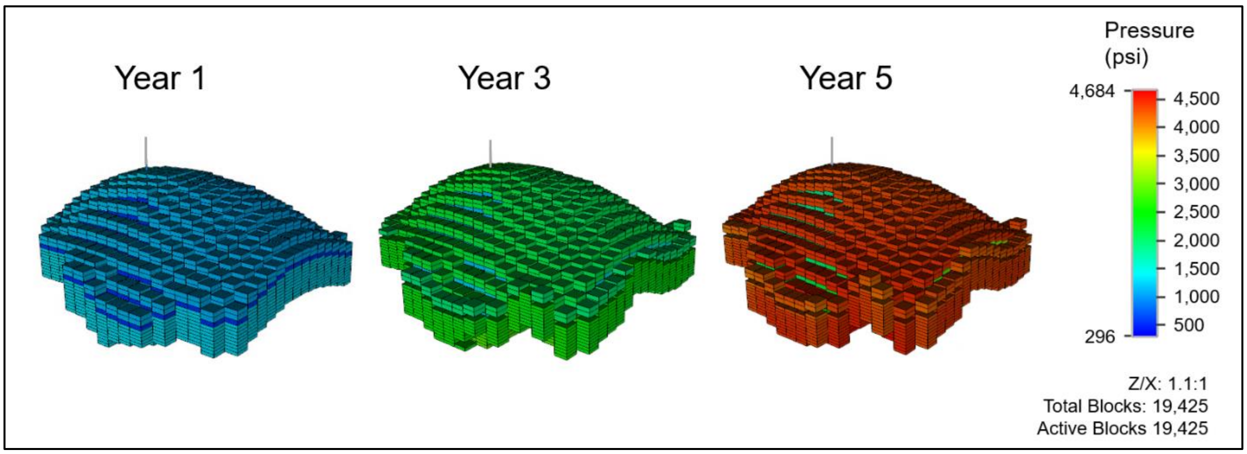

Figure 10. Pressure development in the Reef Structure over 5 years of injection from an initial pressure of 300 psi. Also shown is the approximate location of the Smith 3-21 injection well where it enters the Reef Structure.

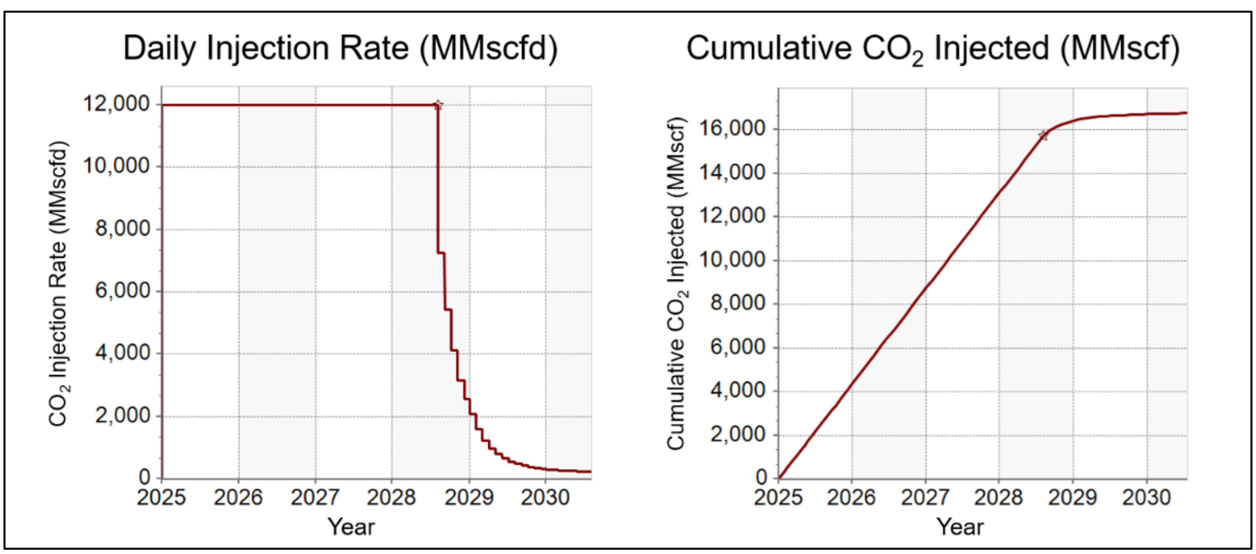

Figure 11. Daily injection rate and cumulative gas injection into the Reef Structure.

2.6 CO_2 Capture and Storage

The Antrim Shale in the northern part of the Michigan Basin is a biogenic gas reservoir. A byproduct of the microbial generation of methane is carbon dioxide that must be stripped from the gas before it is sold. The South Chester CO_2 Treating Plant (the Plant) located in Section 10 of Chester Township, Otsego County, Michigan, and operated by Phillips 66, removes CO_2 from natural gas produced from the Antrim Shale. As operator of the majority of wells producing natural gas being processed by the Plant, Riverside owns 60% of the CO_2 that would normally be vented from the natural gas plant. Riverside is currently constructing the necessary facilities to capture the entire vent stream of about 380,000 metric tons of CO_2 per year. It is expected that the Plant will continue to operate for another 10 to 20 years, dependent on market conditions. The Plant utilizes amine to strip CO_2 from the natural gas. The vent gas resulting from this process is typically 98% CO_2 or greater, and this composition is not expected to change over time. Riverside is installing four rotary screw compressors and reconfiguring one reciprocating compressor unit that in sum will comprise the Turtle Lake Capture Facility (Capture Facility) to compress the CO_2 for transportation and storage. CO_2 will be transported on a dedicated pipeline from the Capture Facility to the Chester 21-29N-02W Storage Facility. The Storage Facility will consist of one injection well (Smith 3-21) drilled into the Chester 21-29N-02W Reef Structure. In the future, the pipeline may become part of a larger distribution system for delivering CO_2 to multiple depleted gas reef storage facilities operated by Riverside for the purpose of permanently disposing and sequestering the CO_2 waste stream derived solely from the production of Antrim natural gas.

Figure 12 is a process flow diagram of the Capture Facility, pipeline, and Storage Facility. The key meter for calculating the mass of CO_2 injected is identified as the Injection Meter in this figure. This dedicated Coriolis mass flow meter will measure and verify the mass of CO_2 being received and injected.

Riverside also has the option to deliver CO_2 to a third party for Enhanced Oil Recovery (EOR). Riverside will have access to data generated by the third party's Coriolis mass flow meter (Delivery Point Meter in Figure 12) positioned near the outlet of the Capture Facility and inlet to their pipeline, which will serve as the custody transfer point. This data will be used for the accurate determination of CO_2 delivered to the third party. The third party operates their EOR projects under an approved MRV plan (facility ID 1010117) is wholly separate from this Storage Facility and this MRV plan.

The requirements of Subpart PP are applicable to the Capture Facility. Riverside will fully comply with the requirements outlined therein.

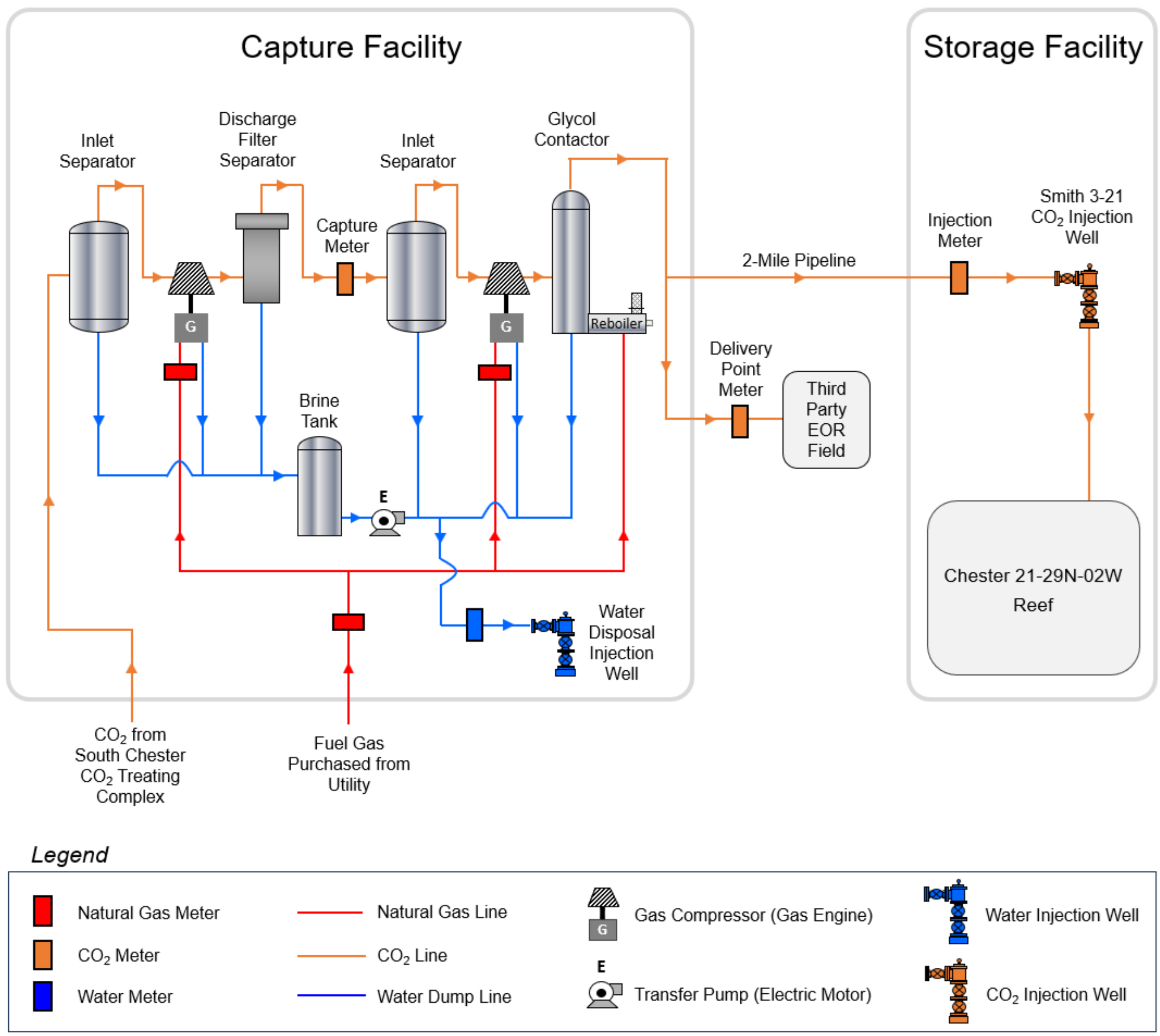

Figure 12. Process flow diagram of the Turtle Lake Capture Facility and the Chester 21-29N-02W Storage Facility.

2.7 Ownership

It is helpful to understand the corporate structure and relationship between the entities; refer to Figure 13 below. Riverside Energy Michigan, LLC (Riverside) and Riverside Carbon Holdings (RCH), LLC are 100% owned subsidiaries of Riverside Energy Holdings, LLC. Riverside is operator of the Antrim Shale natural gas wells and permittee of the injection well. Riverside Carbon Solutions, LLC, RCS Capture Antrim, LLC and RCS Storage Michigan, LLC are 100% owned subsidiaries of RCH. RCS Capture Antrim, LLC holds the Capture Facility assets including leased acreage upon which the facilities reside. RCS Storage Michigan LLC holds rights to the minerals and pore space in the Chester 21-29N-02W Reef Structure. Riverside will be the operator of the Storage Facility on behalf of Riverside Carbon Solutions, LLC.

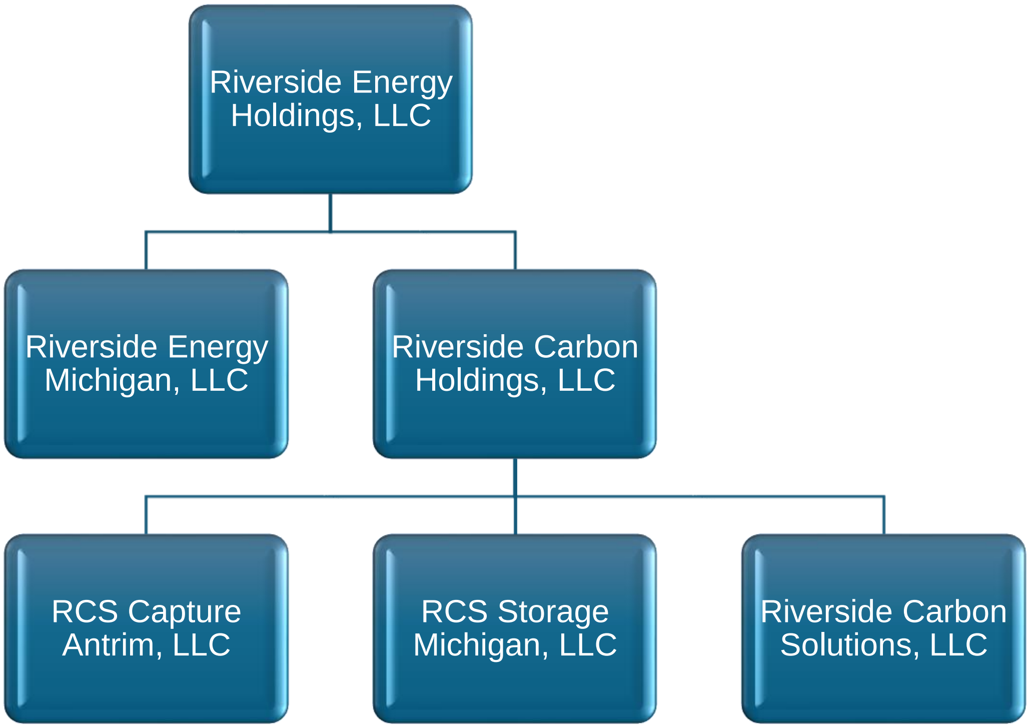

Figure 13. Organizational structure of the Riverside entities involved in the generation, capture and storage of CO_2.

2.8 Data Collection

All flow meters and other instrumentation at the Capture and Storage Facilities will be wired into Riverside's Supervisory Control and Data Acquisition (SCADA) system. The software continuously logs data from the meters and other instrumentation to a secure server with remote data backup and provides a Human-Machine Interface (HMI) for operators. It also has the capability to send an alarm to operators should parameters deviate outside of prescribed limits. Together, these data streams provide accurate accounting of all CO_2 being captured, delivered, received and injected.

Section 5.0 provides a more detailed explanation of the monitoring data that will be collected in order to detect any leakage of CO_2 from the Storage Facility. *Section 6.0* of this MRV Plan provides a more detailed explanation for how this data and other means will be used to establish baseline data for comparison to data collected during operation of the Storage Facility to detect possible surface leakage.

3. DELINEATION OF THE MONITORING AREA

3.1 Active Monitoring Area

The Active Monitoring Area (AMA) is defined (40 CFR 98.449) as follows:

Active monitoring area is the area that will be monitored over a specific time interval from the first year of the period (n) to the last year in the period (t). The boundary of the active monitoring area is established by superimposing two areas:

(1) The area projected to contain the free phase CO_2 plume at the end of year t, plus an all around buffer zone 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 t + 5.

At the Chester 21-29N-02W Storage Facility this definition translates to be the Chester 21-29N-02W Reef Structure Area (to the nearest 10-acre square) plus a one-half mile buffer zone outward in all directions. The Reef Structure and AMA are shown in Figure 14. This AMA delineation will be in place for a 10-year period which will cover the expected operational life of the Project.

Riverside plans to inject CO_2 at a rate of 12,000 Mcfd or approximately 230,000 metric tons of CO_2 per year. This rate may vary depending on site specific injection capabilities. The reef's current pressure is estimated at approximately 300 psi. Injection will continue until the reef pressure increases to the maximum bottomhole pressure of 4,345 psi. Once additional injection is constrained by bottomhole pressure limit, injection will stop. Based on the mass balance and injection simulation work described in *Sections 2.4 and 2.5*, the storage reservoir is expected to fill up after approximately 5 years at an average injection rate of 12,000 Mcfd.

Riverside is defining the time period of this AMA as 10 years in order to cover the expected operational life of the Project with some incorporated buffer time for any maintenance, downtime, or unexpected delays. 40 CFR 98.449 defines the AMA as the area projected to contain the free phase CO_2 plume at the end of year t + 5 plus a one-half mile all around buffer. Therefore, the AMA boundary is delineated based on the extent of the CO_2 plume at the end of year 15 plus a one-half mile buffer zone outward in all directions. After 15 years, the free phase CO_2 plume is projected to remain within the Reef Structure. Should the project be operational after 10 years of initial injection, Riverside will submit a revised MRV plan with an updated AMA.

The compartmentalized nature of the Niagaran reef creates conditions whereby an injection plume is limited to the shape and volume of the reef structure itself. The following factors were considered in defining the Reef Structure and AMA boundaries.

- The Reef Structure is encased within massive anhydrite and ultra-low permeability limestone, efficiently sealing the reef's storage intervals and preventing lateral and upward migration of CO_2. The effectiveness of the reef's seal is demonstrated by the trapping of hydrocarbons within the reef over geologic time.
- The boundaries of the reef structure have been defined using 2D seismic data. Where 2D seismic data is not available, reef edges were approximated using all wells surrounding and penetrating the reef, along with analog reef geometry.
- The stored CO_2 and the lateral extent of the CO_2 plume will remain within the reef and will not migrate over geologic time, as is demonstrated by the injection simulation described in *Section 2.5* and the trapping of oil and gas within the reef over geologic

time.

- There are no known leakage pathways that extend laterally from the Reef Structure that would warrant an expansion of the AMA beyond the one-half-mile buffer distance.

3.2 Maximum Monitoring Area

The project's Maximum Monitoring Area (MMA) is equal to the Active Monitoring Area (AMA) and is similarly defined as the Chester 21-29N-02W Reef Structure (to the nearest 10-acre square) plus a one-half mile buffer zone outward in all directions. This MMA is shown in Figure 14.

Pursuant to 40 CFR 98.449 the Maximum Monitoring Area 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 zone of at least one-half mile. For the reasons described in *Section 3.1*, the stabilized plume boundary will remain within the Reef Structure at the Project.

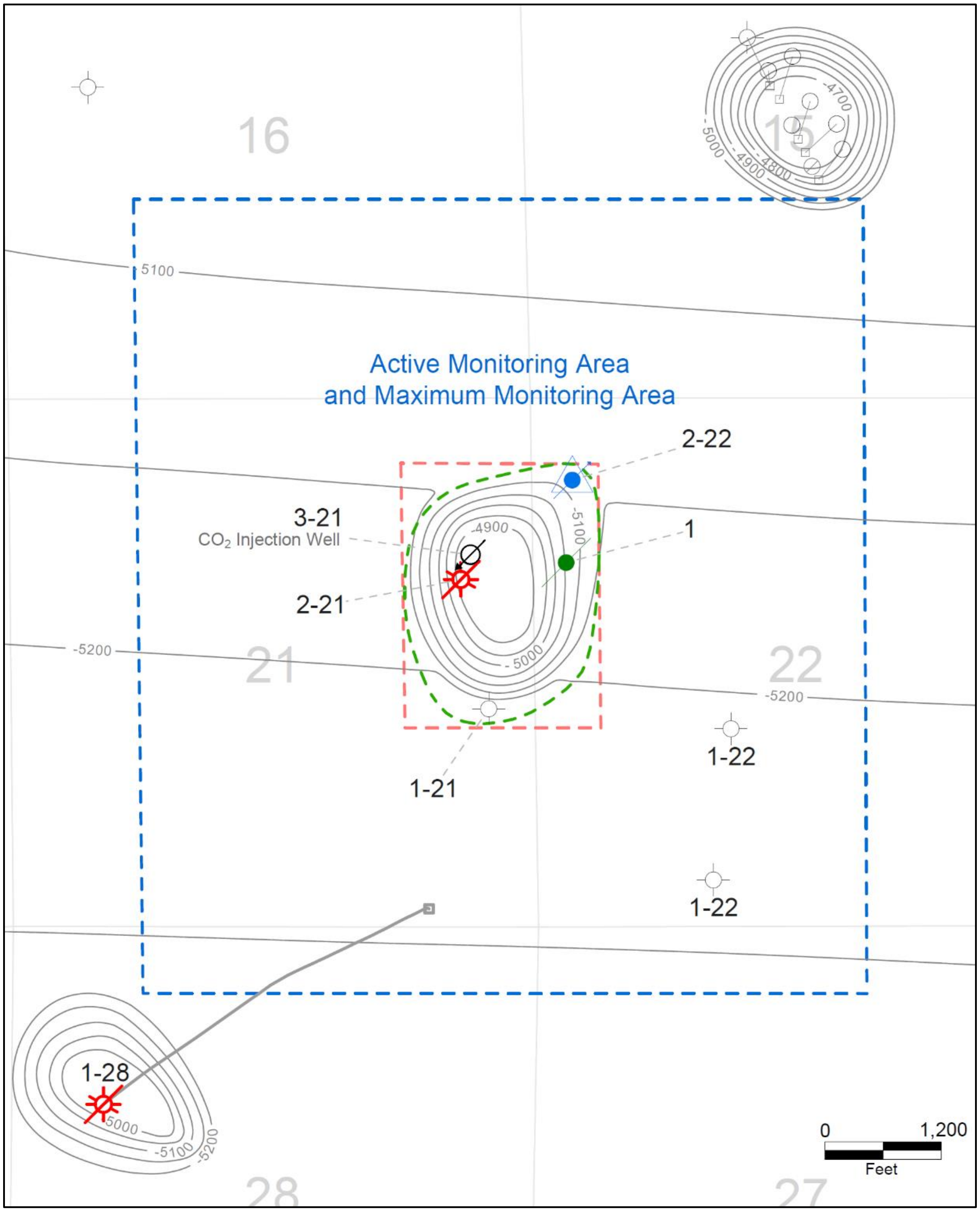

Figure 14. Map depicting the AMA/MMA (total area enclosed by the dashed blue boundary), structure contours of the top of the A1 Carbonate (top of the storage interval), and the Chester 21-29N-02W Reef (central) flanked by the Chester 15 reef to the northeast, and the Chester 28 reef to the southeast. The Chester 21-29N-02W Reef boundary (green dashed line) which is also the stabilized plume boundary, has herein also been regularized to the nearest 10-acre square (dashed red boundary) to help in establishing the boundary positions of the AMA and MMA. Well spots have been filtered to show only wells with total depths below 3,000 ft TVD, and for clarity purposes only wellbores within the AMA/MMA have been labeled. The planned 3-21 UIC Class II injection well is labeled in the northeast quadrant of the Chester 21-29N-02W Reef.

4. POTENTIAL PATHWAYS FOR LEAKAGE

Riverside has identified the following as potential surface leakage pathways at the Project per 40 CFR 98.448(a)[2]:

- Leakage from surface equipment
- Leakage from existing wellbores
- Leakage from wells not yet drilled
- Leakage from the injection wellbore
- Leakage from existing faults and fractures
- Leakage from natural or induced seismicity
- Leakage through confining layers
- Leakage from lateral migration of CO_2

This section discusses the likelihood, magnitude, and timing of potential surface leakage of CO_2 from these pathways. *Section 5* discusses the monitoring plan to detect any surface leakage and strategies for quantifying leakage from these pathways.

4.1 Leakage from Surface Equipment

The injection mass flow meter will be located on the well pad near the wellhead of the injection well. As the CO_2 that is received and metered by this mass flow meter will be wholly injected and not mixed with any other supply of CO_2 and no production from the storage formation will occur, the potential leakage pathways from surface equipment are limited to the mass flow meter, the injection wellhead, the short flowline between the two, and any pipe fittings or valves installed along the flowline or wellhead. The likelihood of leakage from these surface components is low and further mitigated by the following:

- Locating the CO_2 received and injection mass flow meter near the wellhead to minimize opportunities for potential leakage from surface equipment.
- Adhering to high material selection and construction standards when designing and constructing the wellhead and flowline.
- Continuously monitoring the wellhead and mass flow meter with the SCADA system.
- Routinely conducting audible, visual and olfactory (AVO) inspections of the surface equipment for leaks. These checks will occur each time operators visit the well site but not less than once per week. Leaks can be heard as a hissing sound, seen by the distortion of objects on the other side of the leak, or smelled as an odor downwind of the leak.
- Monitoring surface equipment with Optical Gas Imaging (OGI) technology such as an infrared (IR) or thermal imaging camera on a quarterly schedule.

The magnitude of potential leakage from these surface components is small with any leaked volume likely limited to the volume of CO_2 in the flowline or wellhead components. The timing of leakage risk spans from the start of injection and through the active injection period until the well is plugged and abandoned.

4.2 Leakage from Existing Wells

There are four boreholes that penetrate the A2 Evaporite confining layer within the Reef Structure, the area expected to contain the free-phase CO_2-occupied plume. Well data for these boreholes is listed in *Section 2.3*. Three of these boreholes, the Marshall, Glen #1 well, the Underwood, N M & Knapp, C A #1-21 well, and the Leacock Hubbard Underwood & Knapp #2-21 well have been plugged and abandoned according to State of Michigan standards and determined by Riverside to be an unlikely pathway for CO_2 migration above the confining interval. The State of Michigan requires a cement plug be placed within the wellbore to confine oil, gas, and water to the strata from which the oil, gas, and brine were produced. Upon review of the plugging reports for these three wellbores, Riverside has determined that a cement plug has been placed within the A2 Evaporite confining layer, as well as within several overlying intervals. Therefore, leakage through these legacy wellbores is unlikely.

The fourth borehole that penetrates the A2 Evaporite confining layer within the Reef Structure, the State Chester 2-22, is an active brine disposal well permitted in the Dundee formation. It was originally drilled in 1974 to a total depth of 6,660 ft below surface to the top of the Brown Niagaran formation. As this well is located at the far flank of the reef, it tested dry for hydrocarbons. It was then reworked into a brine disposal well by plugging back and completing the well within the Dundee formation at approximately 2,450 ft. The plugging records indicate a cement plug was placed at the base of the well, within the A2 Evaporite confining layer, as well as over additional intervals up hole. The well continues to pass mechanical integrity tests (MITs) in accordance with State of Michigan standards. Riverside has determined that the State Chester 2-22 well is a low risk for CO_2 leakage because it has been properly plugged downhole and recompleted above. It is subject to ongoing monitoring and MITs as an active brine disposal well by a different operator.

The magnitude of potential leakage from existing wellbores is considered to be low. Most of the existing wells are located on the reef flank, limiting their intersection with the projected CO_2 plume. The timing of leakage risk begins when the CO_2 plume intersects with an abandoned well. Riverside considers the likelihood of leakage from existing wells to be low because the four legacy wells that penetrate the Reef Structure have been abandoned to State of Michigan standards with multiple cement plugs.

Outside of the Reef Structure, but within the one-half-mile buffer distance of the AMA and MMA, there are two boreholes (Underwood, Knapp, and Ashland Farms, INC 1; and Underwood, Nellie M & Knapp, Clara Ann 1-22) that penetrate the A2 Evaporite confining layer. The surface location of one additional directionally drilled wellbore, the State Chester 1-28, is located within the AMA and MMA. However, its bottomhole location and penetration of the A2 Evaporite confining layer are located outside of the Project's AMA and MMA. These three wellbores have been plugged and abandoned according to State of Michigan standards. The likelihood of leakage from these

wells is very low as they do not intersect the Reef Structure and the projected free-phase CO_2 plume.

There are 21 wellbores within the AMA and MMA that do not penetrate the A2 Evaporite confining layer (Table 2). The likelihood of CO_2 leakage through any of these wellbores is assessed to be very low because the bottom of each of these boreholes is at least 3,350 vertical feet above the top of the A2 Evaporite confining layer. Furthermore, the geologic formations within this minimum 3,350 feet of vertical separation consists primarily of regionally deposited evaporites and tight carbonates with characteristically low vertical permeability.

There are also four water wells within the AMA and MMA that pose an even lesser risk of CO_2 leakage for the same reasons stated above and the fact that they do not even reach bedrock below the glacial drift (Table 4). Note that the last two wells in Table 4 were drilled by Riverside to support the drilling operations for the Smith 3-21 injection well. One will be plugged when drilling operations have ended, and one will be retained as a ground water monitoring well as described in *Section 6.4*.

Table 4. List of water wells within the AMA/MMA.

Well ID	Owner Name	Construction Date	Depth (ft)	Geographic Coordinates	
				Latitude	Longitude
69000004263	Cody & Sandi Smith	3/8/2021	65	44.892795	-84.541395
69000004281	Doug Sheridan	5/11/2021	50	44.892034	-84.545048
69000009481	Riverside Energy Michigan	1/15/2025	60	44.895742	-84.548594
69000009482	Riverside Energy Michigan	1/15/2025	60	44.8958147	-84.548585

4.3 Leakage from Wells Not Yet Drilled

Wellbores drilled in the future through the Reef Structure may be a potential leakage pathway for CO_2. The likelihood of leakage from wells not yet drilled is low and any risk is mitigated by the following:

- Hydrocarbon production from the A1 Carbonate and Brown Niagaran formations in the Chester 21-29N-02W Reef will be no longer possible after injection of CO_2 begins.
- There are no known hydrocarbon producing formations below the Brown Niagaran in the AMA and MMA. The St. Peter Sandstone (approx.10,000 ft) is an occasional gas producer where on anticlinal structure in central and northern Michigan. There are several St. Peter dry holes within a few miles of the Storage Facility, and the Storage Facility is not on an anticline as confirmed by well control and 2D seismic.
- Future wells drilled outside of the Reef Structure but within the AMA and MMA will not interact with the free-phase CO_2 plume.
- All well records and injection data will be shared with Michigan-EGLE to ensure that potential drillers are aware of the Project for the indefinite future.
- Michigan Admin. Code R. 324.413 regulates the drilling of wellbores to strata beneath gas storage reservoirs. The rule describes specific drilling equipment, casing design, and

completion standards that must be deployed to ensure drilling occurs safely through natural gas storage reservoirs. While this rule applies to natural gas storage projects (not CO_2 storage projects), Michigan-EGLE already has experience in protecting and regulating the drilling of new wells through gas storage reservoirs.

For these reasons, it is unlikely that any future wells will be drilled through the A2 Evaporite confining layer within the Reef Structure and projected free-phase CO_2 plume. The magnitude of potential leakage from wells not yet drilled is low.

4.4 Leakage from the Injection Wellbore

The Smith 3-21 injection well will be permitted and constructed as a Class II oil field waste disposal well with Michigan-EGLE. As this injection well is an additional penetration that could offer a leakage pathway to the surface, Riverside is taking the following steps to mitigate potential leakage:

- The Smith 3-21 injection well will be constructed more rigorously than Michigan Class II standards. Figure 15 describes the proposed injection well design. Chromium alloy long-string casing will be installed from total depth through the A2 Evaporite and cemented in place with SLB's *EverCRETE* CO_2 resistant cement.
- Prior to injection, a cement bond log and MIT will be run to ensure proper well construction.
- Riverside will perform a MIT at least every 5 years per Michigan-EGLE requirements.
- The annular fluid volume between the casing and injection tubing will be monitored quarterly.
- The surface pressure of the tubing and annular space will be continuously monitored by the SCADA system to detect any abnormalities that indicate a loss of integrity or leak has occurred.
- Riverside will be monitoring surface components and the injection wellhead with OGI technology on a quarterly schedule and performing an AVO inspection weekly.
- After injection, the Smith 3-21 injection well will be plugged and abandoned with cement plugs placed to prevent any future leakage of CO_2.

Leakage from the injection wellbore is unlikely due to the constant monitoring of the wellbore and periodic mechanical integrity testing. The magnitude of leakage from the injection wellbore is small. It is unlikely that a blowdown of the wellbore would be necessary, but if one occurs, the leaked CO_2 would be limited to the volume contained in the wellbore and could be easily quantified using volume, pressure, and temperature data. The timing of leakage risk from the injection wellbore occurs from the beginning of injection until proper plugging and abandonment.

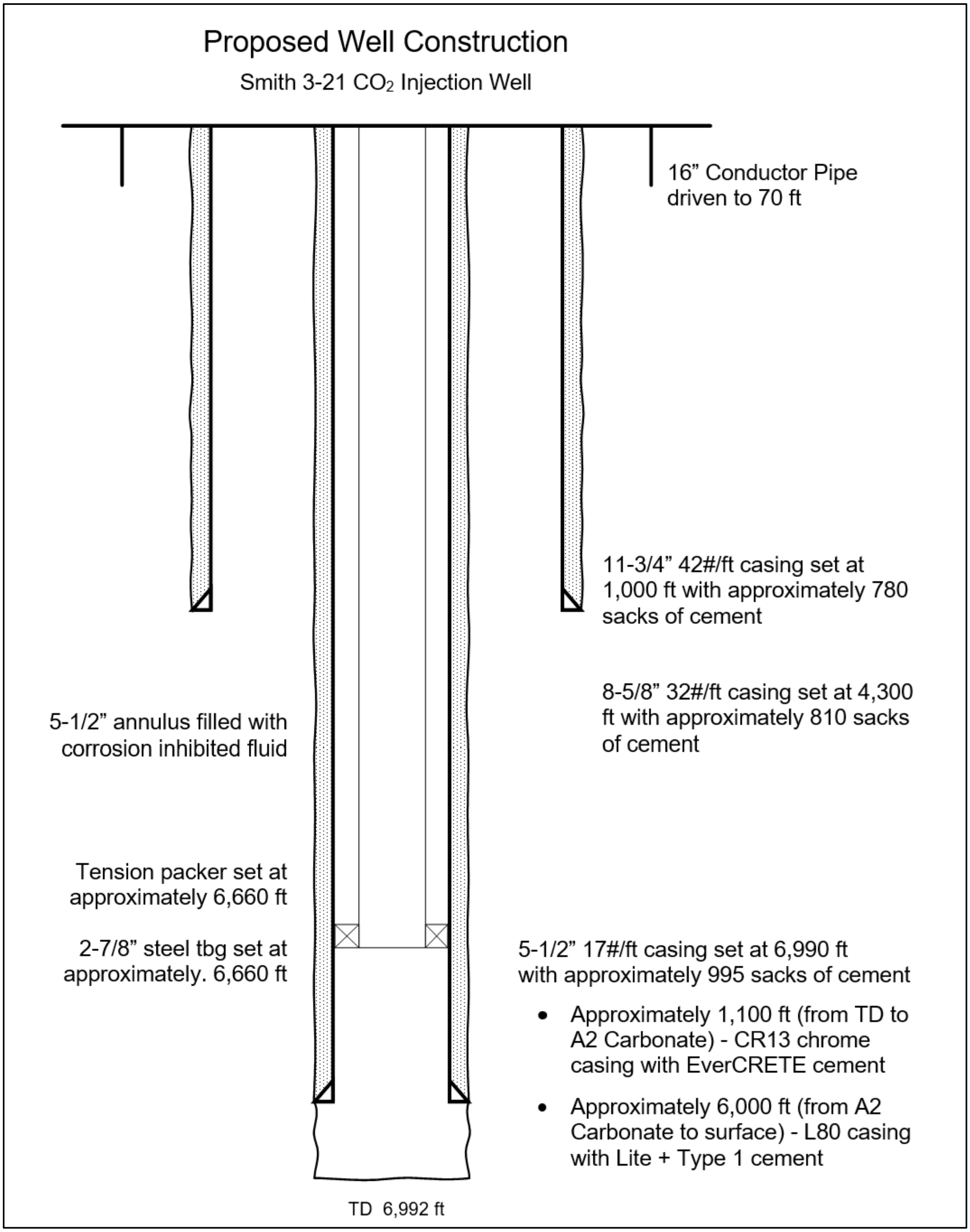

Figure 15. Proposed construction design for Smith 3-21 injection well.

4.5 Leakage from Existing Faults and Fractures

Evaluation of 2D seismic did not reveal any faults or fractures in the Reef Structure, and there are no known faults or fractures through the A2 Evaporite confining layer in the AMA and MMA that would allow CO_2 movement into overlying formations. The risk of leakage of CO_2 from an unknown fault or fracture is very low, because hydrocarbons were sealed within the Reef Structure throughout geological time.

4.6 Leakage from Natural or Induced Seismicity

The likelihood of natural seismicity is very low. The Michigan Basin is structurally stable with few major structural features. No naturally occurring earthquakes greater than magnitude 2.5 have originated within 100 miles of the Storage Facility since 1900. The USGS's 2023 50-State Long-term National Seismic Hazard Model classifies northern Michigan as having the lowest chance of experiencing a slight or greater damaging earthquake in the next 100 years[1].

Natural gas storage in nearby Niagaran reef fields offers an analog to CO_2 injection and experience with reservoir response under pressure. To date, Riverside is unaware of any induced seismicity issues associated with natural gas storage in Niagaran reefs. Many reefs are permitted with a maximum bottomhole pressure greater than 4,600 psi at depths of 6,600 to 6,800 ft[2]. The planned maximum bottomhole pressure for the Storage Facility is 4,345 psi (6,036 ft depth * 0.8 psi/ft fracture gradient * 0.9 safety factor). For these reasons, the likelihood of leakage from induced seismicity is low and the risk would be limited to the active injection period because the reservoir pressure will be highest during the injection period.

4.7 Leakage through Confining Layers

The primary seal of the Project is the A2 Evaporite confining layer. The A2 Evaporite is comprised of anhydrite which has virtually no porosity or permeability. Above the A2 Evaporite confining layer, additional evaporite and low-permeability carbonate sequences are present that further reduce the risk of upward movement of CO_2 through overlying strata.

The likelihood of leakage through confining layers is very low, because the A2 Evaporite confining layer's sealing capacity has been proven by the previous trapping of hydrocarbons throughout geologic time.

4.8 Leakage from Lateral Migration of CO_2

As shown in Figure 4, the Reef Structure is fully compartmentalized due to the unique formation of the pinnacle reef and subsequent deposition of overlying strata. The Reef Structure is encased in a tight carbonate and non-porous evaporate seal that prevents the vertical and lateral migration

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[1] https://www.usgs.gov/programs/earthquake-hazards/science/2023-50-state-long-term-national-seismic-hazard-model
[2] https://www.govinfo.gov/content/pkg/FR-1994-03-28/html/94-7181.htm

of fluids. Underlying the storage formation are tight units of the Brown and Gray Niagaran formation.

Riverside does not believe that the A1 Carbonate and Brown Niagaran storage intervals are in communication with any other Niagaran reservoir or reef. Water infiltration from below the reservoir was not observed during the production history of the Chester 21-29N-02W Reef and the current reservoir pressure is expected to be at the reef's depleted pressure of approximately 300 psi.

The likelihood of leakage from lateral migration of CO_2 is very low as demonstrated by the production history of the Chester 21-29N-02W Reef. The magnitude of any potential leakage is low due to the closed structure of the reef.

5. MONITORING AND LEAK QUANTIFICATION STRATEGY

This section describes the monitoring plan to detect any surface leakage from the pathways identified in *Section 4* and the strategies for quantifying leakage should it occur.

5.1 Detecting and Quantifying Leakage from Surface Equipment

The injection mass flow meter will be located near the wellhead, limiting the amount of equipment subject to monitoring for leakage to the wellhead, the mass flow meter, and the flowline and any valves between the wellhead and mass flow meter. To detect any leakage from this equipment, OGI surveys will occur quarterly using either an IR or thermal imaging camera, and AVO inspections will be conducted by trained personnel at least weekly. In addition, the wellhead and mass flow meter will be continuously monitored by the SCADA system.

Emissions from surface equipment downstream of the mass flow meter such as the flowline, valves, fittings or the wellhead assembly will be estimated and repaired as quickly as possible. If CO_2 must be vented downstream of the meter to make a repair, the amount of CO_2 vented will be estimated using the methods specified in 40 CFR 98 Subpart W. Data that could be considered for estimating the amount of CO_2 leaked may include but not limited to: any anomalies in metered pressures or mass flow, average pressures or mass flow, the time between inspections, physical measurements of pinholes and/or the relative size and intensity of the leakage plume as detected by OGI.

5.2 Detecting and Quantifying Leakage from Existing Wellbores and Future Wells

As discussed in *Section 4*, few existing wells will encounter the CO_2 plume, and all of these wells have been plugged and abandoned to State of Michigan standards. Riverside will be conducting quarterly groundwater monitoring and optical gas imaging on the injection well pad. Pressure transducers installed in the tubing and annulus at the wellhead will be monitored by the SCADA system and bottomhole pressure and temperature surveys will occur periodically through the injection period to identify possible abnormalities in operational parameters that would indicate a subsurface leak. Riverside will conduct bottomhole pressure tests and temperature surveys every

six months for the first two years and annually thereafter. Should a future well be drilled within the AMA and MMA, Riverside will work with Michigan-EGLE to ensure the well will not interfere with CO_2 storage within the Storage Facility.

If a leak is detected at a legacy well or a well not yet drilled, its volumetric flow will be attempted to be metered if possible. If not, the latest injection data and reservoir pressure, volume and temperature data will be used to estimate a leakage volume and rate with a mass balance approach from the storage intervals. The timing of the leak will be determined by an estimate of the CO_2 plume's intersection with the legacy or future well.

5.3 Detecting and Quantifying Leakage from the Injection Wellbore

Riverside will deploy multiple monitoring strategies to detect leakage from the injection wellbore. The long string casing, injection tubing string and packer assembly are subjected to a MIT every 5 years as well as once before injection begins. The annular space between the casing and tubing will be filled with a corrosion inhibiting fluid and checked quarterly for significant changes in volume. The tubing and annular pressure at the wellhead will be monitored continuously with pressure transducers tied to the SCADA system. At a minimum, Riverside will conduct bottomhole pressure tests and temperature surveys every six months for the first two years, and annually thereafter. If the temperature survey detects an anomaly suggesting CO_2 intrusion behind casing, a radioactive tracer/gamma ray tool will be run to investigate. Further, the quarterly OGI and weekly AVO inspections would also encompass the area around the wellbore at the surface.

A workover of the well to replace components may be required and surface and downhole equipment would be thoroughly inspected for signs of wear or corrosion responsible for a potential leak.

If the mechanical integrity of the injection wellbore is lost, the injection will stop and not begin again until a MIT test is passed in compliance with Michigan-EGLE regulations. If a leak is determined to have taken place, it will be quantified using the timing of the loss of integrity and any pressure or annular fluid data from the MIT that can be used to characterize the leak.

Venting of CO_2 from the well may occur while making repairs and would be estimated and documented in accordance with Subpart W procedures. Typically, wells undergoing a workover are "killed" with sufficiently dense fluid to overcome the reservoir pressure and prevent venting of gases from the well to atmosphere.

5.4 Detecting and Quantifying Leakage from Existing Faults and Fractures and Natural or Induced Seismicity

Leakage from existing faults or fractures or fractures created by natural or induced seismicity will be monitored by continuous monitoring of operational parameters at the wellbore, periodic reservoir pressure and temperature surveys, and quarterly ground water monitoring near the injection well pad. At a minimum, Riverside will conduct bottomhole pressure tests and temperature surveys every six months for the first two years, and annually thereafter. Abnormalities in operational and reservoir parameters and such as the injection tubing and

reservoir pressures will be investigated to determine if there is a subsurface leak. If it is determined a subsurface leak has occurred, the latest injection data and reservoir pressure, volume and temperature data will be used with a mass balance approach to estimate a leakage volume and rate from the storage intervals. The timing of the leak will be determined by an estimate of the CO_2 plume's intersection with the leakage pathway.

As discussed in *Section 4*, natural and induced seismicity are considered to be unlikely. Riverside will subscribe to the USGS' Earthquake Hazards Program Earthquake Notification Service (ENS)[3] to receive notifications of any earthquakes with magnitude 2.0 or greater in Michigan. If an earthquake occurs, Riverside will evaluate the monitoring data to determine if the wellbore or Storage Facility are affected. Annulus pressure is continuously monitored and could indicate a loss of wellbore integrity issues caused by seismicity.

5.5 Detecting and Quantifying Leakage through Confining Layers or Lateral Migration

Leakage through the confining layers or from lateral migration will be monitored by periodic groundwater monitoring and reservoir pressure tests. Quarterly groundwater sampling and testing will occur in the water well to be drilled at the injection well pad for drilling operations and will be retained for ground water monitoring. A description of the groundwater testing that will occur is included in *Section 6.4*.

If it is determined a subsurface leak has occurred, the latest injection data and reservoir pressure, volume and temperature data will be used with a mass balance approach to estimate a leakage volume and rate from the storage intervals. The timing of the leak will be determined by an estimate of the CO_2 plume's intersection with the leakage pathway.

6. ESTABLISHING SURFACE LEAKAGE BASELINES

Prior to the start of continuous injection, the following data will have been collected to establish baselines for the Storage Facility against which future data may be compared in order to detect surface leakage.

6.1 Wellbore Integrity

After injection well construction is completed but before injection begins, a MIT and annular pressure test will be completed to confirm wellbore integrity. The initial volume of annular fluid will be noted, and it will be monitored during the start-up of injection to determine how it responds during injection start up. Its stabilized volume will be noted after at least a week of continuous injection. The injection tubing and annulus pressures at the wellhead will be recorded prior to CO_2 injection and continuously monitored thereafter with the SCADA system. MITs will occur at least every 5 years in accordance with Michigan-EGLE requirements.

[3] https://earthquake.usgs.gov/ens/help

6.2 Injection Well Operating Parameters

Riverside has established target injection and storage rates based on experience from other operators injecting and storing fluids in other Niagaran reefs. An initial model, described in *Section 2.5*, has been developed to confirm these baseline injection parameters. Riverside plans to inject CO_2 at a rate of 12,000 Mcfd or approximately 230,000 metric tons of CO_2 per year. This rate may vary depending on injection capabilities of the well.

During injection operations, Riverside will use site-specific data during wellbore construction and the initial injection period to update nominal injection parameters such as wellhead tubing and annulus pressures and injection flow rates.

6.3 Reservoir Conditions

Initial bottomhole pressure will be recorded at mid-perforations and a temperature survey with gradient stops will be completed before injection. A bottomhole pressure test and temperature survey will be conducted at least every six months for the first two years of injection and then annually thereafter. After approximately 48 hours of continuous CO_2 injection, Riverside will run in hole to mid-perforations to establish reservoir pressure and temperature and run a gradient on the way out of the hole while noting casing and tubing pressures at surface.

6.4 Groundwater Monitoring

Groundwater monitoring will occur from a water well drilled on the injection well pad (to approx. 100 ft) and include the following analyses to detect the presence of fugitive CO_2:

- Standard field parameters form a calibrated water quality meter: temperature, pH, conductivity, dissolved oxygen, oxidation reduction potential, and turbidity.
- Standard EPA UIC lab analyses barium, calcium, sodium, magnesium, potassium, total iron, chloride, sulfate, sulfide, carbonate, bicarbonate, TDS, resistivity, specific gravity, and pH.
- Lab analyses for dissolved methane, ethane, propane, and calculated dissolved CO_2 from carbonate, bicarbonate, and dissolved inorganic carbon.

A sample will be collected before injection begins from the ground water monitoring well to establish baseline parameters. During injection, groundwater sampling and testing will occur at least quarterly.

6.5 Surface Equipment Monitoring

After the site equipment is constructed but before injection begins, Riverside will conduct a baseline OGI survey with either an IR or thermal imaging camera. Within the first month of injection, an additional OGI survey will occur to ensure no leakage from surface equipment during the beginning of injection. Thereafter, Riverside will conduct OGI surveys quarterly at the injection well pad to detect for surface leakage of CO_2.

7. SITE-SPECIFIC CONSIDERATIONS FOR THE MASS BALANCE EQUATION

Riverside will utilize the mass balance equations listed in 40 CFR 98.443 to calculate the mass of CO_2 sequestered. The site-specific considerations for these equations are discussed in this section.

7.1 Mass of CO_2 Received and Injected

In accordance with 40 CFR 98.444(a)[4], Riverside will determine the annual mass of CO_2 injected as the total annual mass of CO_2 received instead of using Equation RR-1 or RR-2 to calculate CO_2 received. The CO_2 received at the Storage Facility will be wholly injected and not mixed with any other supply of CO_2. There will be no production from the Storage Facility.

Equation RR-4 in 40 CFR 98.443(c) of Subpart RR will be used to calculate the mass of CO_2 received at the Storage Facility each year.

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

where:

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

$Q_{p,u}$ = Quarterly mass flow rate measurement for flow meter u in quarter p (metric tons per quarter).

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

p = Quarter of the year.

u = Flow meter.

7.2 Mass of CO_2 Produced

There will be no production from the Storage Facility. The purpose of the Storage Facility is to permanently dispose and sequester the CO2 waste stream derived solely from the production of Antrim natural gas.

7.3 Mass of CO_2 Emitted by Surface Leakage

Riverside will quantify the mass of CO_2 emitted by each identified surface leakage pathway as outlined in *Section 5*. Equation RR-10 will be used to calculate the total mass of CO_2 emitted by surface leakage at the Storage Facility.

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

where:

CO_{2E} = Total annual CO_2 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.

7.4 Mass of CO_2 Emitted from Equipment Leaks and Vented Emissions

As discussed in *Section 5.1*, Riverside will quantify the 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 injection mass flow meter and the wellhead in accordance with the procedures provided under Subpart W of 40 CFR 98. At the Storage Facility, the injection mass flow meter is located near the wellhead, limiting the equipment to the mass flow meter, the injection wellhead, the short flowline between the two, and any pipefittings or valves installed along this flowline or wellhead.

7.5 Mass of CO_2 Sequestered

Since no production will occur at the Storage Facility, Riverside will use equation RR-12 to calculate the total mass of CO_2 sequestered in the Storage Facility for the reporting year.

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

where:

CO_2 = Total annual CO_2 mass sequestered in subsurface geologic formations (metric tons) at the facility in the reporting year.

CO_{2I} = 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_{2E} = 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 mass flow meter used to measure injection quantity and the injection wellhead, for which a calculation procedure is provided in Subpart W of 40 CFR 98.

8. ESTIMATED SCHEDULE FOR IMPLEMENTATION OF MRV PLAN

Riverside will implement this plan as soon as it is approved by EPA. Riverside plans to be ready to begin CO_2 injection and to begin collecting data for calculating the total amount of CO_2 sequestered by March 1, 2025. All baselines will have been established and leakage detection strategies implemented prior to this date. This plan will be in effect until EPA approves Riverside's request for discontinuation of reporting. Riverside plans to submit a request for discontinuation of reporting after all wells in the Storage Facility are plugged and abandoned and has demonstrated that the injected CO_2 stream is not expected to migrate in the future in a manner likely to result in surface leakage, in accordance with 40 CFR 98.441(b).

9. QUALITY ASSURANCE PROGRAM

9.1 Monitoring of CO_2 Received

In accordance with 40 CFR 98.444(a)[4], Equation RR-4 will be used to calculate the total annual mass of CO_2 received because CO_2 received at the Storage Facility is wholly injected and metered by a single injection mass flow meter.

9.2 Monitoring of CO_2 Injected

At the injection well, the volume of CO_2 injected will be measured continuously by an Emerson Micro Motion ELITE Coriolis mass flow meter. Riverside will report quarterly averages of the flow rate and total mass injected. Injection stream samples will be collected at least quarterly to measure the CO_2 concentration immediately upstream or downstream of the injection mass flow meter.

The injection mass flow meter will operate continuously except as necessary for maintenance and calibration. It will be operated using the calibration and accuracy requirements in 40 CFR 98.3(i). Meter accuracy is based on accredited calibration standards according to ISO 17025/IEC 17025.

9.3 Procedures for Estimating Missing Data

In the event Riverside is unable to collect data required for performing the mass balance calculations, procedures for estimating missing data in 40 CFR 98.445 will be implemented as follows:

- Quarterly mass of injected CO_2 will be estimated using representative mass flow rate data from the nearest previous time period. Pressure data at the wellhead will be compared to previous time period's pressure data and mass of injected CO_2 to ensure similar consistency.
- Quarterly CO_2 stream concentration data will be estimated using a representative concentration value from the nearest previous time period.
- CO_2 emissions associated with equipment leaks or venting will be estimated following the missing data procedures contained in 40 CFR 98 Subpart W.

9.4 MRV Plan Revisions

Riverside will revise this plan and submit the latest version to the EPA Administrator within 180 days of making a material change to the monitoring and/or operational parameters, a change in the permit class of the UIC permit, notification of substantive errors in the MRV plan, or for any other reason Riverside should choose to revise this MRV plan in any reporting year.

10. RECORDS RETENTION

Riverside will retain the following records in accordance with 40 CFR 98.3(g).

(1) A list of all units, operations, processes, and activities for which GHG emission were calculated.

(2) The data used to calculate the GHG emissions for each unit, operation, process, and activity, categorized by fuel or material type. These data include but are not limited to the following information in this paragraph (g)(2):

> (i) The GHG emissions calculations and methods used. For data required by 40 CFR 98.5(b) to be entered into verification software specified in 40 CFR 98.5(b), maintain the entered data in the format generated by the verification software according to 40 CFR 98.5(b).
>
> (ii) Analytical results for the development of site-specific emissions factors.
>
> (iii) The results of all required analyses for high heat value, carbon content, and other required fuel or feedstock parameters.
>
> (iv) Any facility operating data or process information used for the GHG emission calculations.

(3) The annual GHG reports.

(4) Missing data computations. For each missing data event, also retain a record of the cause of the event and the corrective actions taken to restore malfunctioning monitoring equipment.

(5) The most recent copy of this GHG Monitoring Plan.

(6) The results of all required certification and quality assurance tests of continuous monitoring systems, fuel flow meters, and other instrumentation used to provide data for the GHGs reported under this part.

(7) Maintenance records for all continuous monitoring systems, flow meters, and other instrumentation used to provide data for the GHGs reported under this part.

In addition, Riverside will retain the following records for at least three years in accordance with 40 CFR 98.447:

- 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 mass 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 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 wellhead.

11. REFERENCES

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Appendix B: Submissions and Responses to Requests for Additional Information

Riverside Energy Michigan, LLC Chester 21-29N-02W Storage Facility Subpart RR Monitoring, Reporting, and Verification Plan

February 6, 2025

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Abbreviations and Acronyms

°F	Degrees Fahrenheit
AMA	Active Monitoring Area
API	American Petroleum Institute
BBL	Barrel
Bcf	Billion cubic feet
BHL	Bottom hole location
cf	Cubic feet
CO_2	Carbon dioxide and other carbon oxides
EGLE	Environment, Great Lakes, and Energy
EOR	Enhanced oil recovery
EPA	United States Environmental Protection Agency
ft	Foot (feet)
GOR	Gas to oil ratio
GRMD	Geologic Resources Management Division
HMI	Human Machine Interface
IP	Initial production
KB	Kelly bushing
lbs	Pounds
Mcf	Thousand cubic feet
Mcfd	Thousand cubic feet per day
MD	Measured depth
md	Millidarcy
MIT	Mechanical integrity test
MMA	Maximum Monitoring Area
MMscf	Million standard cubic feet
MMscfd	Million standard cubic feet per day
MRV	Monitoring, Reporting, and Verification
NNPRT	Northern Niagaran Pinnacle Reef Trend
P&A	Plugged and abandoned
PBTD	Plugged back total depth
pH	Scale of acidity
psi	Pounds per square inch
SCADA	Supervisory Control and Data Acquisition
scf	Standard cubic feet
SHL	Surface hole location
SLB	Schlumberger
SWD	Salt water disposal
TD	Total depth
TDS	Total dissolved solids
TVD	True vertical depth
UIC	Underground Injection Control
USGS	United States Geologic Survey

1. STORAGE FACILITY INFORMATION

1.1 Project Overview

The Chester 21-29N-02W Storage Facility is a CO_2 acid gas disposal injection project being developed by Riverside Energy Michigan, LLC (Riverside) in Otsego County, Michigan. The purpose of the project is to securely store the CO_2 emissions captured from the processing of natural gas produced from the Antrim Shale biogenic gas play in the northern Michigan Basin. The captured CO_2 will be injected into a Niagaran Pinnacle Reef reservoir, the Chester 21-29N-02W Reef.

The Chester 21-29N-02W Reef was once a natural gas producing field but has since been depleted, plugged, and abandoned. The Niagaran reservoir at a depth of approximately 6,100 feet (ft) enables CO_2 to be stored efficiently in a critical gas phase. This Monitoring, Reporting, and Verification (MRV) plan is designed in accordance with 40 CFR 98.440-449, Subpart RR, to define and describe the Chester 21-29N-02W Storage Facility (Storage Facility).

The Chester 21-29N-02W Storage Facility spatially consists of the surface and subsurface areas contained within the active and maximum monitoring areas, defined in *Section 3*. In process terms, the Chester 21-29N-02W Storage Facility begins at the mass flow meter positioned on the CO_2 flowline immediately upstream of the injection wellhead and ends in the subsurface at the reservoir's lithofacies-controlled aerial limits. Figure 1 shows the location of the Chester 21-29N-02W Storage Facility, the separate Turtle Lake Capture Facility (Capture Facility) from where CO_2 is sourced, and the approximately 2 miles of CO_2 flowline that links the two.

The Devonian age Antrim Shale Formation, from which the CO_2 originates as a minor co-constitute of natural gas production, produces regionally from a subsurface depth of approximately 1,000 to 2,000 ft. In contrast, the Silurian age Niagaran reef reservoir that constitutes the Chester 21-29N-02W Storage Facility is approximately 6,000 to 7,000 ft deep and currently has neither unplugged wells nor hydrocarbon production associated with it. It is the explicit purpose and design of this project to sequester and dispose of CO2 and not to facilitate any additional production from the Storage Facility. As such, the Turtle Lake Capture Facility exists and operates separate from the Storage Facility and is not a part of the Storage Facility as defined in this MRV plan.

1.2 Reporter Number

Greenhouse Gas Reporting Program Identifier: 589821

Operator: Riverside Energy Michigan, LLC on behalf of Riverside Carbon Solutions, LLC

1.3 Storage Facility Location

The Storage Facility is located in Otsego County, Michigan, approximately 9 miles southeast of the town of Gaylord, Michigan.

Storage Facility location description in the Public Land Survey System:

Sections 21 and 22, T29N-R02W

Storage Facility coordinates in North American Datum of 1983 (NAD83):

Latitude: 44.896048°
Longitude: -84.547381°

1.4 Underground Injection Control Permit Class: Class II

The Michigan Department of Environment, Great Lakes, and Energy (Michigan-EGLE) Geologic Resources Management Division (GRMD) administers the Underground Injection Control (UIC) program in Michigan for all Class II injection wells, by the statutes and rules subject to Part 615, Supervisor of Wells, of the Michigan Natural Resources and Environmental Protection Act (NREPA), Public Act 451 of 1994, as amended. The CO_2 injection well (Smith 3-21) will be operated by Riverside Energy Michigan, LLC, permitted as a UIC Class II well, and regulated by Michigan-EGLE GRMD.

The UIC Class II permit for the proposed Smith 3-21 injection well was issued by Michigan-EGLE GRMD on 1/10/2025 (EGLE permit number 61818).

The unique identifer assigned to the well is API number 21-137-62019-00-00.

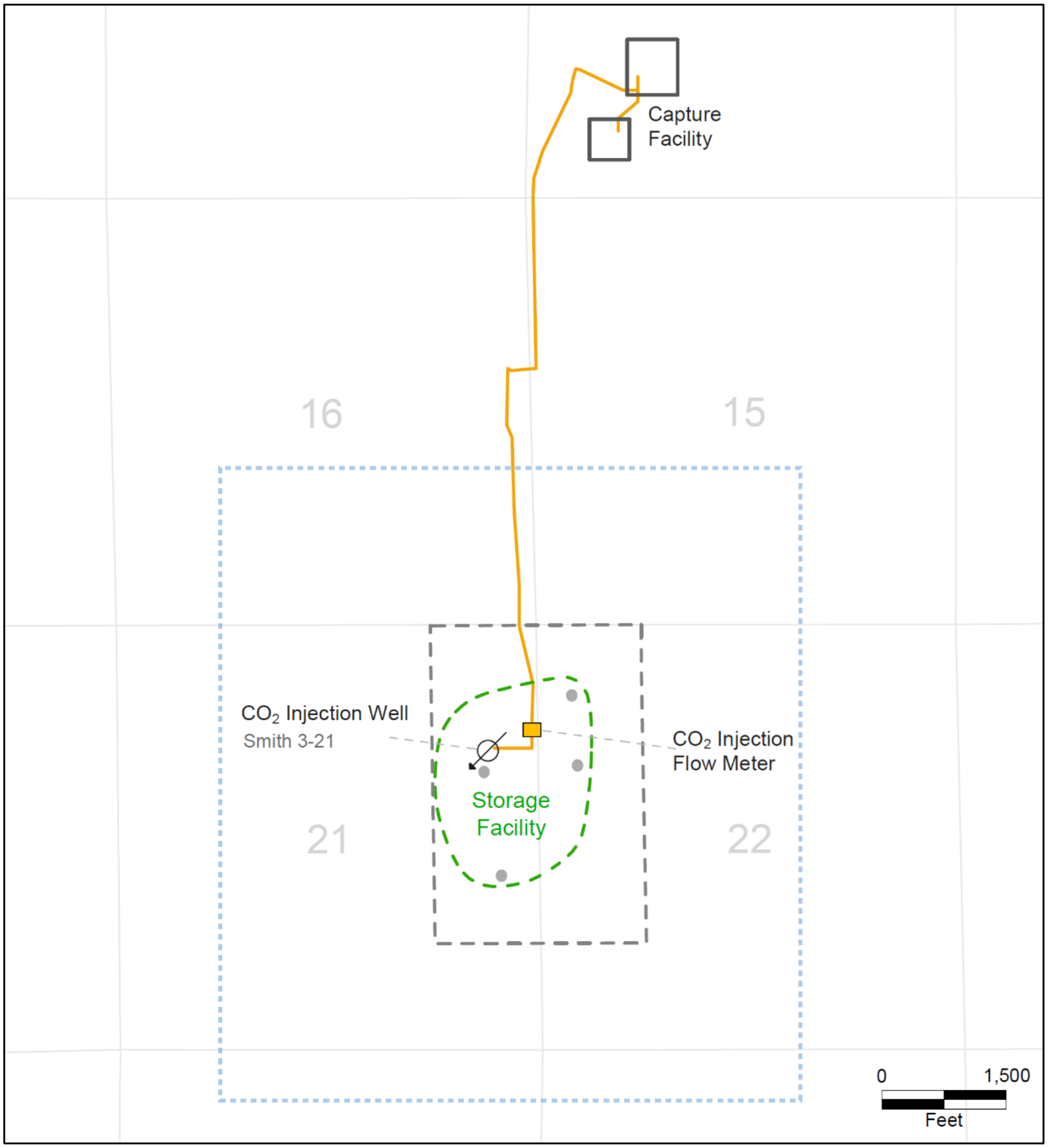

Figure 1. Map of the Chester 21-29N-02W Storage Facility (dashed green outline), showing the Capture Facility, CO_2 pipeline (orange) from the Capture Facility, Injection Unit (dashed gray rectangular outline) permitted with Michigan-EGLE, the Active and Maximum Monitoring Areas for the Storage Facility (dashed blue outline), the Smith 3-21 CO_2 Injection Well, and all plugged wells within the Storage Facility (gray circles). Section 3 and Figure 14 discuss the Active and Maximum Monitoring Areas in greater detail. The base map depicts the PLSS and shows all or portions of sections within T29N-R02W.

2. PROJECT DESCRIPTION

2.1 Regional Geology

The Northern Niagaran Pinnacle Reef Trend (NNPRT) in the Michigan Basin features several hundred highly compartmentalized pinnacle reefs found at an average dept of about 6,000 ft

below the ground surface. These reefs are separated from one another by distances as little as hundreds of feet to as much as several miles. The NNPRT originated from coral reefs formed during the Silurian Period 420 to 440 million years ago in tropical sea environments (Figure 2).

The reefs were subsequently buried by sediments deposited around and above the reefs encasing them within mostly impermeable layers of evaporitic and carbonate rocks. These impermeable evaporitic and carbonate rocks are responsible for trapping and sealing prolific quantities of oil and gas within these reefs.

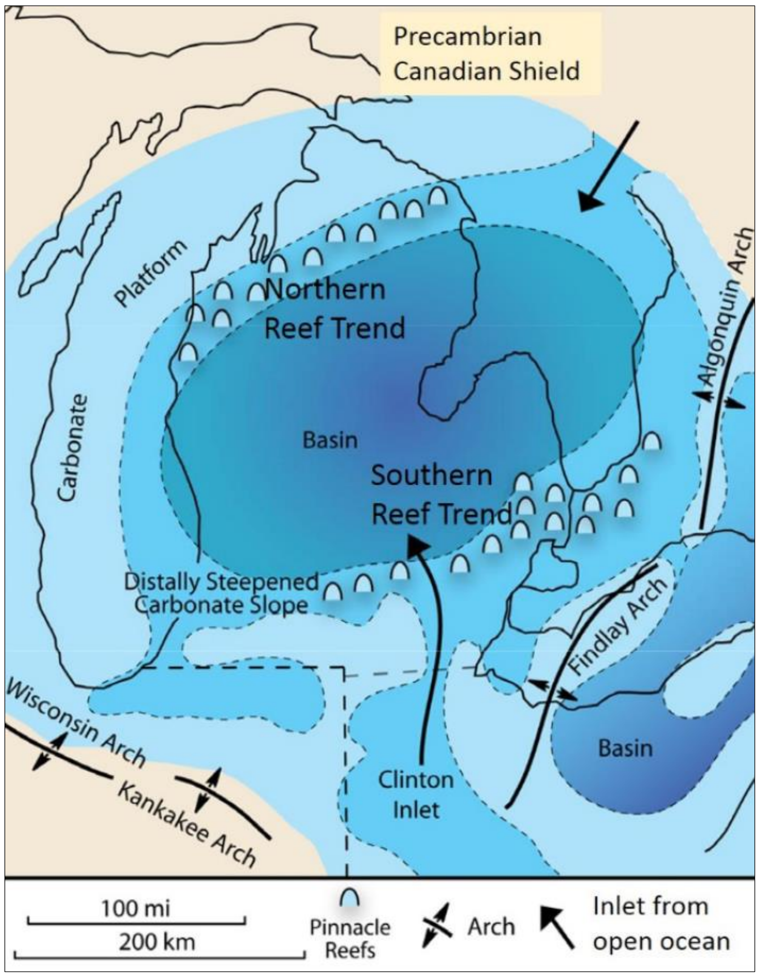

Figure 2. Map of the Michigan Basin and interpreted paleogeography during the Silurian Period, depicting the Northern Niagaran Reef Trend amongst regional environments. Ritter (2008) modified after Briggs and Briggs (1974).

The NNPRT forms a part of a broader shallow shelf carbonate depositional system that partially encircles the Michigan Basin. The NNPRT is positioned along the margin of the system's carbonate platform. Individual reefs typically range in area from 50 to 500 acres and have vertical heights between 100 to 700 ft in the subsurface.

The reservoir facies primarily consist of porous and permeable dolomite and limestone. Some reefs are completely dolomitized, while others are essentially all limestones. Dolomitization of the reefs, which helps enhance porosity, increases as the reefs become shallower. Salt and anhydrite plugging of porosity occurs in the deeper reefs (Gill 1979). Reef porosity values can be as high as 35%, but typically average 3 to 12%. Net pay intervals can total from only a few feet to several hundred feet. The most productive reef reservoirs are characterized by dolomitized reef facies with well-developed inter-crystalline and vuggy porosity. Secondary porosity is present and can enhance permeability, which typically averages 3 to 10 millidarcies.

The Niagara and A1 Carbonate Formations of the early Silurian Niagara Group contain the main reservoir units within the reefs, shown in the stratigraphic column in Figure 3. The base of the Niagara Formation, referred to as the “Lockport” or “White Niagaran” is typically a partially dolomitized to dolomitized crinoidal wackestone, (Charbonneau, 1990). Overlying the Lockport, the Guelph Formation is comprised of units commonly referred to as the “Gray” and “Brown” Niagaran. The Gray Niagaran and Lockport are typically characterized by very low porosity. The Brown Niagaran comprises the core of the reef reservoir and pinnacle reef buildup. It is characterized by dolomite and limestone skeletal wackestones and boundstones, (Huh, 1973).

The A1 Carbonate overlies the Brown Niagaran at the reef crest and is sometimes referred to as the “Ruff” Formation. The A1 Carbonate is considered a reservoir unit in the crest of some reefs but grades into tight, low porosity dolomitic mudstone near the reef flanks, (Huh, 1973).

The A1 Carbonate and Brown Niagaran Formations are encased by a sequence of evaporites and salt-plugged carbonates, comprising the seal for the reefs. The A1 Evaporite is typically thin or not present at the crest of the reef but forms a seal of the Brown Niagaran at reef flanks. Overlying the A1 Carbonate and providing the primary seal for the Storage Facility is the A2-Evaporite, Figure 3. The A2 Evaporite is characterized by non-porous and impermeable anhydrite at the reef crest. It transitions to halite dominated facies off the structure of the reef. Further overlying the A2 Evaporite are hundreds of feet of non-porous evaporite and low porosity carbonate and shale sequences that comprise the Salina Group.

The lithostratigraphy and internal reef structure are visualized in Figure 4. Reef formation began surrounding a carbonate bioherm in warm, shallow waters, (Rine, 2017). The reef core grew upwards as sea level in the Michigan Basin rose. When sea level fell, the reefs became exposed and evaporite deposition encased the reefs.

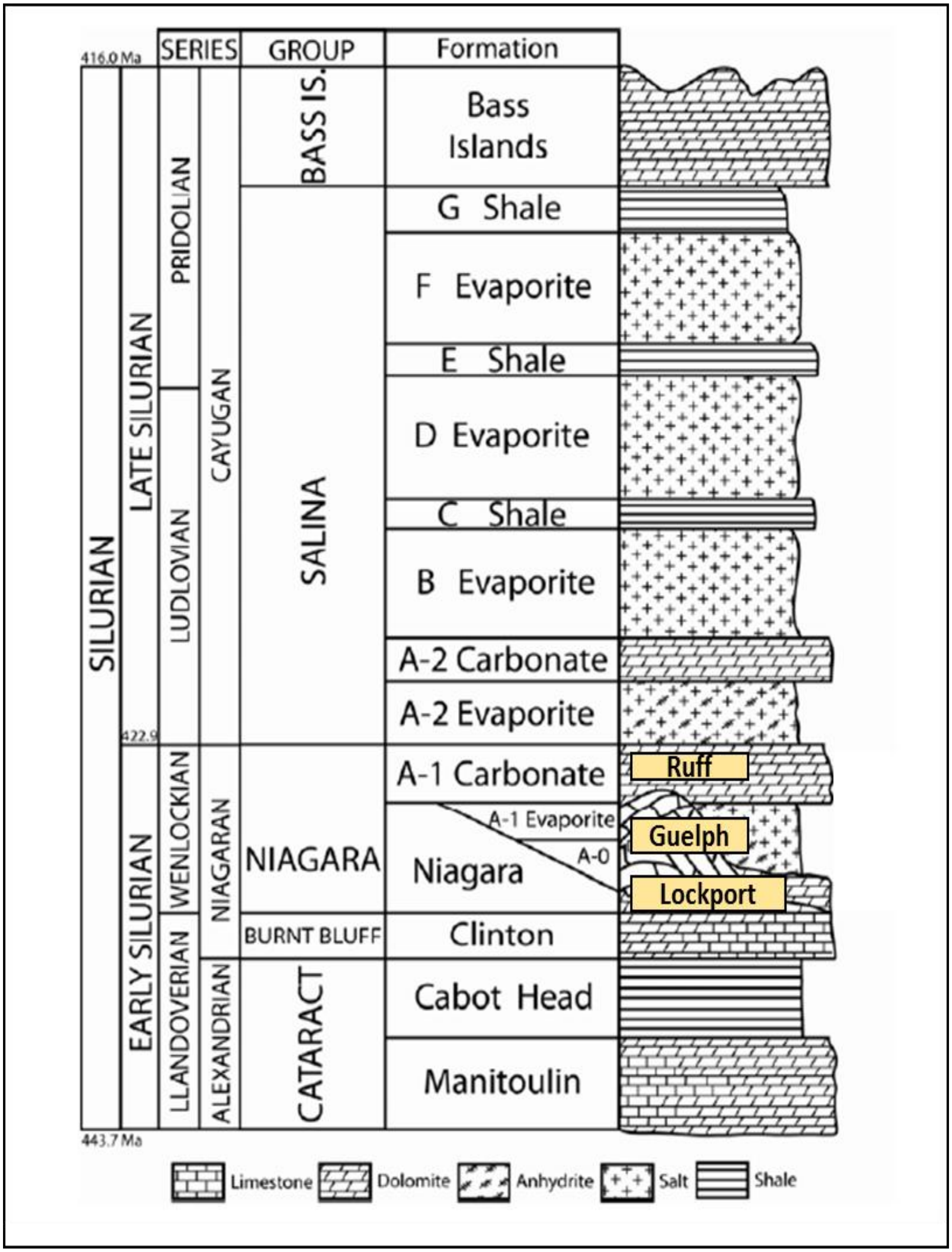

Figure 3. Generalized stratigraphic column for Silurian period deposits in the Michigan Basin, with emphasis on Niagaran reefs (Ritter, 2008).

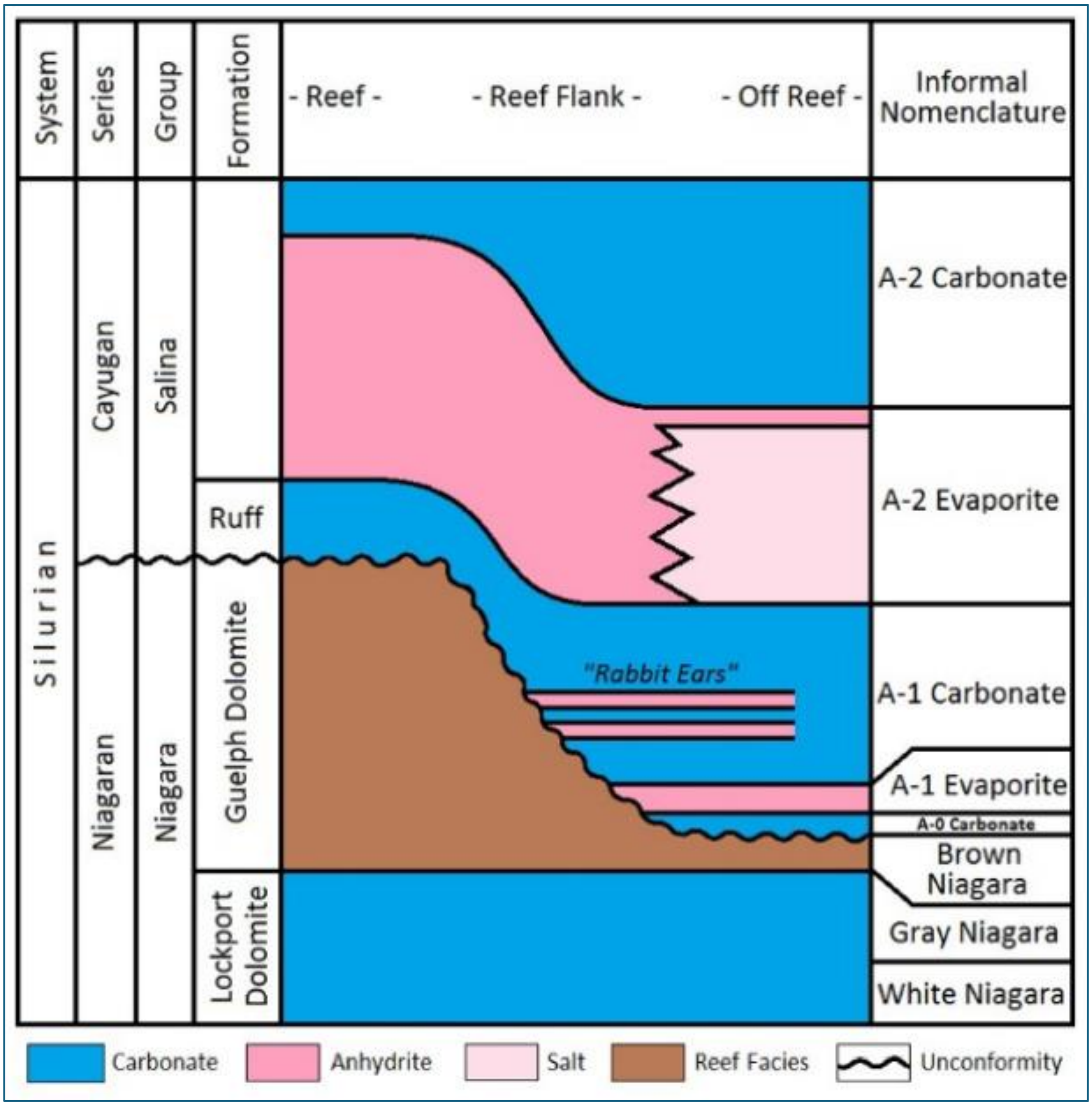

Figure 4. Lithostratigraphy visualization of a Niagaran reef interval, (Gupta et al., 2020 modified from Gill 1979 and Huh 1973).

2.2 Site Characterization

The Chester 21-29N-02W Field is a Northern Niagaran Pinnacle Reef located in Sections 21 and 22 of Township 29 North, Range 2 West, Otsego County, Michigan. The Field has a footprint of approximately 90 acres and is buried to a depth of 6,710 ft TVD (-5,472 ft subsea TVD) at its base to 6,160 ft (-4,921 ft subsea TVD) at its top.

While the reef structure itself is 550 ft tall and consists of the Brown Niagaran Formation, an additional 60 ft of A1 Carbonate Formation rests directly on top of the Brown Niagaran Formation and serves as a vertical extension of the physical reservoir observed in the Niagaran interval. Porosity of the A1 Carbonate and Brown Niagaran reservoir intervals derived from wireline logs ranges from 1 to 16% and averages 5.4%. Unless otherwise specified, all subsequent mentions

in this document of the Reef, Reef Structure, or Field will mean to refer to the total interval that includes both the Brown Niagaran Formation and the A1 Carbonate Formation.

The A2 Evaporite Formation rests directly on top of the A1 Carbonate Formation and serves as the primary seal for the Storage Facility. Above the 120 ft thick A2 Evaporite Formation is a 1,300 ft thick series of massive evaporite deposits and interbedded shale and limestone deposits that make up the bulk of the Salina Group.

The following geologic data was compiled for the Chester 21-29N-02W Reef and surrounding area:

- Well data from historic wellbores including wireline logs, drillers reports, and state curated well files.
- 2D seismic data, composed of 5 lines that each traverse the Reef Structure and adjacent surrounding area.
- Oil and gas production histories as reported to the State of Michigan.

Figure 5 shows the shot point locations of 2D seismic lines used to interpret the Reef Structure at the Storage Facility. Figure 6 is a stratigraphic cross section of well logs through the Storage Facility and Figure 7 is the cross-section reference map.

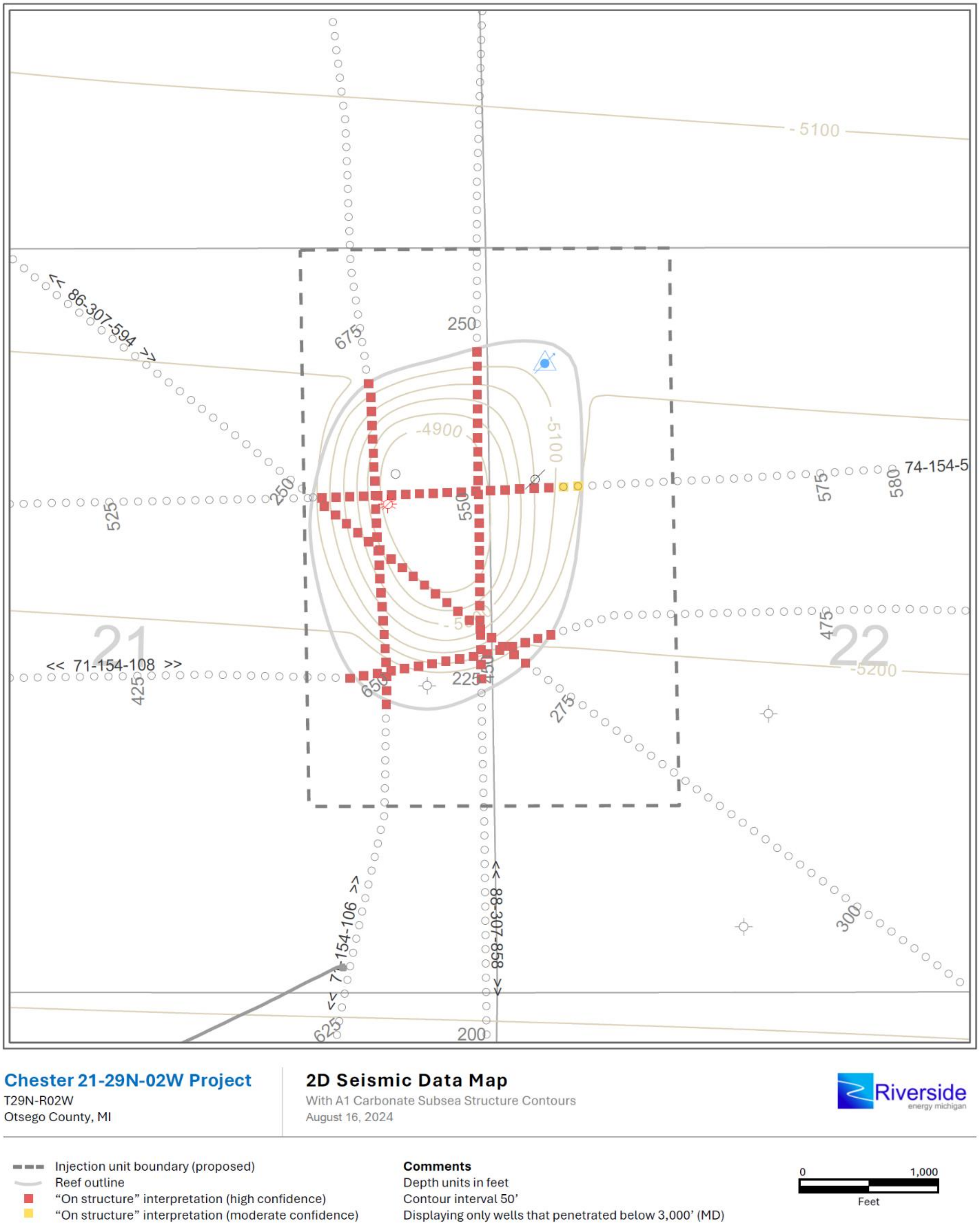

Figure 5. 2D seismic shot point locations used to determine the position of the Chester 21-29N-02W Reef Structure.

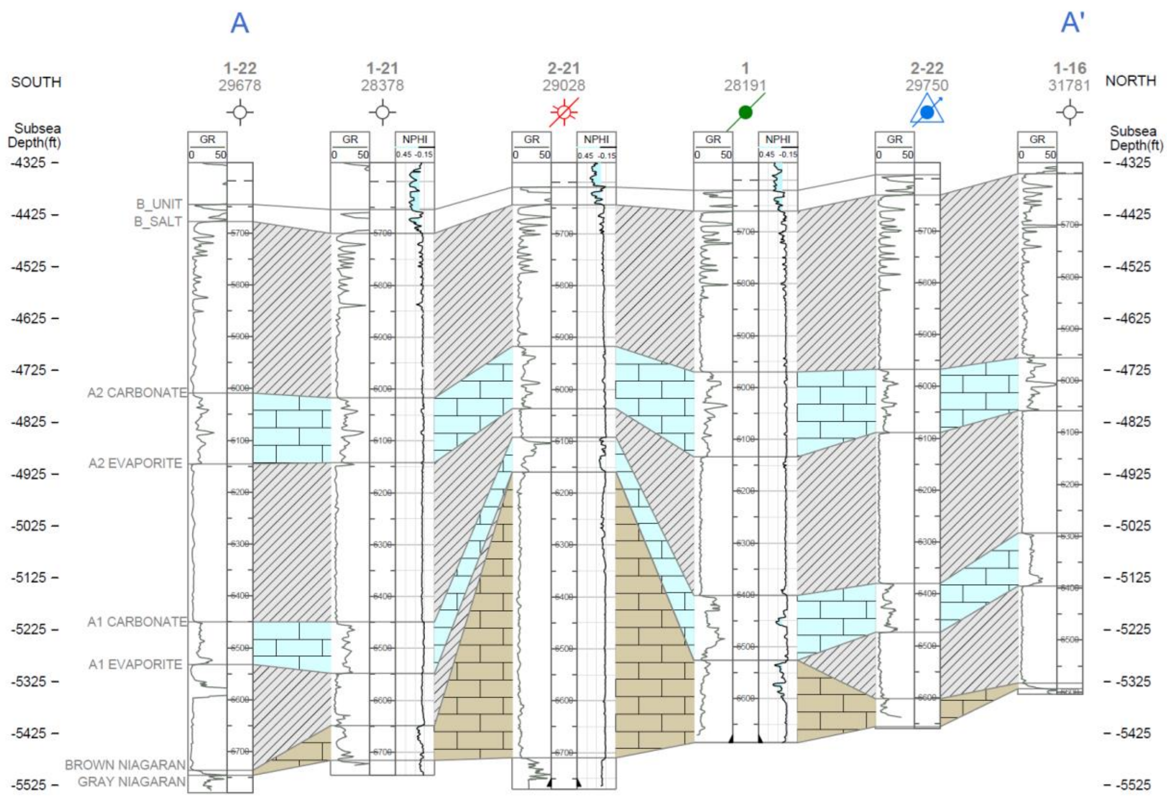

Figure 6. Stratigraphic-structural cross-section of Niagaran reef interval at the Chester 21-29N-02W Storage Facility and surrounding area. Wireline log tracks include Gamma Ray log response ("GR", scale 0 to 50 API) left of each wellbore, and where available Neutron Porosity log response ("NPHI", 0.45 to -0.15%) right of wellbore.

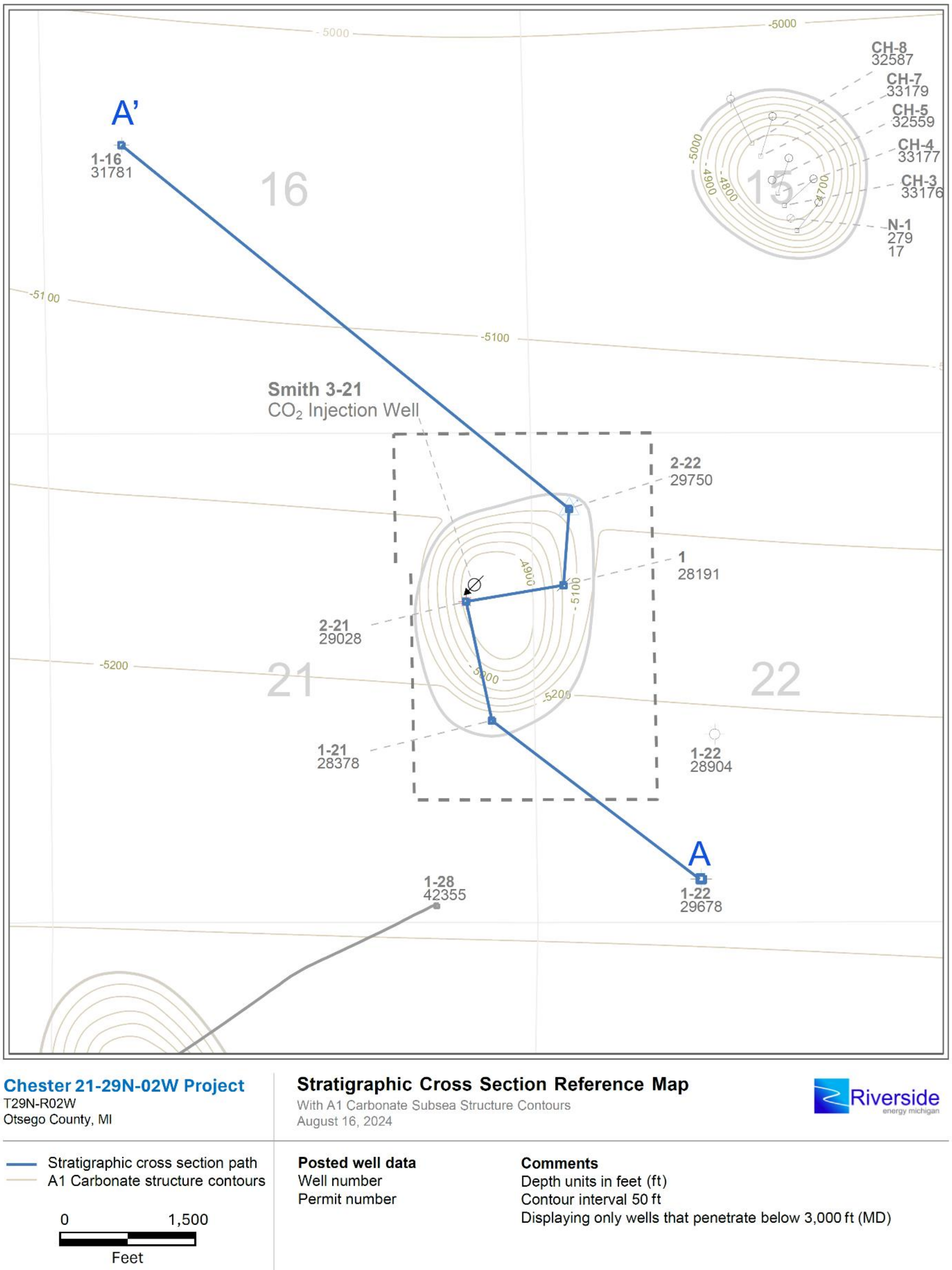

Figure 7. Reference map for the stratigraphic cross-section in Figure 6.

2.3 Operational History of the Chester 21-29N-02W Reef and Existing Wells

The Chester 21-29N-02W Reef was discovered in 1970 by Great Lakes Exploration that developed a single discovery well for oil production. The drilling of three additional wells was attempted between 1971 and 1974, resulting in one gas producing well and two dry holes. One of these dry holes, the State Chester 2-22, has been converted into a brine disposal well into the shallower Dundee Formation, disposing of water produced from Antrim Shale gas production. This well was recompleted with a cement plug within the Niagaran below. These four wells are the only wells ever drilled into the Chester 21-29N-02W Reef and summarized in Table 1.

Table 1. List of wellbore penetrations within the Reef Structure.

Well Name	**Marshall, Glen**	**Underwood, N M & Knapp C A**	**Leacock Hubbard Underwood**	**State Chester**
Well No.	1	1-21	2-21	2-22
API	21137281910000	21137283780000	21137290280000	21137297500000
MI Permit No.	28191	28378	29028	29750
Well Status	P&A	P&A	P&A	Active PBTD SWD
Well Designation	Oil	Dry Hole	Gas	Initially a Dry Hole, now PBTD SWD
First Operator	Great Lakes Exploration	Miller Brothers	Miller Brothers	Reef Petroleum Corporation
Last Operator	ANR Pipeline	Miller Brothers	Saba Energy of Texas	VCP Michigan
Formation at TD	Gray Niagaran	Gray Niagaran	Gray Niagaran	Gray Niagaran
TD (MD, TVD per KB)	6,685	6,744	6,770	6,660
Datum Elevation (KB)	1,242	1,239	1,238	1,244
SHL Latitude	44.89582	44.89186	44.89537	44.89806
SHL Longitude	-84.54549	-84.54850	-84.54952	-84.54523
BHL Latitude	44.89582	44.89186	44.89537	44.89806
BHL Longitude	-84.54549	-84.54850	-84.54952	-84.54523
Note				PBTD 4,215 ft MD
Producing Formation	Brown Niagaran	-	Brown Niagaran	-
IP oil (BBL/day)	480	-	NA	-
IP gas (Mcf/day)	NA	-	20,000	-
Cumulative oil (BBL)	25,483	-	162,238	-
Cumulative gas (Mcf)	520,175	-	9,951,270	-
Cumulative water (BBL)	Unknown	-	Unknown	-
Permit date	9/24/1970	3/23/1971	9/14/1972	5/13/1974
Well spud date	11/20/1970	4/22/1971	12/9/1972	5/23/1974
Completion date	1/25/1971	5/26/1971	2/26/1973	6/19/1974
Abandonment date	11/21/1990	5/29/1971	6/8/2002	

Table 2 summarizes the additional wells that exist within the active and maximum monitoring areas of the Storage Facility but do not penetrate the Reef Structure. The majority of these wells targeted the Antrim Shale Formation for natural gas production and typically only penetrate in depth to approximately -250 ft to -950 ft (subsea), whereas the Primary Seal and Storage

Reservoir each exceed -4,500 ft (subsea) throughout the Active and Maximum Monitoring Areas. See *Section 3* for the definition and map of the Active and Maximum Monitoring Areas.

Table 2. List of wellbore penetrations within Active and Maximum Monitoring Areas.

Evaluation Group	API	Well Name	Well No.	TD (subsea ft)	Well Type	Well Status
This Project's Pending CO2 injection well	TBD	Smith	3-21	-5,250	CO2 Injection	Permit pending
Penetrations into the Reef Structure	21-137-29028-0000	Leacock Hubbard Underwood Knapp	2-21	-5,532	Gas	P&A
	21-137-28378-0000	Underwood, N M & Knapp	1-21	-5,505	Dry Hole	P&A
	21-137-28191-0000	Marshall, Glen	1	-5,443	Oil	P&A
	21-137-29750-0000	State Chester	2-22	-5,416	SWD	Active
Penetrations depth equivalent to, but not into, the Reef Structure	21-137-28904-0000	Underwood & Knapp & Ashland Farms	1-22	-5,541	Dry Hole	P&A
	21-137-29678-0000	Underwood, Nellie M, & Knapp	1-22	-5,540	Dry Hole	P&A
	21-137-42355-0000	State Chester	1-28	-5,371	Gas	P&A
Penetrations at least 3,350 ft above Primary Seal	21-137-46107-0000	Campbell et al.	1-22	-1,454	SWD	Active
	21-137-55872-0000	State Chester	A3-28	-938	Gas	Producing
	21-137-55871-0000	State Chester	A1-27	-937	Gas	Producing
	21-137-50566-0000	State Chester	24-21	-840	Gas	P&A
	21-137-50567-0000	State Chester	23-21	-772	Gas	Producing
	21-137-55327-0000	Jaeger	D4-21	-718	Gas	Producing
	21-137-55326-0000	Jaeger	C4-21	-704	Gas	Producing
	21-137-55399-0000	Wright	B3-21	-692	Gas	Producing
	21-137-44259-0000	State Chester Venture	51	-633	Gas	Producing
	21-137-45622-0000	Campbell et al.	14-22	-604	Gas	Producing
	21-137-45588-0000	Campbell et al.	13-22	-600	Gas	Producing
	21-137-45536-0000	Campbell et al.	23-22	-593	Gas	Producing
	21-137-45537-0000	Marshall	12-22	-592	Gas	Producing
	21-137-45589-0000	Campbell et al.	24-22	-585	Gas	Producing
	21-137-44261-0000	State Chester Venture	52	-544	Gas	Producing
	21-137-40014-0000	State Chester Venture	31	-400	Gas	Producing
	21-137-39042-0000	State Chester Venture	22	-370	Gas	Producing
	21-137-41430-0000	State Chester	47	-348	Gas	Producing
	21-137-42229-0000	State Chester Venture	54	-329	Gas	Producing
	21-137-41432-0000	State Chester	45	-312	Gas	Producing
	21-137-27029-0000	State Chester	13	-260	Gas	Producing

In total, the Chester 21-29N-02W Field has produced 10,583,601 Mcf of natural gas, 203,105 barrels of oil, and an unknown volume of water. The production totals are summarized in Table 3. The Leacock Hubbard Underwood & Knapp #2-21 tested at an initial reservoir pressure of 3,227 psi at approximately 6,300 ft (0.51 psi per foot gradient) with a temperature of 114°F. It is believed the reservoir was depleted to a current pressure of approximately 300 psi or less. The Marshal, Glen #1 well was plugged and abandoned in 1990, and the Leacock Hubbard Underwood & Knapp #2-21 well was the final well at the Reef Structure to be plugged and abandoned in 2002.

Table 3. Summary of production from Chester 21-29N-02W Field.

Well Name	Date of First Production	Total Production		
		BO	Mcf	GOR
Marshall, Glen #1	1/19/1971	41,062	529,169	12,887
Leacock Hubbard Underwood & Knapp #2-21	2/6/1973	162,043	10,054,432	62,048
Total		203,105	10,583,601	52,109

As there are no longer any producing wells into the Reef Structure and as the structure is laterally limited, there will be no production associated with the Storage Facility. The Smith 3-21 UIC Class II CO_2 injection well will be the only wellbore penetrating the Reef Structure.

2.4 Mass Balance Estimate of Storage Resources

A mass balance approach using natural gas production data was used to estimate approximately 1 million metric tons of CO_2 storage resources at the Storage Facility. This mass balance approach does not consider produced water or oil that may provide additional accessible pore volume for storage. This mass balance approach does not consider a storage efficiency factor.

Determining the accessible reservoir pore volume:

10.5 Bcf produced natural gas
Formation volume gas factor Bg = 0.0042 cf/scf at 114°F and 3,168 psi
1/Bg = 238 scf/cf
Reservoir pore volume = 10,500,000,000 scf / 238 scf/cf = 44,100,000 cf

Determining the storage resources of the accessible reservoir pore volume for CO_2:

Confining interval top depth = 6,035 ft
Fracture pressure (estimate) = 0.80 psi/ft
Current reservoir pressure (estimated) = 300 psi
Injection pressure limit = 6,035 ft * 0.80 psi/ft * .90 safety factor = 4,345 psi
CO_2 density @ 4,345 psi = 55 lbs/cf
Storage resource given 44,100,000 cf of accessible pore space = 1,080,000 metric tons of CO_2

2.5 Reservoir Modelling and Injection Simulation

A simple geologic model was developed to complete computational injection simulations and evaluate the dynamic storage capacity of the Storage Facility. The model was generated from 2D seismic (structure) and well log information (top depths and porosity) in IHS' *Petra*® software. Computer Modeling Group's *GEM*™ reservoir simulation software was used to complete injection simulation.

Figure 8 shows the 3D view of the initial gridded model of the Chester 21-29N-02W Reef used for injection simulation with the position of the injection well entering the top of the reef. The model covers a 3,430 by 3,640 ft (0.65 by 0.69 miles) area and contains the approximate 90-acre (0.14 square mile) Chester 21-29N-02W Reef Structure within it. Porosity of the A1 Carbonate and Brown Niagaran reservoir intervals ranges from 2 to 9%. Permeability of the reservoir intervals ranges from 1 to 5 millidarcies and was derived from basin-wide Niagaran reef porosity-permeability cross plots by Gupta et al. (2020).

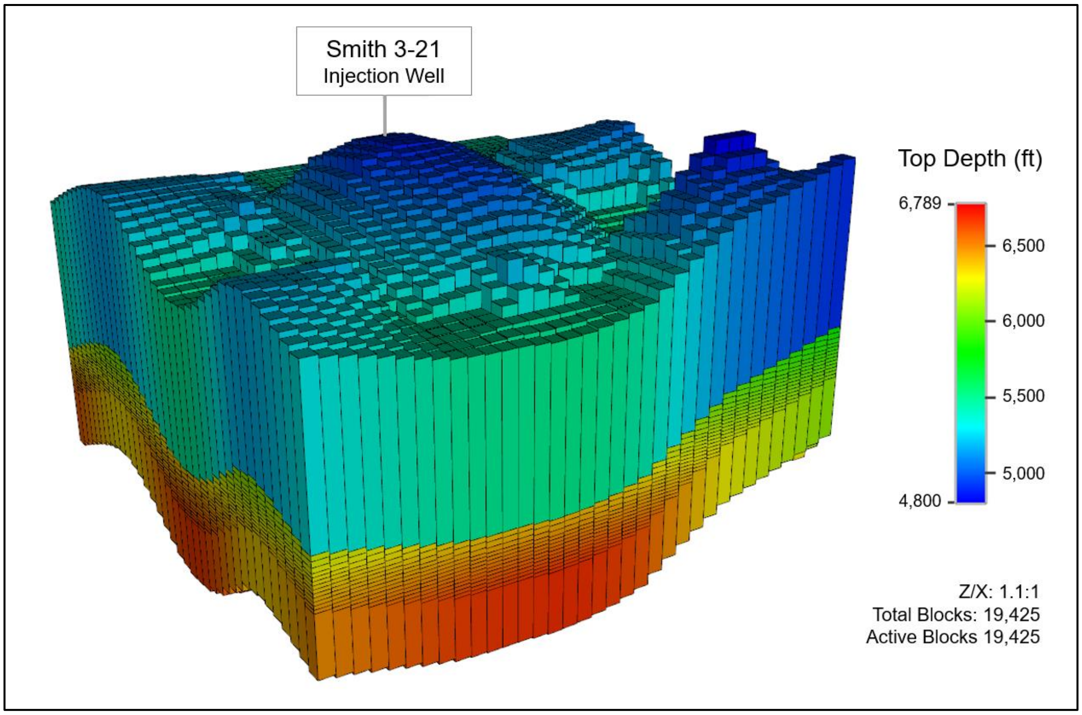

Figure 8. Gridded Model of the Chester 21-29N-02W Area Used for Injection Simulation. Also shown is the approximate location of the Smith 3-21 injection well.

The reef reservoir is modeled as a closed system with all model boundaries closed. The reef reservoir was initialized with depleted gas, oil, and water saturations at 300 psi. Injection rate was set at 12,000 Mcfd based on basin experience from CO_2 injection in other Niagaran reef projects. The maximum bottomhole pressure was limited to 4,345 psi (6,036 ft depth * 0.8 psi/ft fracture gradient * 0.9 safety factor).

The simulation was run for 15 years. After approximately 4 years, the maximum bottomhole pressure limit was reached, limiting further injection. Nearly no CO_2 was injected after 5 years. The simulation injected 16.7 Bcf of CO_2 or approximately 880,000 metric tons of CO_2 after 5 years. Figure 9 shows the development of the CO_2 plume within the Reef Structure over time. The CO_2 is limited to the 90-acre Reef Structure and contained within the dashed green Reef Structure boundary shown in Figure 14. Figure 10 shows the average Reef Structure pressure over time. Figure 11 reports the daily CO_2 injection rate and cumulative CO_2 injection totals over 5 years of injection.

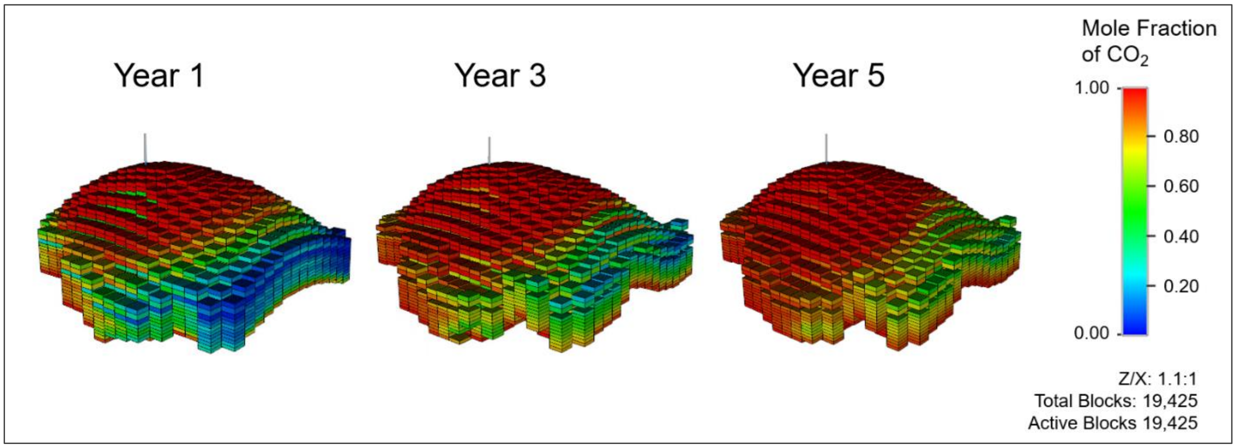

Figure 9. CO_2 plume development in the Reef Structure over 5 years of injection (Mole fraction of CO_2 in reservoir blocks). Also shown is the approximate location of the Smith 3-21 injection well where it enters the Reef Structure.

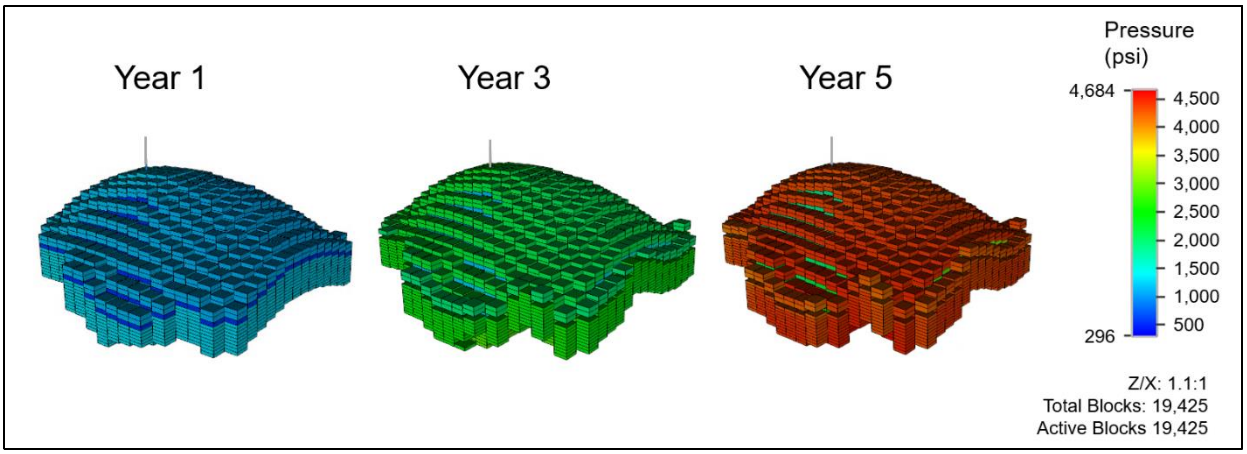

Figure 10. Pressure development in the Reef Structure over 5 years of injection from an initial pressure of 300 psi. Also shown is the approximate location of the Smith 3-21 injection well where it enters the Reef Structure.

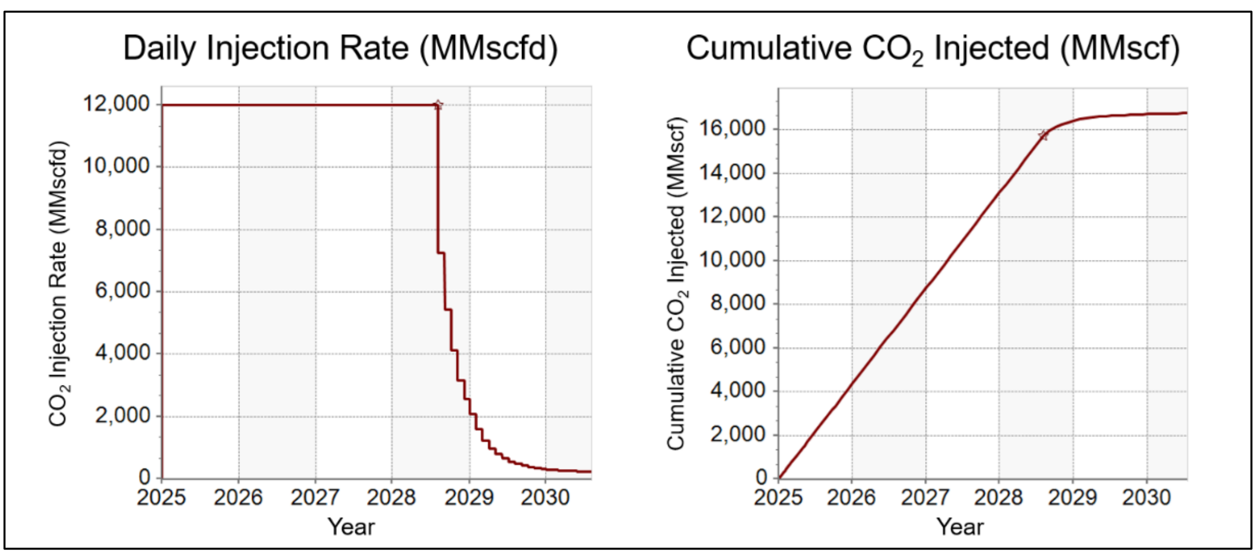

Figure 11. Daily injection rate and cumulative gas injection into the Reef Structure.

2.6 CO_2 Capture and Storage

The Antrim Shale in the northern part of the Michigan Basin is a biogenic gas reservoir. A byproduct of the microbial generation of methane is carbon dioxide that must be stripped from the gas before it is sold. The South Chester CO_2 Treating Plant (the Plant) located in Section 10 of Chester Township, Otsego County, Michigan, and operated by Phillips 66, removes CO_2 from natural gas produced from the Antrim Shale. As operator of the majority of wells producing natural gas being processed by the Plant, Riverside owns 60% of the CO_2 that would normally be vented from the natural gas plant. Riverside is currently constructing the necessary facilities to capture the entire vent stream of about 380,000 metric tons of CO_2 per year. It is expected that the Plant will continue to operate for another 10 to 20 years, dependent on market conditions. The Plant utilizes amine to strip CO_2 from the natural gas. The vent gas resulting from this process is typically 98% CO_2 or greater, and this composition is not expected to change over time. Riverside is installing four rotary screw compressors and reconfiguring one reciprocating compressor unit that in sum will comprise the Turtle Lake Capture Facility (Capture Facility) to compress the CO_2 for transportation and storage. CO_2 will be transported on a dedicated pipeline from the Capture Facility to the Chester 21-29N-02W Storage Facility. The Storage Facility will consist of one injection well (Smith 3-21) drilled into the Chester 21-29N-02W Reef Structure. In the future, the pipeline may become part of a larger distribution system for delivering CO_2 to multiple depleted gas reef storage facilities operated by Riverside for the purpose of permanently disposing and sequestering the CO_2 waste stream derived solely from the production of Antrim natural gas.

Figure 12 is a process flow diagram of the Capture Facility, pipeline, and Storage Facility. The key meter for calculating the mass of CO_2 injected is identified as the Injection Meter in this figure. This dedicated Coriolis mass flow meter will measure and verify the mass of CO_2 being received and injected.

Riverside also has the option to deliver CO_2 to a third party for Enhanced Oil Recovery (EOR). Riverside will have access to data generated by the third party's Coriolis mass flow meter (Delivery Point Meter in Figure 12) positioned near the outlet of the Capture Facility and inlet to their pipeline, which will serve as the custody transfer point. This data will be used for the accurate determination of CO_2 delivered to the third party. The third party operates their EOR projects under an approved MRV plan (facility ID 1010117) is wholly separate from this Storage Facility and this MRV plan.

The requirements of Subpart PP are applicable to the Capture Facility. Riverside will fully comply with the requirements outlined therein.

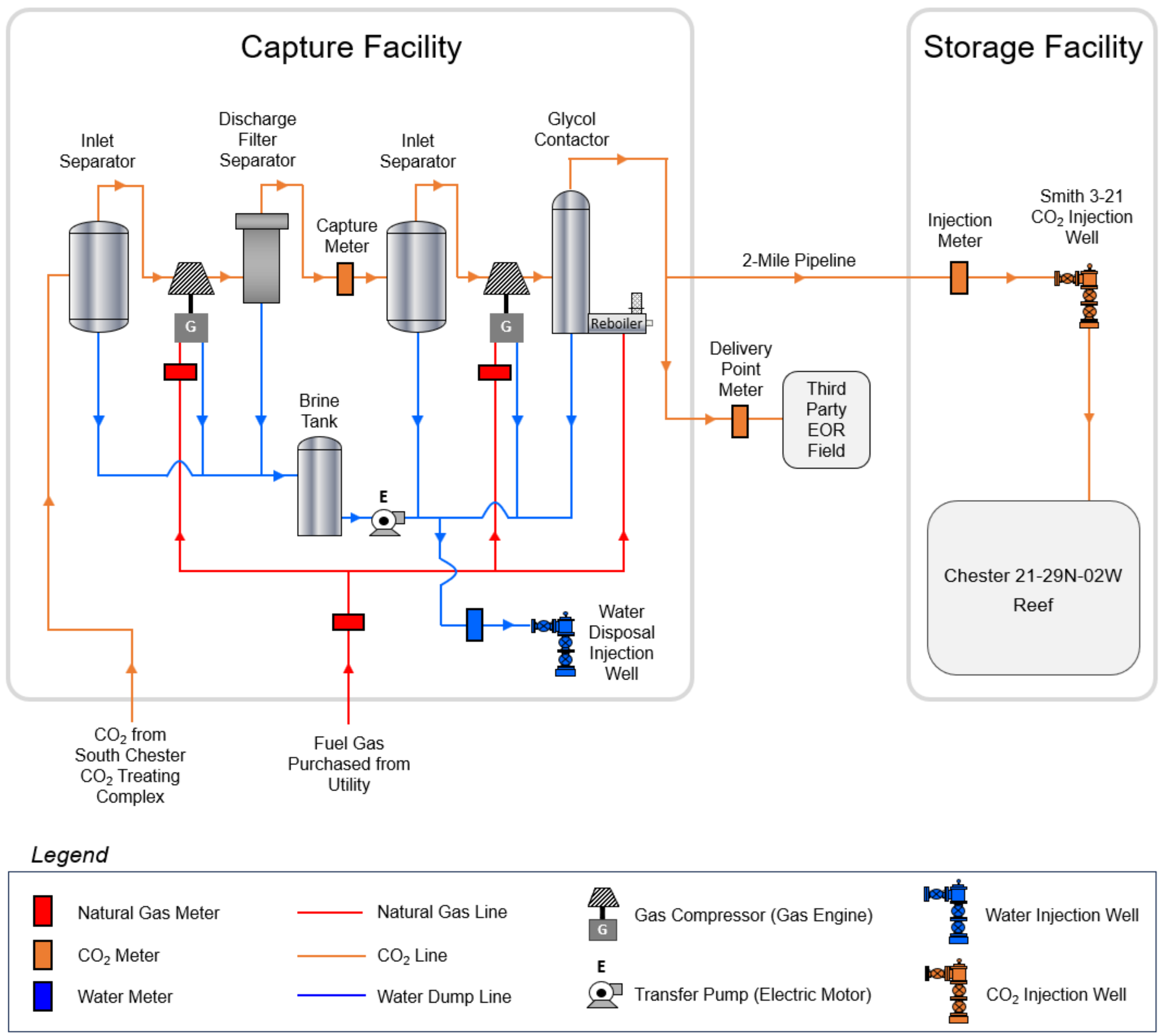

Figure 12. Process flow diagram of the Turtle Lake Capture Facility and the Chester 21-29N-02W Storage Facility.

2.7 Ownership

It is helpful to understand the corporate structure and relationship between the entities; refer to Figure 13 below. Riverside Energy Michigan, LLC (Riverside) and Riverside Carbon Holdings (RCH), LLC are 100% owned subsidiaries of Riverside Energy Holdings, LLC. Riverside is operator of the Antrim Shale natural gas wells and permittee of the injection well. Riverside Carbon Solutions, LLC, RCS Capture Antrim, LLC and RCS Storage Michigan, LLC are 100% owned subsidiaries of RCH. RCS Capture Antrim, LLC holds the Capture Facility assets including leased acreage upon which the facilities reside. RCS Storage Michigan LLC holds rights to the minerals and pore space in the Chester 21-29N-02W Reef Structure. Riverside will be the operator of the Storage Facility on behalf of Riverside Carbon Solutions, LLC.

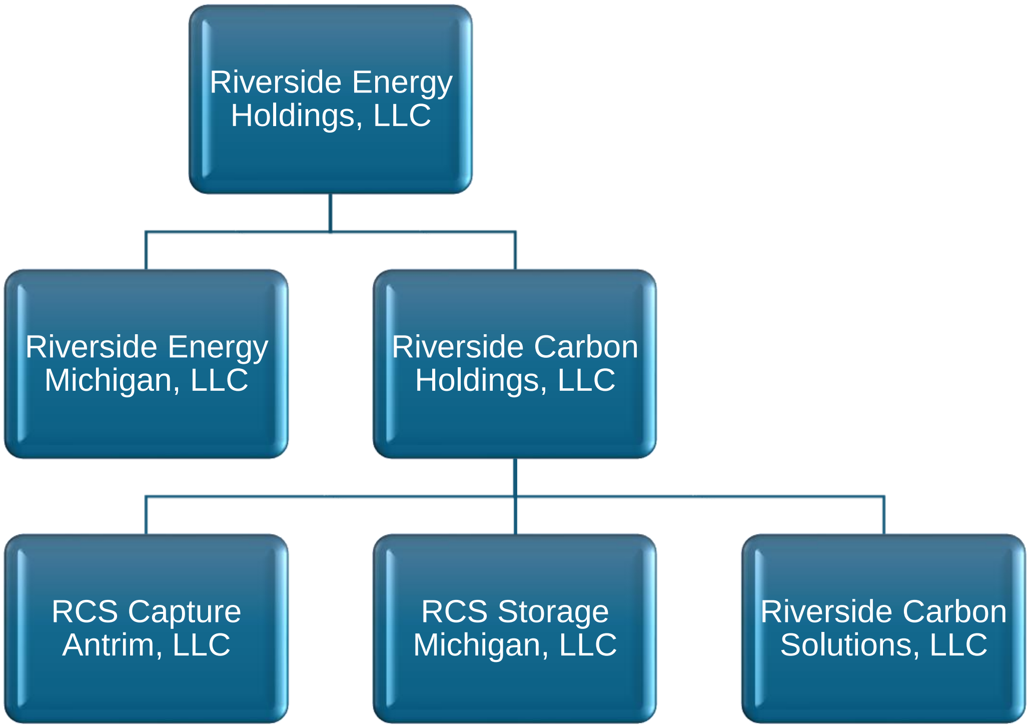

Figure 13. Organizational structure of the Riverside entities involved in the generation, capture and storage of CO_2.

2.8 Data Collection

All flow meters and other instrumentation at the Capture and Storage Facilities will be wired into Riverside's Supervisory Control and Data Acquisition (SCADA) system. The software continuously logs data from the meters and other instrumentation to a secure server with remote data backup and provides a Human-Machine Interface (HMI) for operators. It also has the capability to send an alarm to operators should parameters deviate outside of prescribed limits. Together, these data streams provide accurate accounting of all CO_2 being captured, delivered, received and injected.

Section 5.0 provides a more detailed explanation of the monitoring data that will be collected in order to detect any leakage of CO_2 from the Storage Facility. *Section 6.0* of this MRV Plan provides a more detailed explanation for how this data and other means will be used to establish baseline data for comparison to data collected during operation of the Storage Facility to detect possible surface leakage.

3. DELINEATION OF THE MONITORING AREA

3.1 Active Monitoring Area

The Active Monitoring Area (AMA) is defined (40 CFR 98.449) as follows:

Active monitoring area is the area that will be monitored over a specific time interval from the first year of the period (n) to the last year in the period (t). The boundary of the active monitoring area is established by superimposing two areas:

(1) The area projected to contain the free phase CO_2 plume at the end of year t, plus an all around buffer zone 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 t + 5.

At the Chester 21-29N-02W Storage Facility this definition translates to be the Chester 21-29N-02W Reef Structure Area (to the nearest 10-acre square) plus a one-half mile buffer zone outward in all directions. The Reef Structure and AMA are shown in Figure 14. This AMA delineation will be in place for a 10-year period which will cover the expected operational life of the Project.

Riverside plans to inject CO_2 at a rate of 12,000 Mcfd or approximately 230,000 metric tons of CO_2 per year. This rate may vary depending on site specific injection capabilities. The reef's current pressure is estimated at approximately 300 psi. Injection will continue until the reef pressure increases to the maximum bottomhole pressure of 4,345 psi. Once additional injection is constrained by bottomhole pressure limit, injection will stop. Based on the mass balance and injection simulation work described in *Sections 2.4 and 2.5*, the storage reservoir is expected to fill up after approximately 5 years at an average injection rate of 12,000 Mcfd.

Riverside is defining the time period of this AMA as 10 years in order to cover the expected operational life of the Project with some incorporated buffer time for any maintenance, downtime, or unexpected delays. 40 CFR 98.449 defines the AMA as the area projected to contain the free phase CO_2 plume at the end of year t + 5 plus a one-half mile all around buffer. Therefore, the AMA boundary is delineated based on the extent of the CO_2 plume at the end of year 15 plus a one-half mile buffer zone outward in all directions. After 15 years, the free phase CO_2 plume is projected to remain within the Reef Structure. Should the project be operational after 10 years of initial injection, Riverside will submit a revised MRV plan with an updated AMA.

The compartmentalized nature of the Niagaran reef creates conditions whereby an injection plume is limited to the shape and volume of the reef structure itself. The following factors were considered in defining the Reef Structure and AMA boundaries.

- The Reef Structure is encased within massive anhydrite and ultra-low permeability limestone, efficiently sealing the reef's storage intervals and preventing lateral and upward migration of CO_2. The effectiveness of the reef's seal is demonstrated by the trapping of hydrocarbons within the reef over geologic time.
- The boundaries of the reef structure have been defined using 2D seismic data. Where 2D seismic data is not available, reef edges were approximated using all wells surrounding and penetrating the reef, along with analog reef geometry.
- The stored CO_2 and the lateral extent of the CO_2 plume will remain within the reef and will not migrate over geologic time, as is demonstrated by the injection simulation described in *Section 2.5* and the trapping of oil and gas within the reef over geologic

time.

- There are no known leakage pathways that extend laterally from the Reef Structure that would warrant an expansion of the AMA beyond the one-half-mile buffer distance.

3.2 Maximum Monitoring Area

The project's Maximum Monitoring Area (MMA) is equal to the Active Monitoring Area (AMA) and is similarly defined as the Chester 21-29N-02W Reef Structure (to the nearest 10-acre square) plus a one-half mile buffer zone outward in all directions. This MMA is shown in Figure 14.

Pursuant to 40 CFR 98.449 the Maximum Monitoring Area 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 zone of at least one-half mile. For the reasons described in *Section 3.1*, the stabilized plume boundary will remain within the Reef Structure at the Project.

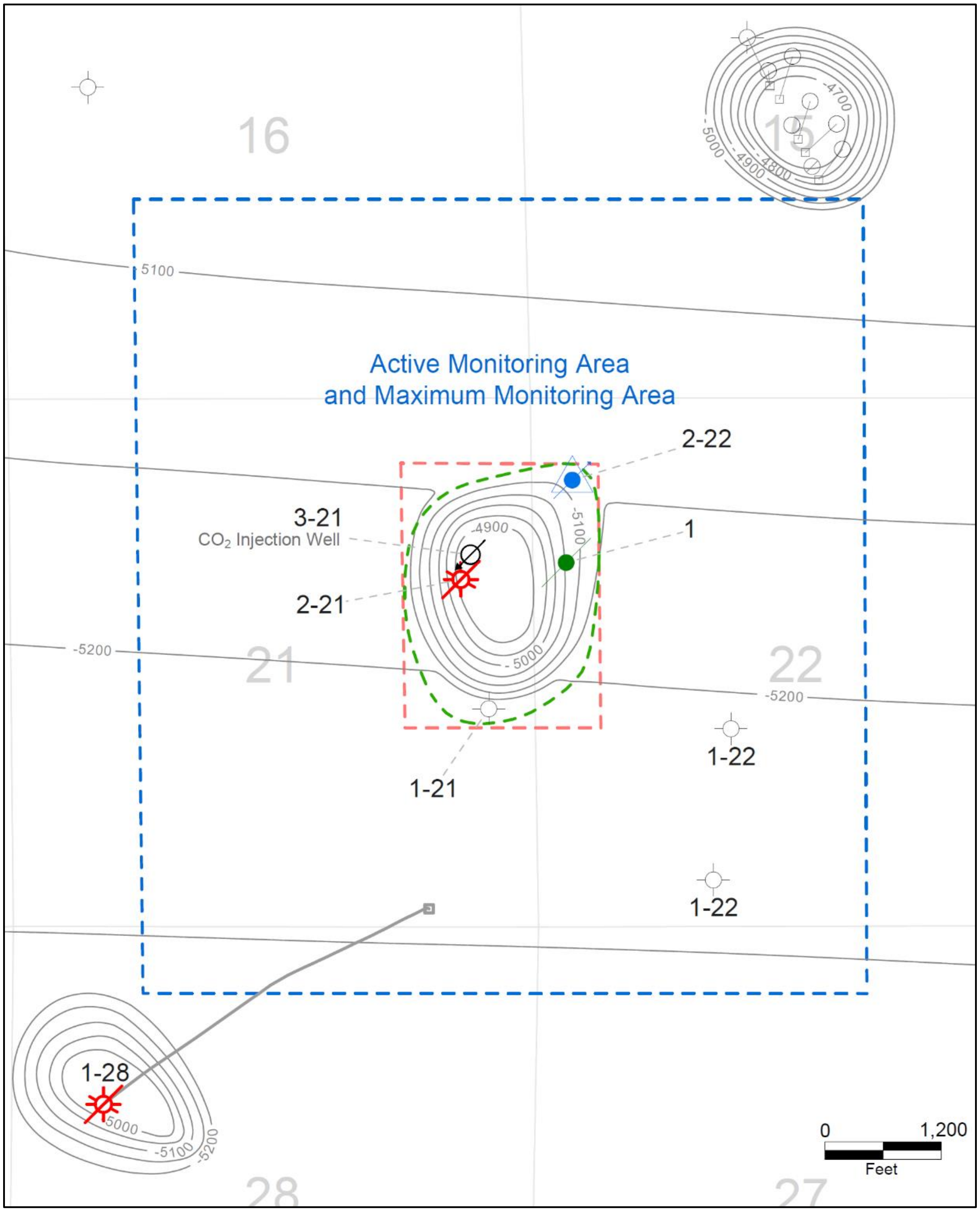

Figure 14. Map depicting the AMA/MMA (total area enclosed by the dashed blue boundary), structure contours of the top of the A1 Carbonate (top of the storage interval), and the Chester 21-29N-02W Reef (central) flanked by the Chester 15 reef to the northeast, and the Chester 28 reef to the southeast. The Chester 21-29N-02W Reef boundary (green dashed line) which is also the stabilized plume boundary, has herein also been regularized to the nearest 10-acre square (dashed red boundary) to help in establishing the boundary positions of the AMA and MMA. Well spots have been filtered to show only wells with total depths below 3,000 ft TVD, and for clarity purposes only wellbores within the AMA/MMA have been labeled. The planned 3-21 UIC Class II injection well is labeled in the northeast quadrant of the Chester 21-29N-02W Reef.

4. POTENTIAL PATHWAYS FOR LEAKAGE

Riverside has identified the following as potential surface leakage pathways at the Project per 40 CFR 98.448(a)[2]:

- Leakage from surface equipment
- Leakage from existing wellbores
- Leakage from wells not yet drilled
- Leakage from the injection wellbore
- Leakage from existing faults and fractures
- Leakage from natural or induced seismicity
- Leakage through confining layers
- Leakage from lateral migration of CO_2

This section discusses the likelihood, magnitude, and timing of potential surface leakage of CO_2 from these pathways. *Section 5* discusses the monitoring plan to detect any surface leakage and strategies for quantifying leakage from these pathways.

4.1 Leakage from Surface Equipment

The injection mass flow meter will be located on the well pad near the wellhead of the injection well. As the CO_2 that is received and metered by this mass flow meter will be wholly injected and not mixed with any other supply of CO_2 and no production from the storage formation will occur, the potential leakage pathways from surface equipment are limited to the mass flow meter, the injection wellhead, the short flowline between the two, and any pipe fittings or valves installed along the flowline or wellhead. The likelihood of leakage from these surface components is low and further mitigated by the following:

- Locating the CO_2 received and injection mass flow meter near the wellhead to minimize opportunities for potential leakage from surface equipment.
- Adhering to high material selection and construction standards when designing and constructing the wellhead and flowline.
- Continuously monitoring the wellhead and mass flow meter with the SCADA system.
- Routinely conducting audible, visual and olfactory (AVO) inspections of the surface equipment for leaks. These checks will occur each time operators visit the well site but not less than once per week. Leaks can be heard as a hissing sound, seen by the distortion of objects on the other side of the leak, or smelled as an odor downwind of the leak.
- Monitoring surface equipment with Optical Gas Imaging (OGI) technology such as an infrared (IR) or thermal imaging camera on a quarterly schedule.

The magnitude of potential leakage from these surface components is small with any leaked volume likely limited to the volume of CO_2 in the flowline or wellhead components. The timing of leakage risk spans from the start of injection and through the active injection period until the well is plugged and abandoned.

4.2 Leakage from Existing Wells

There are four boreholes that penetrate the A2 Evaporite confining layer within the Reef Structure, the area expected to contain the free-phase CO_2-occupied plume. Well data for these boreholes is listed in *Section 2.3*. Three of these boreholes, the Marshall, Glen #1 well, the Underwood, N M & Knapp, C A #1-21 well, and the Leacock Hubbard Underwood & Knapp #2-21 well have been plugged and abandoned according to State of Michigan standards and determined by Riverside to be an unlikely pathway for CO_2 migration above the confining interval. The State of Michigan requires a cement plug be placed within the wellbore to confine oil, gas, and water to the strata from which the oil, gas, and brine were produced. Upon review of the plugging reports for these three wellbores, Riverside has determined that a cement plug has been placed within the A2 Evaporite confining layer, as well as within several overlying intervals. Therefore, leakage through these legacy wellbores is unlikely.

The fourth borehole that penetrates the A2 Evaporite confining layer within the Reef Structure, the State Chester 2-22, is an active brine disposal well permitted in the Dundee formation. It was originally drilled in 1974 to a total depth of 6,660 ft below surface to the top of the Brown Niagaran formation. As this well is located at the far flank of the reef, it tested dry for hydrocarbons. It was then reworked into a brine disposal well by plugging back and completing the well within the Dundee formation at approximately 2,450 ft. The plugging records indicate a cement plug was placed at the base of the well, within the A2 Evaporite confining layer, as well as over additional intervals up hole. The well continues to pass mechanical integrity tests (MITs) in accordance with State of Michigan standards. Riverside has determined that the State Chester 2-22 well is a low risk for CO_2 leakage because it has been properly plugged downhole and recompleted above. It is subject to ongoing monitoring and MITs as an active brine disposal well by a different operator.

The magnitude of potential leakage from existing wellbores is considered to be low. Most of the existing wells are located on the reef flank, limiting their intersection with the projected CO_2 plume. The timing of leakage risk begins when the CO_2 plume intersects with an abandoned well. Riverside considers the likelihood of leakage from existing wells to be low because the four legacy wells that penetrate the Reef Structure have been abandoned to State of Michigan standards with multiple cement plugs.

Outside of the Reef Structure, but within the one-half-mile buffer distance of the AMA and MMA, there are two boreholes (Underwood, Knapp, and Ashland Farms, INC 1; and Underwood, Nellie M & Knapp, Clara Ann 1-22) that penetrate the A2 Evaporite confining layer. The surface location of one additional directionally drilled wellbore, the State Chester 1-28, is located within the AMA and MMA. However, its bottomhole location and penetration of the A2 Evaporite confining layer are located outside of the Project's AMA and MMA. These three wellbores have been plugged and abandoned according to State of Michigan standards. The likelihood of leakage from these

wells is very low as they do not intersect the Reef Structure and the projected free-phase CO_2 plume.

There are 21 wellbores within the AMA and MMA that do not penetrate the A2 Evaporite confining layer (Table 2). The likelihood of CO_2 leakage through any of these wellbores is assessed to be very low because the bottom of each of these boreholes is at least 3,350 vertical feet above the top of the A2 Evaporite confining layer. Furthermore, the geologic formations within this minimum 3,350 feet of vertical separation consists primarily of regionally deposited evaporites and tight carbonates with characteristically low vertical permeability.

There are also four water wells within the AMA and MMA that pose an even lesser risk of CO_2 leakage for the same reasons stated above and the fact that they do not even reach bedrock below the glacial drift (Table 4). Note that the last two wells in Table 4 were drilled by Riverside to support the drilling operations for the Smith 3-21 injection well. One will be plugged when drilling operations have ended, and one will be retained as a ground water monitoring well as described in *Section 6.4*.

Table 4. List of water wells within the AMA/MMA.

Well ID	Owner Name	Construction Date	Depth (ft)	Geographic Coordinates	
				Latitude	Longitude
69000004263	Cody & Sandi Smith	3/8/2021	65	44.892795	-84.541395
69000004281	Doug Sheridan	5/11/2021	50	44.892034	-84.545048
69000009481	Riverside Energy Michigan	1/15/2025	60	44.895742	-84.548594
69000009482	Riverside Energy Michigan	1/15/2025	60	44.8958147	-84.548585

4.3 Leakage from Wells Not Yet Drilled

Wellbores drilled in the future through the Reef Structure may be a potential leakage pathway for CO_2. The likelihood of leakage from wells not yet drilled is low and any risk is mitigated by the following:

- Hydrocarbon production from the A1 Carbonate and Brown Niagaran formations in the Chester 21-29N-02W Reef will be no longer possible after injection of CO_2 begins.
- There are no known hydrocarbon producing formations below the Brown Niagaran in the AMA and MMA. The St. Peter Sandstone (approx.10,000 ft) is an occasional gas producer where on anticlinal structure in central and northern Michigan. There are several St. Peter dry holes within a few miles of the Storage Facility, and the Storage Facility is not on an anticline as confirmed by well control and 2D seismic.
- Future wells drilled outside of the Reef Structure but within the AMA and MMA will not interact with the free-phase CO_2 plume.
- All well records and injection data will be shared with Michigan-EGLE to ensure that potential drillers are aware of the Project for the indefinite future.
- Michigan Admin. Code R. 324.413 regulates the drilling of wellbores to strata beneath gas storage reservoirs. The rule describes specific drilling equipment, casing design, and

completion standards that must be deployed to ensure drilling occurs safely through natural gas storage reservoirs. While this rule applies to natural gas storage projects (not CO_2 storage projects), Michigan-EGLE already has experience in protecting and regulating the drilling of new wells through gas storage reservoirs.

For these reasons, it is unlikely that any future wells will be drilled through the A2 Evaporite confining layer within the Reef Structure and projected free-phase CO_2 plume. The magnitude of potential leakage from wells not yet drilled is low.

4.4 Leakage from the Injection Wellbore

The Smith 3-21 injection well will be permitted and constructed as a Class II oil field waste disposal well with Michigan-EGLE. As this injection well is an additional penetration that could offer a leakage pathway to the surface, Riverside is taking the following steps to mitigate potential leakage:

- The Smith 3-21 injection well will be constructed more rigorously than Michigan Class II standards. Figure 15 describes the proposed injection well design. Chromium alloy long-string casing will be installed from total depth through the A2 Evaporite and cemented in place with SLB's *EverCRETE* CO_2 resistant cement.
- Prior to injection, a cement bond log and MIT will be run to ensure proper well construction.
- Riverside will perform a MIT at least every 5 years per Michigan-EGLE requirements.
- The annular fluid volume between the casing and injection tubing will be monitored quarterly.
- The surface pressure of the tubing and annular space will be continuously monitored by the SCADA system to detect any abnormalities that indicate a loss of integrity or leak has occurred.
- Riverside will be monitoring surface components and the injection wellhead with OGI technology on a quarterly schedule and performing an AVO inspection weekly.
- After injection, the Smith 3-21 injection well will be plugged and abandoned with cement plugs placed to prevent any future leakage of CO_2.

Leakage from the injection wellbore is unlikely due to the constant monitoring of the wellbore and periodic mechanical integrity testing. The magnitude of leakage from the injection wellbore is small. It is unlikely that a blowdown of the wellbore would be necessary, but if one occurs, the leaked CO_2 would be limited to the volume contained in the wellbore and could be easily quantified using volume, pressure, and temperature data. The timing of leakage risk from the injection wellbore occurs from the beginning of injection until proper plugging and abandonment.

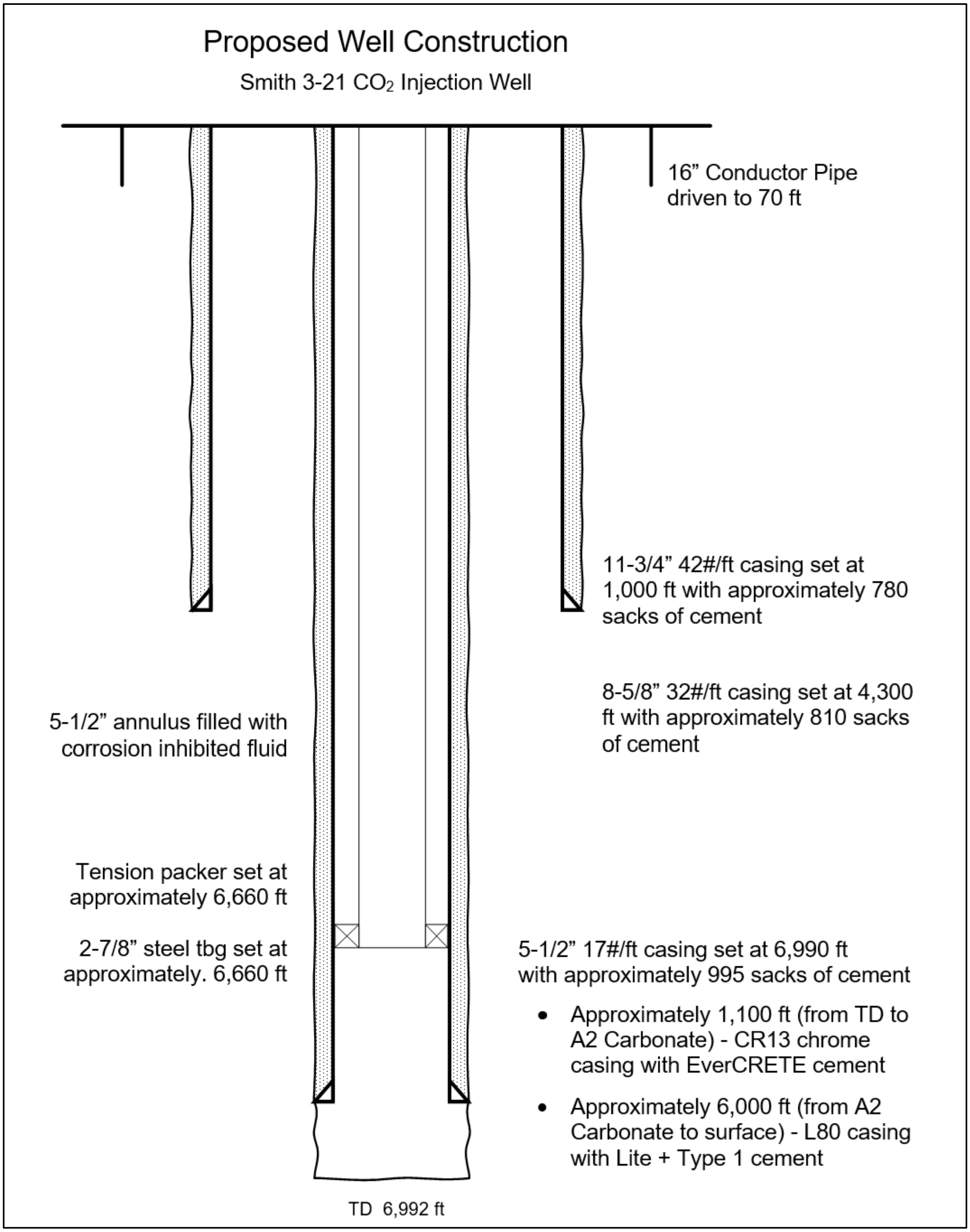

Figure 15. Proposed construction design for Smith 3-21 injection well.

4.5 Leakage from Existing Faults and Fractures

Evaluation of 2D seismic did not reveal any faults or fractures in the Reef Structure, and there are no known faults or fractures through the A2 Evaporite confining layer in the AMA and MMA that would allow CO_2 movement into overlying formations. The risk of leakage of CO_2 from an unknown fault or fracture is very low, because hydrocarbons were sealed within the Reef Structure throughout geological time.

4.6 Leakage from Natural or Induced Seismicity

The likelihood of natural seismicity is very low. The Michigan Basin is structurally stable with few major structural features. No naturally occurring earthquakes greater than magnitude 2.5 have originated within 100 miles of the Storage Facility since 1900. The USGS's 2023 50-State Long-term National Seismic Hazard Model classifies northern Michigan as having the lowest chance of experiencing a slight or greater damaging earthquake in the next 100 years[1].

Natural gas storage in nearby Niagaran reef fields offers an analog to CO_2 injection and experience with reservoir response under pressure. To date, Riverside is unaware of any induced seismicity issues associated with natural gas storage in Niagaran reefs. Many reefs are permitted with a maximum bottomhole pressure greater than 4,600 psi at depths of 6,600 to 6,800 ft[2]. The planned maximum bottomhole pressure for the Storage Facility is 4,345 psi (6,036 ft depth * 0.8 psi/ft fracture gradient * 0.9 safety factor). For these reasons, the likelihood of leakage from induced seismicity is low and the risk would be limited to the active injection period because the reservoir pressure will be highest during the injection period.

4.7 Leakage through Confining Layers

The primary seal of the Project is the A2 Evaporite confining layer. The A2 Evaporite is comprised of anhydrite which has virtually no porosity or permeability. Above the A2 Evaporite confining layer, additional evaporite and low-permeability carbonate sequences are present that further reduce the risk of upward movement of CO_2 through overlying strata.

The likelihood of leakage through confining layers is very low, because the A2 Evaporite confining layer's sealing capacity has been proven by the previous trapping of hydrocarbons throughout geologic time.

4.8 Leakage from Lateral Migration of CO_2

As shown in Figure 4, the Reef Structure is fully compartmentalized due to the unique formation of the pinnacle reef and subsequent deposition of overlying strata. The Reef Structure is encased in a tight carbonate and non-porous evaporate seal that prevents the vertical and lateral migration

[1] https://www.usgs.gov/programs/earthquake-hazards/science/2023-50-state-long-term-national-seismic-hazard-model
[2] https://www.govinfo.gov/content/pkg/FR-1994-03-28/html/94-7181.htm

of fluids. Underlying the storage formation are tight units of the Brown and Gray Niagaran formation.

Riverside does not believe that the A1 Carbonate and Brown Niagaran storage intervals are in communication with any other Niagaran reservoir or reef. Water infiltration from below the reservoir was not observed during the production history of the Chester 21-29N-02W Reef and the current reservoir pressure is expected to be at the reef's depleted pressure of approximately 300 psi.

The likelihood of leakage from lateral migration of CO_2 is very low as demonstrated by the production history of the Chester 21-29N-02W Reef. The magnitude of any potential leakage is low due to the closed structure of the reef.

5. MONITORING AND LEAK QUANTIFICATION STRATEGY

This section describes the monitoring plan to detect any surface leakage from the pathways identified in *Section 4* and the strategies for quantifying leakage should it occur.

5.1 Detecting and Quantifying Leakage from Surface Equipment

The injection mass flow meter will be located near the wellhead, limiting the amount of equipment subject to monitoring for leakage to the wellhead, the mass flow meter, and the flowline and any valves between the wellhead and mass flow meter. To detect any leakage from this equipment, OGI surveys will occur quarterly using either an IR or thermal imaging camera, and AVO inspections will be conducted by trained personnel at least weekly. In addition, the wellhead and mass flow meter will be continuously monitored by the SCADA system.

Emissions from surface equipment downstream of the mass flow meter such as the flowline, valves, fittings or the wellhead assembly will be estimated and repaired as quickly as possible. If CO_2 must be vented downstream of the meter to make a repair, the amount of CO_2 vented will be estimated using the methods specified in 40 CFR 98 Subpart W. Data that could be considered for estimating the amount of CO_2 leaked may include but not limited to: any anomalies in metered pressures or mass flow, average pressures or mass flow, the time between inspections, physical measurements of pinholes and/or the relative size and intensity of the leakage plume as detected by OGI.

5.2 Detecting and Quantifying Leakage from Existing Wellbores and Future Wells

As discussed in *Section 4*, few existing wells will encounter the CO_2 plume, and all of these wells have been plugged and abandoned to State of Michigan standards. Riverside will be conducting quarterly groundwater monitoring and optical gas imaging on the injection well pad. Pressure transducers installed in the tubing and annulus at the wellhead will be monitored by the SCADA system and bottomhole pressure and temperature surveys will occur periodically through the injection period to identify possible abnormalities in operational parameters that would indicate a subsurface leak. Riverside will conduct bottomhole pressure tests and temperature surveys every

six months for the first two years and annually thereafter. Should a future well be drilled within the AMA and MMA, Riverside will work with Michigan-EGLE to ensure the well will not interfere with CO_2 storage within the Storage Facility.

If a leak is detected at a legacy well or a well not yet drilled, its volumetric flow will be attempted to be metered if possible. If not, the latest injection data and reservoir pressure, volume and temperature data will be used to estimate a leakage volume and rate with a mass balance approach from the storage intervals. The timing of the leak will be determined by an estimate of the CO_2 plume's intersection with the legacy or future well.

5.3 Detecting and Quantifying Leakage from the Injection Wellbore

Riverside will deploy multiple monitoring strategies to detect leakage from the injection wellbore. The long string casing, injection tubing string and packer assembly are subjected to a MIT every 5 years as well as once before injection begins. The annular space between the casing and tubing will be filled with a corrosion inhibiting fluid and checked quarterly for significant changes in volume. The tubing and annular pressure at the wellhead will be monitored continuously with pressure transducers tied to the SCADA system. At a minimum, Riverside will conduct bottomhole pressure tests and temperature surveys every six months for the first two years, and annually thereafter. If the temperature survey detects an anomaly suggesting CO_2 intrusion behind casing, a radioactive tracer/gamma ray tool will be run to investigate. Further, the quarterly OGI and weekly AVO inspections would also encompass the area around the wellbore at the surface.

A workover of the well to replace components may be required and surface and downhole equipment would be thoroughly inspected for signs of wear or corrosion responsible for a potential leak.

If the mechanical integrity of the injection wellbore is lost, the injection will stop and not begin again until a MIT test is passed in compliance with Michigan-EGLE regulations. If a leak is determined to have taken place, it will be quantified using the timing of the loss of integrity and any pressure or annular fluid data from the MIT that can be used to characterize the leak.

Venting of CO_2 from the well may occur while making repairs and would be estimated and documented in accordance with Subpart W procedures. Typically, wells undergoing a workover are "killed" with sufficiently dense fluid to overcome the reservoir pressure and prevent venting of gases from the well to atmosphere.

5.4 Detecting and Quantifying Leakage from Existing Faults and Fractures and Natural or Induced Seismicity

Leakage from existing faults or fractures or fractures created by natural or induced seismicity will be monitored by continuous monitoring of operational parameters at the wellbore, periodic reservoir pressure and temperature surveys, and quarterly ground water monitoring near the injection well pad. At a minimum, Riverside will conduct bottomhole pressure tests and temperature surveys every six months for the first two years, and annually thereafter. Abnormalities in operational and reservoir parameters and such as the injection tubing and

reservoir pressures will be investigated to determine if there is a subsurface leak. If it is determined a subsurface leak has occurred, the latest injection data and reservoir pressure, volume and temperature data will be used with a mass balance approach to estimate a leakage volume and rate from the storage intervals. The timing of the leak will be determined by an estimate of the CO_2 plume's intersection with the leakage pathway.

As discussed in *Section 4*, natural and induced seismicity are considered to be unlikely. Riverside will subscribe to the USGS' Earthquake Hazards Program Earthquake Notification Service (ENS)[3] to receive notifications of any earthquakes with magnitude 2.0 or greater in Michigan. If an earthquake occurs, Riverside will evaluate the monitoring data to determine if the wellbore or Storage Facility are affected. Annulus pressure is continuously monitored and could indicate a loss of wellbore integrity issues caused by seismicity.

5.5 Detecting and Quantifying Leakage through Confining Layers or Lateral Migration

Leakage through the confining layers or from lateral migration will be monitored by periodic groundwater monitoring and reservoir pressure tests. Quarterly groundwater sampling and testing will occur in the water well to be drilled at the injection well pad for drilling operations and will be retained for ground water monitoring. A description of the groundwater testing that will occur is included in *Section 6.4*.

If it is determined a subsurface leak has occurred, the latest injection data and reservoir pressure, volume and temperature data will be used with a mass balance approach to estimate a leakage volume and rate from the storage intervals. The timing of the leak will be determined by an estimate of the CO_2 plume's intersection with the leakage pathway.

6. ESTABLISHING SURFACE LEAKAGE BASELINES

Prior to the start of continuous injection, the following data will have been collected to establish baselines for the Storage Facility against which future data may be compared in order to detect surface leakage.

6.1 Wellbore Integrity

After injection well construction is completed but before injection begins, a MIT and annular pressure test will be completed to confirm wellbore integrity. The initial volume of annular fluid will be noted, and it will be monitored during the start-up of injection to determine how it responds during injection start up. Its stabilized volume will be noted after at least a week of continuous injection. The injection tubing and annulus pressures at the wellhead will be recorded prior to CO_2 injection and continuously monitored thereafter with the SCADA system. MITs will occur at least every 5 years in accordance with Michigan-EGLE requirements.

[3] https://earthquake.usgs.gov/ens/help

6.2 Injection Well Operating Parameters

Riverside has established target injection and storage rates based on experience from other operators injecting and storing fluids in other Niagaran reefs. An initial model, described in *Section 2.5*, has been developed to confirm these baseline injection parameters. Riverside plans to inject CO_2 at a rate of 12,000 Mcfd or approximately 230,000 metric tons of CO_2 per year. This rate may vary depending on injection capabilities of the well.

During injection operations, Riverside will use site-specific data during wellbore construction and the initial injection period to update nominal injection parameters such as wellhead tubing and annulus pressures and injection flow rates.

6.3 Reservoir Conditions

Initial bottomhole pressure will be recorded at mid-perforations and a temperature survey with gradient stops will be completed before injection. A bottomhole pressure test and temperature survey will be conducted at least every six months for the first two years of injection and then annually thereafter. After approximately 48 hours of continuous CO_2 injection, Riverside will run in hole to mid-perforations to establish reservoir pressure and temperature and run a gradient on the way out of the hole while noting casing and tubing pressures at surface.

6.4 Groundwater Monitoring

Groundwater monitoring will occur from a water well drilled on the injection well pad (to approx. 100 ft) and include the following analyses to detect the presence of fugitive CO_2:

- Standard field parameters form a calibrated water quality meter: temperature, pH, conductivity, dissolved oxygen, oxidation reduction potential, and turbidity.
- Standard EPA UIC lab analyses barium, calcium, sodium, magnesium, potassium, total iron, chloride, sulfate, sulfide, carbonate, bicarbonate, TDS, resistivity, specific gravity, and pH.
- Lab analyses for dissolved methane, ethane, propane, and calculated dissolved CO_2 from carbonate, bicarbonate, and dissolved inorganic carbon.

A sample will be collected before injection begins from the ground water monitoring well to establish baseline parameters. During injection, groundwater sampling and testing will occur at least quarterly.

6.5 Surface Equipment Monitoring

After the site equipment is constructed but before injection begins, Riverside will conduct a baseline OGI survey with either an IR or thermal imaging camera. Within the first month of injection, an additional OGI survey will occur to ensure no leakage from surface equipment during the beginning of injection. Thereafter, Riverside will conduct OGI surveys quarterly at the injection well pad to detect for surface leakage of CO_2.

7. SITE-SPECIFIC CONSIDERATIONS FOR THE MASS BALANCE EQUATION

Riverside will utilize the mass balance equations listed in 40 CFR 98.443 to calculate the mass of CO_2 sequestered. The site-specific considerations for these equations are discussed in this section.

7.1 Mass of CO_2 Received and Injected

In accordance with 40 CFR 98.444(a)[4], Riverside will determine the annual mass of CO_2 injected as the total annual mass of CO_2 received instead of using Equation RR-1 or RR-2 to calculate CO_2 received. The CO_2 received at the Storage Facility will be wholly injected and not mixed with any other supply of CO_2. There will be no production from the Storage Facility.

Equation RR-4 in 40 CFR 98.443(c) of Subpart RR will be used to calculate the mass of CO_2 received at the Storage Facility each year.

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

where:

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

$Q_{p,u}$ = Quarterly mass flow rate measurement for flow meter u in quarter p (metric tons per quarter).

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

p = Quarter of the year.

u = Flow meter.

7.2 Mass of CO_2 Produced

There will be no production from the Storage Facility. The purpose of the Storage Facility is to permanently dispose and sequester the CO2 waste stream derived solely from the production of Antrim natural gas.

7.3 Mass of CO_2 Emitted by Surface Leakage

Riverside will quantify the mass of CO_2 emitted by each identified surface leakage pathway as outlined in *Section 5*. Equation RR-10 will be used to calculate the total mass of CO_2 emitted by surface leakage at the Storage Facility.

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

where:

CO_{2E} = Total annual CO_2 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.

7.4 Mass of CO_2 Emitted from Equipment Leaks and Vented Emissions

As discussed in *Section 5.1*, Riverside will quantify the 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 injection mass flow meter and the wellhead in accordance with the procedures provided under Subpart W of 40 CFR 98. At the Storage Facility, the injection mass flow meter is located near the wellhead, limiting the equipment to the mass flow meter, the injection wellhead, the short flowline between the two, and any pipefittings or valves installed along this flowline or wellhead.

7.5 Mass of CO_2 Sequestered

Since no production will occur at the Storage Facility, Riverside will use equation RR-12 to calculate the total mass of CO_2 sequestered in the Storage Facility for the reporting year.

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

where:

CO_2 = Total annual CO_2 mass sequestered in subsurface geologic formations (metric tons) at the facility in the reporting year.

CO_{2I} = 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_{2E} = 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 mass flow meter used to measure injection quantity and the injection wellhead, for which a calculation procedure is provided in Subpart W of 40 CFR 98.

8. ESTIMATED SCHEDULE FOR IMPLEMENTATION OF MRV PLAN

Riverside will implement this plan as soon as it is approved by EPA. Riverside plans to be ready to begin CO_2 injection and to begin collecting data for calculating the total amount of CO_2 sequestered by March 1, 2025. All baselines will have been established and leakage detection strategies implemented prior to this date. This plan will be in effect until EPA approves Riverside's request for discontinuation of reporting. Riverside plans to submit a request for discontinuation of reporting after all wells in the Storage Facility are plugged and abandoned and has demonstrated that the injected CO_2 stream is not expected to migrate in the future in a manner likely to result in surface leakage, in accordance with 40 CFR 98.441(b).

9. QUALITY ASSURANCE PROGRAM

9.1 Monitoring of CO_2 Received

In accordance with 40 CFR 98.444(a)[4], Equation RR-4 will be used to calculate the total annual mass of CO_2 received because CO_2 received at the Storage Facility is wholly injected and metered by a single injection mass flow meter.

9.2 Monitoring of CO_2 Injected

At the injection well, the volume of CO_2 injected will be measured continuously by an Emerson Micro Motion ELITE Coriolis mass flow meter. Riverside will report quarterly averages of the flow rate and total mass injected. Injection stream samples will be collected at least quarterly to measure the CO_2 concentration immediately upstream or downstream of the injection mass flow meter.

The injection mass flow meter will operate continuously except as necessary for maintenance and calibration. It will be operated using the calibration and accuracy requirements in 40 CFR 98.3(i). Meter accuracy is based on accredited calibration standards according to ISO 17025/IEC 17025.

9.3 Procedures for Estimating Missing Data

In the event Riverside is unable to collect data required for performing the mass balance calculations, procedures for estimating missing data in 40 CFR 98.445 will be implemented as follows:

- Quarterly mass of injected CO_2 will be estimated using representative mass flow rate data from the nearest previous time period. Pressure data at the wellhead will be compared to previous time period's pressure data and mass of injected CO_2 to ensure similar consistency.
- Quarterly CO_2 stream concentration data will be estimated using a representative concentration value from the nearest previous time period.
- CO_2 emissions associated with equipment leaks or venting will be estimated following the missing data procedures contained in 40 CFR 98 Subpart W.

9.4 MRV Plan Revisions

Riverside will revise this plan and submit the latest version to the EPA Administrator within 180 days of making a material change to the monitoring and/or operational parameters, a change in the permit class of the UIC permit, notification of substantive errors in the MRV plan, or for any other reason Riverside should choose to revise this MRV plan in any reporting year.

10. RECORDS RETENTION

Riverside will retain the following records in accordance with 40 CFR 98.3(g).

(1) A list of all units, operations, processes, and activities for which GHG emission were calculated.

(2) The data used to calculate the GHG emissions for each unit, operation, process, and activity, categorized by fuel or material type. These data include but are not limited to the following information in this paragraph (g)(2):

> (i) The GHG emissions calculations and methods used. For data required by 40 CFR 98.5(b) to be entered into verification software specified in 40 CFR 98.5(b), maintain the entered data in the format generated by the verification software according to 40 CFR 98.5(b).
>
> (ii) Analytical results for the development of site-specific emissions factors.
>
> (iii) The results of all required analyses for high heat value, carbon content, and other required fuel or feedstock parameters.
>
> (iv) Any facility operating data or process information used for the GHG emission calculations.

(3) The annual GHG reports.

(4) Missing data computations. For each missing data event, also retain a record of the cause of the event and the corrective actions taken to restore malfunctioning monitoring equipment.

(5) The most recent copy of this GHG Monitoring Plan.

(6) The results of all required certification and quality assurance tests of continuous monitoring systems, fuel flow meters, and other instrumentation used to provide data for the GHGs reported under this part.

(7) Maintenance records for all continuous monitoring systems, flow meters, and other instrumentation used to provide data for the GHGs reported under this part.

In addition, Riverside will retain the following records for at least three years in accordance with 40 CFR 98.447:

- 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 mass 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 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 wellhead.

11. REFERENCES

Briggs, L. I., and Briggs, D. 1974, Niagara-Salina Relationships in the Michigan Basin, In *Silurian Reef-Evaporite Relationships*, by L. I Briggs and D. Briggs, 1-23, Lansing, MI: Michigan Basin Geological Society.

Charbonneau, S. L., 1990, Subaerial exposure and meteoric diagenesis in Middle Silurian Guelph Formation (Niagaran) pinnacle reef bioherms of the Michigan Basin, Southwest Ontario, Kingston, ONT: Quenn's University 1-208.

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Ritter, A.L., 2008, Evaluating the Controls on Reservoir Heterogeneity of Silurian Pinnacle Reefs, Michigan Basin: Thesis (MS), Western Michigan University, Kalamazoo, Michigan, 247 p.

Request for Additional Information: Chester 21-29N-02W
February 4, 2025

Instructions: Please enter responses into this table and make corresponding revisions to the MRV Plan as necessary. Any long responses, references, or supplemental information may be attached to the end of the table as an appendix. This table may be uploaded to the Electronic Greenhouse Gas Reporting Tool (e-GGRT) in addition to any MRV Plan resubmissions.

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
1.	2.3	15	Please include discussion regarding the presence of water wells within the boundaries of the active monitoring area (AMA) and maximum monitoring area (MMA).	This discussion and a new table including the water wells was added to Section 4.2.
2.	2.6	20	"If CO2 is delivered to this third party, Riverside will review for applicability of Subpart PP and comply with its requirements if applicable." We recommend reviewing the source category definition at subpart PP when making the determination of applicability. Subpart PP applies not only to facilities that capture and send CO2 to third parties, but also to facilities "that capture and maintain custody of a CO_2 stream in order to sequester or otherwise inject it underground."	After further review, our compliance team agrees. The referenced sentence has been replaced to indicate that Subpart PP is applicable to the Capture Facility and that Riverside will comply with the requirements of Subpart PP.
3.	7.1	36	"Equation RR-4 in 40 CFR 98.444(c) of Subpart RR will be used to calculate the mass of CO2 received at the Storage Facility each year." Please update the MRV plan to reflect the proper citation of 40 CFR 98.443(c) for Equation RR-4.	This has been corrected.

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
4.	7.2	36	In this section, we recommend explaining why it was determined that there will be no production previously injected CO_2, and/or providing references to other sections of the MRV plan that support this determination.	This has been addressed. The following sentence was added to Section 7.2: "The purpose of the Storage Facility is to permanently dispose and sequester the CO_2 waste stream derived solely from the production of Antrim natural gas."
5.	1.4	5		The text in Section 1.4 was updated to reflect that the UIC Class II permit has been issued by EGLE for the injection well and includes the proper well identifier.

Riverside Energy Michigan, LLC Chester 21-29N-02W Storage Facility Subpart RR Monitoring, Reporting, and Verification Plan

December 27, 2024

TABLE OF CONTENTS

Abbreviations and Acronyms

°F	Degrees Fahrenheit
AMA	Active Monitoring Area
BBL	Barrel
Bcf	Billion cubic feet
BHL	Bottom hole location
cf	Cubic feet
CO_2	Carbon dioxide and other carbon oxides
EGLE	Environment, Great Lakes, and Energy
EOR	Enhanced oil recovery
EPA	United States Environmental Protection Agency
ft	Foot (feet)
GOR	Gas to oil ratio
GRMD	Geologic Resources Management Division
HMI	Human Machine Interface
IP	Initial production
KB	Kelly bushing
lbs	Pounds
Mcf	Thousand cubic feet
Mcfd	Thousand cubic feet per day
MD	Measured depth
md	Millidarcy
MIT	Mechanical integrity test
MMA	Maximum Monitoring Area
MMscf	Million standard cubic feet
MMscfd	Million standard cubic feet per day
MRV	Monitoring, Reporting, and Verification
NNPRT	Northern Niagaran Pinnacle Reef Trend
P&A	Plugged and abandoned
PBTD	Plugged back total depth
pH	Scale of acidity
psi	Pounds per square inch
SCADA	Supervisory Control and Data Acquisition
scf	Standard cubic feet
SHL	Surface hole location
SLB	Schlumberger
SWD	Salt water disposal
TD	Total depth
TDS	Total dissolved solids
TVD	True vertical depth
UIC	Underground Injection Control
USGS	United States Geologic Survey

1. STORAGE FACILITY INFORMATION

1.1 Project Overview

The Chester 21-29N-02W Storage Facility is a CO_2 acid gas disposal injection project being developed by Riverside Energy Michigan, LLC (Riverside) in Otsego County, Michigan. The purpose of the project is to securely store the CO_2 emissions captured from the processing of natural gas produced from the Antrim Shale biogenic gas play in the northern Michigan Basin. The captured CO_2 will be injected into a Niagaran Pinnacle Reef reservoir, the Chester 21-29N-02W Reef.

The Chester 21-29N-02W Reef was once a natural gas producing field but has since been depleted, plugged, and abandoned. The Niagaran reservoir at a depth of approximately 6,100 feet (ft) enables CO_2 to be stored efficiently in a critical gas phase. This Monitoring, Reporting, and Verification (MRV) plan is designed in accordance with 40 CFR 98.440-449, Subpart RR, to define and describe the Chester 21-29N-02W Storage Facility (Storage Facility).

The Chester 21-29N-02W Storage Facility spatially consists of the surface and subsurface areas contained within the active and maximum monitoring areas, defined in *Section 3*. In process terms, the Chester 21-29N-02W Storage Facility begins at the mass flow meter positioned on the CO_2 flowline immediately upstream of the injection wellhead and ends in the subsurface at the reservoir's lithofacies-controlled aerial limits. Figure 1 shows the location of the Chester 21-29N-02W Storage Facility, the separate Turtle Lake Capture Facility (Capture Facility) from where CO_2 is sourced, and the approximately 2 miles of CO_2 flowline that links the two.

The Devonian age Antrim Shale Formation, from which the CO_2 originates as a minor co-constitute of natural gas production, produces regionally from a subsurface depth of approximately 1,000 to 2,000 ft. In contrast, the Silurian age Niagaran reef reservoir that constitutes the Chester 21-29N-02W Storage Facility is approximately 6,000 to 7,000 ft deep and currently has neither unplugged wells nor hydrocarbon production associated with it. It is the explicit purpose and design of this project to sequester and dispose of CO2 and not to facilitate any additional production from the Storage Facility. As such, the Turtle Lake Capture Facility exists and operates separate from the Storage Facility and is not a part of the Storage Facility as defined in this MRV plan.

1.2 Reporter Number

Greenhouse Gas Reporting Program ID: 589821

Operator: Riverside Energy Michigan, LLC on behalf of Riverside Carbon Solutions, LLC.

1.3 Storage Facility Location

The Storage Facility is located in Otsego County, Michigan, approximately 9 miles southeast of the town of Gaylord, Michigan.

Storage Facility location description in the Public Land Survey System:

Sections 21 and 22, T29N-R02W

Storage Facility coordinates in North American Datum of 1983 (NAD83):

Latitude: 44.896048°
Longitude: -84.547381°

1.4 Underground Injection Control Permit Class: Class II

The Michigan Department of Environment, Great Lakes, and Energy (Michigan-EGLE) Geologic Resources Management Division (GRMD) administers the Underground Injection Control (UIC) program in Michigan for all Class II injection wells, by the statutes and rules subject to Part 615, Supervisor of Wells, of the Michigan Natural Resources and Environmental Protection Act (NREPA), Public Act 451 of 1994, as amended. The CO_2 injection well (Smith 3-21) will be operated by Riverside Energy Michigan, LLC, permitted as a UIC Class II well, and regulated by Michigan-EGLE GRMD.

As of December 27, 2024, the UIC Class II permit application for the proposed Smith 3-21 injection well is under review by Michigan-EGLE GRMD. Additionally, a well identification number has not yet been issued but will be shared with EPA when available.

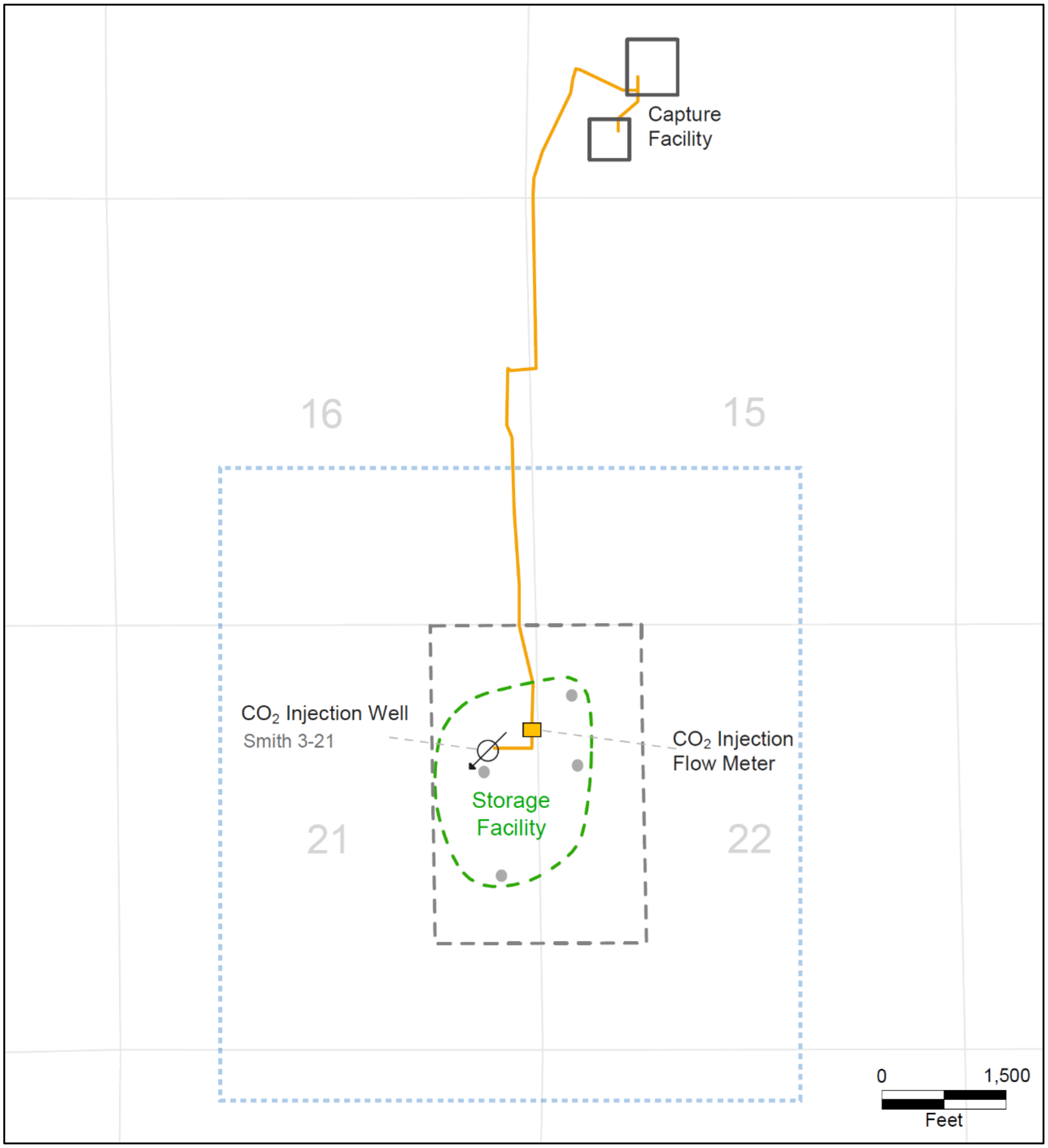

Figure 1. Map of the Chester 21-29N-02W Storage Facility (dashed green outline), showing the Capture Facility, CO_2 pipeline (orange) from the Capture Facility, Injection Unit (dashed gray rectangular outline) permitted with Michigan-EGLE, the Active and Maximum Monitoring Areas for the Storage Facility (dashed blue outline), the Smith 3-21 CO_2 Injection Well, and all plugged wells within the Storage Facility (gray circles). Section 3 and Figure 14 discuss the Active and Maximum Monitoring Areas in greater detail. The base map depicts the PLSS and shows all or portions of sections within T29N-R02W.

2. PROJECT DESCRIPTION

2.1 Regional Geology

The Northern Niagaran Pinnacle Reef Trend (NNPRT) in the Michigan Basin features several hundred highly compartmentalized pinnacle reefs found at an average dept of about 6,000 ft

below the ground surface. These reefs are separated from one another by distances as little as hundreds of feet to as much as several miles. The NNPRT originated from coral reefs formed during the Silurian Period 420 to 440 million years ago in tropical sea environments (Figure 2).

The reefs were subsequently buried by sediments deposited around and above the reefs encasing them within mostly impermeable layers of evaporitic and carbonate rocks. These impermeable evaporitic and carbonate rocks are responsible for trapping and sealing prolific quantities of oil and gas within these reefs.

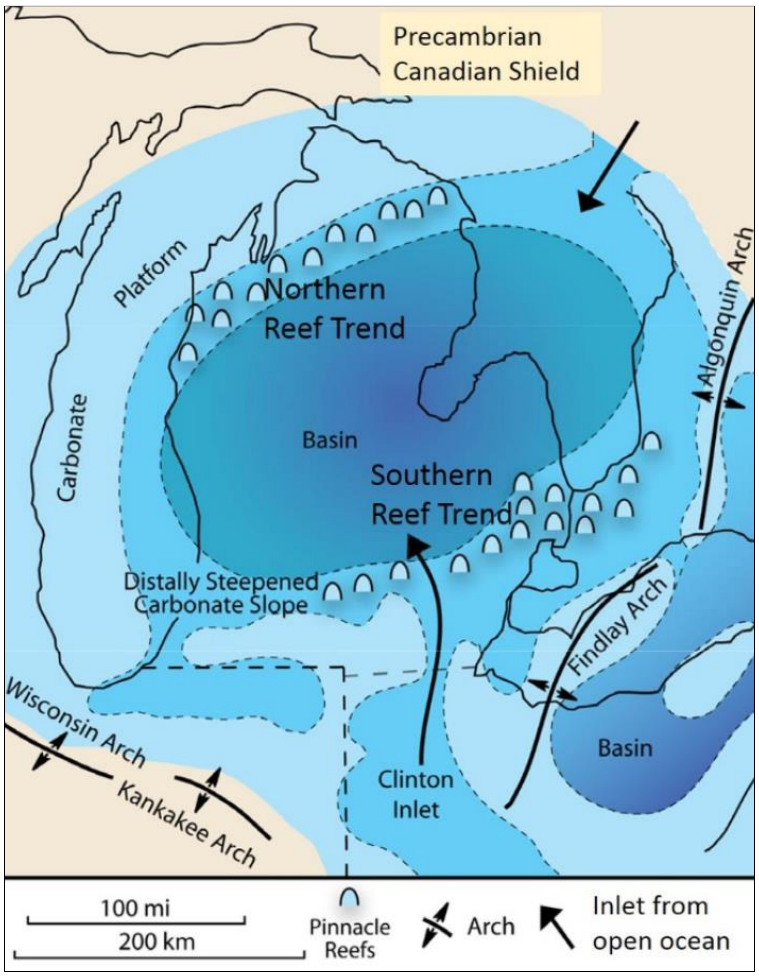

Figure 2. Map of the Michigan Basin and interpreted paleogeography during the Silurian Period, depicting the Northern Niagaran Reef Trend amongst regional environments. Ritter (2008) modified after Briggs and Briggs (1974).

The NNPRT forms a part of a broader shallow shelf carbonate depositional system that partially encircles the Michigan Basin. The NNPRT is positioned along the margin of the system's carbonate platform. Individual reefs typically range in area from 50 to 500 acres and have vertical heights between 100 to 700 ft in the subsurface.

The reservoir facies primarily consist of porous and permeable dolomite and limestone. Some reefs are completely dolomitized, while others are essentially all limestones. Dolomitization of the reefs, which helps enhance porosity, increases as the reefs become shallower. Salt and anhydrite plugging of porosity occurs in the deeper reefs (Gill 1979). Reef porosity values can be as high as 35%, but typically average 3 to 12%. Net pay intervals can total from only a few feet to several hundred feet. The most productive reef reservoirs are characterized by dolomitized reef facies with well-developed inter-crystalline and vuggy porosity. Secondary porosity is present and can enhance permeability, which typically averages 3 to 10 millidarcies.

The Niagara and A1 Carbonate Formations of the early Silurian Niagara Group contain the main reservoir units within the reefs, shown in the stratigraphic column in Figure 3. The base of the Niagara Formation, referred to as the “Lockport” or “White Niagaran” is typically a partially dolomitized to dolomitized crinoidal wackestone, (Charbonneau, 1990). Overlying the Lockport, the Guelph Formation is comprised of units commonly referred to as the “Gray” and “Brown” Niagaran. The Gray Niagaran and Lockport are typically characterized by very low porosity. The Brown Niagaran comprises the core of the reef reservoir and pinnacle reef buildup. It is characterized by dolomite and limestone skeletal wackestones and boundstones, (Huh, 1973).

The A1 Carbonate overlies the Brown Niagaran at the reef crest and is sometimes referred to as the “Ruff” Formation. The A1 Carbonate is considered a reservoir unit in the crest of some reefs but grades into tight, low porosity dolomitic mudstone near the reef flanks, (Huh, 1973).

The A1 Carbonate and Brown Niagaran Formations are encased by a sequence of evaporites and salt-plugged carbonates, comprising the seal for the reefs. The A1 Evaporite is typically thin or not present at the crest of the reef but forms a seal of the Brown Niagaran at reef flanks. Overlying the A1 Carbonate and providing the primary seal for the Storage Facility is the A2-Evaporite, Figure 3. The A2 Evaporite is characterized by non-porous and impermeable anhydrite at the reef crest. It transitions to halite dominated facies off the structure of the reef. Further overlying the A2 Evaporite are hundreds of feet of non-porous evaporite and low porosity carbonate and shale sequences that comprise the Salina Group.

The lithostratigraphy and internal reef structure are visualized in Figure 4. Reef formation began surrounding a carbonate bioherm in warm, shallow waters, (Rine, 2017). The reef core grew upwards as sea level in the Michigan Basin rose. When sea level fell, the reefs became exposed and evaporite deposition encased the reefs.

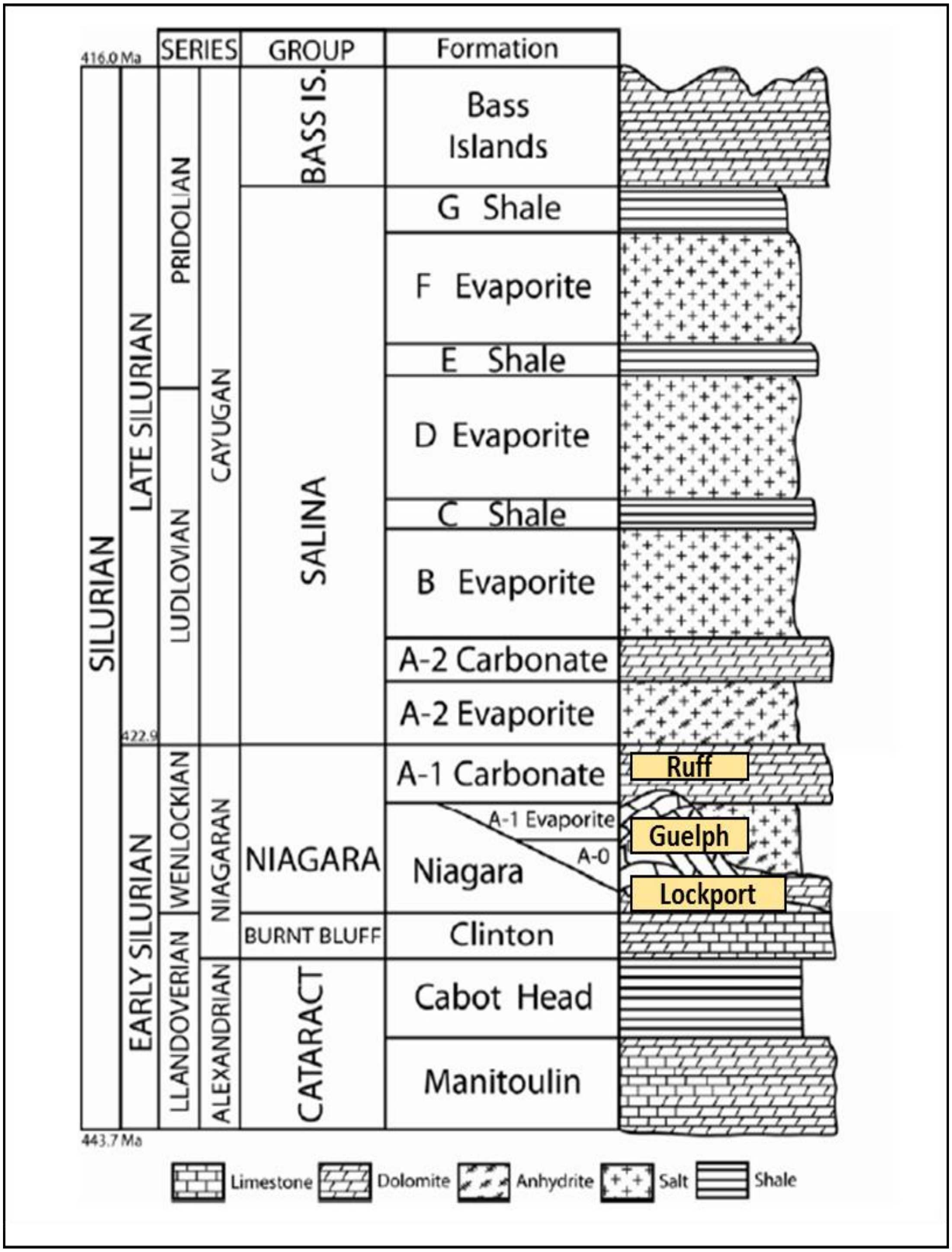

Figure 3. Generalized stratigraphic column for Silurian period deposits in the Michigan Basin, with emphasis on Niagaran reefs (Ritter, 2008).

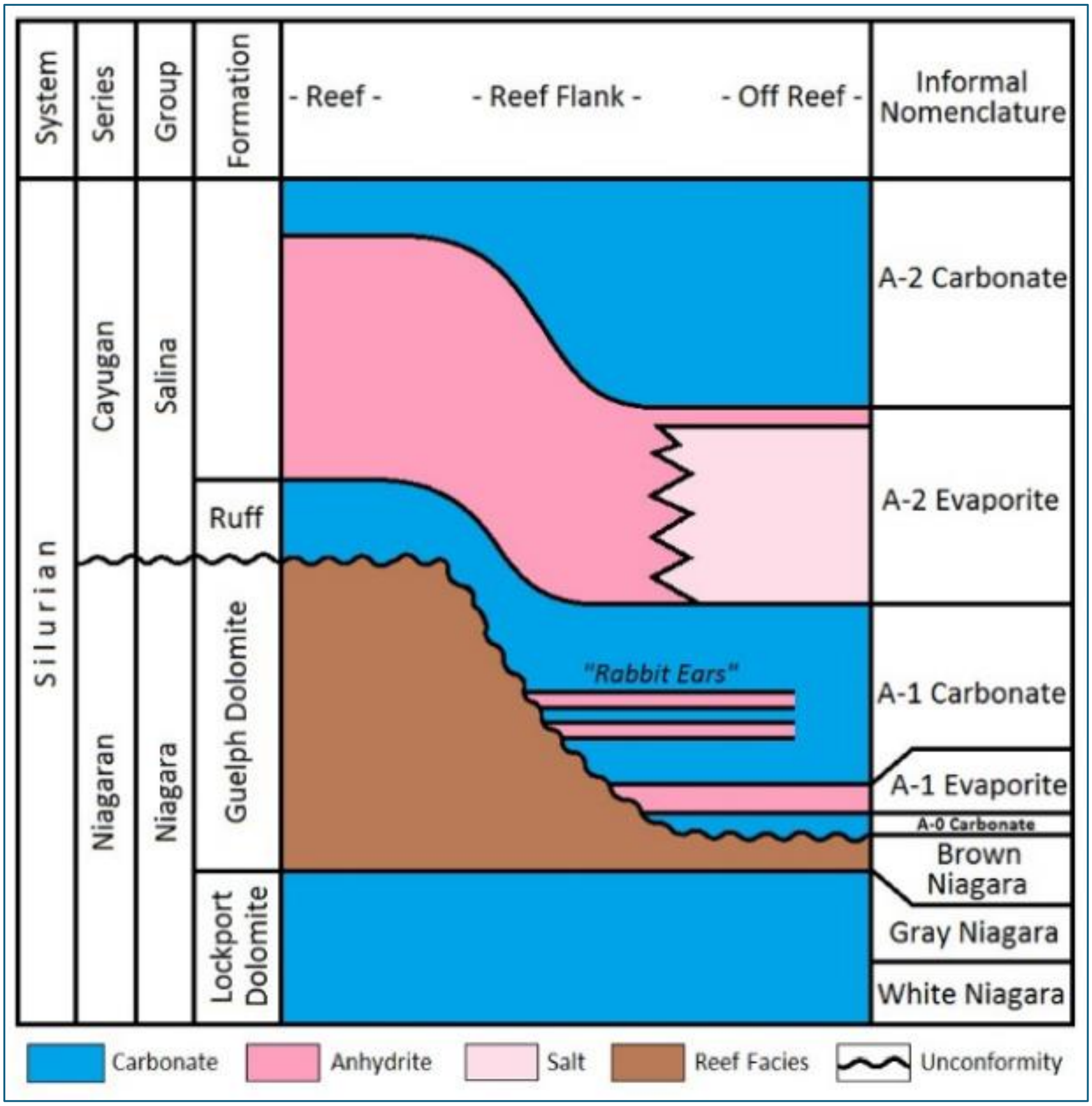

Figure 4. Lithostratigraphy visualization of a Niagaran reef interval, (Gupta et al., 2020 modified from Gill 1979 and Huh 1973).

2.2 Site Characterization

The Chester 21-29N-02W Field is a Northern Niagaran Pinnacle Reef located in Sections 21 and 22 of Township 29 North, Range 2 West, Otsego County, Michigan. The Field has a footprint of approximately 90 acres and is buried to a depth of 6,710 ft TVD (-5,472 ft subsea TVD) at its base to 6,160 ft (-4,921 ft subsea TVD) at its top.

While the reef structure itself is 550 ft tall and consists of the Brown Niagaran Formation, an additional 60 ft of A1 Carbonate Formation rests directly on top of the Brown Niagaran Formation and serves as a vertical extension of the physical reservoir observed in the Niagaran interval. Porosity of the A1 Carbonate and Brown Niagaran reservoir intervals derived from wireline logs ranges from 1 to 16% and averages 5.4%. Unless otherwise specified, all subsequent mentions

in this document of the Reef, Reef Structure, or Field will mean to refer to the total interval that includes both the Brown Niagaran Formation and the A1 Carbonate Formation.

The A2 Evaporite Formation rests directly on top of the A1 Carbonate Formation and serves as the primary seal for the Storage Facility. Above the 120 ft thick A2 Evaporite Formation is a 1,300 ft thick series of massive evaporite deposits and interbedded shale and limestone deposits that make up the bulk of the Salina Group.

The following geologic data was compiled for the Chester 21-29N-02W Reef and surrounding area:

- Well data from historic wellbores including wireline logs, drillers reports, and state curated well files.
- 2D seismic data, composed of 5 lines that each traverse the Reef Structure and adjacent surrounding area.
- Oil and gas production histories as reported to the State of Michigan.

Figure 5 shows the shot point locations of 2D seismic lines used to interpret the Reef Structure at the Storage Facility. Figure 6 is a stratigraphic cross section of well logs through the Storage Facility and Figure 7 is the cross-section reference map.

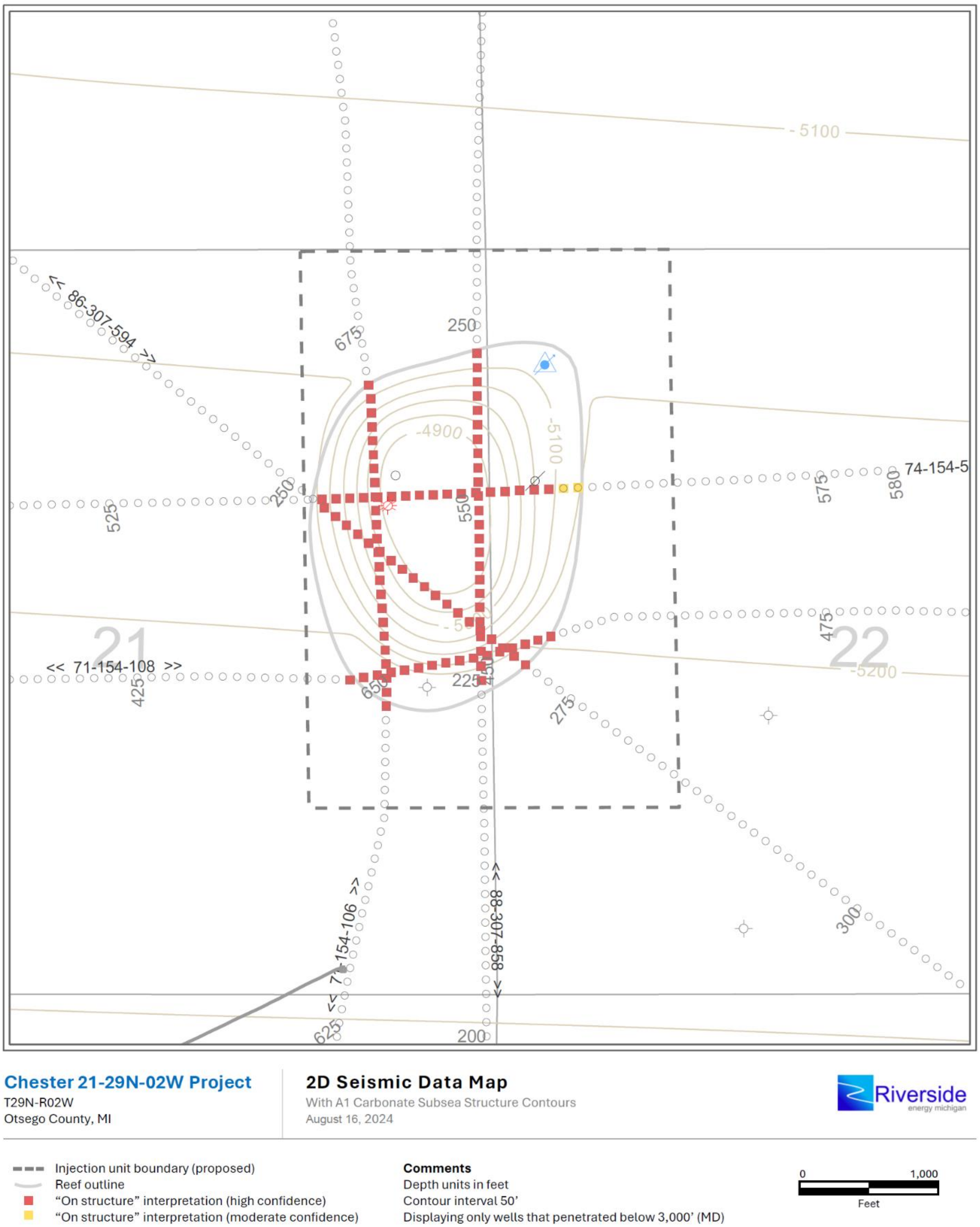

Figure 5. 2D seismic shot point locations used to determine the position of the Chester 21-29N-02W Reef Structure.

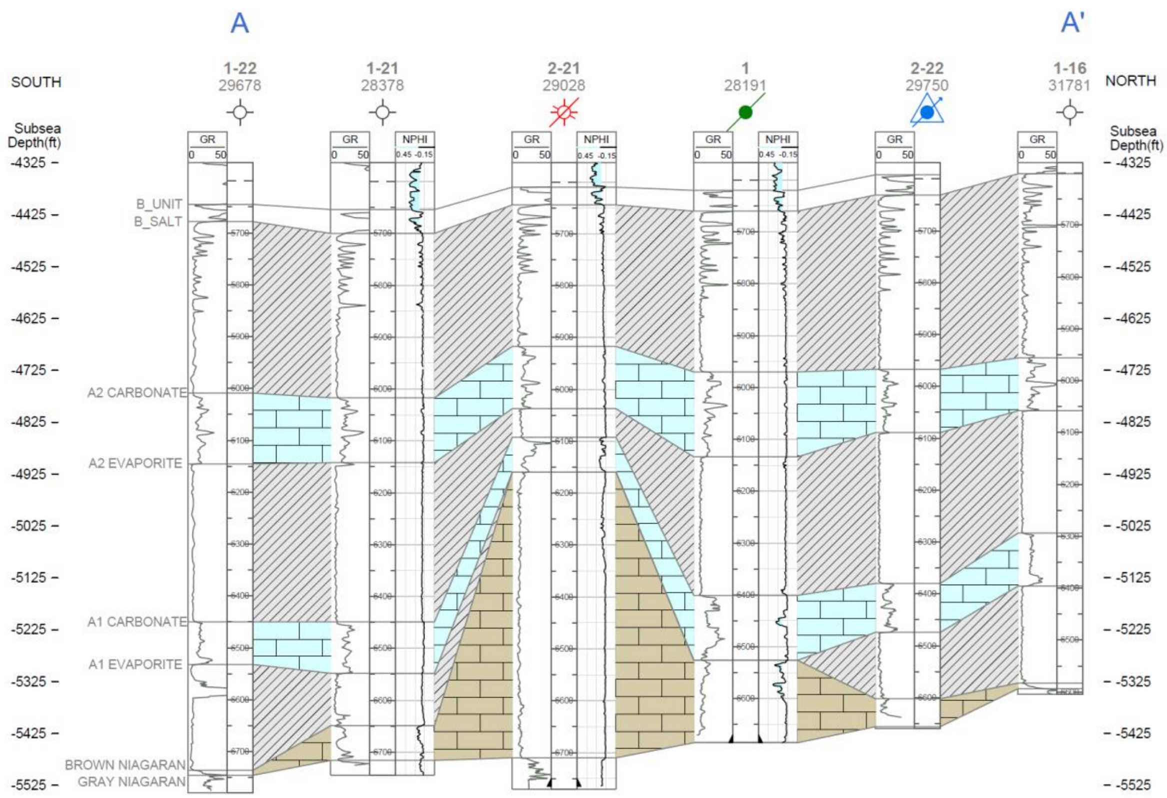

Figure 6. Stratigraphic-structural cross-section of Niagaran reef interval at the Chester 21-29N-02W Storage Facility and surrounding area. Wireline log tracks include Gamma Ray log response ("GR", scale 0 to 50 API) left of each wellbore, and where available Neutron Porosity log response ("NPHI", 0.45 to -0.15%) right of wellbore.

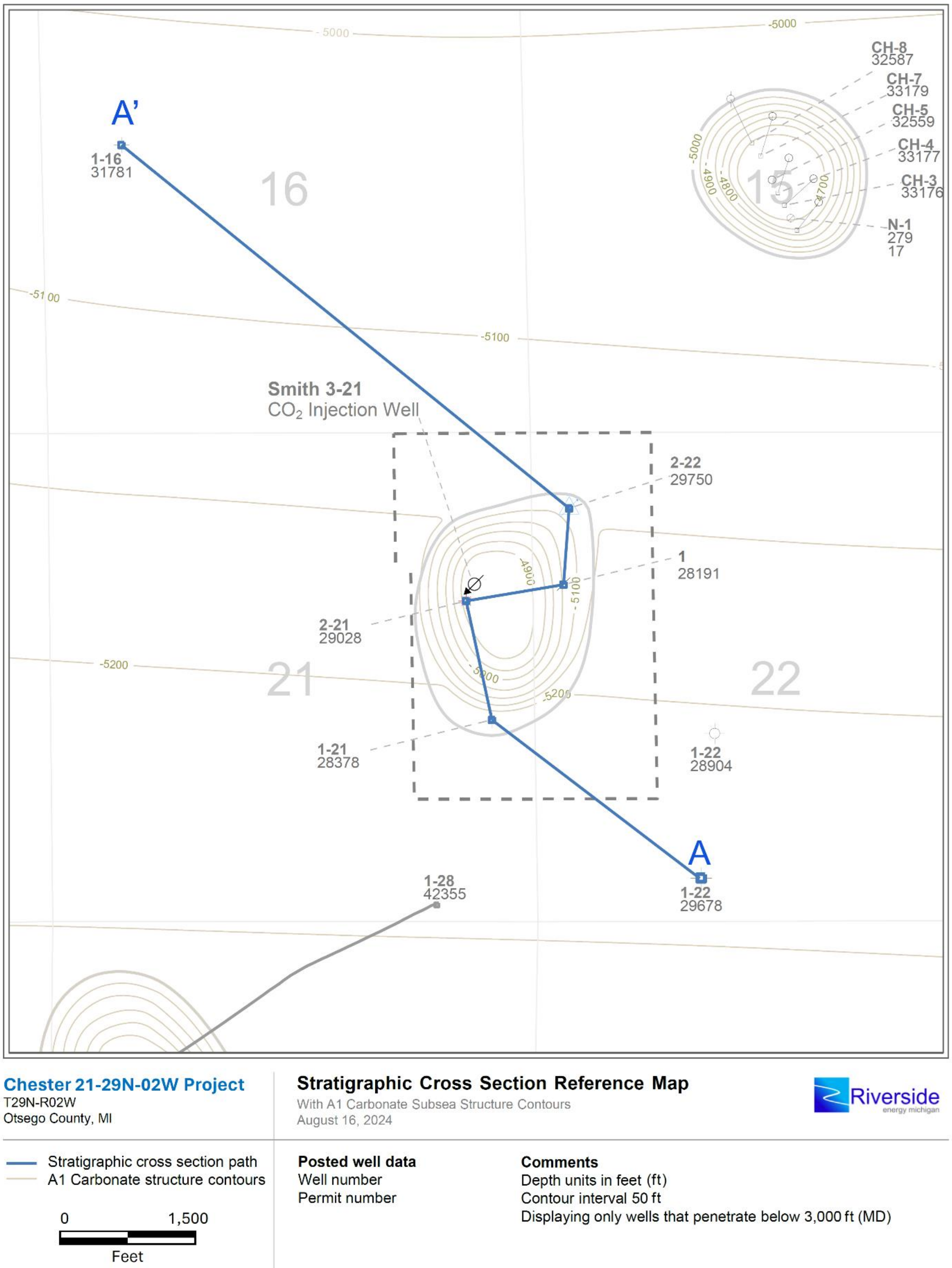

Figure 7. Reference map for the stratigraphic cross-section in Figure 6.

2.3 Operational History of the Chester 21-29N-02W Reef and Existing Wells

The Chester 21-29N-02W Reef was discovered in 1970 by Great Lakes Exploration that developed a single discovery well for oil production. The drilling of three additional wells was attempted between 1971 and 1974, resulting in one gas producing well and two dry holes. One of these dry holes, the State Chester 2-22, has been converted into a brine disposal well into the shallower Dundee Formation, disposing of water produced from Antrim Shale gas production. This well was recompleted with a cement plug within the Niagaran below. These four wells are the only wells ever drilled into the Chester 21-29N-02W Reef and summarized in Table 1.

Table 1. List of wellbore penetrations within the Reef Structure.

Well Name	**Marshall, Glen**	**Underwood, N M & Knapp C A**	**Leacock Hubbard Underwood**	**State Chester**
Well No.	1	1-21	2-21	2-22
API	21137281910000	21137283780000	21137290280000	21137297500000
MI Permit No.	28191	28378	29028	29750
Well Status	P&A	P&A	P&A	Active PBTD SWD
Well Designation	Oil	Dry Hole	Gas	Initially a Dry Hole, now PBTD SWD
First Operator	Great Lakes Exploration	Miller Brothers	Miller Brothers	Reef Petroleum Corporation
Last Operator	ANR Pipeline	Miller Brothers	Saba Energy of Texas	VCP Michigan
Formation at TD	Gray Niagaran	Gray Niagaran	Gray Niagaran	Gray Niagaran
TD (MD, TVD per KB)	6,685	6,744	6,770	6,660
Datum Elevation (KB)	1,242	1,239	1,238	1,244
SHL Latitude	44.89582	44.89186	44.89537	44.89806
SHL Longitude	-84.54549	-84.54850	-84.54952	-84.54523
BHL Latitude	44.89582	44.89186	44.89537	44.89806
BHL Longitude	-84.54549	-84.54850	-84.54952	-84.54523
Note				PBTD 4,215 ft MD
Producing Formation	Brown Niagaran	-	Brown Niagaran	-
IP oil (BBL/day)	480	-	NA	-
IP gas (Mcf/day)	NA	-	20,000	-
Cumulative oil (BBL)	25,483	-	162,238	-
Cumulative gas (Mcf)	520,175	-	9,951,270	-
Cumulative water (BBL)	Unknown	-	Unknown	-
Permit date	9/24/1970	3/23/1971	9/14/1972	5/13/1974
Well spud date	11/20/1970	4/22/1971	12/9/1972	5/23/1974
Completion date	1/25/1971	5/26/1971	2/26/1973	6/19/1974
Abandonment date	11/21/1990	5/29/1971	6/8/2002	

Table 2 summarizes the additional wells that exist within the active and maximum monitoring areas of the Storage Facility but do not penetrate the Reef Structure. The majority of these wells targeted the Antrim Shale Formation for natural gas production and typically only penetrate in depth to approximately -250 ft to -950 ft (subsea), whereas the Primary Seal and Storage

Reservoir each exceed -4,500 ft (subsea) throughout the Active and Maximum Monitoring Areas. See *Section 3* for the definition and map of the Active and Maximum Monitoring Areas.

Table 2. List of wellbore penetrations within Active and Maximum Monitoring Areas.

Evaluation Group	API	Well Name	Well No.	TD (subsea ft)	Well Type	Well Status
This Project's Pending CO2 injection well	TBD	Smith	3-21	-5,250	CO2 Injection	Permit pending
Penetrations into the Reef Structure	21-137-29028-0000	Leacock Hubbard Underwood Knapp	2-21	-5,532	Gas	P&A
	21-137-28378-0000	Underwood, N M & Knapp	1-21	-5,505	Dry Hole	P&A
	21-137-28191-0000	Marshall, Glen	1	-5,443	Oil	P&A
	21-137-29750-0000	State Chester	2-22	-5,416	SWD	Active
Penetrations depth equivalent to, but not into, the Reef Structure	21-137-28904-0000	Underwood & Knapp & Ashland Farms	1-22	-5,541	Dry Hole	P&A
	21-137-29678-0000	Underwood, Nellie M, & Knapp	1-22	-5,540	Dry Hole	P&A
	21-137-42355-0000	State Chester	1-28	-5,371	Gas	P&A
Penetrations at least 3,350 ft above Primary Seal	21-137-46107-0000	Campbell et al.	1-22	-1,454	SWD	Active
	21-137-55872-0000	State Chester	A3-28	-938	Gas	Producing
	21-137-55871-0000	State Chester	A1-27	-937	Gas	Producing
	21-137-50566-0000	State Chester	24-21	-840	Gas	P&A
	21-137-50567-0000	State Chester	23-21	-772	Gas	Producing
	21-137-55327-0000	Jaeger	D4-21	-718	Gas	Producing
	21-137-55326-0000	Jaeger	C4-21	-704	Gas	Producing
	21-137-55399-0000	Wright	B3-21	-692	Gas	Producing
	21-137-44259-0000	State Chester Venture	51	-633	Gas	Producing
	21-137-45622-0000	Campbell et al.	14-22	-604	Gas	Producing
	21-137-45588-0000	Campbell et al.	13-22	-600	Gas	Producing
	21-137-45536-0000	Campbell et al.	23-22	-593	Gas	Producing
	21-137-45537-0000	Marshall	12-22	-592	Gas	Producing
	21-137-45589-0000	Campbell et al.	24-22	-585	Gas	Producing
	21-137-44261-0000	State Chester Venture	52	-544	Gas	Producing
	21-137-40014-0000	State Chester Venture	31	-400	Gas	Producing
	21-137-39042-0000	State Chester Venture	22	-370	Gas	Producing
	21-137-41430-0000	State Chester	47	-348	Gas	Producing
	21-137-42229-0000	State Chester Venture	54	-329	Gas	Producing
	21-137-41432-0000	State Chester	45	-312	Gas	Producing
	21-137-27029-0000	State Chester	13	-260	Gas	Producing

In total, the Chester 21-29N-02W Field has produced 10,583,601 Mcf of natural gas, 203,105 barrels of oil, and an unknown volume of water. The production totals are summarized in Table 3. The Leacock Hubbard Underwood & Knapp #2-21 tested at an initial reservoir pressure of 3,227 psi at approximately 6,300 ft (0.51 psi per foot gradient) with a temperature of 114°F. It is believed the reservoir was depleted to a current pressure of approximately 300 psi or less. The Marshal, Glen #1 well was plugged and abandoned in 1990, and the Leacock Hubbard Underwood & Knapp #2-21 well was the final well at the Reef Structure to be plugged and abandoned in 2002.

Table 3. Summary of production from Chester 21-29N-02W Field.

Well Name	Date of First Production	Total Production		
		BO	Mcf	GOR
Marshall, Glen #1	1/19/1971	41,062	529,169	12,887
Leacock Hubbard Underwood & Knapp #2-21	2/6/1973	162,043	10,054,432	62,048
Total		203,105	10,583,601	52,109

As there are no longer any producing wells into the Reef Structure and as the structure is laterally limited, there will be no production associated with the Storage Facility. The Smith 3-21 UIC Class II CO_2 injection well will be the only wellbore penetrating the Reef Structure.

2.4 Mass Balance Estimate of Storage Resources

A mass balance approach using natural gas production data was used to estimate approximately 1 million metric tons of CO_2 storage resources at the Storage Facility. This mass balance approach does not consider produced water or oil that may provide additional accessible pore volume for storage. This mass balance approach does not consider a storage efficiency factor.

Determining the accessible reservoir pore volume:

10.5 Bcf produced natural gas
Formation volume gas factor Bg = 0.0042 cf/scf at 114°F and 3,168 psi
1/Bg = 238 scf/cf
Reservoir pore volume = 10,500,000,000 scf / 238 scf/cf = 44,100,000 cf

Determining the storage resources of the accessible reservoir pore volume for CO_2:

Confining interval top depth = 6,035 ft
Fracture pressure (estimate) = 0.80 psi/ft
Current reservoir pressure (estimated) = 300 psi
Injection pressure limit = 6,035 ft * 0.80 psi/ft * .90 safety factor = 4,345 psi
CO_2 density @ 4,345 psi = 55 lbs/cf
Storage resource given 44,100,000 cf of accessible pore space = 1,080,000 metric tons of CO_2

2.5 Reservoir Modelling and Injection Simulation

A simple geologic model was developed to complete computational injection simulations and evaluate the dynamic storage capacity of the Storage Facility. The model was generated from 2D seismic (structure) and well log information (top depths and porosity) in IHS' *Petra®* software. Computer Modeling Group's *GEM™* reservoir simulation software was used to complete injection simulation.

Figure 8 shows the 3D view of the initial gridded model of the Chester 21-29N-02W Reef used for injection simulation with the position of the injection well entering the top of the reef. The model covers a 3,430 by 3,640 ft (0.65 by 0.69 miles) area and contains the approximate 90-acre (0.14 square mile) Chester 21-29N-02W Reef Structure within it. Porosity of the A1 Carbonate and Brown Niagaran reservoir intervals ranges from 2 to 9%. Permeability of the reservoir intervals ranges from 1 to 5 millidarcies and was derived from basin-wide Niagaran reef porosity-permeability cross plots by Gupta et al. (2020).

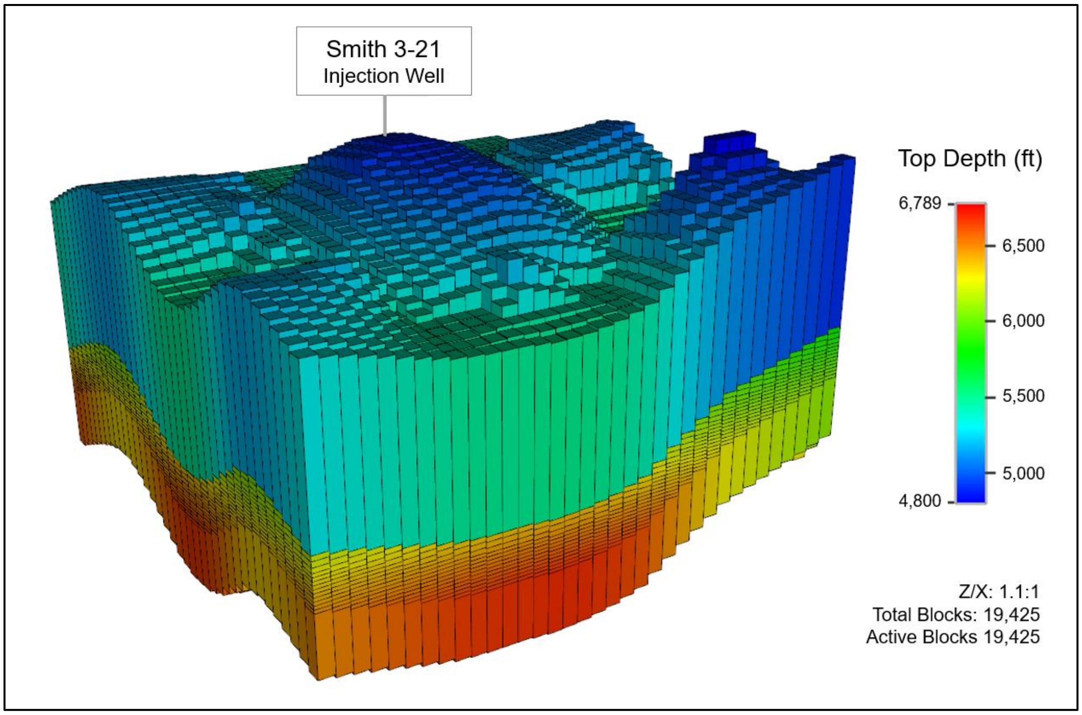

Figure 8. Gridded Model of the Chester 21-29N-02W Area Used for Injection Simulation. Also shown is the approximate location of the Smith 3-21 injection well.

The reef reservoir is modeled as a closed system with all model boundaries closed. The reef reservoir was initialized with depleted gas, oil, and water saturations at 300 psi. Injection rate was set at 12,000 Mcfd based on basin experience from CO_2 injection in other Niagaran reef projects. The maximum bottomhole pressure was limited to 4,345 psi (6,036 ft depth * 0.8 psi/ft fracture gradient * 0.9 safety factor).

The simulation was run for 15 years. After approximately 4 years, the maximum bottomhole pressure limit was reached, limiting further injection. Nearly no CO_2 was injected after 5 years. The simulation injected 16.7 Bcf of CO_2 or approximately 880,000 metric tons of CO_2 after 5 years. Figure 9 shows the development of the CO_2 plume within the Reef Structure over time. The CO_2 is limited to the 90-acre Reef Structure and contained within the dashed green Reef Structure boundary shown in Figure 14. Figure 10 shows the average Reef Structure pressure over time. Figure 11 reports the daily CO_2 injection rate and cumulative CO_2 injection totals over 5 years of injection.

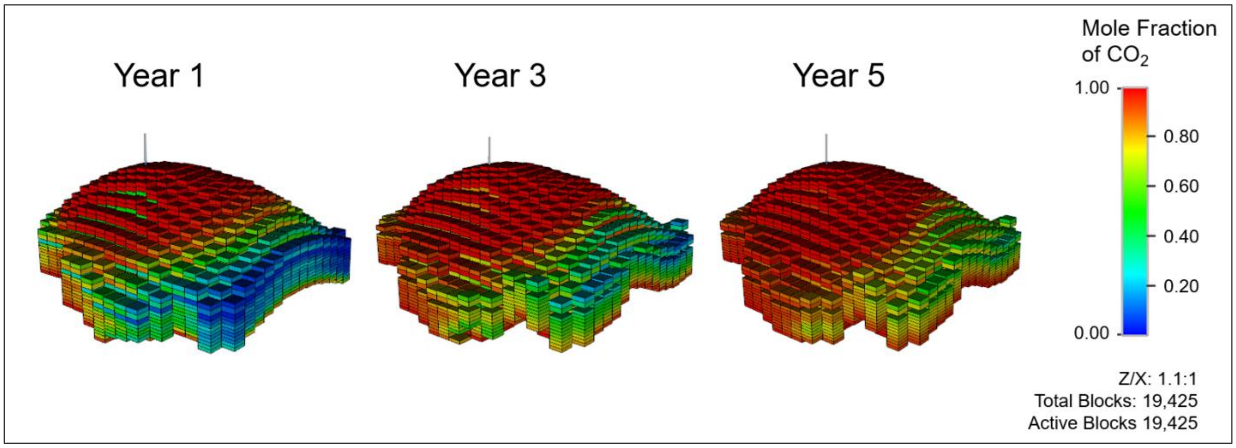

Figure 9. CO_2 plume development in the Reef Structure over 5 years of injection (Mole fraction of CO_2 in reservoir blocks). Also shown is the approximate location of the Smith 3-21 injection well where it enters the Reef Structure.

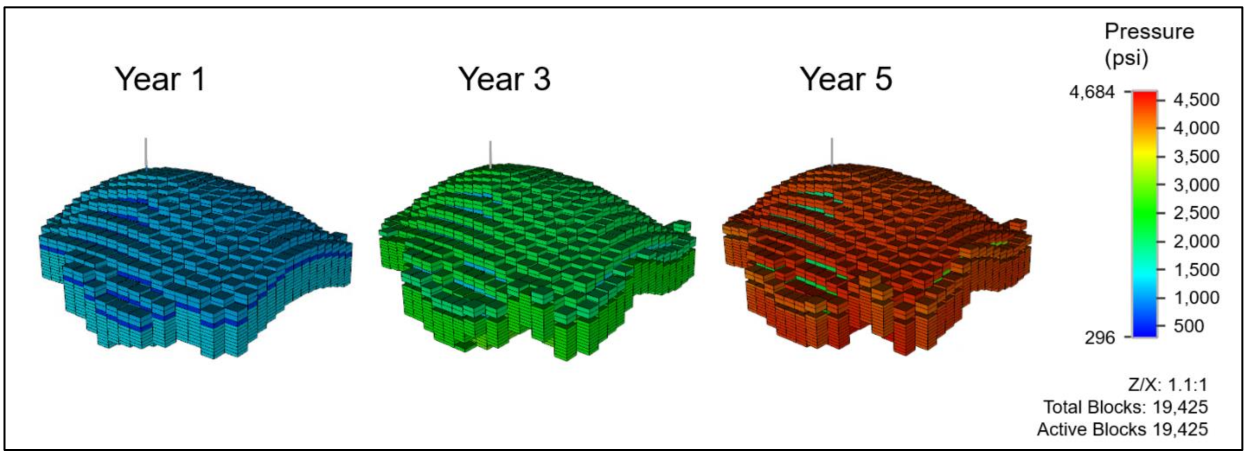

Figure 10. Pressure development in the Reef Structure over 5 years of injection from an initial pressure of 300 psi. Also shown is the approximate location of the Smith 3-21 injection well where it enters the Reef Structure.

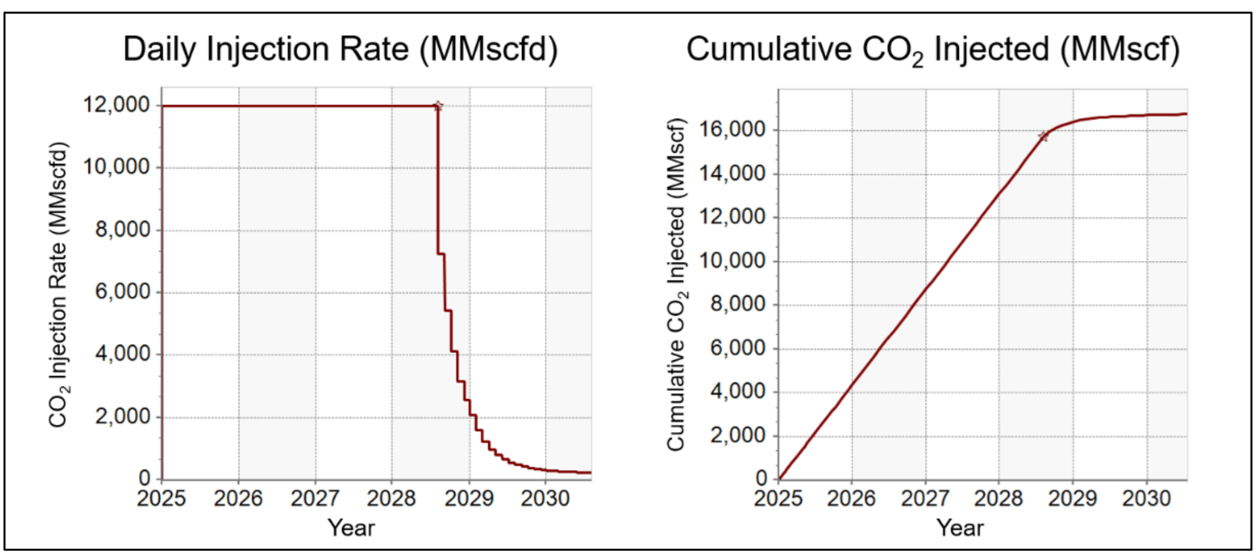

Figure 11. Daily injection rate and cumulative gas injection into the Reef Structure.

2.6 CO_2 Capture and Storage

The Antrim Shale in the northern part of the Michigan Basin is a biogenic gas reservoir. A byproduct of the microbial generation of methane is carbon dioxide that must be stripped from the gas before it is sold. The South Chester CO_2 Treating Plant (the Plant) located in Section 10 of Chester Township, Otsego County, Michigan, and operated by Phillips 66, removes CO_2 from natural gas produced from the Antrim Shale. As operator of the majority of wells producing natural gas being processed by the Plant, Riverside owns 60% of the CO_2 that would normally be vented from the natural gas plant. Riverside is currently constructing the necessary facilities to capture the entire vent stream of about 380,000 metric tons of CO_2 per year. It is expected that the Plant will continue to operate for another 10 to 20 years, dependent on market conditions. The Plant utilizes amine to strip CO_2 from the natural gas. The vent gas resulting from this process is typically 98% CO_2 or greater, and this composition is not expected to change over time. Riverside is installing four rotary screw compressors and reconfiguring one reciprocating compressor unit that in sum will comprise the Turtle Lake Capture Facility (Capture Facility) to compress the CO_2 for transportation and storage. CO_2 will be transported on a dedicated pipeline from the Capture Facility to the Chester 21-29N-02W Storage Facility. The Storage Facility will consist of one injection well (Smith 3-21) drilled into the Chester 21-29N-02W Reef Structure. In the future, the pipeline may become part of a larger distribution system for delivering CO_2 to multiple depleted gas reef storage facilities operated by Riverside for the purpose of permanently disposing and sequestering the CO_2 waste stream derived solely from the production of Antrim natural gas.

Figure 12 is a process flow diagram of the Capture Facility, pipeline, and Storage Facility. The key meter for calculating the mass of CO_2 injected is identified as the Injection Meter in this figure. This dedicated Coriolis mass flow meter will measure and verify the mass of CO_2 being received and injected.

Riverside also has the option to deliver CO_2 to a third party for Enhanced Oil Recovery (EOR). Riverside will have access to data generated by the third party's Coriolis mass flow meter (Delivery Point Meter in Figure 12) positioned near the outlet of the Capture Facility and inlet to their pipeline, which will serve as the custody transfer point. This data will be used for the accurate determination of CO_2 delivered to the third party. The third party operates their EOR projects under an approved MRV plan (facility ID 1010117) is wholly separate from this Storage Facility and this MRV plan. If CO_2 is delivered to this third party, Riverside will review for applicability of Subpart PP and comply with its requirements if applicable.

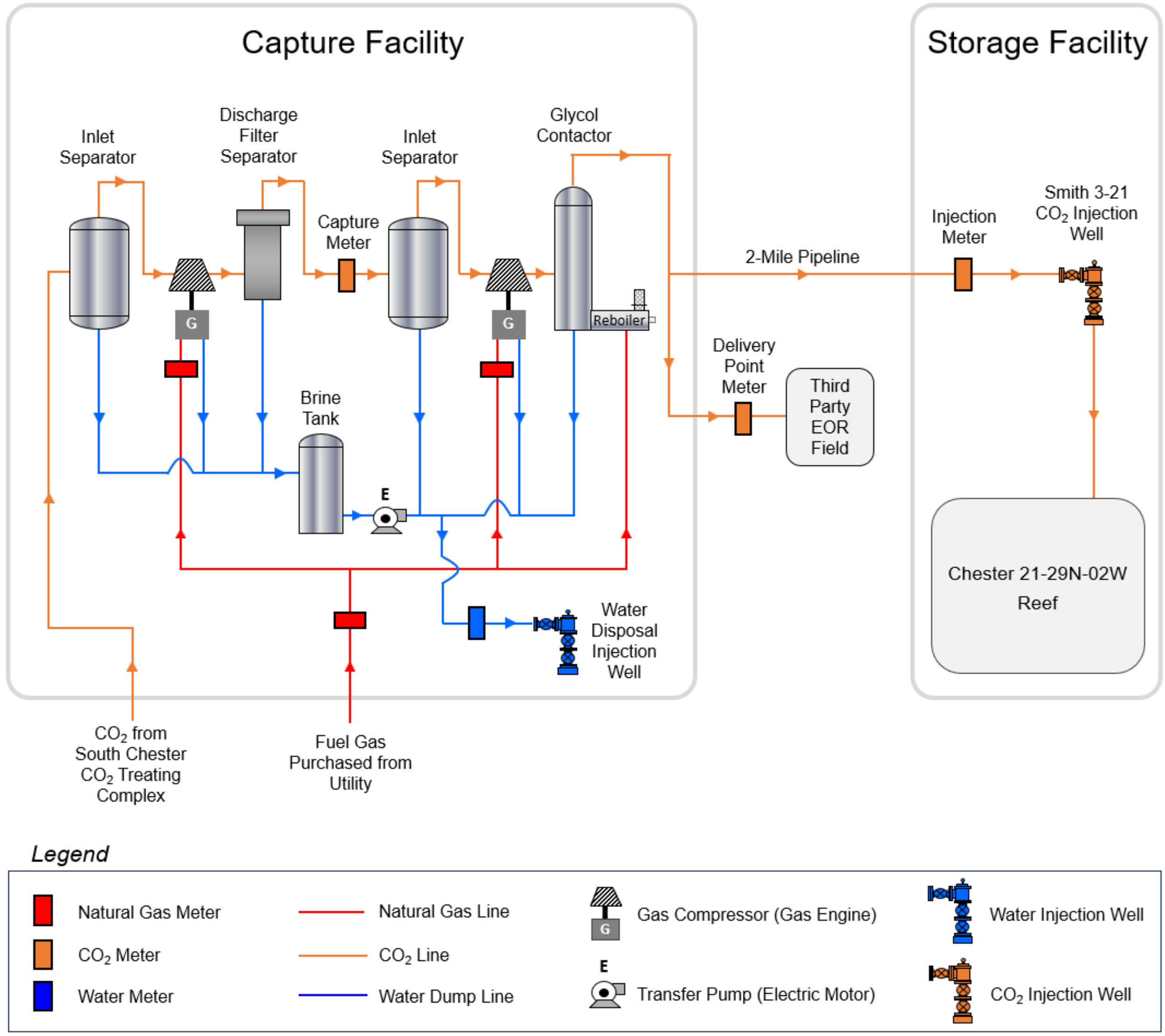

Figure 12. Process flow diagram of the Turtle Lake Capture Facility and the Chester 21-29N-02W Storage Facility.

2.7 Ownership

It is helpful to understand the corporate structure and relationship between the entities; refer to Figure 13 below. Riverside Energy Michigan, LLC (Riverside) and Riverside Carbon Holdings (RCH), LLC are 100% owned subsidiaries of Riverside Energy Holdings, LLC. Riverside is operator of the Antrim Shale natural gas wells and permittee of the injection well. Riverside Carbon Solutions, LLC, RCS Capture Antrim, LLC and RCS Storage Michigan, LLC are 100% owned subsidiaries of RCH. RCS Capture Antrim, LLC holds the Capture Facility assets including leased acreage upon which the facilities reside. RCS Storage Michigan LLC holds rights to the minerals and pore space in the Chester 21-29N-02W Reef Structure. Riverside will be the operator of the Storage Facility on behalf of Riverside Carbon Solutions, LLC.

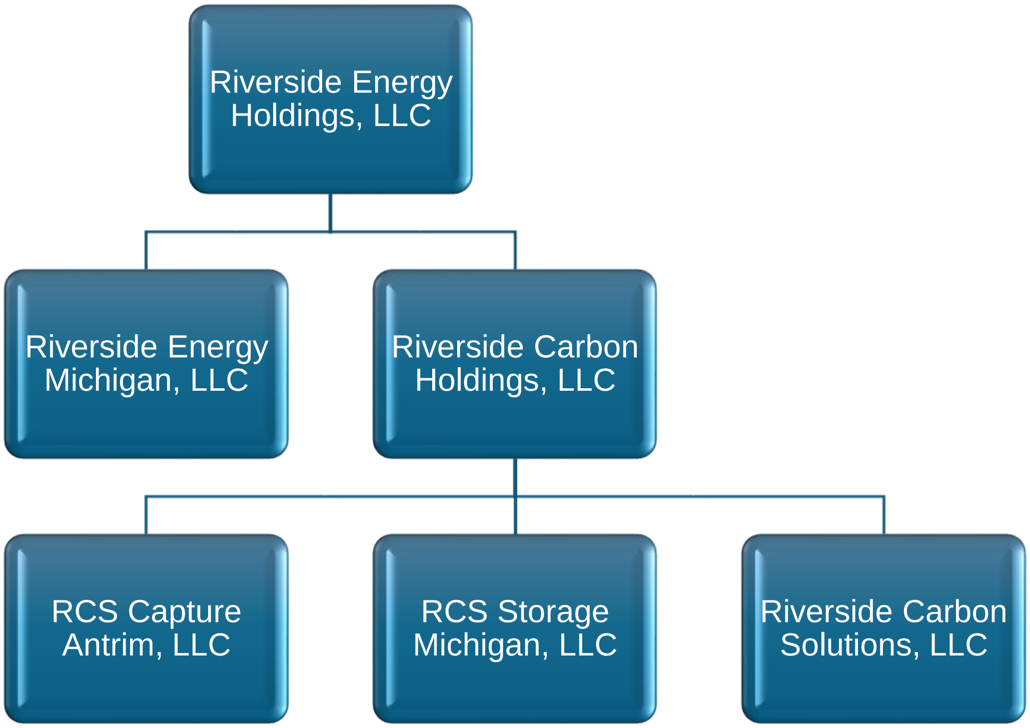

Figure 13. Organizational structure of the Riverside entities involved in the generation, capture and storage of CO_2.

2.8 Data Collection

All flow meters and other instrumentation at the Capture and Storage Facilities will be wired into Riverside's Supervisory Control and Data Acquisition (SCADA) system. The software continuously logs data from the meters and other instrumentation to a secure server with remote data backup and provides a Human-Machine Interface (HMI) for operators. It also has the capability to send an alarm to operators should parameters deviate outside of prescribed limits. Together, these data streams provide accurate accounting of all CO_2 being captured, delivered, received and injected.

Section 5.0 provides a more detailed explanation of the monitoring data that will be collected in order to detect any leakage of CO_2 from the Storage Facility. *Section 6.0* of this MRV Plan provides a more detailed explanation for how this data and other means will be used to establish baseline data for comparison to data collected during operation of the Storage Facility to detect possible surface leakage.

3. DELINEATION OF THE MONITORING AREA

3.1 Active Monitoring Area

The Active Monitoring Area (AMA) is defined (40 CFR 98.449) as follows:

Active monitoring area is the area that will be monitored over a specific time interval from the first year of the period (n) to the last year in the period (t). The boundary of the active monitoring area is established by superimposing two areas:

(1) The area projected to contain the free phase CO_2 plume at the end of year t, plus an all around buffer zone 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 t + 5.

At the Chester 21-29N-02W Storage Facility this definition translates to be the Chester 21-29N-02W Reef Structure Area (to the nearest 10-acre square) plus a one-half mile buffer zone outward in all directions. The Reef Structure and AMA are shown in Figure 14. This AMA delineation will be in place for a 10-year period which will cover the expected operational life of the Project.

Riverside plans to inject CO_2 at a rate of 12,000 Mcfd or approximately 230,000 metric tons of CO_2 per year. This rate may vary depending on site specific injection capabilities. The reef's current pressure is estimated at approximately 300 psi. Injection will continue until the reef pressure increases to the maximum bottomhole pressure of 4,345 psi. Once additional injection is constrained by bottomhole pressure limit, injection will stop. Based on the mass balance and injection simulation work described in *Sections 2.4 and 2.5*, the storage reservoir is expected to fill up after approximately 5 years at an average injection rate of 12,000 Mcfd.

Riverside is defining the time period of this AMA as 10 years in order to cover the expected operational life of the Project with some incorporated buffer time for any maintenance, downtime, or unexpected delays. 40 CFR 98.449 defines the AMA as the area projected to contain the free phase CO_2 plume at the end of year t + 5 plus a one-half mile all around buffer. Therefore, the AMA boundary is delineated based on the extent of the CO_2 plume at the end of year 15 plus a one-half mile buffer zone outward in all directions. After 15 years, the free phase CO_2 plume is projected to remain within the Reef Structure. Should the project be operational after 10 years of initial injection, Riverside will submit a revised MRV plan with an updated AMA.

The compartmentalized nature of the Niagaran reef creates conditions whereby an injection plume is limited to the shape and volume of the reef structure itself. The following factors were considered in defining the Reef Structure and AMA boundaries.

- The Reef Structure is encased within massive anhydrite and ultra-low permeability limestone, efficiently sealing the reef's storage intervals and preventing lateral and upward migration of CO_2. The effectiveness of the reef's seal is demonstrated by the trapping of hydrocarbons within the reef over geologic time.
- The boundaries of the reef structure have been defined using 2D seismic data. Where 2D seismic data is not available, reef edges were approximated using all wells surrounding and penetrating the reef, along with analog reef geometry.
- The stored CO_2 and the lateral extent of the CO_2 plume will remain within the reef and will not migrate over geologic time, as is demonstrated by the injection simulation described in *Section 2.5* and the trapping of oil and gas within the reef over geologic

time.

- There are no known leakage pathways that extend laterally from the Reef Structure that would warrant an expansion of the AMA beyond the one-half-mile buffer distance.

3.2 Maximum Monitoring Area

The project's Maximum Monitoring Area (MMA) is equal to the Active Monitoring Area (AMA) and is similarly defined as the Chester 21-29N-02W Reef Structure (to the nearest 10-acre square) plus a one-half mile buffer zone outward in all directions. This MMA is shown in Figure 14.

Pursuant to 40 CFR 98.449 the Maximum Monitoring Area 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 zone of at least one-half mile. For the reasons described in *Section 3.1*, the stabilized plume boundary will remain within the Reef Structure at the Project.

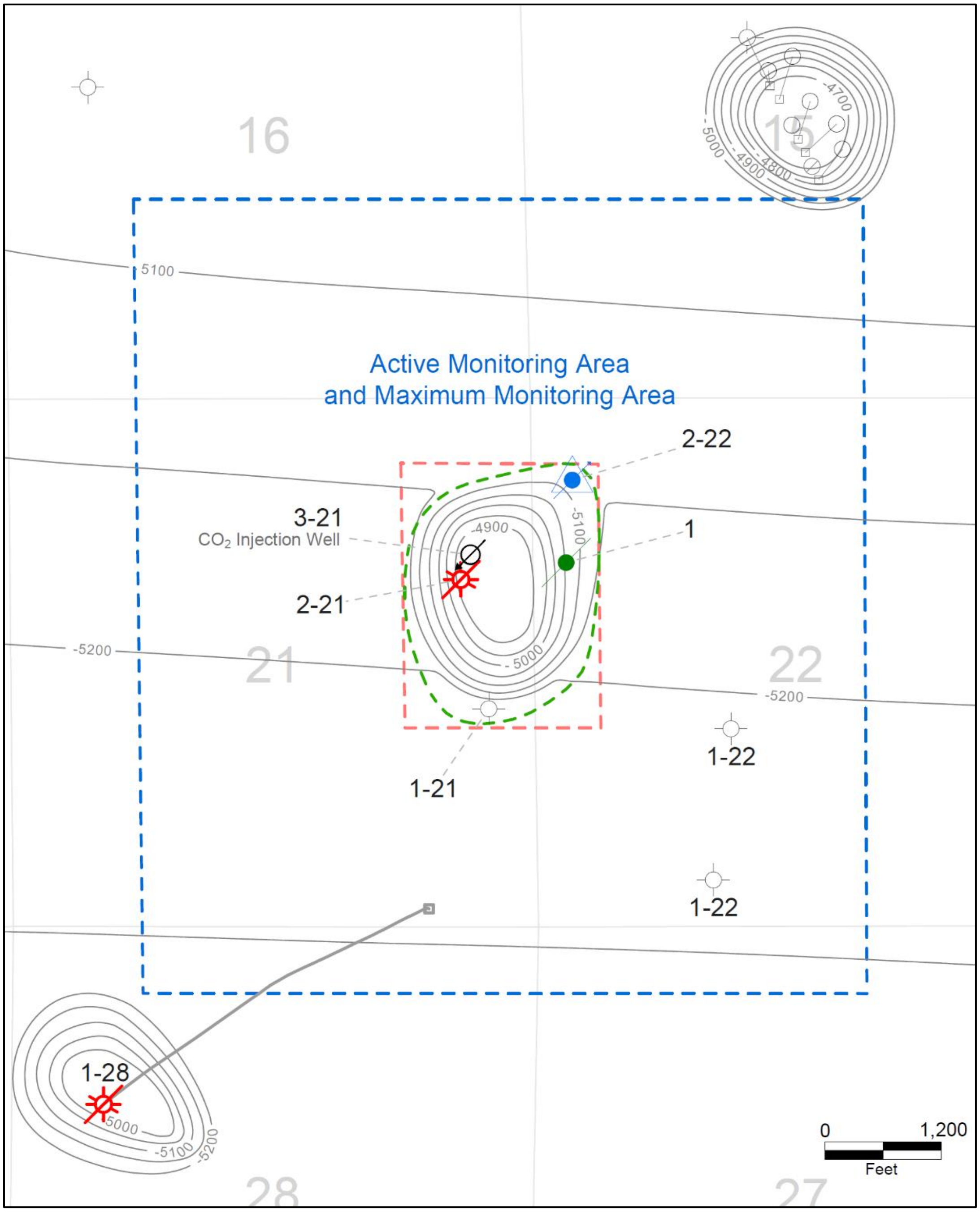

Figure 14. Map depicting the AMA/MMA (total area enclosed by the dashed blue boundary), structure contours of the top of the A1 Carbonate (top of the storage interval), and the Chester 21-29N-02W Reef (central) flanked by the Chester 15 reef to the northeast, and the Chester 28 reef to the southeast. The Chester 21-29N-02W Reef boundary (green dashed line) which is also the stabilized plume boundary, has herein also been regularized to the nearest 10-acre square (dashed red boundary) to help in establishing the boundary positions of the AMA and MMA. Well spots have been filtered to show only wells with total depths below 3,000 ft TVD, and for clarity purposes only wellbores within the AMA/MMA have been labeled. The planned 3-21 UIC Class II injection well is labeled in the northeast quadrant of the Chester 21-29N-02W Reef.

4. POTENTIAL PATHWAYS FOR LEAKAGE

Riverside has identified the following as potential surface leakage pathways at the Project per 40 CFR 98.448(a)[2]:

- Leakage from surface equipment
- Leakage from existing wellbores
- Leakage from wells not yet drilled
- Leakage from the injection wellbore
- Leakage from existing faults and fractures
- Leakage from natural or induced seismicity
- Leakage through confining layers
- Leakage from lateral migration of CO_2

This section discusses the likelihood, magnitude, and timing of potential surface leakage of CO_2 from these pathways. *Section 5* discusses the monitoring plan to detect any surface leakage and strategies for quantifying leakage from these pathways.

4.1 Leakage from Surface Equipment

The injection mass flow meter will be located on the well pad near the wellhead of the injection well. As the CO_2 that is received and metered by this mass flow meter will be wholly injected and not mixed with any other supply of CO_2 and no production from the storage formation will occur, the potential leakage pathways from surface equipment are limited to the mass flow meter, the injection wellhead, the short flowline between the two, and any pipe fittings or valves installed along the flowline or wellhead. The likelihood of leakage from these surface components is low and further mitigated by the following:

- Locating the CO_2 received and injection mass flow meter near the wellhead to minimize opportunities for potential leakage from surface equipment.
- Adhering to high material selection and construction standards when designing and constructing the wellhead and flowline.
- Continuously monitoring the wellhead and mass flow meter with the SCADA system.
- Routinely conducting audible, visual and olfactory (AVO) inspections of the surface equipment for leaks. These checks will occur each time operators visit the well site but not less than once per week. Leaks can be heard as a hissing sound, seen by the distortion of objects on the other side of the leak, or smelled as an odor downwind of the leak.
- Monitoring surface equipment with Optical Gas Imaging (OGI) technology such as an infrared (IR) or thermal imaging camera on a quarterly schedule.

The magnitude of potential leakage from these surface components is small with any leaked volume likely limited to the volume of CO_2 in the flowline or wellhead components. The timing of leakage risk spans from the start of injection and through the active injection period until the well is plugged and abandoned.

4.2 Leakage from Existing Wells

There are four boreholes that penetrate the A2 Evaporite confining layer within the Reef Structure, the area expected to contain the free-phase CO_2-occupied plume. Well data for these boreholes is listed in *Section 2.3*. Three of these boreholes, the Marshall, Glen #1 well, the Underwood, N M & Knapp, C A #1-21 well, and the Leacock Hubbard Underwood & Knapp #2-21 well have been plugged and abandoned according to State of Michigan standards and determined by Riverside to be an unlikely pathway for CO_2 migration above the confining interval. The State of Michigan requires a cement plug be placed within the wellbore to confine oil, gas, and water to the strata from which the oil, gas, and brine were produced. Upon review of the plugging reports for these three wellbores, Riverside has determined that a cement plug has been placed within the A2 Evaporite confining layer, as well as within several overlying intervals. Therefore, leakage through these legacy wellbores is unlikely.

The fourth borehole that penetrates the A2 Evaporite confining layer within the Reef Structure, the State Chester 2-22, is an active brine disposal well permitted in the Dundee formation. It was originally drilled in 1974 to a total depth of 6,660 ft below surface to the top of the Brown Niagaran formation. As this well is located at the far flank of the reef, it tested dry for hydrocarbons. It was then reworked into a brine disposal well by plugging back and completing the well within the Dundee formation at approximately 2,450 ft. The plugging records indicate a cement plug was placed at the base of the well, within the A2 Evaporite confining layer, as well as over additional intervals up hole. The well continues to pass mechanical integrity tests (MITs) in accordance with State of Michigan standards. Riverside has determined that the State Chester 2-22 well is a low risk for CO_2 leakage because it has been properly plugged downhole and recompleted above. It is subject to ongoing monitoring and MITs as an active brine disposal well by a different operator.

The magnitude of potential leakage from existing wellbores is considered to be low. Most of the existing wells are located on the reef flank, limiting their intersection with the projected CO_2 plume. The timing of leakage risk begins when the CO_2 plume intersects with an abandoned well. Riverside considers the likelihood of leakage from existing wells to be low because the four legacy wells that penetrate the Reef Structure have been abandoned to State of Michigan standards with multiple cement plugs.

Outside of the Reef Structure, but within the one-half-mile buffer distance of the AMA and MMA, there are two boreholes (Underwood, Knapp, and Ashland Farms, INC 1; and Underwood, Nellie M & Knapp, Clara Ann 1-22) that penetrate the A2 Evaporite confining layer. The surface location of one additional directionally drilled wellbore, the State Chester 1-28, is located within the AMA and MMA. However, its bottomhole location and penetration of the A2 Evaporite confining layer are located outside of the Project's AMA and MMA. These three wellbores have been plugged and abandoned according to State of Michigan standards. The likelihood of leakage from these

wells is very low as they do not intersect the Reef Structure and the projected free-phase CO_2 plume.

There are 21 wellbores within the AMA and MMA that do not penetrate the A2 Evaporite confining layer (Table 2). The likelihood of CO_2 leakage through any of these wellbores is assessed to be very low because the bottom of each of these boreholes is at least 3,350 vertical feet above the top of the A2 Evaporite confining layer. Furthermore, the geologic formations within this minimum 3,350 feet of vertical separation consists primarily of regionally deposited evaporites and tight carbonates with characteristically low vertical permeability.

4.3 Leakage from Wells Not Yet Drilled

Wellbores drilled in the future through the Reef Structure may be a potential leakage pathway for CO_2. The likelihood of leakage from wells not yet drilled is low and any risk is mitigated by the following:

- Hydrocarbon production from the A1 Carbonate and Brown Niagaran formations in the Chester 21-29N-02W Reef will be no longer possible after injection of CO_2 begins.
- There are no known hydrocarbon producing formations below the Brown Niagaran in the AMA and MMA. The St. Peter Sandstone (approx.10,000 ft) is an occasional gas producer where on anticlinal structure in central and northern Michigan. There are several St. Peter dry holes within a few miles of the Storage Facility, and the Storage Facility is not on an anticline as confirmed by well control and 2D seismic.
- Future wells drilled outside of the Reef Structure but within the AMA and MMA will not interact with the free-phase CO_2 plume.
- All well records and injection data will be shared with Michigan-EGLE to ensure that potential drillers are aware of the Project for the indefinite future.
- Michigan Admin. Code R. 324.413 regulates the drilling of wellbores to strata beneath gas storage reservoirs. The rule describes specific drilling equipment, casing design, and completion standards that must be deployed to ensure drilling occurs safely through natural gas storage reservoirs. While this rule applies to natural gas storage projects (not CO_2 storage projects), Michigan-EGLE already has experience in protecting and regulating the drilling of new wells through gas storage reservoirs.

For these reasons, it is unlikely that any future wells will be drilled through the A2 Evaporite confining layer within the Reef Structure and projected free-phase CO_2 plume. The magnitude of potential leakage from wells not yet drilled is low.

4.4 Leakage from the Injection Wellbore

The Smith 3-21 injection well will be permitted and constructed as a Class II oil field waste disposal well with Michigan-EGLE. As this injection well is an additional penetration that could offer a leakage pathway to the surface, Riverside is taking the following steps to mitigate potential leakage:

- The Smith 3-21 injection well will be constructed more rigorously than Michigan Class II standards. Figure 15 describes the proposed injection well design. Chromium alloy long-string casing will be installed from total depth through the A2 Evaporite and cemented in place with SLB's *EverCRETE* CO_2 resistant cement.
- Prior to injection, a cement bond log and MIT will be run to ensure proper well construction.
- Riverside will perform a MIT at least every 5 years per Michigan-EGLE requirements.
- The annular fluid volume between the casing and injection tubing will be monitored quarterly.
- The surface pressure of the tubing and annular space will be continuously monitored by the SCADA system to detect any abnormalities that indicate a loss of integrity or leak has occurred.
- Riverside will be monitoring surface components and the injection wellhead with OGI technology on a quarterly schedule and performing an AVO inspection weekly.
- After injection, the Smith 3-21 injection well will be plugged and abandoned with cement plugs placed to prevent any future leakage of CO_2.

Leakage from the injection wellbore is unlikely due to the constant monitoring of the wellbore and periodic mechanical integrity testing. The magnitude of leakage from the injection wellbore is small. It is unlikely that a blowdown of the wellbore would be necessary, but if one occurs, the leaked CO_2 would be limited to the volume contained in the wellbore and could be easily quantified using volume, pressure, and temperature data. The timing of leakage risk from the injection wellbore occurs from the beginning of injection until proper plugging and abandonment.

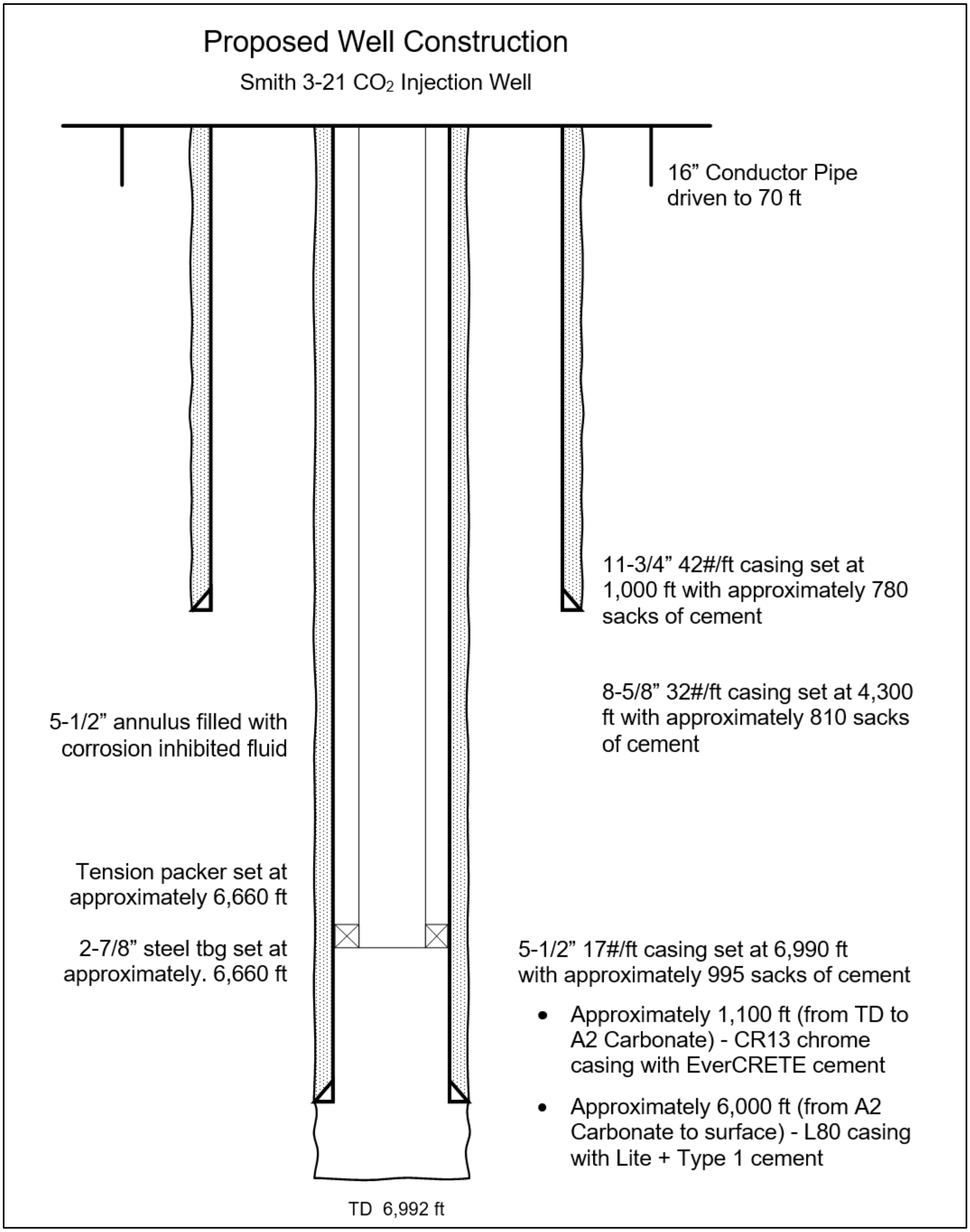

Figure 15. Proposed construction design for Smith 3-21 injection well.

4.5 Leakage from Existing Faults and Fractures

Evaluation of 2D seismic did not reveal any faults or fractures in the Reef Structure, and there are no known faults or fractures through the A2 Evaporite confining layer in the AMA and MMA that would allow CO_2 movement into overlying formations. The risk of leakage of CO_2 from an unknown fault or fracture is very low, because hydrocarbons were sealed within the Reef Structure throughout geological time.

4.6 Leakage from Natural or Induced Seismicity

The likelihood of natural seismicity is very low. The Michigan Basin is structurally stable with few major structural features. No naturally occurring earthquakes greater than magnitude 2.5 have originated within 100 miles of the Storage Facility since 1900. The USGS's 2023 50-State Long-term National Seismic Hazard Model classifies northern Michigan as having the lowest chance of experiencing a slight or greater damaging earthquake in the next 100 years[1].

Natural gas storage in nearby Niagaran reef fields offers an analog to CO_2 injection and experience with reservoir response under pressure. To date, Riverside is unaware of any induced seismicity issues associated with natural gas storage in Niagaran reefs. Many reefs are permitted with a maximum bottomhole pressure greater than 4,600 psi at depths of 6,600 to 6,800 ft[2]. The planned maximum bottomhole pressure for the Storage Facility is 4,345 psi (6,036 ft depth * 0.8 psi/ft fracture gradient * 0.9 safety factor). For these reasons, the likelihood of leakage from induced seismicity is low and the risk would be limited to the active injection period because the reservoir pressure will be highest during the injection period.

4.7 Leakage through Confining Layers

The primary seal of the Project is the A2 Evaporite confining layer. The A2 Evaporite is comprised of anhydrite which has virtually no porosity or permeability. Above the A2 Evaporite confining layer, additional evaporite and low-permeability carbonate sequences are present that further reduce the risk of upward movement of CO_2 through overlying strata.

The likelihood of leakage through confining layers is very low, because the A2 Evaporite confining layer's sealing capacity has been proven by the previous trapping of hydrocarbons throughout geologic time.

4.8 Leakage from Lateral Migration of CO_2

As shown in Figure 4, the Reef Structure is fully compartmentalized due to the unique formation of the pinnacle reef and subsequent deposition of overlying strata. The Reef Structure is encased in a tight carbonate and non-porous evaporate seal that prevents the vertical and lateral migration

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[1] https://www.usgs.gov/programs/earthquake-hazards/science/2023-50-state-long-term-national-seismic-hazard-model
[2] https://www.govinfo.gov/content/pkg/FR-1994-03-28/html/94-7181.htm

of fluids. Underlying the storage formation are tight units of the Brown and Gray Niagaran formation.

Riverside does not believe that the A1 Carbonate and Brown Niagaran storage intervals are in communication with any other Niagaran reservoir or reef. Water infiltration from below the reservoir was not observed during the production history of the Chester 21-29N-02W Reef and the current reservoir pressure is expected to be at the reef's depleted pressure of approximately 300 psi.

The likelihood of leakage from lateral migration of CO_2 is very low as demonstrated by the production history of the Chester 21-29N-02W Reef. The magnitude of any potential leakage is low due to the closed structure of the reef.

5. MONITORING AND LEAK QUANTIFICATION STRATEGY

This section describes the monitoring plan to detect any surface leakage from the pathways identified in *Section 4* and the strategies for quantifying leakage should it occur.

5.1 Detecting and Quantifying Leakage from Surface Equipment

The injection mass flow meter will be located near the wellhead, limiting the amount of equipment subject to monitoring for leakage to the wellhead, the mass flow meter, and the flowline and any valves between the wellhead and mass flow meter. To detect any leakage from this equipment, OGI surveys will occur quarterly using either an IR or thermal imaging camera, and AVO inspections will be conducted by trained personnel at least weekly. In addition, the wellhead and mass flow meter will be continuously monitored by the SCADA system.

Emissions from surface equipment downstream of the mass flow meter such as the flowline, valves, fittings or the wellhead assembly will be estimated and repaired as quickly as possible. If CO_2 must be vented downstream of the meter to make a repair, the amount of CO_2 vented will be estimated using the methods specified in 40 CFR 98 Subpart W. Data that could be considered for estimating the amount of CO_2 leaked may include but not limited to: any anomalies in metered pressures or mass flow, average pressures or mass flow, the time between inspections, physical measurements of pinholes and/or the relative size and intensity of the leakage plume as detected by OGI.

5.2 Detecting and Quantifying Leakage from Existing Wellbores and Future Wells

As discussed in *Section 4*, few existing wells will encounter the CO_2 plume, and all of these wells have been plugged and abandoned to State of Michigan standards. Riverside will be conducting quarterly groundwater monitoring and optical gas imaging on the injection well pad. Pressure transducers installed in the tubing and annulus at the wellhead will be monitored by the SCADA system and bottomhole pressure and temperature surveys will occur periodically through the injection period to identify possible abnormalities in operational parameters that would indicate a subsurface leak. Riverside will conduct bottomhole pressure tests and temperature surveys every

six months for the first two years and annually thereafter. Should a future well be drilled within the AMA and MMA, Riverside will work with Michigan-EGLE to ensure the well will not interfere with CO_2 storage within the Storage Facility.

If a leak is detected at a legacy well or a well not yet drilled, its volumetric flow will be attempted to be metered if possible. If not, the latest injection data and reservoir pressure, volume and temperature data will be used to estimate a leakage volume and rate with a mass balance approach from the storage intervals. The timing of the leak will be determined by an estimate of the CO_2 plume's intersection with the legacy or future well.

5.3 Detecting and Quantifying Leakage from the Injection Wellbore

Riverside will deploy multiple monitoring strategies to detect leakage from the injection wellbore. The long string casing, injection tubing string and packer assembly are subjected to a MIT every 5 years as well as once before injection begins. The annular space between the casing and tubing will be filled with a corrosion inhibiting fluid and checked quarterly for significant changes in volume. The tubing and annular pressure at the wellhead will be monitored continuously with pressure transducers tied to the SCADA system. At a minimum, Riverside will conduct bottomhole pressure tests and temperature surveys every six months for the first two years, and annually thereafter. If the temperature survey detects an anomaly suggesting CO_2 intrusion behind casing, a radioactive tracer/gamma ray tool will be run to investigate. Further, the quarterly OGI and weekly AVO inspections would also encompass the area around the wellbore at the surface.

A workover of the well to replace components may be required and surface and downhole equipment would be thoroughly inspected for signs of wear or corrosion responsible for a potential leak.

If the mechanical integrity of the injection wellbore is lost, the injection will stop and not begin again until a MIT test is passed in compliance with Michigan-EGLE regulations. If a leak is determined to have taken place, it will be quantified using the timing of the loss of integrity and any pressure or annular fluid data from the MIT that can be used to characterize the leak.

Venting of CO_2 from the well may occur while making repairs and would be estimated and documented in accordance with Subpart W procedures. Typically, wells undergoing a workover are "killed" with sufficiently dense fluid to overcome the reservoir pressure and prevent venting of gases from the well to atmosphere.

5.4 Detecting and Quantifying Leakage from Existing Faults and Fractures and Natural or Induced Seismicity

Leakage from existing faults or fractures or fractures created by natural or induced seismicity will be monitored by continuous monitoring of operational parameters at the wellbore, periodic reservoir pressure and temperature surveys, and quarterly ground water monitoring near the injection well pad. At a minimum, Riverside will conduct bottomhole pressure tests and temperature surveys every six months for the first two years, and annually thereafter. Abnormalities in operational and reservoir parameters and such as the injection tubing and

reservoir pressures will be investigated to determine if there is a subsurface leak. If it is determined a subsurface leak has occurred, the latest injection data and reservoir pressure, volume and temperature data will be used with a mass balance approach to estimate a leakage volume and rate from the storage intervals. The timing of the leak will be determined by an estimate of the CO_2 plume's intersection with the leakage pathway.

As discussed in *Section 4*, natural and induced seismicity are considered to be unlikely. Riverside will subscribe to the USGS' Earthquake Hazards Program Earthquake Notification Service (ENS)[3] to receive notifications of any earthquakes with magnitude 2.0 or greater in Michigan. If an earthquake occurs, Riverside will evaluate the monitoring data to determine if the wellbore or Storage Facility are affected. Annulus pressure is continuously monitored and could indicate a loss of wellbore integrity issues caused by seismicity.

5.5 Detecting and Quantifying Leakage through Confining Layers or Lateral Migration

Leakage through the confining layers or from lateral migration will be monitored by periodic groundwater monitoring and reservoir pressure tests. Quarterly groundwater sampling and testing will occur in the water well to be drilled at the injection well pad for drilling operations and will be retained for ground water monitoring. A description of the groundwater testing that will occur is included in *Section 6.4*.

If it is determined a subsurface leak has occurred, the latest injection data and reservoir pressure, volume and temperature data will be used with a mass balance approach to estimate a leakage volume and rate from the storage intervals. The timing of the leak will be determined by an estimate of the CO_2 plume's intersection with the leakage pathway.

6. ESTABLISHING SURFACE LEAKAGE BASELINES

Prior to the start of continuous injection, the following data will have been collected to establish baselines for the Storage Facility against which future data may be compared in order to detect surface leakage.

6.1 Wellbore Integrity

After injection well construction is completed but before injection begins, a MIT and annular pressure test will be completed to confirm wellbore integrity. The initial volume of annular fluid will be noted, and it will be monitored during the start-up of injection to determine how it responds during injection start up. Its stabilized volume will be noted after at least a week of continuous injection. The injection tubing and annulus pressures at the wellhead will be recorded prior to CO_2 injection and continuously monitored thereafter with the SCADA system. MITs will occur at least every 5 years in accordance with Michigan-EGLE requirements.

[3] https://earthquake.usgs.gov/ens/help

6.2 Injection Well Operating Parameters

Riverside has established target injection and storage rates based on experience from other operators injecting and storing fluids in other Niagaran reefs. An initial model, described in *Section 2.5*, has been developed to confirm these baseline injection parameters. Riverside plans to inject CO_2 at a rate of 12,000 Mcfd or approximately 230,000 metric tons of CO_2 per year. This rate may vary depending on injection capabilities of the well.

During injection operations, Riverside will use site-specific data during wellbore construction and the initial injection period to update nominal injection parameters such as wellhead tubing and annulus pressures and injection flow rates.

6.3 Reservoir Conditions

Initial bottomhole pressure will be recorded at mid-perforations and a temperature survey with gradient stops will be completed before injection. A bottomhole pressure test and temperature survey will be conducted at least every six months for the first two years of injection and then annually thereafter. After approximately 48 hours of continuous CO_2 injection, Riverside will run in hole to mid-perforations to establish reservoir pressure and temperature and run a gradient on the way out of the hole while noting casing and tubing pressures at surface.

6.4 Groundwater Monitoring

Groundwater monitoring will occur at a water well drilled on the injection well pad (to approx. 100 ft) and include the following analyses to detect the presence of fugitive CO_2:

- Standard field parameters form a calibrated water quality meter: temperature, pH, conductivity, dissolved oxygen, oxidation reduction potential, and turbidity.
- Standard EPA UIC lab analyses barium, calcium, sodium, magnesium, potassium, total iron, chloride, sulfate, sulfide, carbonate, bicarbonate, TDS, resistivity, specific gravity, and pH.
- Lab analyses for dissolved methane, ethane, propane, and calculated dissolved CO_2 from carbonate, bicarbonate, and dissolved inorganic carbon.

A sample will be collected before injection begins from the ground water monitoring well to establish baseline parameters. During injection, groundwater sampling and testing will occur at least quarterly.

6.5 Surface Equipment Monitoring

After the site equipment is constructed but before injection begins, Riverside will conduct a baseline OGI survey with either an IR or thermal imaging camera. Within the first month of injection, an additional OGI survey will occur to ensure no leakage from surface equipment during the beginning of injection. Thereafter, Riverside will conduct OGI surveys quarterly at the injection well pad to detect for surface leakage of CO_2.

7. SITE-SPECIFIC CONSIDERATIONS FOR THE MASS BALANCE EQUATION

Riverside will utilize the mass balance equations listed in 40 CFR 98.443 to calculate the mass of CO_2 sequestered. The site-specific considerations for these equations are discussed in this section.

7.1 Mass of CO_2 Received and Injected

In accordance with 40 CFR 98.444(a)[4], Riverside will determine the annual mass of CO_2 injected as the total annual mass of CO_2 received instead of using Equation RR-1 or RR-2 to calculate CO_2 received. The CO_2 received at the Storage Facility will be wholly injected and not mixed with any other supply of CO_2. There will be no production from the Storage Facility.

Equation RR-4 in 40 CFR 98.444(c) of Subpart RR will be used to calculate the mass of CO_2 received at the Storage Facility each year.

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

where:

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

$Q_{p,u}$ = Quarterly mass flow rate measurement for flow meter u in quarter p (metric tons per quarter).

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

p = Quarter of the year.

u = Flow meter.

7.2 Mass of CO_2 Produced

There will be no production from the Storage Facility.

7.3 Mass of CO_2 Emitted by Surface Leakage

Riverside will quantify the mass of CO_2 emitted by each identified surface leakage pathway as outlined in *Section 5*. Equation RR-10 will be used to calculate the total mass of CO_2 emitted by surface leakage at the Storage Facility.

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

where:

CO_{2E} = Total annual CO_2 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.

7.4 Mass of CO_2 Emitted from Equipment Leaks and Vented Emissions

As discussed in *Section 5.1*, Riverside will quantify the 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 injection mass flow meter and the wellhead in accordance with the procedures provided under Subpart W of 40 CFR 98. At the Storage Facility, the injection mass flow meter is located near the wellhead, limiting the equipment to the mass flow meter, the injection wellhead, the short flowline between the two, and any pipefittings or valves installed along this flowline or wellhead.

7.5 Mass of CO_2 Sequestered

Since no production will occur at the Storage Facility, Riverside will use equation RR-12 to calculate the total mass of CO_2 sequestered in the Storage Facility for the reporting year.

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

where:

CO_2 = Total annual CO_2 mass sequestered in subsurface geologic formations (metric tons) at the facility in the reporting year.

CO_{2I} = 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_{2E} = 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 mass flow meter used to measure injection quantity and the injection wellhead, for which a calculation procedure is provided in Subpart W of 40 CFR 98.

8. ESTIMATED SCHEDULE FOR IMPLEMENTATION OF MRV PLAN

Riverside will implement this plan as soon as it is approved by EPA. Riverside plans to be ready to begin CO_2 injection and to begin collecting data for calculating the total amount of CO_2 sequestered by March 1, 2025. All baselines will have been established and leakage detection strategies implemented prior to this date. This plan will be in effect until EPA approves Riverside's request for discontinuation of reporting. Riverside plans to submit a request for discontinuation of reporting after all wells in the Storage Facility are plugged and abandoned and has demonstrated that the injected CO_2 stream is not expected to migrate in the future in a manner likely to result in surface leakage, in accordance with 40 CFR 98.441(b).

9. QUALITY ASSURANCE PROGRAM

9.1 Monitoring of CO_2 Received

In accordance with 40 CFR 98.444(a)[4], Equation RR-4 will be used to calculate the total annual mass of CO_2 received because CO_2 received at the Storage Facility is wholly injected and metered by a single injection mass flow meter.

9.2 Monitoring of CO_2 Injected

At the injection well, the volume of CO_2 injected will be measured continuously by an Emerson Micro Motion ELITE Coriolis mass flow meter. Riverside will report quarterly averages of the flow rate and total mass injected. Injection stream samples will be collected at least quarterly to measure the CO_2 concentration immediately upstream or downstream of the injection mass flow meter.

The injection mass flow meter will operate continuously except as necessary for maintenance and calibration. It will be operated using the calibration and accuracy requirements in 40 CFR 98.3(i). Meter accuracy is based on accredited calibration standards according to ISO 17025/IEC 17025.

9.3 Procedures for Estimating Missing Data

In the event Riverside is unable to collect data required for performing the mass balance calculations, procedures for estimating missing data in 40 CFR 98.445 will be implemented as follows:

- Quarterly mass of injected CO_2 will be estimated using representative mass flow rate data from the nearest previous time period. Pressure data at the wellhead will be compared to previous time period's pressure data and mass of injected CO_2 to ensure similar consistency.
- Quarterly CO_2 stream concentration data will be estimated using a representative concentration value from the nearest previous time period.
- CO_2 emissions associated with equipment leaks or venting will be estimated following the missing data procedures contained in 40 CFR 98 Subpart W.

9.4 MRV Plan Revisions

Riverside will revise this plan and submit the latest version to the EPA Administrator within 180 days of making a material change to the monitoring and/or operational parameters, a change in the permit class of the UIC permit, notification of substantive errors in the MRV plan, or for any other reason Riverside should choose to revise this MRV plan in any reporting year.

10. RECORDS RETENTION

Riverside will retain the following records in accordance with 40 CFR 98.3(g).

(1) A list of all units, operations, processes, and activities for which GHG emission were calculated.

(2) The data used to calculate the GHG emissions for each unit, operation, process, and activity, categorized by fuel or material type. These data include but are not limited to the following information in this paragraph (g)(2):

> (i) The GHG emissions calculations and methods used. For data required by 40 CFR 98.5(b) to be entered into verification software specified in 40 CFR 98.5(b), maintain the entered data in the format generated by the verification software according to 40 CFR 98.5(b).
>
> (ii) Analytical results for the development of site-specific emissions factors.
>
> (iii) The results of all required analyses for high heat value, carbon content, and other required fuel or feedstock parameters.
>
> (iv) Any facility operating data or process information used for the GHG emission calculations.

(3) The annual GHG reports.

(4) Missing data computations. For each missing data event, also retain a record of the cause of the event and the corrective actions taken to restore malfunctioning monitoring equipment.

(5) The most recent copy of this GHG Monitoring Plan.

(6) The results of all required certification and quality assurance tests of continuous monitoring systems, fuel flow meters, and other instrumentation used to provide data for the GHGs reported under this part.

(7) Maintenance records for all continuous monitoring systems, flow meters, and other instrumentation used to provide data for the GHGs reported under this part.

In addition, Riverside will retain the following records for at least three years in accordance with 40 CFR 98.447:

- 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 mass 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 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 wellhead.

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Request for Additional Information: Chester 21-29N-02W
December 19, 2024

Instructions: Please enter responses into this table and make corresponding revisions to the MRV Plan as necessary. Any long responses, references, or supplemental information may be attached to the end of the table as an appendix. This table may be uploaded to the Electronic Greenhouse Gas Reporting Tool (e-GGRT) in addition to any MRV Plan resubmissions.

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
1.	N/A	N/A	Please review the Figures and the Figure Descriptions included in the MRV plan to ensure that all text is legible, scale bars and legends are scaled appropriately, etc. For example, Figures 1, 4, 6, 7, 8, 9, 10, and 13 are low resolution and difficult to read, and there are various text formatting inconsistencies in most of the figure descriptions. Furthermore, the headings of sections 4.7 and 5 contained a misspelling, so we recommend doing an additional review for spelling, grammar, etc.	All figures have been reviewed for clarity and formatting purposes and updated where applicable. Additionally, a full document review of spelling and grammar was completed, and minor spelling and grammar changes were made throughout.
2.	N/A	N/A	Please ensure that all acronyms are defined during the first use within the MRV plan. For example, "TVD, MSCFD, USGS" are not defined within the text.	The draft text has been updated to clarify all abbreviations and acronyms used, foremost with the inclusion of an abbreviation and acronym explanation table at the beginning.
3.	1.4	5	"As of October 2024, the UIC Class II permit application is under review by Michigan-EGLE GRMD. The proposed Smith 3-21 UIC Class II injection well identification number will be shared with EPA when available." Please clarify whether there is an existing well identification number that can be included in the MRV plan consistent with 40 CFR 98.448(a)(6).	As of December 27, 2024 a well identification number has not yet been issued. To clarify this point, the draft text has been modified as follows: "As of December 27, 2024, the UIC Class II permit application for the proposed Smith 3-21 injection well is under review by Michigan-EGLE GRMD. Additionally, a well identification number has not yet been issued but will be shared with EPA when available."
4.	2.4	14	We recommend including details on the estimated composition of the CO_2 injectant stream and whether you expect it to change over time.	The draft text has been updated to include details on the composition of the CO2 injectant stream, as well as our expectation of the potential for compositional changes over time.

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
5.	3.2	20-21	"The project's Maximum Monitoring Area (MMA) is equal to the Active Monitoring Area (AMA) and is similarly defined as the Chester 21-29N-02W Reef Structure (to the nearest 10-acre square) plus a one-half mile buffer zone outward in all directions. This MMA is shown in Figure 13." In Figure 13, the stabilized plume boundary is represented as a dashed red rectangle. Please clarify if this rectangular boundary represents the reef structure and/or plume boundary. If there is a more granular depiction of the reef structure available, please include it in Figure 13.	Figure 13 has been updated to more clearly depict the Reef Structure boundary (green dashed line), and the figure caption has been updated for better description.
6.	3.1	20	"40 CFR §98.449 defines the AMA as the area projected to contain the free phase CO2 plume at the end of year t + 5 plus a one-half mile all around buffer." The full definition of AMA is: *Active monitoring area* is the area that will be monitored over a specific time interval from the first year of the period (n) to the last year in the period (t). The boundary of the active monitoring area is established by superimposing two areas: (1) The area projected to contain the free phase CO_2 plume at the end of year t, plus an all around buffer zone 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 t + 5. Please revise the above statement to reflect the full definition of AMA and revise any AMA discussion as necessary to reflect this definition.	The full definition of the AMA (40 CFR §98.449) has now been included in the draft text in section 3.1.

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
7.	4.1	22	"The likelihood of leakage from these surface components is low and further mitigated by the following… Routinely conducting visual inspections of the surface equipment." Please include details on the referenced visual inspections.	The draft text has been updated to include details on the referenced visual inspections.
8.	4.2	23	"There are four boreholes that penetrate the A2 Evaporite confining layer within the Reef Structure…" Please provide more information about any wellbores within the MMA that do not penetrate the confining layer. Please include an evaluation of the potential leakage through these wells.	The draft text has been updated to include the assessed risk level of potential leakage through wellbores that do not penetrate the A2 Evaporite confining layer.
9.	7	31-32	"There will be no production from the Storage Facility." "Since no production will occur at the Storage Facility, Riverside will use equation RR-12." In this section and/or others, please provide additional explanation of why the facility is making the determination that there is no production associated with this facility and why it is proposing to use RR-12 instead of RR-11. For example, please explain the relationship between the capture and injection facilities (are they one facility or separate per the definition at 40 CFR 98.6 "Facility") and explain whether the injected CO2 plume could be projected to reach or interact with the production wells.	The draft text has been updated for clarity in distinguishing the Capture Facility as existing and operating separate from the Storage Facility, and to emphasize that the Chester 21-29N-02W Reef Structure currently has no production associated with it, nor is there any design or intent from this project to use the field in the future for enhanced recovery processes.

No.				
10.	7.1	31	"$Q_{r,u}$ = Quarterly mass flow rate measurement for flow meter u in quarter p (metric tons per quarter)." In Equation RR-4, this variable is $Q_{p,u}$ = Quarterly mass flow rate measurement for flow meter u in quarter p (metric tons per quarter). Equations and variables cannot be modified from the regulations. Please revise this section and ensure that all equations listed are consistent with the text in 40 CFR 98.443	Equation RR-4 as described in the draft text has now been modified to accurately reflect the equation and variables from the regulations (i.e. $Q_{r,u}$ has been changed to $Q_{p,u}$).
11.	8	32	"Riverside will implement this plan as soon as it is approved by EPA." 40 CFR 98.448(a)(7) requires a "Proposed date to begin collecting data for calculating total amount sequestered according to equation RR–11 or RR–12 of this subpart. This date must be after expected baselines as required by paragraph (a)(4) of this section are established and the leakage detection and quantification strategy as required by paragraph (a)(3) of this section is implemented in the initial AMA." Please clarify whether such a date is specified in the MRV plan.	The draft text has been updated to include this date and to clarify this date's defining conditions.

Riverside Energy Michigan, LLC Chester 21-29N-02W Storage Facility Subpart RR Monitoring, Reporting, and Verification Plan

November 19, 2024

TABLE OF CONTENTS

1. STORAGE FACILITY INFORMATION

1.1 Project Overview

The Chester 21-29N-02W Storage Facility is a CO_2 acid gas disposal injection project being developed by Riverside Energy Michigan, LLC (Riverside) in Otsego County, Michigan. The purpose of the project is to securely store the CO_2 emissions captured from the processing of natural gas produced from the Antrim Shale gas play in the northern Michigan Basin. The captured CO_2 will be injected into a Niagaran Pinnacle Reef reservoir at the Chester 21-29N-02W Field.

The Chester 21-29N-02W Reef was once a gas producing field but has since been depleted, plugged, and abandoned. The Niagaran reservoir at a depth of approximately 6,100 ft enables CO_2 to be stored efficiently in a critical gas phase. This Monitoring, Reporting, and Verification (MRV) plan is designed in accordance with 40 CFR §98.440-449, Subpart RR, to define and describe the Chester 21-29N-02W Storage Facility.

The Chester 21-29N-02W Storage Facility spatially consists of the surface and subsurface areas contained within the active and maximum monitoring areas, defined in *Section 3*. In process terms, the Chester 21-29N-02W Storage Facility begins at the mass flow meter positioned on the CO_2 flowline immediately upstream of the injection wellhead and ends in the subsurface at the reservoir's lithofacies-controlled aerial limits. Figure 1 shows the location of the Chester 21-29N-02W Storage Facility, the capture facility, and the CO_2 flowline between the two.

The Chester 21-29N-02W Storage Facility is hereafter referred to in this document as the "Chester 21-29N-02W Storage Facility" and as the "Storage Facility".

1.2 Reporter number

Greenhouse Gas Reporting Program ID: 589821

Operator: Riverside Energy Michigan, LLC on behalf of Riverside Carbon Solutions, LLC.

1.3 Storage Facility Location

The Storage Facility is located in Otsego County, Michigan, approximately 9-miles southeast of the town of Gaylord, Michigan.

Storage Facility location description in the Public Land Survey System:

Sections 21 and 22, T29N-R02W

Storage Facility coordinates in North American Datum of 1983 (NAD83):

Latitude: 44.896048°
Longitude: -84.547381°

1.4 Underground Injection Control Permit Class: Class II

The Michigan Department of Environment, Great Lakes, and Energy (Michigan-EGLE) Geologic Resources Management Division (GRMD) administers the Underground Injection Control (UIC) program in Michigan for all Class II injection wells, by the statutes and rules subject to Part 615, Supervisor of Wells, of the Michigan Natural Resources and Environmental Protection Act (NREPA), Public Act 451 of 1994, as amended. The CO_2 injection well (Smith 3-21) will be operated by Riverside Energy Michigan, LLC, it will be permitted as a UIC Class II well and will be regulated by Michigan-EGLE GRMD.

As of October 2024, the UIC Class II permit application is under review by Michigan-EGLE GRMD. The proposed Smith 3-21 UIC Class II injection well identification number will be shared with EPA when available.

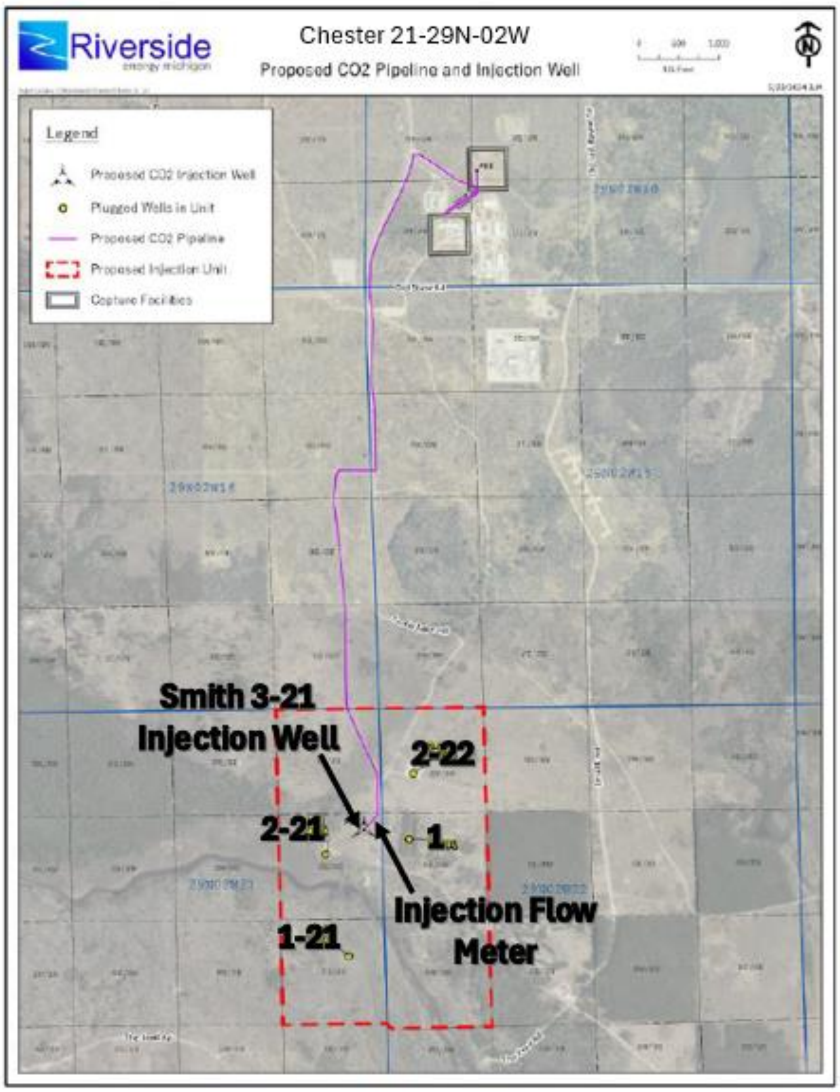

Figure 1. Map of the Chester 21-29N-02W Storage Facility with CO_2 pipeline from capture facilities. The red outline describes the injection unit permitted with Michigan-EGLE. Figure 13 in Section 3 describes the active and maximum monitoring areas for the Storage Facility.

2. PROJECT DESCRIPTION

2.1 Regional Geology

The Northern Niagaran Pinnacle Reef Trend (NNPRT) in the Michigan Basin features several hundred highly compartmentalized pinnacle reefs found at an average dept of about 6,000 feet below the ground surface. These reefs are separated from one another by distances as little as hundreds of feet to as much as several miles. The NNPRT originated from coral reefs formed during the Silurian Period 420 to 440 million years ago in tropical sea environments (Figure 2).

The reefs were subsequently buried by sediments deposited around and above the reefs encasing them within mostly impermeable layers of evaporitic and carbonate rocks. These impermeable evaporitic and carbonate rocks are responsible for trapping and sealing prolific quantities of oil and gas within these reefs.

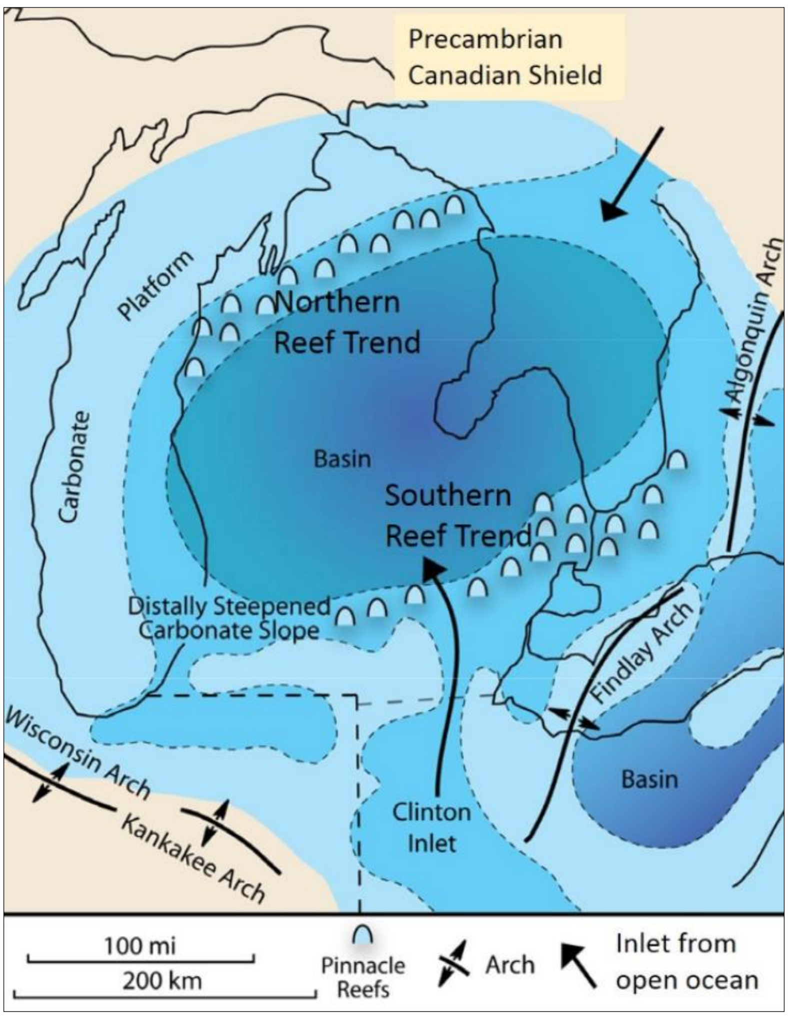

Figure 2. Map of the Michigan Basin and interpreted paleogeography during the Silurian Period, depicting the Northern Niagaran Reef Trend amongst regional environments. Ritter (2008) modified after Briggs and Briggs (1974).

The NNPRT forms a part of a broader shallow shelf carbonate depositional system that partially encircles the Michigan Basin. The NNPRT is positioned along the margin of the system's carbonate platform. Individual reefs typically range in area from 50 to 500 acres, and in the subsurface have vertical heights between 100 to 700 feet.

The reservoir facies primarily consist of porous and permeable dolomite and limestone. Some reefs are completely dolomitized, while others are essentially all limestones. Dolomitization of the reefs, which helps enhance porosity, increases as the reefs become shallower. Salt and anhydrite plugging of porosity occurs in the deeper reefs (Gill 1979). Reef porosity values can be as high as 35%, but typically average 3 to 12%. Net pay intervals can total from only a few feet to several hundred feet. The most productive reef reservoirs are characterized by dolomitized reef facies with well-developed inter-crystalline and vuggy porosity. Secondary porosity is present and can enhance permeability, which typically averages 3 to 10 millidarcies.

The Niagara and A1 Carbonate Formations of the early Silurian Niagara Group contain the main reservoir units within the reefs, shown in the stratigraphic column in Figure 3. The base of the Niagara Formation, referred to as the "Lockport" or "White Niagaran" is typically a partially dolomitized to dolomitized crinoidal wackestone, (Charbonneau, 1990). Overlying the Lockport, the Guelph Formation is comprised of units commonly referred to as the "Gray" and "Brown" Niagaran. The Gray Niagaran and Lockport are typically characterized by very low porosity. The Brown Niagaran comprises the core of the reef reservoir and pinnacle reef buildup. It is characterized by dolomite and limestone skeletal wackestones and boundstones, (Huh, 1973).

The A1 Carbonate overlies the Brown Niagaran at the reef crest and is sometimes referred to as the "Ruff" Formation. The A1 Carbonate is considered a reservoir unit the crest of some reefs but grades into tight, low porosity dolomitic mudstone near the reef flanks, (Huh, 1973).

The A1 Carbonate and Brown Niagaran Formations are encased by a sequence of evaporites and salt-plugged carbonates, comprising the seal for the reefs. The A1 Evaporite is typically thin or not present at the crest of the reef but forms a seal of the Brown Niagaran at reef flanks. Overlying the A1 Carbonate and providing the primary seal for the Storage Facility is the A2-Evaporite, Figure 3. The A2 Evaporite is characterized by non-porous and impermeable anhydrite at the reef crest. It transitions to halite dominated facies off the structure of the reef. Further overlying the A2 Evaporite are hundreds of feet of non-porous evaporite and low porosity carbonate and shale sequences that comprise the Salina Group.

The lithostratigraphy and internal reef structure are visualized in Figure 4. Reef formation began surrounding a carbonate bioherm in warm, shallow waters, (Rine, 2017). The reef core grew upwards as sea level in the Michigan Basin rose. When sea level fell, the reefs became exposed and evaporite deposition encased the reefs.

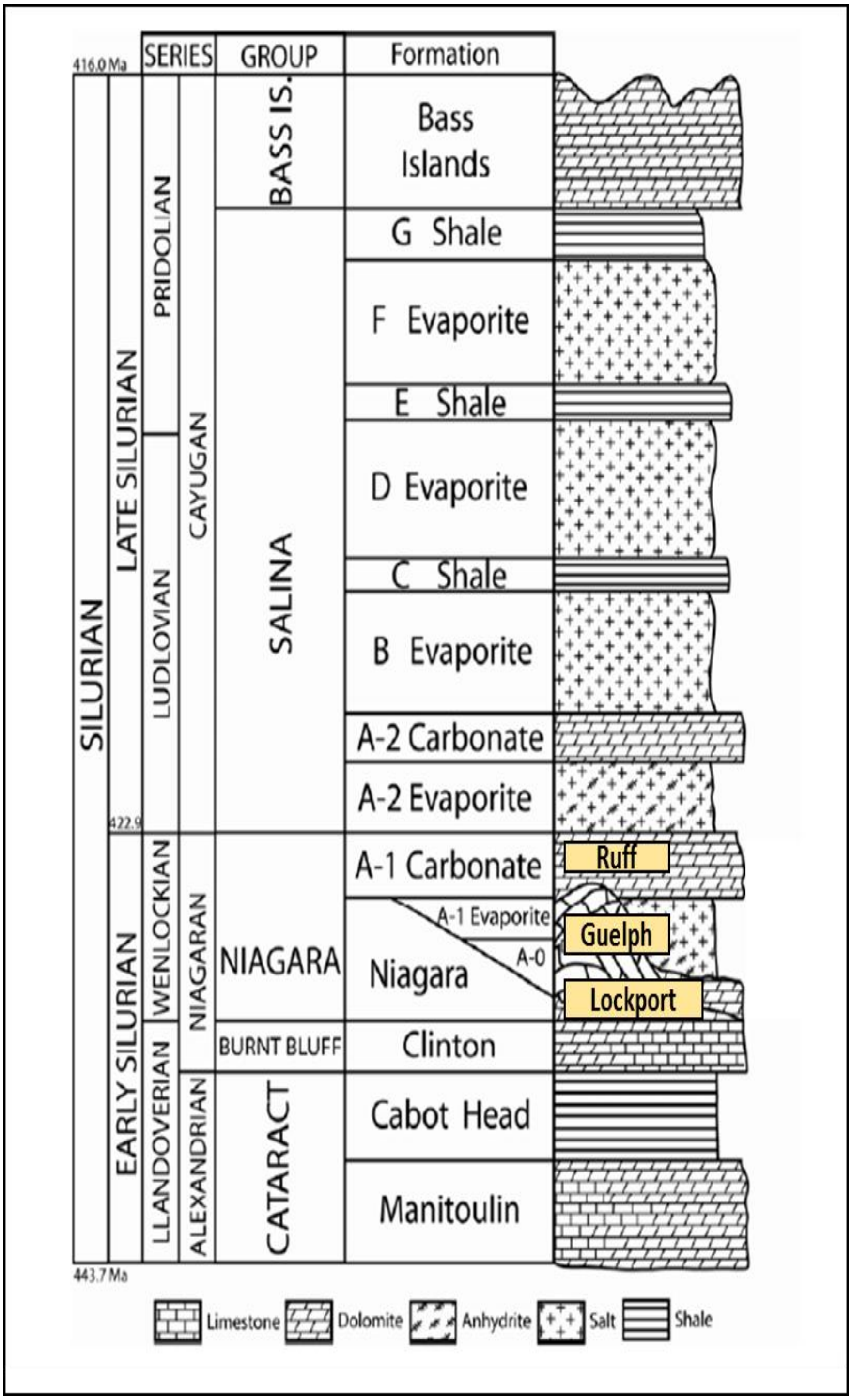

Figure 3. Generalized stratigraphic column for the Niagaran reefs in the Michigan Basin, (Ritter, 2008).

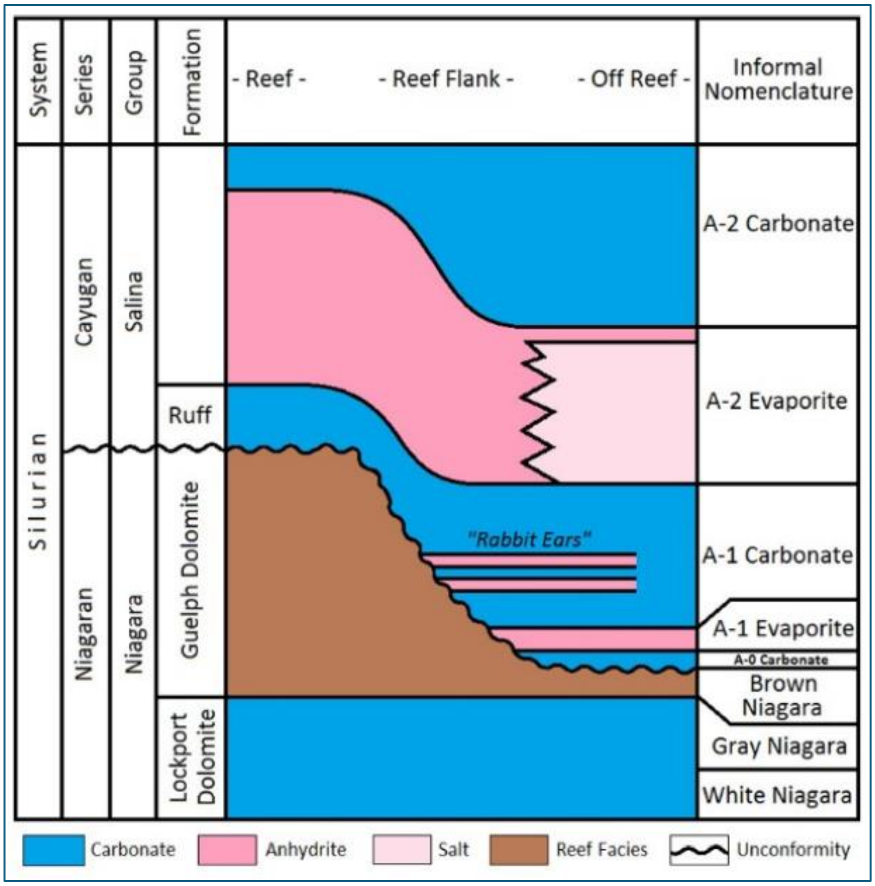

Figure 4. Lithostratigraphy visualization of a Niagaran reef interval, (Gupta et al., 2020 modified from Gill 1979 and Huh 1973).

2.2 Site Characterization

The Chester 21-29N-02W Field is a Northern Niagaran Pinnacle Reef located in Sections 21 and 22 of Township 29 north, Range 2 west, Otsego County, Michigan. The Field has a footprint of approximately 90-acres and is buried to depth of 6,710' TVD (-5,472 subsea TVD) at its base, to 6,160' (-4,921 subsea TVD) at its top.

While the reef structure itself is 550' tall and consists of the Brown Niagaran Formation, an additional 60' of A1 Carbonate Formation rests directly on top of the Brown Niagaran Formation and serves as a vertical extension of the physical reservoir observed in the Niagaran interval. Porosity of the A1 Carbonate and Brown Niagaran reservoir intervals derived from wireline logs ranges from 1 to 16% and averages 5.4%. Unless otherwise specified, all subsequent mentions in this document of the Reef Structure or Field will mean to refer to the total interval that includes both the Brown Niagaran Formation and the A1 Carbonate Formation.

The A2 Evaporite Formation rests directly on top of the A1 Carbonate Formation and serves as the primary seal for the Storage Facility. Above the 120' thick A2 Evaporite Formation is a 1,300' thick series of massive evaporite deposits, and interbedded shale and limestone deposits that make up the bulk of the Salina Group.

The following geologic data was compiled for the Chester 21-29N-02W Reef and surrounding area:

- Well data from historic wellbores including wireline logs, drillers reports, and state curated well files.
- 2D seismic data, composed of 5 lines that each traverse the Reef Structure and adjacent surrounding area.
- Oil and gas production histories as reported to the State of Michigan.

Porosity of the A1 Carbonate and Brown Niagaran reservoir intervals derived from wireline logs ranges from 1 to 16% and averages 5.4%. Figure 4 shows the shot point locations of 2D seismic lines used to interpret the Reef Structure at the Storage Facility. Figure 5 is a stratigraphic cross section of well logs through the Storage Facility and Figure 6 is the cross-section reference map.

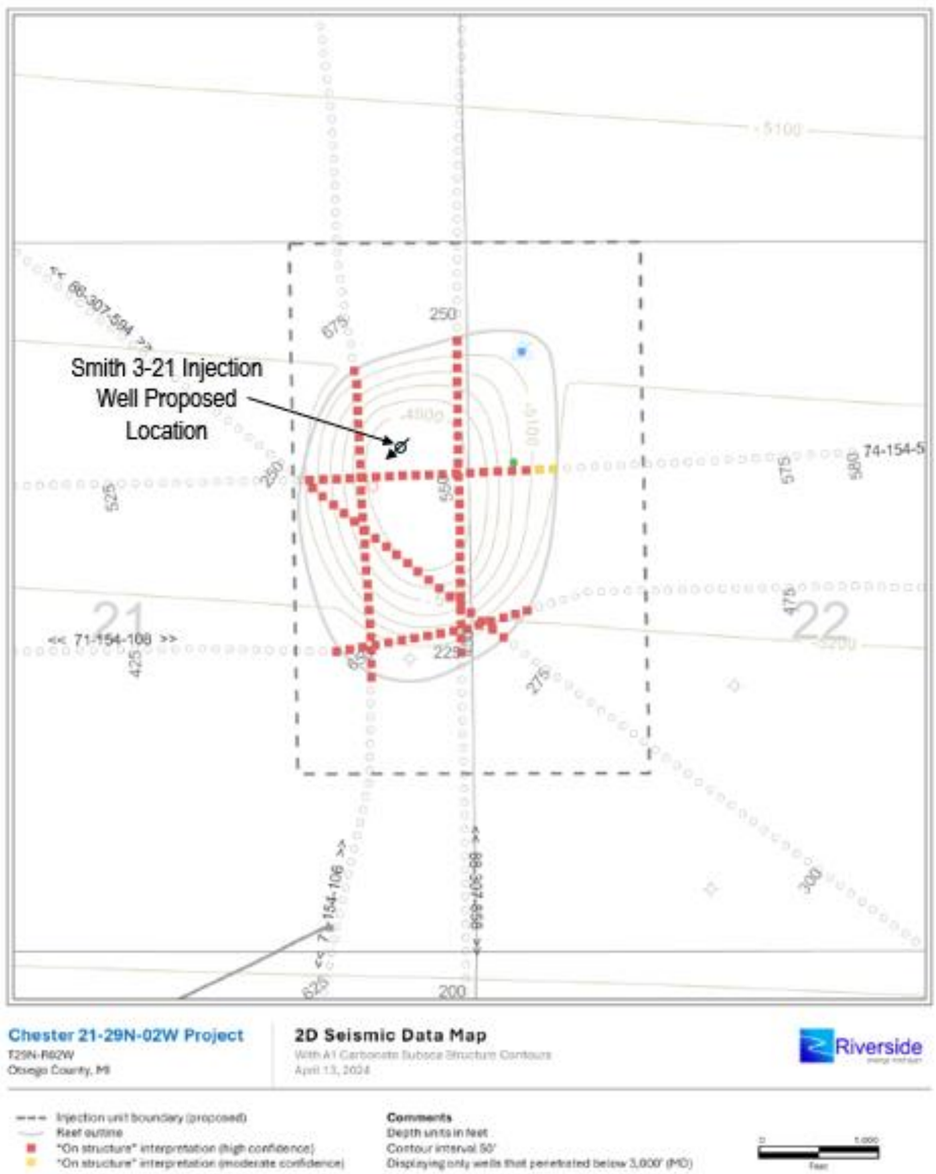

Figure 4. 2D seismic shot point locations used to determine Chester 21-29N-02W reef structure.

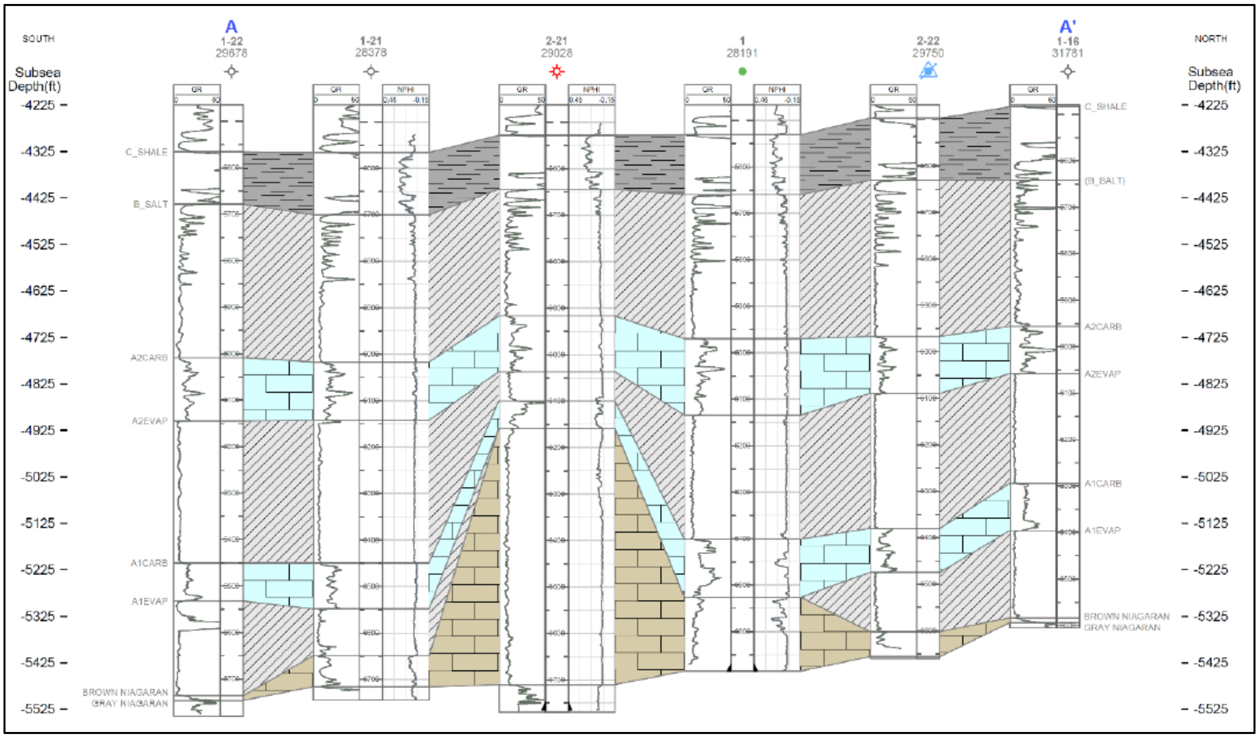

Figure 5. Stratigraphic cross-section of reef intervals at the Chester 21-29N-02W Storage Facility.

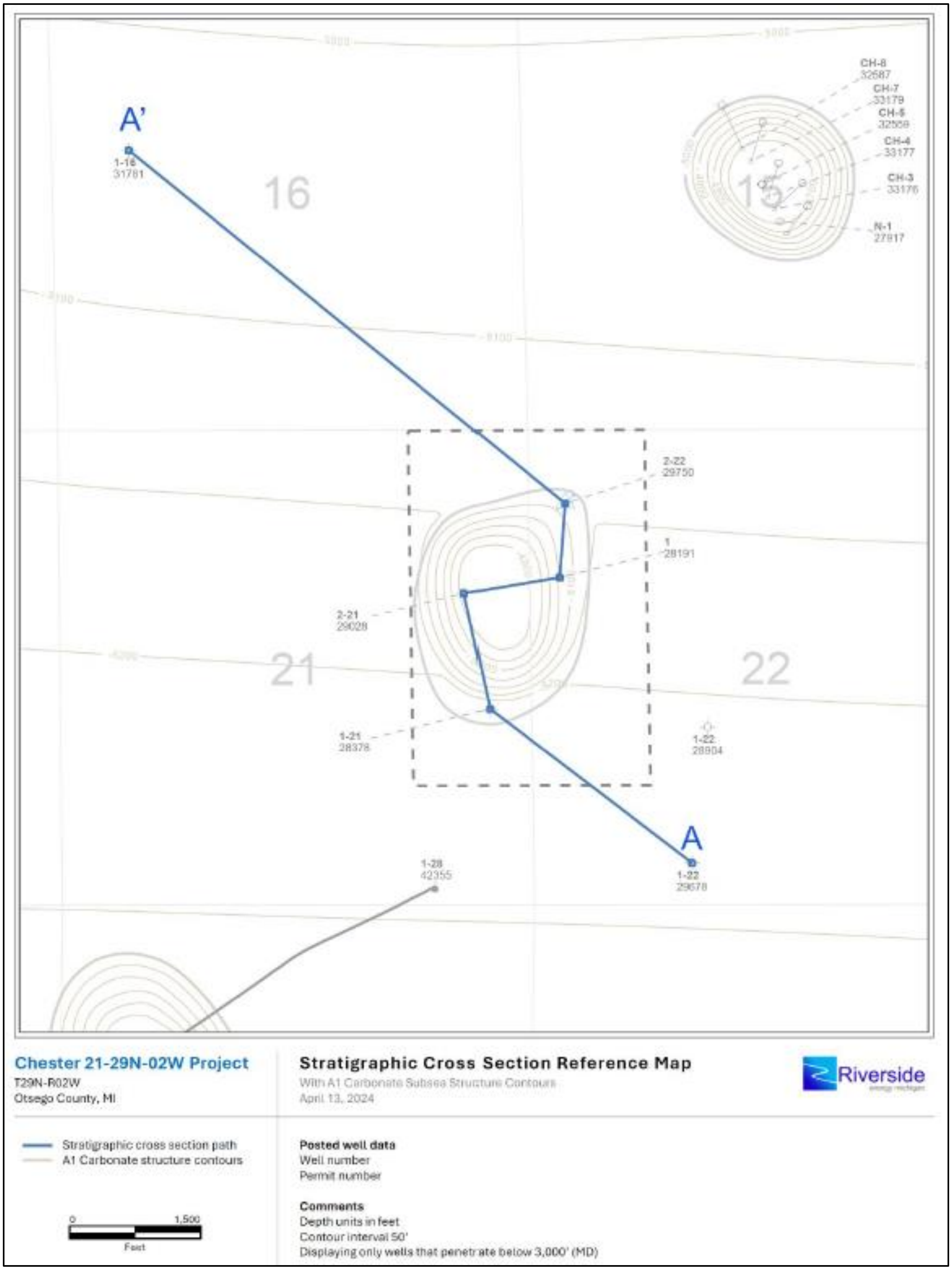

Figure 6. Reference map for the stratigraphic cross-section in Figure 5.

2.3 Operational History of the Chester 21-29N-02W Reef and Existing Wells

The Chester 21-29N-02W reef was discovered in 1970 by Great Lakes Exploration who developed their single discovery well for oil production. The drilling of three additional wells was attempted between 1971 and 1974, resulting in one gas producing well, and two dry holes. One of these dry holes, the State Chester 2-22, has been converted into a water disposal well into the shallower Dundee Formation. This well was recompleted with a cement plug within the Niagaran below. These four wells are the only wells ever drilled into the Chester 21-29N-02W Field. They are summarized in Table 1.

Table 1. List of wellbore penetrations within the Reef Structure.

Well Name	Marshall, Glen	Underwood, N M & Knapp C A	Leacock Hubbard Underwood	State Chester
Well No.	1	1-21	2-21	2-22
API	21137281910000	21137283780000	21137290280000	21137297500000
MI Permit No.	28191	28378	29028	29750
Well Status	P&A	P&A	P&A	Active PBTD SWD
Well Designation	Oil	Dry Hole	Gas	Initially a Dry Hole, now PBTD SWD
First Operator	Great Lakes Exploration	Miller Brothers	Miller Brothers	Reef Petroleum Corporation
Last Operator	ANR Pipeline	Miller Brothers	Saba Energy of Texas	VCP Michigan
Formation at TD	Gray Niagaran	Gray Niagaran	Gray Niagaran	Gray Niagaran
TD (MD, TVD per KB)	6,685	6,744	6,770	6,660
Datum Elevation (KB)	1,242	1,239	1,238	1,244
SHL Latitude	44.89582	44.89186	44.89537	44.89806
SHL Longitude	-84.54549	-84.54850	-84.54952	-84.54523
BHL Latitude	44.89582	44.89186	44.89537	44.89806
BHL Longitude	-84.54549	-84.54850	-84.54952	-84.54523
Note				PBTD 4,215' MD
Producing Formation	Brown Niagaran	-	Brown Niagaran	-
IP oil (BBL/day)	480	-	NA	-
IP gas (MCF/day)	NA	-	20,000	-
Cumulative oil (BBL)	25,483	-	162,238	-
Cumulative gas (MCF)	520,175	-	9,951,270	-
Cumulative water (BBL)	Unknown	-	Unknown	-
Permit date	9/24/1970	3/23/1971	9/14/1972	5/13/1974
Well spud date	11/20/1970	4/22/1971	12/9/1972	5/23/1974
Completion date	1/25/1971	5/26/1971	2/26/1973	6/19/1974
Abandonment date	11/21/1990	5/29/1971	6/8/2002	

Table 2 summarizes the additional wells that exist within the active and maximum monitoring areas of the Storage Facility but do not penetrate the Reef Structure. The majority of these wells targeted the Antrim Shale Formation for natural gas production and typically only penetrate in depth to approximately -250 feet to -950 feet (subsea), whereas the Primary Seal and Storage

Reservoir each exceed -4,500 feet (subsea) throughout the active and maximum monitoring areas. See *Section 3* for the definition and map of the active and maximum monitoring areas.

Table 2. List of wellbore penetrations within active and maximum monitoring areas.

Evaluation Group	API	Well Name	Well No.	TD (subsea feet)	Well Type	Well Status
This Project's Pending CO2 injection well	TBD	Smith	3-21	-5,250	CO2 Injection	Permit pending
Penetrations into the Reef Structure	21-137-29028-0000	Leacock Hubbard Underwood Knapp	2'21	-5,532	Gas	P&A
	21-137-28378-0000	Underwood, N M & Knapp	1-21	-5,505	Dry Hole	P&A
	21-137-28191-0000	Marshall, Glen	1	-5,443	Oil	P&A
	21-137-29750-0000	State Chester	2-22	-5,416	SWD	Active
Penetrations depth equivalent to, but not into, the Reef Structure	21-137-28904-0000	Underwood & Knapp & Ashland Farms	1-22	-5,541	Dry Hole	P&A
	21-137-29678-0000	Underwood, Nellie M, & Knapp	1-22	-5,540	Dry Hole	P&A
	21-137-42355-0000	State Chester	1-28	-5,371	Gas	P&A
Penetrations at least 3,350' above Primary Seal	21-137-46107-0000	Campbell et al.	1-22	-1,454	SWD	Active
	21-137-55872-0000	State Chester	A3-28	-938	Gas	Producing
	21-137-55871-0000	State Chester	A1-27	-937	Gas	Producing
	21-137-50566-0000	State Chester	24-21	-840	Gas	P&A
	21-137-50567-0000	State Chester	23-21	-772	Gas	Producing
	21-137-55327-0000	Jaeger	D4-21	-718	Gas	Producing
	21-137-55326-0000	Jaeger	C4-21	-704	Gas	Producing
	21-137-55399-0000	Wright	B3-21	-692	Gas	Producing
	21-137-44259-0000	State Chester Venture	51	-633	Gas	Producing
	21-137-45622-0000	Campbell et al.	14-22	-604	Gas	Producing
	21-137-45588-0000	Campbell et al.	13-22	-600	Gas	Producing
	21-137-45536-0000	Campbell et al.	23-22	-593	Gas	Producing
	21-137-45537-0000	Marshall	12-22	-592	Gas	Producing
	21-137-45589-0000	Campbell et al.	24-22	-585	Gas	Producing
	21-137-44261-0000	State Chester Venture	52	-544	Gas	Producing
	21-137-40014-0000	State Chester Venture	31	-400	Gas	Producing
	21-137-39042-0000	State Chester Venture	22	-370	Gas	Producing
	21-137-41430-0000	State Chester	47	-348	Gas	Producing
	21-137-42229-0000	State Chester Venture	54	-329	Gas	Producing
	21-137-41432-0000	State Chester	45	-312	Gas	Producing
	21-137-27029-0000	State Chester	13	-260	Gas	Producing

In total the Chester 21-29N-02W Field has produced 10,583,601 Mcf of natural gas, 203,105 barrels of oil and an unknown volume of water. The production totals are summarized in Table 3. The Leacock Hubbard Underwood & Knapp #2-21 tested at an initial reservoir pressure of 3,227 psi at approximately 6,300 ft (.51 psi per ft gradient) with a temperature of 114°F. It is believed the reservoir was depleted to a current pressure of approximately 300 psi or less. The Leacock Hubbard Underwood & Knapp #2-21 well was plugged and abandoned in 2002.

Table 3. Summary of production from Chester 21-29N-02W Field.

Chester 21-29N-02W

Well Name	Date of First Production	Total Production BO	Mcf	GOR
Marshall, Glen #1	1/19/1971	41,062	529,169	12,887
Leacock Hubbard Underwood & Knapp #2-21	2/6/1973	162,043	10,054,432	62,048
Total		203,105	10,583,601	52,109

2.4 Mass Balance Estimate of Storage Resources

A mass balance approach using natural gas production data was used to estimate approximately 1 million metric tons of CO_2 storage resources at the Storage Facility. This mass balance approach does not consider produced water or oil that may provide additional accessible pore volume for storage. This mass balance approach does not consider a storage efficiency factor.

Determining the accessible reservoir pore volume:

10.5 Bcf produced natural gas
Formation volume gas factor Bg = 0.0042 cf/scf at 114°F and 3,168 psi
1/Bg = 238 scf/cf
Reservoir pore volume = 10,500,000,000 scf / 238 scf/cf = 44,100,000 cf.

Determining the storage resources of the accessible reservoir pore volume for CO_2:

Confining interval top depth = 6,035 ft
Fracture pressure (estimate) = 0.80 psi/ft
Current reservoir pressure (estimated) = 300 psi
Injection pressure limit = 6,035 ft * 0.80 psi/ft * .90 safety factor = 4,345 psi.
CO_2 density @ 4,345 psi = 55 lbs/cf
Storage resource given 44,100,000 cf of accessible pore space = 1,080,000 metric tons of CO_2.

2.5 Reservoir Modelling and Injection Simulation

A simple geologic model was developed to complete computational injection simulations and evaluate the dynamic storage capacity of the Storage Facility. The model was generated from 2D seismic (structure) and well log information (top depths and porosity) in IHS' *Petra*® software. Computer Modeling Group's *GEM*™ reservoir simulation software was used to complete injection simulation.

Figure 7 shows the 3D view of the initial simulation model with the Chester 21-29N-02W Reef at the center. The model covers a 3,430 ft by 3,640 ft (0.65 mi by 0.69 mi) area and contains the approximate 90 acre (0.14 sq mi) Chester 21-29N-02W Reef Structure within it. Porosity of the A1 Carbonate and Brown Niagaran reservoir intervals ranges from 2% to 9%. Permeability of the reservoir intervals ranges from 1 to 5 millidarcies and was derived from basin wide Niagaran reef porosity-permeability cross plots in (Gupta et al., 2020).

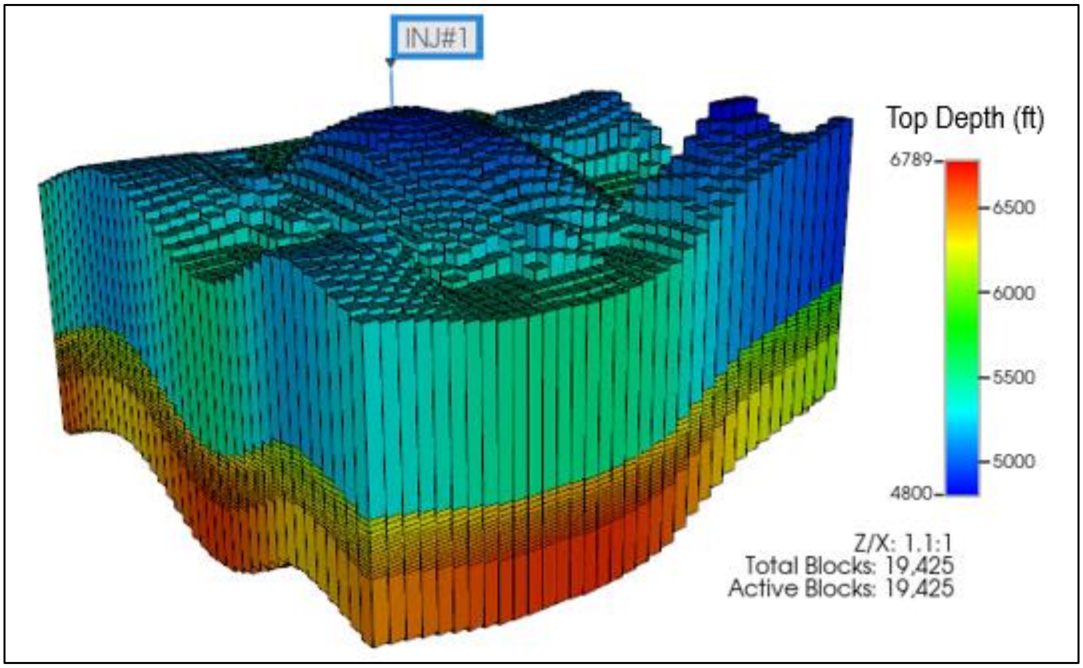

Figure 7. CO_2 plume development in Reef Structure over 5 years of injection (Mole fraction of CO_2 in reservoir blocks).

The reef reservoir is modeled as a closed system with all model boundaries closed. The reef reservoir was initialized with depleted gas, oil and water saturations at 300 psi. Injection rate was set at 12,000 Mcfd based on basin experience from CO_2 injection in other Niagaran reef projects. The maximum bottom hole pressure was limited to 4,345 psi (6,036 ft depth * 0.8 psi/ft fracture gradient * 0.9 safety factor).

The simulation was run for 15 years. After approximately 4 years the maximum bottomhole pressure limit was reached, limiting further injection. Nearly no CO_2 was injected after 5 years. The simulation injected 16.7 Bcf of CO_2 or approximately 880,000 metric tons of CO_2 after 5 years. Figure 8 shows the development of the CO_2 plume within the Reef Structure over time. The CO_2 is limited to the 90-acre Reef Structure and contained within the dashed red Reef Structure boundary shown in Figure 13. Figure 9 shows the average Reef Structure pressure over time. Figure 10 reports the daily CO_2 injection rate and cumulative CO_2 injection totals over 5 years of injection.

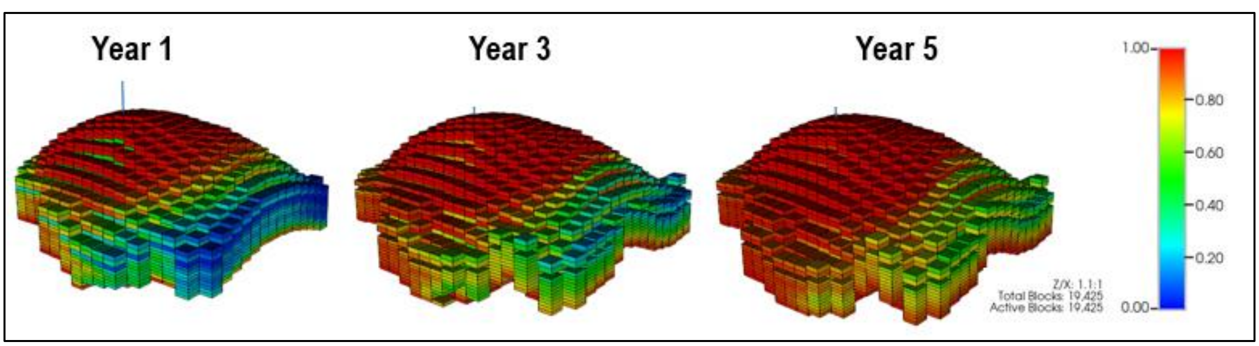

Figure 8. CO_2 plume development in Reef Structure over 5 years of injection (Mole fraction of CO_2 in reservoir blocks).

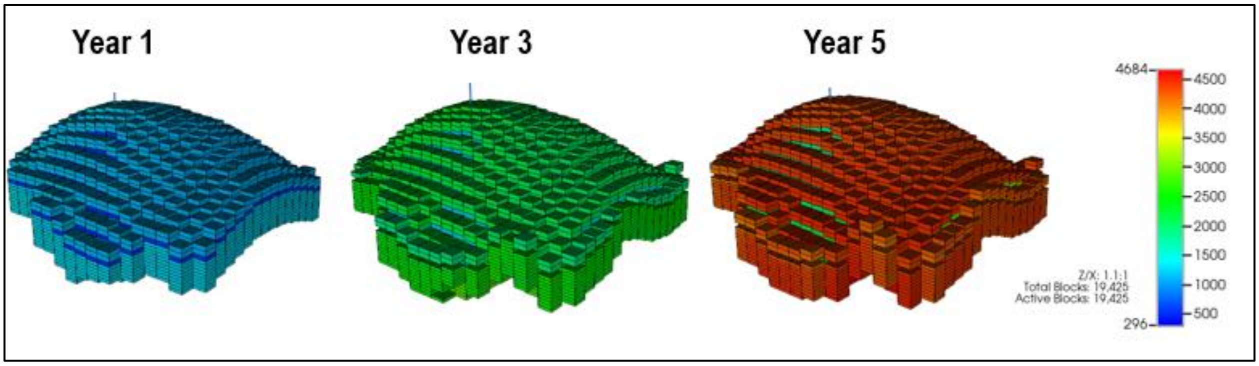

Figure 9. Pressure development in Reef Structure over 5 years of injection from an initial pressure of 300 psi.

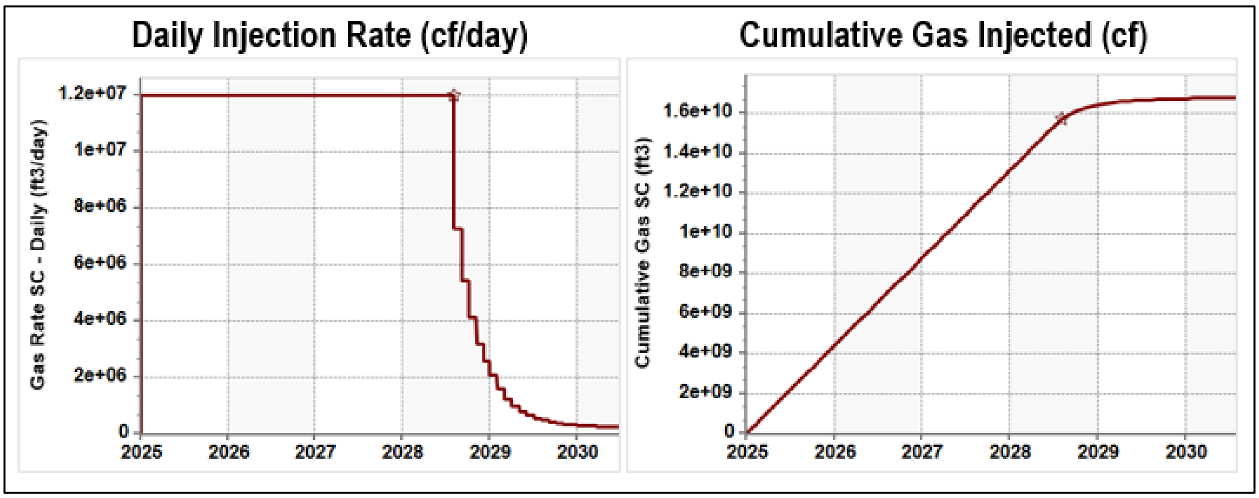

Figure 10. Daily injection rate and cumulative gas injection into the Reef Structure.

2.5 CO_2 Capture and Storage

The Antrim Shale is a biogenic gas reservoir. A byproduct of the microbial generation of methane is carbon dioxide that must be stripped from the gas before it is sold. The South Chester CO_2 Treating Plant (the Plant) located in Section 10 of Chester Township, Otsego County, Michigan, and operated by Phillips 66, removes CO_2 from natural gas produced from the Antrim Shale. As operator of the majority of wells producing natural gas being processed by the Plant, Riverside owns 60% of the CO_2 that would normally be vented from the natural gas plant. Riverside is currently constructing the necessary facilities to capture the entire vent stream of about 400,000 metric tons of CO_2 per year. It is expected that the Plant will continue to operate for another 10 to 20 years, dependent on market conditions. Riverside is installing four rotary screw compressors and reconfiguring one reciprocating compressor unit that in sum will comprise the Turtle Lake Capture Facility ("Capture Facility") to compress the CO_2 for transportation and storage. CO_2 will be transported on a dedicated pipeline from the Capture Facility to the Chester 21-29N-02W Storage Facility. The Storage Facility will consist of one injection well (Smith 3-21) drilled into the Chester 21-29N-02W Reef Structure. In the future, the pipeline may become part of a larger distribution system for delivering CO_2 to multiple depleted gas reef storage facilities operated by Riverside for the purpose of permanently disposing and sequestering the CO_2 waste stream derived solely from the production of Antrim natural gas.

Figure 11 is a process flow diagram of the capture facility, pipeline, and storage facility. The key meter for calculating the mass of CO_2 injected is identified as the Injection Meter in this figure. This dedicated Coriolis mass flow meter will measure and verify the mass of CO_2 being received and injected.

Riverside also has the option to deliver CO_2 to a third party for Enhanced Oil Recovery (EOR). Riverside will have access to data generated by the third party's Coriolis mass flow meter (Delivery Point Meter in Figure 11) positioned near the outlet of the capture facility and inlet to their pipeline, which will serve as the custody transfer point. This data will be used for the accurate determination of CO_2 delivered to the third party. The third party operates their EOR projects under an approved MRV plan (facility ID 1010117) is wholly separate from this Storage Facility and this MRV plan.

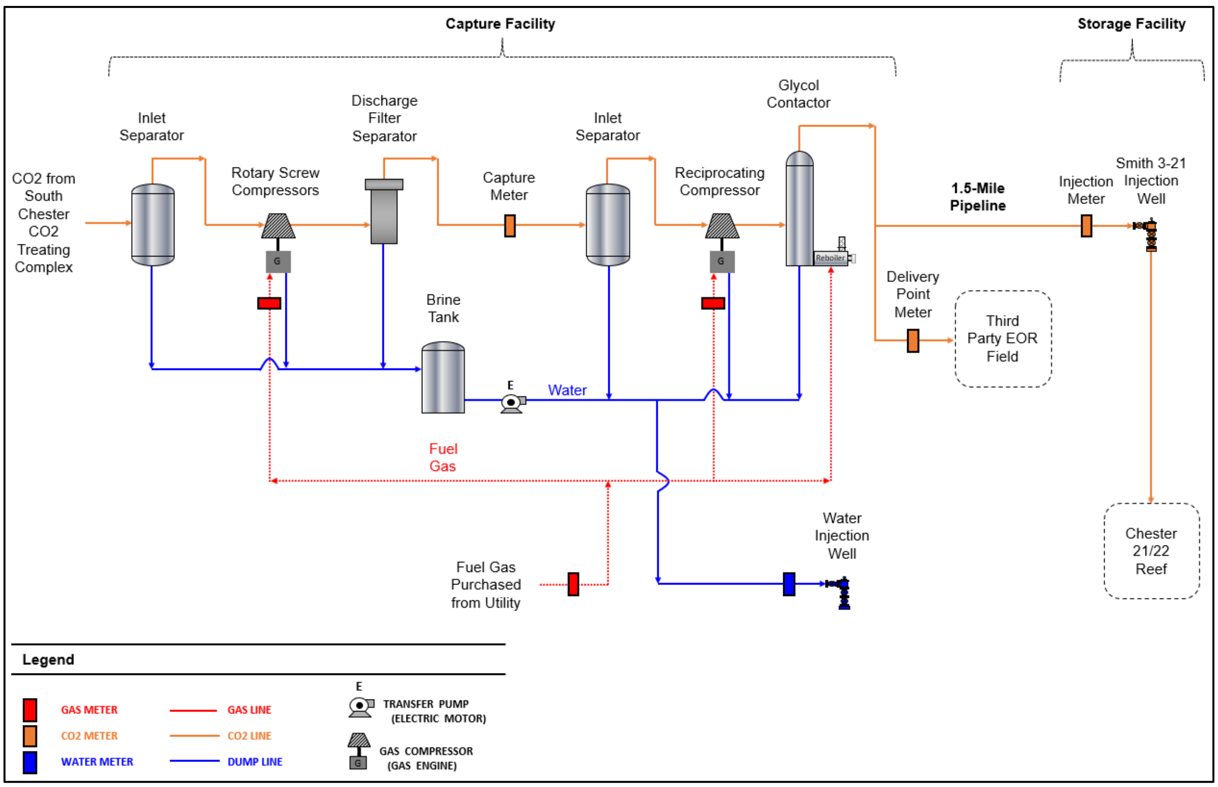

Figure 11. Process flow diagram of Capture and Storage Facilities.

2.6 Ownership

It is helpful to understand the corporate structure and relationship between the entities; refer to Figure 12 below. Riverside Energy Michigan, LLC (Riverside) and Riverside Carbon Holdings (RCH), LLC are 100% owned subsidiaries of Riverside Energy Holdings, LLC. Riverside is operator of the Antrim Shale natural gas wells and permittee of the injection well. Riverside Carbon Solutions, LLC, RCS Capture Antrim, LLC and RCS Storage Michigan, LLC are 100% owned subsidiaries of RCH. RCS Capture Antrim, LLC holds the Capture Facility assets including leased acreage upon which the facilities reside. RCS Storage Michigan LLC holds rights to the minerals and pore space in the Chester 21-29N-02W Reef Structure. Riverside will be the operator of the Storage Facility on behalf of Riverside Carbon Solutions, LLC.

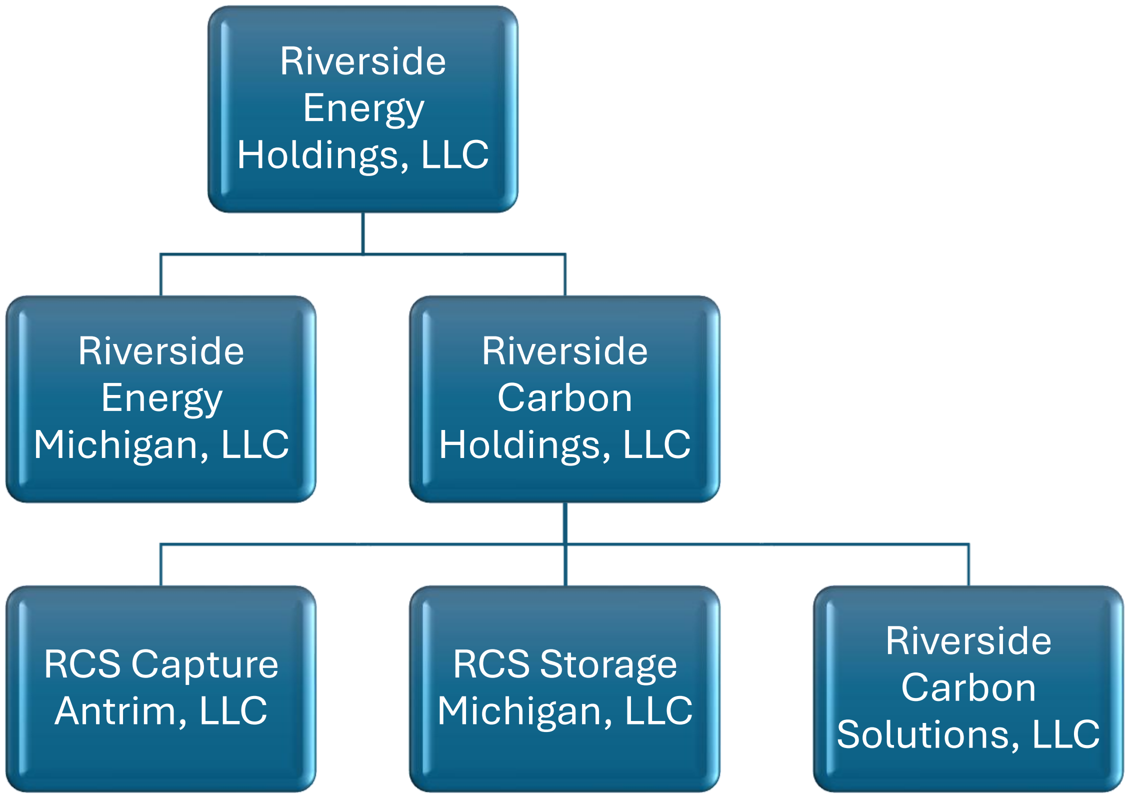

Figure 12. Organizational structure of the various Riverside entities involved in the generation, capture and storage of CO_2.

2.7 Data Collection

All flow meters and other instrumentation at the capture and storage facilities will be wired into Riverside's Supervisory Control and Data Acquisition (SCADA) system. The software continuously logs data from the meters and other instrumentation to a secure server with remote data backup and provides a Human-Machine Interface (HMI) for operators. It also has the capability to alarm operators should parameters deviate outside of prescribed limits. Together, these data streams provide accurate accounting of all CO_2 being captured, received and injected.

Section 5.0 provides a more detailed explanation of the monitoring data that will be collected in order to detect any leakage of CO_2 from the Storage Facility. *Section 6.0* of this MRV Plan provides a more detailed explanation for how this data and other means will be used to establish baseline data for comparison to data collected during operation of the storage facility to detect possible surface leakage.

3. DELINEATION OF THE MONITORING AREA

3.1 Active Monitoring Area

The Active Monitoring Area (AMA) is defined as the Chester 21-29N-02W Reef Structure Area (to the nearest 10-acre square) plus a one-half mile buffer zone outward in all directions, in accordance with 40 CFR §98.449. The Reef Structure and AMA are shown in Figure 13. This AMA delineation will be in place for a 10-year period which will cover the expected operational life of the Project.

Riverside plans to inject CO_2 at a rate of 12,000 Mcfd or approximately 230,000 metric tons of CO_2 per year. This rate may vary depending on site specific injection capabilities. The reef's current pressure is estimated at approximately 300 psi. Injection will continue until the reef pressure increases to the maximum bottomhole pressure of 4,345 psi. Once additional injection is constrained by bottomhole pressure limit, injection will stop. Based on the mass balance and injection simulation work described in *Sections 2.4 and 2.5*, the storage reservoir is expected to fill up after approximately 5 years at an average injection rate of 12,000 Mcfd.

Riverside is defining the time period of this AMA as 10 years in order to cover the expected operational life of the Project with some incorporated buffer time for any maintenance, downtime, or unexpected delays. 40 CFR §98.449 defines the AMA as the area projected to contain the free phase CO_2 plume at the end of year t + 5 plus a one-half mile all around buffer. Therefore, the AMA boundary is delineated based on the extent of the CO_2 plume at the end of year 15 plus a one-half mile buffer zone outward in all directions. After 15 years, the free phase CO_2 plume is projected to remain within the Reef Structure. Should the project be operational after 10 years of initial injection, Riverside will submit a revised MRV plan with an updated AMA.

The compartmentalized nature of the Niagaran reef creates conditions whereby an injection plume is limited to the shape and volume of the reef structure itself. The following factors were considered in defining the Reef Structure and AMA boundaries.

- The Reef Structure is encased within massive anhydrite and ultra-low permeability limestone, efficiently sealing reef's storage intervals and preventing lateral and upward migration of CO_2. The effectiveness of the reef's seal is demonstrated by the trapping of hydrocarbons within the reef over geologic time.
- The boundaries of the reef structure have been defined using 2D seismic data. Where 2D seismic data is not available, reef edges were approximated using all wells surrounding and penetrating the reef, along with analog reef geometry.
- The stored CO_2 and the lateral extent of the CO_2 plume will remain within the reef and will not migrate over geologic time, as is demonstrated by the injection simulation described in *Section 2.5* and the trapping of oil and gas within the reef over geologic time.
- There are no known leakage pathways that extend laterally from the Reef Structure that would warrant an expansion of the AMA beyond the one-half-mile buffer distance.

3.2 Maximum Monitoring Area

The project's Maximum Monitoring Area (MMA) is equal to the Active Monitoring Area (AMA) and is similarly defined as the Chester 21-29N-02W Reef Structure (to the nearest 10-acre square) plus a one-half mile buffer zone outward in all directions. This MMA is shown in Figure 13.

Pursuant to 40 CFR §98.449 the Maximum Monitoring Area 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 zone of at least one-half mile. For the reasons described in *Section 3.1*, the stabilized plume boundary will remain within the Reef Structure at the Project.

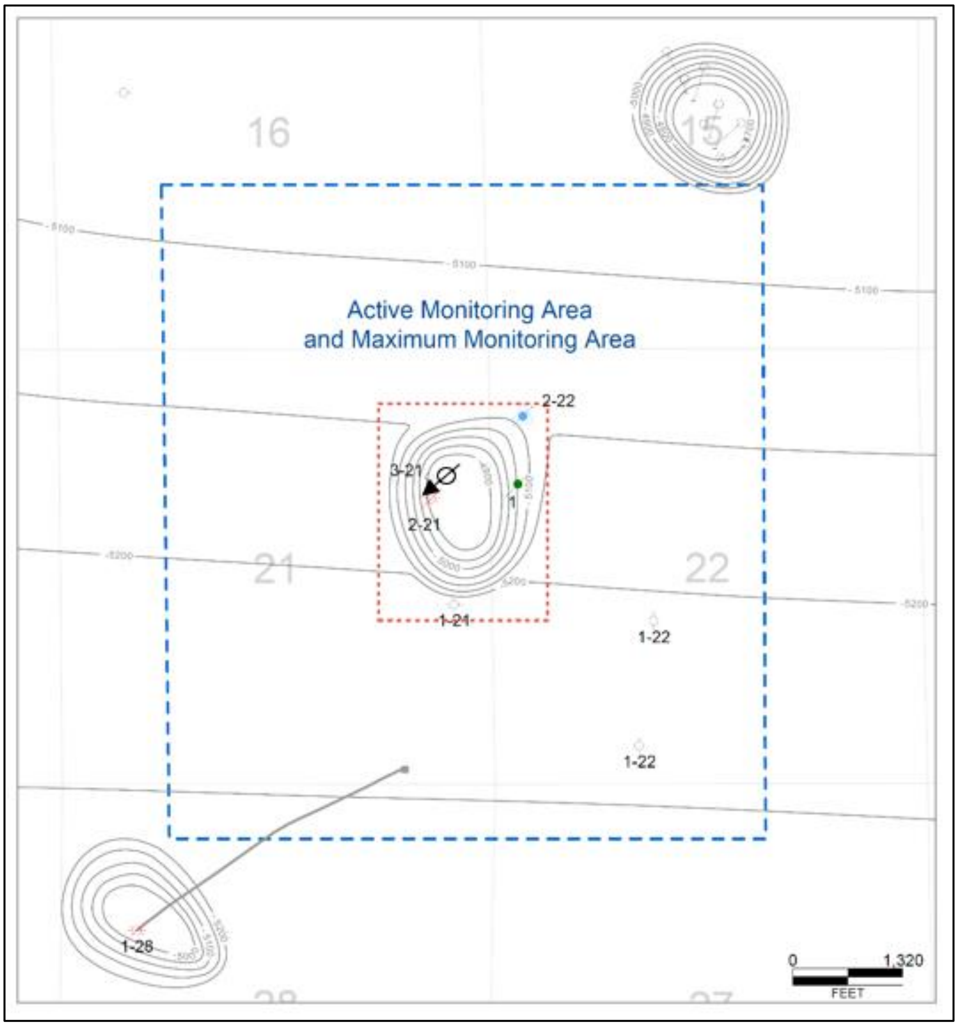

Figure 13. Map depicting the AMA/MMA (total area enclosed by the dashed blue boundary), structure contours of the top of the A1 Carbonate (top of the storage interval), and the Chester 21-29N-02W Reef (central) flanked by the Chester 15 reef to the northeast, and the Chester 28 reef to the southeast. The Chester 21-29N-02W Reef boundary has been regularized to the nearest 10-acre square (dashed red boundary) for establishing the boundary positions of the AMA and MMA. Well spots have been filtered to show only wells with total depths below 3,000' TVD, and for clarity purposes only wells within the AMA/MMA have been labeled. The planned 3-21 Class II injection well is labeled in the northeast quadrant of the Chester 21-29N-02W Reef.

4. POTENTIAL PATHWAYS FOR LEAKAGE

Riverside has identified the following as potential surface leakage pathways at the Project per 40 CFR §98.448(a)[2]:

- Leakage from surface equipment
- Leakage from existing wellbores
- Leakage from not yet drilled wells
- Leakage from the injection wellbore
- Leakage from existing faults and fractures
- Leakage from natural or induced seismicity
- Leakage through confining layers
- Leakage from lateral migration of CO_2

This section discusses the likelihood, magnitude, and timing of potential surface leakage of CO_2 from these pathways. *Section 5* discusses the monitoring plan to detect any surface leakage and strategies for quantifying leakage from these pathways.

4.1 Leakage from Surface Equipment

The injection mass flow meter will be located on the injection well pad near the injection wellhead. As the CO_2 that is received and metered by this mass flow meter will be wholly injected and not mixed with any other supply of CO_2 and no production from the storage formation will occur, the potential leakage pathways from surface equipment are limited to the mass flow meter, the injection wellhead, the short flowline between the two, and any pipefittings or valves installed along the flowline or wellhead. The likelihood of leakage from these surface components is low and further mitigated by the following:

- Locating the CO_2 received and injection mass flow meter near the wellhead to minimize opportunities for potential leakage from surface equipment.
- Adhering to high material selection and construction standards when designing and constructing the wellhead and flowline.
- Continuously monitoring the wellhead and mass flow meter with the SCADA system.
- Routinely conducting visual inspections of the surface equipment.
- Monitoring surface equipment with optical gas imaging technology such as an infrared (IR) or thermal imaging camera on a quarterly schedule.

The magnitude of potential leakage from these surface components is small with any leaked volume likely limited to the volume of CO_2 in the flowline or wellhead components. The timing of leakage risk spans from the start of injection and through the active injection period until the well is plugged and abandoned.

4.2 Leakage from Existing Wells

There are four boreholes that penetrate the A2 Evaporite confining layer within the Reef Structure, the area expected to contain the free-phase CO_2-occupied plume. Well data for these boreholes is listed in *Section 2.3*. Three of these boreholes, the Marshall, Glen #1 well, the Underwood, N M & Knapp, C A #1-21 well, and the Leacock Hubbard Underwood & Knapp #2-21 well have been plugged and abandoned according to State of Michigan standards and determined by Riverside to be an unlikely pathway for CO_2 migration above the confining interval. The State of Michigan requires a cement plug be placed within the wellbore to confine oil, gas, and water to the strata in which the oil, gas, and brine were produced from. Upon review of the plugging reports for these three wellbores, Riverside has determined that a cement plug has been placed within the A2 Evaporite confining layer, as well as within several overlying intervals. Therefore, leakage through these legacy wellbores is unlikely.

The fourth borehole that penetrates the A2 Evaporite confining layer within the Reef Structure, the State Chester 2-22, is an active brine disposal well permitted in the Dundee formation. It was originally drilled in 1974 to a total depth of 6,660 ft below surface to the top of the Brown Niagaran formation. As this well is located at the far flank of the reef, it tested dry for hydrocarbons. It was then reworked into a brine disposal well by plugging up and completing the well within the Dundee formation at approximately 2,450 ft. The plugging records indicate a cement plug was placed at the base of the well, within the A2 Evaporite confining layer, as well as in additional intervals up hole. The well continues to pass mechanical integrity tests (MITs) in accordance with State of Michigan standards. Riverside has determined that the State Chester 2-22 well is a low risk for CO_2 leakage because it has been properly plugged downhole and recompleted above and is subject to ongoing monitoring and MITs as an active brine disposal well by a different operator.

The magnitude of potential leakage from existing wellbores is considered to be low. The majority of existing wells are located on the reef flank, limiting their intersection with the projected CO_2 plume. The timing of leakage risk begins when the CO_2 plume intersects with an abandoned well. Riverside considers the likelihood of leakage from existing wells to be low because the four legacy wells that penetrate the Reef Structure have been abandoned to State of Michigan standards with multiple cement plugs.

Outside of the Reef Structure, but within the one-half-mile buffer distance of the AMA and MMA, there are two boreholes (Underwood, Knapp, and Ashland Farms, INC 1; and Underwood, Nellie M & Knapp, Clara Ann 1-22) that penetrate the A2 Evaporite confining layer. The surface location of one additional directionally drilled wellbore, the State Chester 1-28, is located within the AMA and MMA. However, its bottom hole location and penetration of the A2 Evaporite confining layer are located outside of the Project's AMA and MMA. These three wellbores have been plugged and abandoned according to State of Michigan standards. The likelihood of leakage from these wells is very low as they do not intersect the Reef Structure and the projected free-phase CO_2 plume.

4.3 Leakage from Not Yet Drilled Wells

Wellbores drilled in the future through the Reef Structure may be a potential leakage pathway for CO_2. The likelihood of leakage from not yet drilled wells is low and any risk is mitigated by the following:

- Hydrocarbon production from the A1 Carbonate and Brown Niagaran formations in the Chester 21-29N-02W Reef will be no longer possible after injection of CO_2 begins.
- There are no known hydrocarbon producing formations below the Brown Niagaran in the AMA and MMA. The St. Peter Sandstone (approx.10,000 ft) is an occasional gas producer where on anticlinal structure in central and northern Michigan. There are several St. Peter dry holes within a few miles of the Storage Facility and the Storage facility is not on an anticline as confirmed by well control and 2D seismic.
- Not yet drilled wells located outside of the Reef Structure but within the AMA and MMA will not interact with the free-phase CO_2 plume.
- All well records and injection data will be shared with Michigan-EGLE to ensure that potential drillers are aware of the Project for the indefinite future.
- Michigan Admin. Code R. 324.413 regulates the drilling of wellbores to strata beneath gas storage reservoirs. The rule describes specific drilling equipment, casing design, and completion standards that must be deployed to ensure drilling occurs safely through natural gas storage reservoirs. While this rule applies to natural gas storage projects, not CO_2 storage projects, Michigan-EGLE already has experience in protecting and regulating the drilling of new wells through gas storage reservoirs.

For these reasons, it is unlikely that any future wells will be drilled through the A2 Evaporite confining layer within the Reef Structure and projected free-phase CO_2 plume. The magnitude of potential leakage from not yet drilled wells is low.

4.4 Leakage from the Injection Wellbore

The Smith 3-21 injection well will be permitted and constructed as a Class II oil field waste disposal well with Michigan-EGLE. As this injection well is an additional penetration that could offer a leakage pathway to the surface, Riverside is taking the following steps to mitigate potential leakage:

- The Smith 3-21 injection well will be constructed more rigorously than Michigan Class II standards. Figure 14 describes the proposed injection well design. Chromium alloy long-string casing will be installed from total depth through the A2 Evaporite and cemented in place with SLB's *EverCrete* CO_2 resistant cement.
- Prior to injection, a cement bond log and MIT will be run to ensure proper well construction.
- Riverside will perform a MIT at least every 5 years per Michigan-EGLE requirements.
- The annular fluid volume between the casing and injection tubing will be monitored quarterly.

- The surface pressure of the tubing and annular space will be continuously monitored by the SCADA system to detect any abnormalities that indicate a loss of integrity or leak has occurred.
- Riverside will be monitoring surface components and the injection wellhead with optical gas imaging technology on a quarterly schedule.
- After injection, the Smith 3-21 injection well will be plugged and abandoned with cement plugs placed to prevent any future leakage of CO_2.

Leakage from the injection wellbore is unlikely due to the constant monitoring of the wellbore and periodic mechanical integrity testing. The magnitude of leakage from the injection wellbore is small. It is unlikely that a blowdown of the wellbore would be necessary, but if one occurs, the leaked CO_2 would be limited to the volume contained in the wellbore and could be easily quantified using volume, pressure and temperature data. The timing of leakage risk from the injection wellbore occurs from the beginning of injection until proper plugging and abandonment.

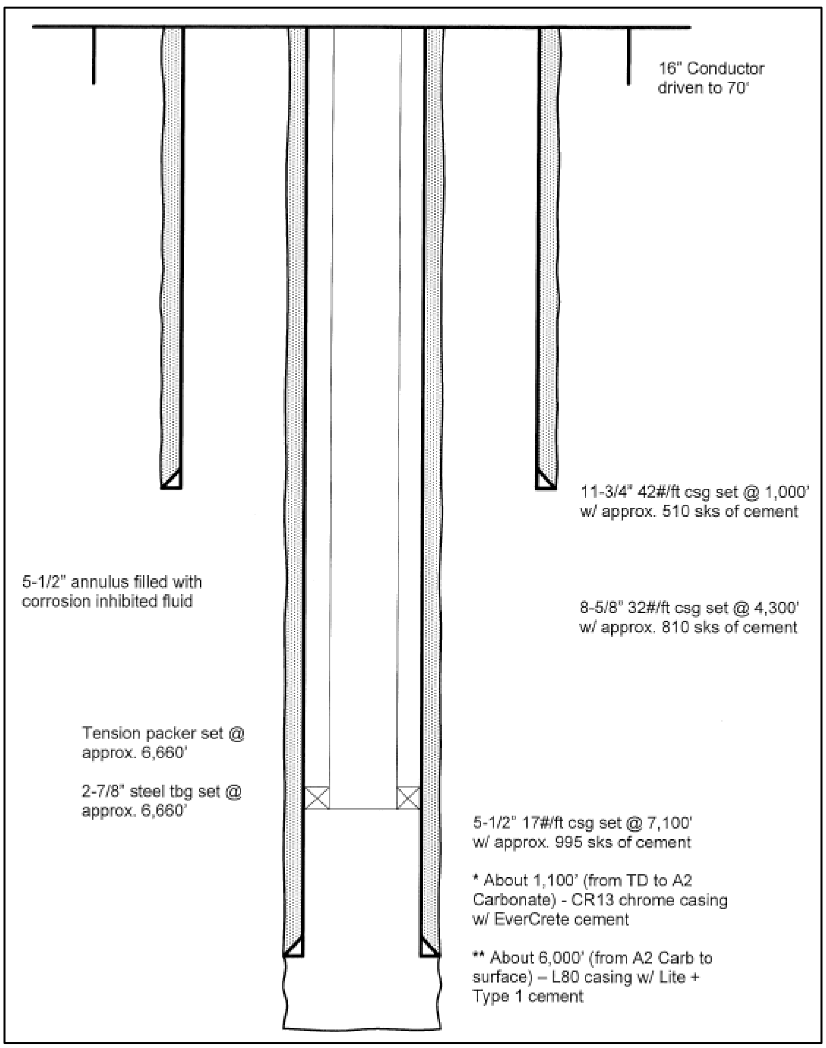

Figure 14. Proposed construction design for Smith 3-21 injection well.

4.5 Leakage from Existing Faults and Fractures

Evaluation of 2D seismic did not reveal any faults or fractures in the Reef Structure and there are no known faults or fractures through the A2 Evaporite confining layer in the AMA and MMA that would allow CO_2 movement into overlying formations. The risk of leakage of CO_2 from an unknown fault or fracture is very low because hydrocarbons were sealed within the Reef Structure throughout geological time.

4.6 Leakage from Natural or Induced Seismicity

The likelihood of natural seismicity is very low. The Michigan Basin is structurally stable with few major structural features. No naturally occurring earthquakes greater than M 2.5 have originated within 100 miles of the Storage Facility since 1900. The USGS's 2023 50-State Long-term National Seismic Hazard Model classifies northern Michigan as having the lowest chance of experiencing a slight or greater damaging earthquake in the next 100 years[1].

Natural gas storage in nearby Niagaran reef fields offers an analog to CO_2 injection and experience with reservoir response under pressure. To date, Riverside is unaware of any induced seismicity issues associated with natural gas storage in Niagaran reefs. Many reefs are permitted with a maximum bottomhole pressure greater than 4,600 psi at depths of 6,600 to 6,800 ft[2]. The planned maximum bottomhole pressure for the Storage Facility is 4,345 psi (6,036 ft depth * 0.8 psi/ft fracture gradient * 0.9 safety factor). For these reasons, the likelihood of leakage from induced seismicity is low and the risk would be limited to the active injection period because the reservoir pressure will be highest during the injection period.

4.7 Leakage through Confining Layes

The primary seal of the Project is the A2 Evaporite confining layer. The A2 Evaporite is comprised of anhydrite which has virtually no porosity or permeability. Above the A2 Evaporite confining layer, additional evaporite and low-permeability carbonate sequences are present that further reduce the risk of upward movement of CO_2 through overlying strata.

The likelihood of leakage through confining layers is very low because A2 Evaporite confining layer's sealing capacity has been proven by the previous trapping of hydrocarbons throughout geologic time.

4.8 Leakage from Lateral Migration of CO_2

As shown in Figure 4, the Reef Structure is fully compartmentalized due to the unique formation of the pinnacle reef and subsequent deposition of overlying strata. The Reef Structure is encased in a tight carbonate and non-porous evaporate seal that prevents the vertical and lateral migration

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1 https://www.usgs.gov/programs/earthquake-hazards/science/2023-50-state-long-term-national-seismic-hazard-model
2 https://www.govinfo.gov/content/pkg/FR-1994-03-28/html/94-7181.htm

of fluids. Underlying the storage formation are tight units of the Brown and Gray Niagaran formation.

Riverside does not believe that the A1 Carbonate and Brown Niagaran storage intervals are in communication with any other Niagaran reservoir or reef. Water infiltration from below the reservoir was not observed during the production history of the Chester 21-29N-02W Reef and the current reservoir pressure is expected to be at the reef's depleted pressure of approximately 300 psi.

The likelihood of leakage from lateral migration of CO_2 is very low as demonstrated by the production history of the Chester 21-29N-02W Reef. The magnitude of any potential leakage is low due to the closed structure of the reef.

5. MONITORING AND LEAK QUANITFICATION STRATEGY

This section describes the monitoring plan to detect any surface leakage from the pathways identified in *Section 4* and the strategies for quantifying leakage should it occur.

5.1 Detecting and Quantifying Leakage from Surface Equipment

The injection mass flow meter will be located near the wellhead, limiting the amount of equipment subject to monitoring for leakage to the wellhead, the mass flow meter, and the flowline and any valves between the wellhead and mass flow meter. To detect any leakage from this equipment, optical gas imaging of this equipment will occur at least on a quarterly schedule with inspection surveys conducted using either an IR or thermal imaging camera. Visual site and equipment inspections will be conducted by trained personnel at least monthly. In addition, the wellhead and mass flow meter will be continuously monitored by the SCADA system.

Emissions from surface equipment downstream of the mass flow meter such as the flowline, valves, fittings or the wellhead assembly will be estimated and repaired as quickly as possible. If CO_2 must be vented downstream of the meter to make a repair, the amount of CO_2 vented will be estimated using the methods specified in 40 CFR Part 98 Subpart W. Data that could be considered for estimating the amount of CO_2 leaked may include but not limited to: any anomalies in metered pressures or mass flow, average pressures or mass flow, the time between inspections, physical measurements of pinholes and/or the relative size and intensity of the leakage plume as detected by optical gas imaging.

5.2 Detecting and Quantifying Leakage from Existing Wellbores and Not Yet Drilled Wells

As discussed in *Section 4*, few existing wells will encounter the CO_2 plume, and all of these wells have been plugged and abandoned to State of Michigan standards. Riverside will be conducting quarterly groundwater monitoring and optical gas imaging on the injection well pad. Pressure transducers installed in the tubing and annulus at the wellhead will be monitored by the SCADA system and bottom hole pressure and temperature surveys will occur periodically through the injection period to identify possible abnormalities in operational parameters that would indicate a subsurface leak. Riverside will conduct bottomhole pressure and tests and temperature surveys every six months for the first two years and annually thereafter. Should a future well be drilled within the AMA and MMA, Riverside will work with Michigan-EGLE to ensure the well will not interfere with CO_2 storage at the Storage Facility.

If a leak is detected at a legacy well or a not yet drilled well, its volumetric flow will be attempted to be metered if possible. If not, the latest injection data and reservoir pressure, volume and temperature data will be used to estimate a leakage volume and rate with a mass balance approach from the storage intervals. The timing of the leak will be determined by an estimate of the CO_2 plume's intersection with the legacy or future well.

5.3 Detecting and Quantifying Leakage from the Injection Wellbore

Riverside will deploy multiple monitoring strategies to detect leakage from the injection wellbore. The long string casing, injection tubing string and packer assembly are subjected to a MIT every 5 years as well as once before injection begins. The annular space between the casing and tubing will be filled with a corrosion inhibiting fluid and checked quarterly for significant changes in volume. The tubing and annular pressure at the wellhead will be monitored continuously with pressure transducers tied to the SCADA system. At a minimum, Riverside will conduct bottom hole pressure tests and temperature surveys every six months for the first two years, and annually thereafter. If the temperature survey detects an anomaly suggesting CO_2 intrusion behind casing, a radioactive tracer/gamma ray tool will be run to investigate. Further, the quarterly optical gas imaging and monthly visual inspections would also encompass the area around the wellbore at the surface.

A workover of the well to replace components may be required and surface and downhole equipment would be thoroughly inspected for signs of wear or corrosion responsible for a potential leak.

If the mechanical integrity of the injection wellbore is lost, the injection will stop and not begin again until a MIT test is passed in compliance with Michigan-EGLE regulations. If a leak is determined to have taken place, it will be quantified using the timing of the loss of integrity and any pressure or annular fluid data from the MIT that can be used to characterize the leak.

Venting of CO_2 from the well may occur while making repairs and would be estimated and documented in accordance with Subpart W procedures. Typically, wells undergoing a workover are "killed" with sufficiently dense fluid to overcome the reservoir pressure and prevent venting of gases from the well to atmosphere.

5.4 Detecting and Quantifying Leakage from Existing Faults and Fractures and Natural or Induced Seismicity

Leakage from existing faults or fractures or fractures created by natural or induced seismicity will be monitored by continuous monitoring of operational parameters at the wellbore, periodic reservoir pressure and temperature surveys, and quarterly ground water monitoring near the injection well pad. At a minimum, Riverside will conduct bottom hole pressure tests and temperature surveys every six months for the first two years, and annually thereafter. Abnormalities in operational and reservoir parameters and such as the injection tubing and reservoir pressures will be investigated to determine if there is a subsurface leak. If it is determined a subsurface leak has occurred, the latest injection data and reservoir pressure, volume and temperature data will be used with a mass balance approach to estimate a leakage volume and rate from the storage intervals. The timing of the leak will be determined by an estimate of the CO_2 plume's intersection with the leakage pathway.

As discussed in *Section 4*, natural and induced seismicity are considered to be unlikely. Riverside will subscribe to the USGS' Earthquake Hazards Program Earthquake Notification Service (ENS)[3] to receive notifications of any earthquakes with magnitude 2.0 or greater in Michigan. If an earthquake occurs, Riverside will evaluate the monitoring data to determine if the wellbore or Storage Facility are affected. Annulus pressure is continuously monitored and could indicate a loss of wellbore integrity issues caused by seismicity.

5.5 Detecting and Quantifying Leakage through the Confining Layers or Lateral Migration

Leakage through the confining layers or from lateral migration will be monitored by periodic groundwater monitoring and reservoir pressure tests. Quarterly groundwater sampling and testing will occur in the water well to be drilled at the injection well pad for drilling operations and will be retained for ground water monitoring. A description of the groundwater testing that will occur is included in *Section 6.4*.

If it is determined a subsurface leak has occurred, the latest injection data and reservoir pressure, volume and temperature data will be used with a mass balance approach to estimate a leakage volume and rate from the storage intervals. The timing of the leak will be determined by an estimate of the CO_2 plume's intersection with the leakage pathway.

6. ESTABLISHING SURFACE LEAKAGE BASELINES

Prior to the start of continuous injection, the following data will have been collected to establish baselines for the storage facility against which future data may be compared in order to detect surface leakage.

6.1 Wellbore Integrity

After injection well construction is completed but before injection begins, a MIT and annular pressure test will be completed to confirm wellbore integrity. The initial volume of annular fluid will be noted, and it will be monitored during the start-up of injection to determine how it responds during injection start up. Its stabilized volume will be noted after at least a week of continuous injection. The injection tubing and annulus pressures at the wellhead will be recorded prior to CO_2

[3] https://earthquake.usgs.gov/ens/help

injection and continuously monitored thereafter with the SCADA system. MITs will occur at least every 5 years in accordance with Michigan-EGLE requirements.

6.2 Injection Well Operating Parameters

Riverside has established target injection and storage rates based on experience from other operators injecting and storing fluids in other Niagaran reefs. An initial model, described in *Section 2.5*, has been developed to confirm these baseline injection parameters. Riverside plans to inject CO_2 at a rate of 12,000 Mcfd or approximately 230,000 metric tons of CO_2 per year. This rate may vary depending on site specific injection capabilities.

During injection operations, Riverside will use site-specific data during wellbore construction and the initial injection period to update nominal injection parameters such as wellhead tubing and annulus pressures and injection flow rates.

6.3 Reservoir Conditions

Initial bottom hole pressure will be recorded at mid-perforations and a temperature survey with gradient stops will be completed before injection. A bottom hole pressure test and temperature survey will be conducted at least every six months for the first two years of injection and then annually thereafter. After approximately 48 hours of continuous CO_2 injection, Riverside will run in hole to mid-perforations to establish injection pressure and temperature, record tubing and casing injection pressures and run gradients on the way out of the hole.

6.4 Groundwater Monitoring

Groundwater monitoring will occur at a water well drilled on the injection well pad (to approx. 100 ft) and include the following analyses to detect the presence of fugitive CO_2:

- Standard field parameters form a calibrated water quality meter: temperature, pH, conductivity, dissolved oxygen, oxidation reduction potential, and turbidity.
- Standard EPA UIC lab analyses barium, calcium, sodium, magnesium, potassium, total iron, chloride, sulfate, sulfide, carbonate, bicarbonate, TDS, resistivity, specific gravity, and pH.
- Lab analyses for dissolved methane, ethane, propane, and calculated dissolved CO_2 from carbonate, bicarbonate, and dissolved inorganic carbon.

A sample will be collected before injection begins from the ground water monitoring well in order to establish baseline parameters. During injection, groundwater sampling and testing will occur at least quarterly.

6.5 Surface Equipment Monitoring

After the site equipment is constructed but before injection begins, Riverside will conduct a baseline optical gas imaging survey with either an IR or thermal imaging camera. Within the first month of injection, an additional optical gas imaging survey will occur to ensure no leakage from surface equipment during the beginning of injection. Thereafter, Riverside will conduct optical gas imaging surveys quarterly at the injection well pad to detect for surface leakage of CO_2.

7. SITE-SPECIFIC CONSIDERATIONS FOR THE MASS BALANCE EQUATION

Riverside will utilize the mass balance equations listed in 40 CFR §98.443 to calculate the mass of CO_2 sequestered. The site-specific considerations for these equations are discussed in this section.

7.1 Mass of CO_2 Received and Injected

In accordance with 40 CFR §98.444(a)[4], Riverside will determine the annual mass of CO_2 injected as the total annual mass of CO_2 received instead of using Equation RR-1 or RR-2 to calculate CO_2 received. The CO_2 received at the storage facility will be wholly injected and not mixed with any other supply of CO_2. There will be no production from the Storage Facility.

Equation RR-4 in 40 CFR §98.444(c) of Subpart RR will be used to calculate the mass of CO_2 received at the capture facility each year.

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

where:

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

$Q_{r,u}$ = Quarterly mass flow rate measurement for flow meter u in quarter p (metric tons per quarter).

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

p = Quarter of the year.

u = Flow meter.

7.2 Mass of CO_2 Produced

There will be no production from the Storage Facility.

7.3 Mass of CO_2 Emitted by Surface Leakage

Riverside will quantify the mass of CO_2 emitted by each identified surface leakage pathway as outlined in *Section 5*. Equation RR-10 will be used to calculate the total mass of CO_2 emitted by surface leakage at the Storage Facility.

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

where:

CO_{2E} = Total annual CO_2 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.

7.4 Mass of CO_2 Emitted from Equipment Leaks and Vented Emissions

As discussed in *Section 5.1*, Riverside will quantify the 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 injection mass flow meter and the wellhead in accordance with the procedures provided under Subpart W of 40 CFR Part 98. At the Storage Facility, the injection mass flow meter is located near the wellhead, limiting the equipment to the mass flow meter, the injection wellhead, the short flowline between the two, and any pipefittings or valves installed along this flowline or wellhead.

7.5 Mass of CO_2 Sequestered

Since no production will occur at the Storage Facility, Riverside will use equation RR-12 to calculate the total mass of CO_2 sequestered in the Storage Facility for the reporting year.

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

where:

CO_2 = Total annual CO_2 mass sequestered in subsurface geologic formations (metric tons) at the facility in the reporting year.

CO_{2I} = 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_{2E} = 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 mass flow meter used to measure injection quantity and the injection wellhead, for which a calculation procedure is provided in Subpart W of 40 CFR Part 98.

8. ESTIMATED SCHDEULE FOR IMPLEMENTATION OF MRV PLAN

Riverside will implement this plan as soon as it is approved by EPA. It will be in effect until EPA approves Riverside's request for discontinuation of reporting. Riverside plans to submit a request for discontinuation of reporting after all wells in the Storage Facility are plugged and abandoned and has demonstrated that the injection CO_2 stream is not expected to migrate in the future in a manner likely to result in surface leakage, in accordance with 40 CFR §98.441(b).

9. QUALITY ASSURANCE PROGRAM

9.1 Monitoring of CO_2 received

In accordance with 40 CFR §98.444(a)[4], Equation RR-4 will be used to calculate the total annual mass of CO_2 received because CO_2 received at the Storage Facility is wholly injected and metered by a single injection mass flow meter.

9.2 Monitoring of CO_2 injected

At the injection well, the volume of CO_2 injected will be measured continuously by an Emerson Micro Motion ELITE Coriolis mass flow meter. Riverside will report quarterly averages of the flow rate and total mass injected. Injection stream samples will be collected at least quarterly to measure the CO_2 concentration immediately upstream or downstream of the injection mass flow meter.

The injection mass flow meter will operate continuously except as necessary for maintenance and calibration. It will be operated using the calibration and accuracy requirements in 40 CFR §98.3(i). Meter accuracy is based on accredited calibration standards according to ISO 17025/IEC 17025.

9.3 Procedures for Estimating Missing Data

In the event Riverside is unable to collect data required for performing the mass balance calculations, procedures for estimating missing data in 40 CFR §98.445 will be implemented as follows:

- Quarterly mass of injected CO_2 will be estimated using representative mass flow rate data from the nearest previous time period. Pressure data at the wellhead will be compared to previous time period’s pressure data and mass of injected CO_2 to ensure similar consistency.
- Quarterly CO_2 stream concentration data will be estimated using a representative concentration value from the nearest previous time period.
- CO_2 emissions associated with equipment leaks or venting will be estimated following the missing data procedures contained in 40 CFR Part 98 Subpart W.

9.4 MRV Plan Revisions

Riverside will revise this plan and submit the latest version to the EPA Administrator within 180 days of making a material change to the monitoring and/or operational parameters, a change in the permit class of the UIC permit, notification of substantive errors in the MRV plan, or for any other reason Riverside should choose to revise this MRV plan in any reporting year.

10. RECORDS RETENTION

Riverside will retain the following records in accordance with 40 CFR §98.3(g).

(1) A list of all units, operations, processes, and activities for which GHG emission were calculated.

(2) The data used to calculate the GHG emissions for each unit, operation, process, and activity, categorized by fuel or material type. These data include but are not limited to the following information in this paragraph (g)(2):

> (i) The GHG emissions calculations and methods used. For data required by § 98.5(b) to be entered into verification software specified in § 98.5(b), maintain the entered data in the format generated by the verification software according to § 98.5(b).
>
> (ii) Analytical results for the development of site-specific emissions factors.
>
> (iii) The results of all required analyses for high heat value, carbon content, and other required fuel or feedstock parameters.
>
> (iv) Any facility operating data or process information used for the GHG emission calculations.

(3) The annual GHG reports.

(4) Missing data computations. For each missing data event, also retain a record of the cause of the event and the corrective actions taken to restore malfunctioning monitoring equipment.

(5) The most recent copy of this GHG Monitoring Plan.

(6) The results of all required certification and quality assurance tests of continuous monitoring systems, fuel flow meters, and other instrumentation used to provide data for the GHGs reported under this part.

(7) Maintenance records for all continuous monitoring systems, flow meters, and other instrumentation used to provide data for the GHGs reported under this part.

In addition, Riverside will retain the following records for at least three years in accordance with 40 CFR §98.447:

- 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 mass 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 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 wellhead.

11. REFERENCES

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