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Permit No: NES123570001

Class VI Permit Application Narrative Voyager 1

Carbon America

[40 CFR 146.82(a)]

Prepared by:

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Submitted to:

U.S. Environmental Protection Agency Region 7
Lenexa, Kansas

Revision	Date	Notes	Written By	Approved By
A	03/12/2024	Issued for Approval		R. Keeling
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Contents

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Making Climate Change History™

Figures

Making Climate Change History™

Tables

Appendices

Attachments

1. Attachments

See the list of attachments in the front matter.

2. Figures

See the list of figures in the front matter.

3. Project Background and Contact Information

3.1 Introduction

Voyager Sequestration, LLC, (Voyager) a wholly owned subsidiary of Carbon America, is a private entity that can be reached at (720) 204-3736. Voyager is proposing the Voyager Project to develop a carbon capture and sequestration (CCS) system for the Bridgeport Ethanol, LLC (BPE) plant, located in Bridgeport, Nebraska. The addition of CCS to the plant would create substantial benefits to public health and welfare and the environment by removing carbon dioxide (CO_2) from facility emissions that would otherwise be released to the atmosphere and contribute to increasing greenhouse gas emissions.

This Permit Application Narrative serves as the primary document for the Class VI permit application, and contains the main project information, site characterization, and summary of attachments. Attachments to this narrative contain specific plans and project requirements, including details for construction, operation, project conclusion, emergency response, and financial assurance.

Carbon America has prepared and submitted this application for review by the U.S. Environmental Protection Agency (EPA) Region 7 for an Underground Injection Control (UIC) Class VI permit. This application has been prepared in accordance with Title 40, Part 146, of the Code of Federal Regulations (40 CFR 146), Subpart H, Criteria and Standards Applicable to Class VI Wells. An injection depth waiver is not being requested, nor is an aquifer exemption expansion.

3.2 Proposed Project

The Voyager Project, located in southwestern Nebraska, will capture 175,000 metric tons per year (mtpy) of CO_2 from the BPE plant and transport it via pipeline to the proposed Class VI injection well ("Voyager 1") for permanent underground sequestration (Figure 1).

The BPE plant is located at 10106 South Railroad Avenue, Bridgeport, and is situated in southwestern Nebraska in Morrill County. The Standard Industrial Classification (SIC) code for the plant is 2869. The BPE plant will have a dedicated CO_2 capture facility.

The BPE plant produces ethanol for use as a renewable fuel through the process of fermenting feedstock. In addition to ethanol, several other products are produced by the ethanol production process, including distiller's grains for livestock and poultry, corn oils, and corn syrups.

Figure 2 demonstrates the ethanol production process. Feedstock includes raw corn from surrounding agricultural areas in northeastern Colorado and western Nebraska. The dry corn is first milled and cooked before entering fermentation tanks, where the corn mash is fermented to produce the primary product, ethanol. During fermentation, associated gases, approximately 99% of which is CO_2, with lesser parts of oxygen (O_2), are liberated and travel through a series of on-site pipes, ultimately being released to the atmosphere.

Appendix 1 presents site plans for the capture facility in relation to the BPE plant.

Voyager 1 will be constructed, including the well pad and access road(s), following approval of this Class VI permit application. The well will be approximately 5.13 miles west northwest of the BPE plant, located at the latitude-longitude of 41.6467346, -103.1524635 in Section 01, Township 19N, Range 51W. Voyager 1 will

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inject an estimated 175,000 mtpy of CO_2 over the course of 12 years, with a total injection of 2.1 million metric tons (mmt) over the lifetime of the project.

The delineation of the Area of Review (AoR), including the lateral and vertical extent of CO_2 plume migration and the region of corresponding pressure elevation, was completed using computational modeling, detailed in **Attachment A: Area of Review and Corrective Action Plan**. The AoR is defined as the region surrounding the injection well where underground sources of drinking water (USDWs) may be endangered by injection activity. The Voyager Project AoR, as characterized in Section 4 of this report, covers a land surface area of approximately 3,086 acres, or 4.82 square miles (sq mi) (see Figure 3). The proposed injection zone is the Permian Lyons Formation located at approximately 5,258 feet (ft) true vertical depth (TVD) below ground surface (bgs) at the Voyager 1 injection well location and is capped by the Flowerpot Anhydrite unit of the Flowerpot Formation (upper confining zone). As stated, CO_2 emissions will be captured at the BPE plant and transported by pipeline to the Voyager 1 injection well. This pipeline will traverse multiple privately owned lands. The CO_2 stream will be transported in a supercritical state from the discharge point at the capture facility to the subsurface point of injection, near 5,258 ft TVD. The CO_2 injectate composition is presented in Appendix 2. The Voyager project AoR and associated facilities, including capture, pipeline, and storage, are not located within current American Indian Lands.

Contacts within the AoR include the following:

- There are no tribal or Indian lands located within the AoR. The closest federally recognized tribal or Indian lands to the Voyager CCS project is the Pine Ridge Reservation, located approximately 90 miles to the north in South Dakota. The Pine Ridge Reservation is home to the Oglala Sioux Tribe. The distance was sourced from American Indian and Alaska Native Land Area Representation (AIAN-LAR) Geographic Information System (GIS) dataset on conservation.gov.
- The surface rights within the AoR are privately owned.

3.3 Owner/Operator Information

Voyager will own and operate the CO_2 injection well and associated injection facilities. Voyager is a private entity.

- Voyager Sequestration, LLC
  450 Angus Ave
  Sterling, CO 80751
  Phone number: (970) 522-1666

Voyager will be operated by S2G/SEG Carbon, LLC (contact information listed in Section 3.4.). BPE will capture CO_2 at their facility, transported, and injected in Voyager 1.

3.4 Facility Permitting Information

The name, mailing address, and location of the facility is listed below:

- Bridgeport Ethanol, LLC, Project Partner
  10106 S Railroad Ave
  Bridgeport, NE 69336
  Phone number: (308) 262-2020

Applicable SIC codes include 2869 (Industrial Organic Chemicals).

In addition to the Class VI UIC permit, a list of relevant project permits and their status is included in Table 1.

Resource Conservation and Recovery Act (RCRA), National Emission Standards for Hazardous Pollutants (NESHAPS), Prevention of Significant Deterioration (PSD) permits, Clean Air Act (CAA) Nonattainment Program permits, and Ocean Dumping permits are not applicable to this project. This project is not located on lands currently under Bureau of Indian Lands management.

Table 1 lists all permits or construction approvals received or applied for under RCRA, the UIC program, National Pollutant Discharge Elimination System (NPDES), Prevention of Significant Deterioration (PSD) program under CAA, nonattainment program under CAA, NESHAPS preconstruction approval under CAA, and other relevant environmental permits, including state-level permits.

Table 1. Facility Permitting Information

Permit	Related Activity	Granting Authority	Status (including received or expected date)	Renewal Frequency
Operatorship	Stratigraphic Test Well, Plume Monitoring Well	Nebraska Oil and Gas Conservation Commission (NOGCC)	Complete	NA
Form 3A Operatorship Bonding			Received 9/22/2022	
Form 2 Notice of Intent to Drill			Approved but has since expired, will refile 6 months before drilling	6 months
Form 2A Temporary Earthen Reserve Pit				
Form 5 Drilling Completions Report			Waiting to drill the well	NA
Stormwater Pollution Prevention Plan	Stratigraphic Test Well, Plume Monitoring Well, Pipeline, Capture Site	Nebraska Department of Environment and Energy (NDEE)	Received approval for stratigraphic test well and pad but has since expired	
Reclamation Plan, Topsoil Protection Plan	Stratigraphic Test Well, Plume Monitoring Well	NOGCC	Engineering designs are complete for well pad	Updated as needed
Nebraska G&P CERT Review	Stratigraphic Test Well, Plume Monitoring Well, Pipeline, Capture Site	Nebraska G&P	Received approval but has since expired. Required a swift fox survey shortly before dirt disturbance.	6 months
Building Permit		Morrill County	Agency waiting on final engineering diagrams to determine whether this is required.	NA
Oversize and Overweight Permits	Any phase of the project when moving heavy equipment across roadways	Nebraska Department of Transportation	Waiting on rig selection and final pipeline and capture designs.	Unknown
Conditional Use/Grading Permits	Any phase of the project if grading is involved	Morrill County	Morrill County was not sure if a building permit negates this permit, but if it is applicable, it will be submitted 2 months prior to any significant earth disturbance	

Table 1 (cont.)

Permit	Related Activity	Granting Authority	Status (including received or expected date)	Renewal Frequency
Pipeline Siting and Permitting/Use by Special Review	Pipeline	Morrill County	Waiting on Pipeline and 90% Engineering Design	NA
Section 401 & 404, Section 10, Nationwide Permit 58 (NWP 58)	Pipeline	U.S. Army Corps of Engineers (USACE)	Do not anticipate entering wetlands requiring USACE permitting. Final determination upon 90% pipeline design.	NA
Road & Bridges Permit		Morrill County	Waiting on Final Ditch Culvert Design coming in 2024	
Regional General Permit (Utility)	Pipeline and/or Capture Facility	USACE	Waiting on Engineering Designs to mature to determine applicability	Unknown
Section 408 Review				
Zoning & Planning / Building permit		Morrill County		NA
Road crossing permits/Driveway permits	Any phase of the project if applicable			
USACE Interest Properties Determination and Outgrant Process	Pipeline	USACE		Unknown
Section 7 Consultations for Threatened or Endangered Species Review and/or Clearance	Pipeline and/or Capture Facility	U.S. Fish and Wildlife Service (USFWS)	Waiting on Engineering Designs to mature to determine applicability. Performed concurrently with the Section 10/404 process. All projects presented to the USACE will undergo a Real Estate review.	
Floodplain Management Permits/Wetland & Waterbody Permitting	Pipeline	Morrill County	Do not current anticipate entering wetlands but a final determination will be made once 90% pipeline design is complete	
Pipeline and Hazardous Materials Safety Administration (PHMSA) Safety Plan		PHMSA	PHMSA Rules are still being written.	

Permit	Related Activity	Granting Authority	Status (including received or expected date)	Renewal Frequency
General Permit NEG672000 for discharges from hydrostatic testing of pipelines, tanks, and similar vessels	Pipeline	NDEE	Will submit once engineering designs are 90%.	Unknown
National Historic Preservation Act (NHPA), Section 106 consultation		State Historic Preservation Office	Will submit once engineering designs are 90%. Carbon America met with the agency, who assisted with a desktop review of the area.	
Raw Water Treatment Plan	Capture Facility Permits will be identified at the 90% design in 2024. In preparation for the design deliverable, many permits are identified below though most of these permits are not anticipated as the capture system does not produce a lot of waste or require water.	NDEE	Waiting on Engineering Designs to mature to determine applicability	
Wastewater Treatment and Discharge Plan				
Construction and Operational Dewatering Plan				
Capture Facility Safety Plan				
Construction Safety Plan		OSHA		
Classification of Hazardous Areas Assessment		NDEE		
Bulk Chemical Storage Plan				
Emergency Response Plan		OSHA		
Noise Assessment and Noise Mitigation Plan		Morrill County		
Spill Prevention Control and Countermeasure Plan		NDEE		

Permit	Related Activity	Granting Authority	Status (including received or expected date)	Renewal Frequency
General Permit NER210000 for construction stormwater discharge	Capture Facility Permits will be identified at the 90% design in 2024. In preparation for the design deliverable, many permits are identified below though most of these permits are not anticipated as the capture system does not produce a lot of waste or require water.	NDEE	Waiting on Engineering Designs to mature to determine applicability	Unknown
Air Permit				Annually
Waste Disposal				Unknown
Municipal Water Use Agreements		Morrill County		
Transportation Plan				
Fencing and Signage Plan		N/A		

3.5 Public Outreach

Bridgeport, Nebraska was founded in 1900 as a station by the Burlington Railroad and is located near many historic trails of the American West. The local economy is grounded in agriculture, oil and gas, and railroad industries. EPA's environmental justice (EJ) screening tool (EJ Screen), Department of Energy's (DOE) EJ tool (Energy Justice Mapping Tool - Disadvantaged Communities Reporter), and the Council on Environmental Quality's (CEQ) EJ tool (Climate and Economic Justice Screening Tool, CEJST) were used to assess nearby community characteristics, such as per capita income and national percentile wastewater discharge. EPA's EJ screening tool and the Energy Justice Dashboard identified an EPA IRA disadvantaged community in the City of Bridgeport. However, the CEJST tool did not identify a disadvantaged community in the Bridgeport area. Regardless, Voyager considered social impacts of the project when selecting the injection well location 4 miles west of the city. Additionally, Carbon America has partnered with the Nebraska Oil and Gas Conservation Commission (NOGCC) to remediate a nearby abandoned produced water injection site with soil and groundwater contamination. Carbon America hired an environmental consultant to prepare Phase I and Phase II Environmental Site Assessments, and the NOGCC will use federal orphan well funding to clean up the site. This allows Carbon America's project to use existing disturbance while also improving the local water resources for the community.

The location of Voyager 1 avoids surface use conflict and population impact. The well is located on a large contiguous private landholding. The injection site is favorable due to ease of access to pore space rights and minimal population density, avoids material conflicts with existing rights (e.g., surface use or areas of active oil and gas production), and avoids sensitive areas and fractionation of wildlife habitat.

The project will permanently remove 175,000 mtpy of CO_2, equivalent to taking 35,000 passenger vehicles off the road, and will enable the BPE plant to reduce the carbon intensity of ethanol production. This CCS project will increase the plant's competitiveness in the market while improving local air quality.

Carbon America is committed to the project being a model of successful community relations for CCS projects, and has an inclusive outreach strategy that educates stakeholders and provides mechanisms for community feedback. Carbon America's Community Engagement Plan is a living document with active input from stakeholders to ensure that implemented methods are appropriate and facilitate widespread social acceptance. This two-way engagement strategy has allowed stakeholders to participate in decisions and shape actions that benefit their local community. Since initial stakeholder analysis and early engagement with key stakeholders in 2022, outreach has continued in the community, with no formal opposition to the project.

As the project advances, Carbon America will identify appropriate project agreements (community benefit agreements, memorandums of understanding, and/or good neighbor agreements) for community partnerships. This process will lay the groundwork to incorporate consent-based siting principles into the engagement plan.

Carbon America has been dedicated to intentional community engagement since 2022. Multiple community meetings and open houses were conducted and over 100 one-on-one meetings with stakeholders and landowners were held. The Voyager project has also been featured in multiple local news outlets and has a project webpage with a mechanism for community feedback. Carbon America has engaged with the following local community, business, and environmental groups, as well as businesses and government officials and agencies:

- Community, Business, and Environmental Groups
  - Morrill Chamber of Commerce
  - Nebraska Cattlemen (Morrill County local affiliate)
  - Morrill County Rodeo Farm and Ranch Association
  - Local Religious groups
  - Society of Farm Managers and Rural Appraisers
  - Nebraska Farm Bureau
  - Seunghee Kim, a University of Nebraska engineering professor who is conducting research on CO2 sequestration at a stratigraphic well in Kearney County
  - Nature Conservancy
  - Nebraska Chapter of the Sierra Club
- Government Officials and Agencies
  - City of Bridgeport
  - Morrill County
  - Emergency responders including the Sherrif, local ambulance and hospital staff
  - Six meetings with the Nebraska Oil and Gas Conservation Commission (NOGCC)
  - EPA Region 7
  - Nebraska Department of Environment and Energy (NDEE)
  - Nebraska Department of Natural Resources (DNR)
  - Nebraska Public Power District
  - Nebraska Wildlife Management
  - United States Department of Agriculture
  - Bridgeport Soil Conservation Natural Resources Conservation Service NRCS
  - Nebraska Department of Transportation (Highway 88)
  - Nebraska Board of Educational Funds BELF
  - State Historical Preservation Office (SHPO)
  - Nebraska Governor Jim Pillen
  - Director of the Nebraska Department of Agriculture

Carbon America has started early discussions on how the CCS project can support local economic development goals and create a positive impact to local businesses, consistent with the goal to establish a strong mutually beneficial relationship with the community through two-way feedback and consent-based siting principles. Carbon America envisions including job opportunities and training commitments in both construction and operation phases of the project, as well as programs to advance science, technology, engineering, and math (STEM) education and diversity. Members of the project team have held early discussions with educators to help guide this work and ensure broad local engagement.

Carbon America anticipates overlap in skills possessed by the region's existing agriculture industry and needed by the emerging CCS industry. The translation of skill sets will be highlighted in the project team's recruiting efforts both in local communities and through college and trade school recruiting.

The Voyager project will require short-term job needs in construction and engineering. A full-scope CCS project will require skilled electricians, welders, millwrights, and other specialty trades that are well-represented in the area. Permanent jobs in these fields can also be filled by individuals already employed in related roles, who will receive pre-employment or on-the-job training in skills particular to the CCS industry.

3.6 Report Organization

The following section of this Permit Application Narrative describes the site geology and characteristics that make the project area suitable for CO_2 sequestration. Sections 3 through 14 summarize detailed project plans and programs. Several sections include checkboxes for verification that required information has been submitted to the EPA through its online Geologic Sequestration Data Tool (GSDT). The various documents that make up this application have been developed based on EPA's provided templates and guidelines.

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

4. Site Characterization

Geologic and hydrogeologic data presented and discussed in this section were used to develop a conceptual site model ("geomodel") for the proposed CO_2 storage site. The geomodel provides foundational data reflecting the regional and local geology surrounding Voyager 1. This information has been used to support the site suitability for CO_2 storage, as the geomodel exhibits adequate injection zone storage and upper confining zone integrity of sufficient areal extent to inhibit the migration of sequestered CO_2 into the project area USDWs. Additionally, the geomodel was used to facilitate the generation of the computational model discussed in **Attachment A: Area of Review and Corrective Action Plan**, and was also used to develop the design, construction, operation, and plugging of the injection and monitoring wells discussed in **Attachment B: Construction Details**.

4.1 Regional Geology, Hydrogeology, and Local Structural Geology

Carbon America proposes to inject CO_2 into the Lyons Formation at the Voyager project location.

The Lyons Formation is a regionally extensive Permian sandstone that can be mapped across the Denver-Julesburg Basin (DJ Basin) from the Colorado Front Range to Kansas. The Lyons Formation is characterized by a massive sandstone unit, easily identified in outcrop (type location in Lyons, Colorado) and traceable basinward through consistent well log characteristics. During the Permian, sandstone was deposited through fluvial, marine, and eolian processes (Walker and Harms, 1972). At the Voyager project site, which is situated along the eastern flank of the DJ Basin, the Lyons Formation exhibits well-sorted, poorly cemented red sandstones with crossbedding sedimentary structures indicative of eolian dune deposition. The red color is attributed to the hematite lining of the quartz matrix (Lee and Bethke, 1994). The Lyons Formation has sufficient porosity and permeability, described below, making it an excellent storage reservoir for CO_2 injection.

The Lyons Formation is bounded above and below by Permian anhydrite-rich formations, isolating the sandstone from fresh water- or hydrocarbon-bearing formations. The primary upper confining zone, the Flowerpot Formation, overlies the Lyons Formation, and is composed of a basal anhydrite and an upper shale. The Flowerpot Formation is approximately 30 ft thick and is mappable throughout the DJ Basin (Oldham, 1996). Hundreds of feet of Permian and Jurassic evaporite and shale layers overlay the Flowerpot Formation and provide secondary upper confining zones and competent no-flow boundaries.

Carbon America previously drilled the Denova 1 stratigraphic test well at the Denova Project site, also situated along the eastern flank of the DJ Basin. The Denova 1 stratigraphic test well was drilled in May 2023 and is located approximately 112 miles south of the Voyager project area, in northeastern Colorado. Robust testing consisted of (1) a high-resolution geophysical log suite, (2) formation fluid sampling, (3) pressure measurements, and (4) core acquisition. Testing program details are outlined in Appendix 3. Due to depositional history and stratigraphic similarities, results from the Denova 1 stratigraphic test well were used as analog data in the evaluation of the Voyager project site. A Voyager project stratigraphic test well is planned for 2024. Until this well is drilled, data from the Camp Clarke 23-22 well are used as the type log for the Voyager project area.

4.1.a Regional Geology

By way of historical aquifer resource evaluation, mineral exploration, and hydrocarbon development, the regional geology of the DJ Basin has been well studied via the collection of well logs, cores, geophysical datasets (e.g., seismic), and outcrop studies. The following section describes the regional and local geologic structure and stratigraphy based on the aforementioned studies, with emphasis on the relevance to the Voyager Project site.

The DJ basin is a foreland sedimentary basin located east of the Rocky Mountain Front Range and encompasses parts of Colorado, Wyoming, Nebraska, and Kansas. The basin is bounded by the Apishapa Arch and Las Animas Arch to the south, Ellis Arch and Cambridge Arch to the east, and the Chadron and Hartville Uplift to the north (Figure 4). The present-day DJ Basin is a strongly asymmetric syncline with its axis positioned close to and parallel to the Front Range with a steep western limb and a gentle eastern flank (Figure 5). Structural relief from the bottom of the basin to the top of the Front Range margin is approximately 21,000 ft. The basin geometry formed primarily through tectonic processes related to the uplift of the Rocky Mountains during two major tectonic events, The Pennsylvanian Ancestral Rockies Uplift and the Cretaceous Laramide Orogeny, that provided the accommodation for sedimentation within the DJ Basin (Figure 6). The Voyager Project site is located in western Nebraska in Morrill County on the shallower-dipping eastern flank of the DJ Basin.

DJ Basin Tectonic and Depositional Timeline

Precambrian

The Proterozoic was a time of major crustal accretion in western North America that formed the DJ Basin. The area of present-day Colorado was accreted onto the existing Archean Wyoming Province. Precambrian basement, exposed along the Colorado Front Range, is composed of Proterozoic rocks of the Yavapai tectonic province and forms the western extent of the DJ basin (Selverstone et al.,1997) and three northeast-trending Precambrian fault and shear zones: the Idaho Springs-Ralston, Moose Mountain, and the Skin Gulch shear zones (Tweto,1980; Warner, 1980). These faults are recognized as seismicity and geohazards for the oil and gas industries in the deep DJ basin in Weld County, Colorado, but do not extend to the western Nebraska Voyager project area (Figure 7).

Paleozoic

Once Precambrian igneous and tectonic activity diminished, erosion of the Front Range area reduced topography to a smoothed lowland. Lower Paleozoic strata are absent from outcrops due to erosion or depositional breaks along the Front Range and in the subsurface of western Nebraska near the Voyager project area. Remnants of Cambrian, Ordovician, Devonian, and Mississippian systems are present in thin sequences in the southern Front Range.

During the Mississippian, a major north-trending land area correlating with the present day Front Range position was subjected to repeated uplift (DeVoto, 1980). Pennsylvanian fault-block uplifting along reactivated Precambrian faults resulted in mountain ranges with as much as 10,000 ft of relief, creating the Ancestral Front Range Highland (DeVoto, 1980).

The Ancestral Front Range Highland was a source area for a thick sequence of Pennsylvanian to Permian clastics deposited along its eastern margin ranging from 800 to 4,000 ft thick. Fault movement was active during the Pennsylvanian as evidenced through abrupt facies changes and thicknesses across fault boundaries. Iron-rich arkosic sandstones and conglomerates of the Fountain Formation were deposited along the ancestral Front Range uplift prograding eastward and transitioned into eolian sandstones and marginal lacustrine carbonates and shales toward an epeiric seaway to the east.

The Permian brought a decrease in uplift of the Ancestral Front Range highland and the establishment of near present-day DJ basin extents with two major subbasins: the Alliance Basin (Nebraska panhandle) and the Sterling Basin (northeastern Colorado), separated by the paleo high of the Transcontinental Arch (Figure 8). Permian deposition east of the front range within the present-day DJ basin was dominated by eolian sandstones of the Lyons Formation and sequences of evaporites. Figure 9 is a paleogeographic reconstruction of the late Permian 253 million years ago (Ma), superimposed on modern-day North America. The Rocky Mountain uplift can be clearly observed in central modern-day Colorado with northeastern trending sand to the east across eastern Colorado into Nebraska and Kansas. The Voyager Project location is noted within the eolian deposition. The Permian ended with multiple sequences of evaporites capping the Lyons sandstone in western Nebraska.

Mesozoic

The Mesozoic era was characterized by the presence of inland seas and fluctuations in relative sea levels, leading to the deposition of alternating cycles of marine sands and terrestrial mixed sediments.

The Triassic is recorded by deposition of red beds atop Permian rocks in an unconformable manner. The precise transition has been a subject of debate in literature, given that Triassic and Jurassic rocks are not visibly exposed in Nebraska but are instead traced underground to outcrops in Wyoming (Candra and Reed, 1959).

Jurassic rocks were subsequently deposited unconformably over the Triassic rocks as the Jurassic inland sea emerged. The Sundance Formation, primarily composed of shales and sandstones, was deposited in shallow to marine systems in western Nebraska. During the Late Jurassic period, the extensive terrestrial Morrison Formation was deposited across a wide expanse following a decline in relative sea levels (Bryant and Naeser, 1980).

The Cretaceous introduced a significant inland sea known as the Western Interior Seaway, stretching from the Arctic Ocean to the Gulf of Mexico. Across various sea level transgressions and regressions, a substantial sequence (>8,000 ft) of continental and marine sediments was laid down. This encompassed the Dakota Group's Lower Cretaceous sands, the Graneros and Greenhorn formations consisting of shales and limestones, Niobrara chalks and marls, and the Pierre shale (Figure 6).

Cenozoic

The Paleogene Laramide Orogeny (70 to 65 Ma) was a time of aggressive tectonism and block-fault mountain building in Colorado forming the present-day Front Range mountains and DJ Basin largely by reactivation of Late Paleozoic basement faults and shear zones (Tweto, 1980). The north-northwest orientation of the Front Range is controlled by the north-northwest Precambrian age faults. Regional uplift of the Front Range and surrounding areas occurred through the Miocene, Pliocene, and Pleistocene, and may continue to this day, as indicated by widespread canyon cutting (Tweto, 1980a; Scott, 1960, 1963, and 1975; Trimble, 1980).

However, the Voyager project area is tectonically stable, and modern occurrences of earthquakes magnitude 3.0 and larger have not been recorded and are likely uncommon. See Section 4.6 for seismic history. The occurrences of earthquakes in the DJ Basin are often linked to hydrocarbon development, and are associated with the presence of wrench faults that do not extend into the project area (Figure 7). Existing three-dimensional (3D) seismic data were purchased and analyzed for the Voyager project area to identify fault concerns (see Section 4.3).

4.1.b Major Stratigraphic Units

The regional and local characteristics, including Voyager project zone designation, formation name, depth, and key properties of the major stratigraphic units for the Voyager project area are presented in Table 2. Approximately 3.5 miles northwest of the proposed Voyager 1 injection well location is a key type well, Camp Clarke 23-22 (2612321538000), drilled by Evertson Operating Co. in 2011, from which a full suite of modern logs was collected and made publicly available through the NOGCC (see Figure 10 for location). Figure 11 depicts key stratigraphic units with their corresponding geologic age and project zone designation. Structural cross sections with well logs through the Voyager Project area are illustrated in Figures 12 and 13.

Table 2. Characteristics of Zones and Formations of the Major Stratigraphic Units from Camp Clarke 23-22 Type Well Near the Planned Voyager 1 Stratigraphic Test Well

Zone	Formation	Formation Division	Depth (ft TVD)	Thickness (ft)	Porosity (%)	Permeability (mD)
Lowermost USDW	Chadron	—	400	87	-	-
Saline Aquifer	Dakota	D Sand	3,977	43	19.2%	4.19
		J Sand	4,114	104	20.4%	20.1
Secondary Upper Confining Zone	Skull Creek	—	4,218	107	19.5%	0.99
Saline Aquifer	Lakota	Upper Lakota	4,325	181	16.6%	66.6
		Lower Lakota	4,506	109	24.6%	183.4
Secondary Upper Confining Zone	Morrison	—	4,615	193	16.1%	1.79
Saline Aquifer	Sundance	—	4,808	79	23.4%	77.8
Secondary Upper Confining Zone	Permian (Undifferentiated)	Minnekahta	4,960	12	<1%	<0.01
		Opeche	4,982	18	11.7%	0.72
		Blaine	5,001	155	3.1%	9.23
Upper Confining Zone	Flowerpot Formation	Flowerpot shale	5,156	19	20.2%	3.92
		Flowerpot anhydrite	5,175	9	<1%	<0.01
Injection Zone	Lyons Formation	—	5,184	46	21%	133.5
Lower Confining Zone	Salt Plain Formation	—	5,230	156	10.7%	1.42
	Wolfcamp	—	5,386	459	3.6%	1.26

mD = milliDarcy

Lower Confining Zones

Stone Corral Formation

The Stone Corral Formation is an evaporite and acts as a lower confining zone, where present, for the injection system. At the Camp Clarke 23-22 well approximately 3.5 miles northwest of the Voyager project area, the Stone Corral Formation is absent. At the Lapaseotes 1 well, approximately 6 miles southeast of the Voyager 1 location, the Stone Corral is approximately 23 ft thick and dominated by salt based on available porosity logs. Where present, the porosity (Φ) and permeability (K_h) are expected to be at or near 0% and 0 millidarcies (mD), respectively, due to the dominance of the mineral halite and/or other evaporites (Table 2).

Regionally, the Stone Corral Formation onlaps the pre-late Leonardian (middle Permian) unconformity (Rascoe and Baars, 1972) and can be up to 100 ft thick. Deposition of the Stone Corral Formation was influenced by the paleotopography of the Permian Sterling Basin, Alliance Basin, and the Transcontinental Arch in eastern Colorado, western Kansas, and southwestern Nebraska (Figure 8). Oldham (1996) describes the Stone Corral Formation as an evaporite composed of white, light brown, and pink anhydrite, pink and light brown dolomite, and in place, halite. Regional cross sections demonstrate the Stone Corral varies in thickness regionally (Figures 12 and 13). Regional structure and isopach maps show the Stone Corral to be thin or absent in the northwest of the purchased 3D seismic outline; however, it is expected to be present (20 to 40 ft thick) in the Voyager project area (Figure 14).

The composition and distribution of the Stone Corral Formation suggest that the depositional environment was a shallow, hypersaline sea. The Stone Corral exhibits porosity and permeability values that inhibit CO_2 fluid migration, making this formation a viable lower confining zone in the Voyager project area.

Salt Plain Formation

The Salt Plain Formation is a brown-red mottled dolomitic, argillaceous, very fine-grained sandstone in sharp contact with the underlying Stone Corral Formation. The Camp Clarke 23-22 type well shows approximately 10.7% porosity and 1.42 mD permeability (Table 2). This low permeability is likely due to high amounts of bioturbation, soft sediment deformation, and anhydrite-filled fractures, all of which were observed in the Salt Plain Formation at Denova 1. The Salt Plain Formation is not an injection zone due to its low permeability, and will act as a lower confining zone.

The Salt Plain Formation (Cragin, 1896) overlies the Stone Corral Formation where present; otherwise, it overlies the Wolfcamp Formation and underlies the Lyons Formation. Regionally, where the Lyons Formation is the thickest near the Front Range, the Salt Plain Formation is thinner (Oldham, 1996). The Salt Plain is described as orange to red-brown shale, silty in places with orange very fine-to fine-grained sandstone (Oldham, 1996). The Salt Plain is often rich in salt content, and is commonly thicker where it overlies the Stone Corral Formation, suggesting that the red clays and silts accumulated in the same restricted basin environment as the Stone Corral (Oldham, 1996). Regional cross sections demonstrate that the Salt Plain Formation is present throughout the Voyager project area (Figures 12 and 13). Regional structure and isopach maps show a dip to the southwest of less than 1.0 degree and display a thickness range from approximately 140 to 240 ft at the Voyager project area and across the dynamic model Area of Interest (AOI) (Figure 15).

The soft sediment deformation and level of bioturbation suggest that the depositional environment was modified lower shoreface.

Injection Zone - Lyons Formation

The Lyons Formation was named by Fenneman (1905) for the pure quartz sandstone of the Front Range that forms the red cliffs of Lyons, Colorado. This unit is also called Cedar Hills, which is a Midcontinent term for the fine-grained sandstone of the Cedar Hills in Barber County of central Kansas (Cragin, 1896). These two units are time equivalent and directly underlie the Flowerpot Formation. To reduce confusion and maintain consistency with Carbon America's Denova Project Class VI permit, this permit will use the Front Range terminology and refer to the injection zone as the Lyons Formation.

Table 2 summarizes the estimated properties of the Lyons Formation at the Camp Clarke 23-22 well. Estimated porosity and permeability are expected to average 21.0% and 133.5 mD at the Camp Clarke 23-22 well. The high porosity and permeability of the Lyons Formation are conducive for CO_2 injection and storage.

Regionally, the Lyons Formation is the thickest, most widespread coarse clastic unit within the DJ Basin (Oldham, 1996). The Lyons Formation is primarily a sandstone deposited during the Permian Period as part of the larger sedimentary sequence that formed during the Pennsylvanian and Permian due to the uplift of the Ancestral Rocky Mountains (Figure 5). It consists of sand-sized quartz grains, feldspars, and cements. The Lyons Formation was deposited in eolian and shallow water environments. Along the Front Range, the Lyons Formation was deposited as eolian sandstones sourced from the north and the east, and intertongues with arkoses derived from the Ancestral Rockies (Fountain Formation) (Sonnenberg and Weimer, 1981). The Lyons Formation is thickest along the Front Range and the axis of the DJ Basin, and thins to the east toward Kansas. It is geographically present throughout the DJ Basin, and was deposited in a complex geological setting involving relative sea level changes, climate change, and tectonic activity.

Regional cross sections demonstrate that the Lyons Formation is present throughout the Voyager project area (Figures 12 and 13). Regional structure and isopach maps across the dynamic model AOI show a dip of less than 1 degree to the southwest and display a thickness range of 27 to 93 ft, with an average thickness of 63.5 ft (Figure 16).

The Lyons Formation at the Voyager project area is interpreted to be deposited in an eolian setting, possibly during a drought due to the lack of cementation. The Lyons Formation transitions into a lower shoreface or semi-isolated lagoonal setting with terrestrial fluvial influence creating ripples and crossbedding.

Primary Confining Zone - Flowerpot Formation

The Flowerpot Formation consists of a lower anhydrite, often informally called the Flowerpot Anhydrite, and an overlying shale, informally called the Flowerpot Shale (Rascoe and Baars, 1972). The Flowerpot Anhydrite is a regional marker bed, as the base marks the top of the Lyons Formation. It is often inconsistently named in the subsurface often being called the wrong formation name by operators. For the purpose of this permit, the Flowerpot Anhydrite and the Flowerpot Shale will be grouped together in the Flowerpot Formation, but can be discussed separately due to the difference in lithology characteristics.

Table 2 summarizes the estimated properties of the Flowerpot Formation at the Camp Clarke 23-22 well near the proposed Voyager 1 stratigraphic well location. The Flowerpot shale overlying the anhydrite has an estimated porosity of 20.2% and permeability of 3.92 mD. This low permeability is likely a result of evaporite porosity fills, which were observed in the Denova 1 core within this formation. The underlying anhydrite has an estimated porosity near 0% and permeability of 0 mD due to the crystalline nature and high density of the rock. The extremely low porosity of the anhydrite layer, the heterogeneity of the shale, and the regional deposition of the Flowerpot Formation make this formation a viable upper confining zone for the Voyager Project.

Regionally, the base of the Flowerpot Formation is an anhydrite, measuring approximately 30 ft thick and present throughout the DJ Basin. Overlying the anhydrite is a shale that can be bright red-orange to light red-brown with anhydrite and halite inclusions. The anhydrite “blooms” of fracture filling cement in the shale is often an indicator of the Flowerpot Formation.

Regional cross sections highlight the continuous nature of the Flowerpot Formation across Voyager Project area (Figures 12 and 13). Regional structure and isopach maps across the dynamic model AOI show an average dip of 0.5 degrees to the southwest. The Flowerpot Formation is 28 ft thick at the Camp Clarke 23-22 type well near the Voyager project location (Figure 17).

The depositional environment for the Flowerpot Formation is interpreted as a transition from a shallow hypersaline sea or semi-isolated coastal lagoon (anhydrite) to a sabkha environment. Terrestrial waters could have introduced fresh water supply to the system through fluvial processes.

Secondary Confining Zone - Blaine through Minnekahta Formations

Overlying the Flowerpot Formation are the thick Permian evaporites and shales of the Blaine, Opeche, and Minnekahta Formations. These formations will be referred to as the secondary confining zone throughout the permit, and are often mapped as Triassic-Permian undifferentiated.

Together, the secondary confining zone for the Lyons injection interval measures 185 ft of total thickness (Blaine 155 ft, Opeche 18 ft, and Minnekahta 12 ft). The shale-rich layers of the Opeche have a calculated average porosity of 11.7% and average permeability of 0.72 mD. The evaporite-rich layers (Minnekahta and Blaine) have a calculated average porosity ranging from 0% to 3.1% and a permeability ranging from 0 to 9.23 mD. Table 2 summarizes the average calculated rock properties for each formation. The thickness, heterogeneity, and low porosity and permeability values make the secondary confining zone a substantial barrier between the injection zone and the overlying geology.

The Permian rocks overlying the Flowerpot Formation consist of three laterally continuous units: the Blaine Formation, the Opeche Member, and the Minnekahta Formation. The Blaine Formation is the youngest unit, and is a persistent thick subsurface marker across the DJ Basin. Regionally, it consists of thick salts or anhydrites. The Opeche Member is a widespread 30- to 50-ft-thick shale with minor siltstone, sandstone, and anhydrite, and can be orange or purple (Oldham, 1996). The Opeche is often described by drillers as “greasy,” and has been nicknamed the “bubblegum shale” due to it being a drilling hazard (Oldham, 1996). The Minnekahta Formation is an anhydrite-rich limestone unit exposed in the Black Hills (Darton, 1909). The Minnekahta is thought to be originally deposited as an evaporate and replaced by calcite (Benison et al., 2018). It is typically recognized in cuttings as a white or light pink dolomite and anhydrite (Oldham, 1996).

Cross sections demonstrate the secondary confining zone is present regionally across the Voyager project area (Figures 12 and 13). Regional structure and isopach maps show a dip of less than 1 degree to the southwest in the Voyager project area (Figure 18.

The Permian deposition following the Flowerpot Formation is a series of evaporates and shales deposited in shallow saline lake and playa environments (Benison et al., 2018; Benison and Goldstein, 2000). The overlying Jurassic Morrison records a complex depositional environment over an extensive area, including fluvial systems, floodplains, and lacustrine environments (Tanner et al., 2014).

Lowermost USDW Formation – Chadron of the High Plains Aquifer

The Lower Oligocene Chadron Formation of the High Plains Aquifer has been identified as the lowermost USDW in the Voyager Project area. The Chadron Formation is considered a Secondary Aquifer for the State of Nebraska (Devine and Sibray, 2017). This aquifer system consists of an upper confining unit with greenish bentonitic clays and thin interbedded lacustrine limestones overlying a complex valley fill sequence of unconsolidated sands and shales. Several basal cut and fill sequences are noted from outcrops to the north near South Dakota (Devine and Sibray, 2017). In the Voyager project area, available log data suggest a 90-ft-thick Chadron sand unit unconformably overlying the Pierre Shale. This will be confirmed during the drilling of the Voyager stratigraphic test well.

Water quality in the Chadron Aquifer is generally very mineralized, with some wells in Morrill County showing high levels of arsenic and uranium. As a result, the water from this aquifer is generally restricted to livestock and limited irrigation (Devine and Sibray, 2017).

The Chadron Formation is a member of the High Plains Aquifer, which consists of continental clastics ranging in age from Latest Eocene to Quaternary and internally subdivided by several unconformities. Significant unconformities are present at the top of the Miocene Ogallala and Oligo-Miocene Arikaree Formations, with time gaps from 2 to 10 million years associated with substantial underlying section loss. Lesser unconformities have been mapped at the top of the Brule and Chadron Formations (Swinehart, 1979, Diffendal et al., 1985; Devine and Sibray, 2017). The base of the High Plains Aquifer system is a significant unconformity at the top of the Upper Cretaceous. The Chadron Formation relationship to area aquifers is discussed further in Section 4.7.

The High Plains Aquifer consists of a mix of alluvial, dune, lacustrine, and fluvial valley fill unconsolidated sands, gravels, silts, and shales deposited during the Oligocene, Miocene, Pliocene and Quaternary. Minor

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ash beds are occasionally useful markers in outcrop, but are less reliable in the subsurface due to limited sampling while drilling the shallow intervals. Reservoirs are generally discontinuous, thin, and difficult to correlate, particularly between widely spaced wells.

In the Voyager Project area, Eocene-Oligocene Chadron Formation continental clastics unconformably overlie Uppermost Cretaceous Pierre marine shales. Regional structure and isopach maps show a dip of less than 1 degree to the southwest in the Voyager project area (Figure 19). The Lyons injection zone and the base of the Chadron are separated by approximately 4,800 ft in the Voyager project area (Figure 20).

The Chadron aquifer was deposited as valley fills (Devine, 2017).

4.1.c Seismic Interpretation

Seismic interpretation was performed on data licensed from an existing 3D seismic survey to assess the geometry and structure of lateral and vertical containment elements for injected CO_2. Reservoir and confining units were mapped, as well as any discontinuities transecting the injection zone that could be interpreted as faults or fracture networks.

The existing Roundhouse Rock 3D survey was acquired in 2011 to map shallow Cretaceous Dakota J Sandstone targets for oil and gas exploration. An area of 30 sq mi of the existing survey was licensed to characterize the continuity of the project area injection and confining zones (Figure 21). Key horizons were identified by tying into a synthetic seismogram generated from the Camp Clarke 23-22 well. Figure 22 shows the synthetic well tie for this well using a zero-phase wavelet matching the frequency content extracted from the Roundhouse Rock 3D survey.

The seismic interpretation workflow followed for this project included the following steps:

- Creating a project in IHS Kingdom Suite including licensed seismic data and all relevant wells with matching datum
- Generating synthetic seismogram and performing the seismic well tie
- Picking key horizons and tying into formation tops from wells with no sonic and density logs
- Tracking key reservoir and confining zone seismic reflectors to assess lateral continuity
- Generating volume and horizon-based attributes to highlight anomalies related to changes in layer thickness, rock properties or structures
- Mapping identifiable discontinuities to assess fault and/or fracture risk, type, offset, and throw
- Producing digital grid files
- Producing point file location data of any identified faults or fracture networks

Seismic interpretation deliverables of relevant horizons include seismic cross sections, depth structure maps, amplitude attribute maps, seismic thickness (isochron) maps, fault and/or fracture network identification, and associated digital files for the above.

Velocity survey data (checkshots) were not available for any wells within the seismic project area. After finalizing the synthetic well tie at the Camp Clarke 23-22 well and matching the key well tops to seismic horizons, a velocity model was generated for depth conversion using Dynamic Depth Conversion (DDC), an IHS Kingdom software module. This final processing step was needed to convert trace volume and all interpreted data sets from two-way time to depth for input into the geomodel.

Figure 23 shows an interpreted seismic profile across the synthetic tie well, the planned Voyager 1 and Voyager IZM locations, and all key horizons within the seismic coverage for the project. This profile shows relative continuity of the reservoir and containment formations at seismic resolution scale. Gaps in seismic coverage exist in the vicinity of the Voyager 1 well location due to no-permit areas during the original acquisition.

3D seismic interpretation provided structural control for the Voyager Project geomodel and provided elevation (depth) grids for the following key formations:

- Skull Creek Shale

- Morrison
- Sundance
- Permian/Blaine (secondary upper confining zone)
- Flowerpot Shale and Flowerpot Anhydrite (upper confining zone)
- Lyons (injection zone)
- Salt Plain Formation (lower confining zone)

Depth grids generated from the seismic data were used to plot additional maps and cross sections of relevant formations throughout the AoR, as detailed in Section 4.2.

4.2 Maps and Cross Sections of the AoR

Carbon America's Denova 1 stratigraphic test well was drilled in May 2023 to collect data for geologic characterization in the Denova project area. High-resolution geophysical log suites, stress testing data, fluids samples, and physical whole cores were collected through the injection zone and adjacent confining layers. The results from the Denova 1 stratigraphic test well were used in conjunction with log analysis of Voyager project area wells to evaluate the Voyager project area. Figures 24 and 25 show the full petrophysical suite of available log data of the injection and confining zones at the Camp Clarke 23-22 well, the Voyager project area type log.

The Voyager project site, located in Morrill County, Nebraska on the shallowly dipping eastern flank of the DJ Basin, is approximately 130 miles from the Front Range (Figure 4). Oil and gas activity is low in this area outside of the Wattenberg Field, where Niobrara and Codell horizontal well development is prominent, and west of the biogenic Niobrara fields of Yuma County. The area has a history of vertical well exploration targeting conventional Dakota J Sand channels, leaving behind numerous plugged and abandoned dry holes (Figure 26). Three wells are still active within the AoR; however, the wells do not penetrate the injection or confining zones. Injection wells, State-or EPA-approved subsurface cleanup sites, surface bodies of water, springs, mines (surface or subsurface), quarries, and State, Tribal, and Territory boundaries do not exist within the project AoR, and therefore are not shown on Figure 26. A 3D seismic survey was shot in 2011 to evaluate a large parcel of state land for development.

The bedrock geology at the Voyager project site is predominantly composed of unconsolidated to semi-consolidated sands and silts of the Eocene to Oligocene White River Formation (Figure 27).

Data from the Camp Clarke 23-22 type well described in Section 4.1.b were used in conjunction with the seismic data described in Section 4.1.c to generate project-area cross sections C-C' and D-D' (Figures 28 and 29). These cross sections are used to demonstrate the lateral and vertical extents of the lower confining zone, the injection zone, the upper confining zone, and the secondary upper confining zone. The horizon tops are labeled in Figures 28 and 29.

4.3 Faults and Fractures 40 CFR 146.82(a)(3)(ii)]

As mentioned in Section 4.1.a detailing the regional geology of the basin, the Voyager Project area is situated in the shallower, west-dipping eastern flank of the DJ Basin. The easternmost extent of faulting associated with the basement wrench zones emanating from the Front Range in the western part of the basin is more than 130 miles from the Voyager project area (Figure 7). No faults related to these basement-involved structures are present within the AoR or geomodel area. At a local scale, the geologic structure at the project site was assessed for the presence of faulting and to identify different fault types (i.e., critically stressed, sealing, leaking) by conducting a detailed seismic and well data evaluation (Section 4.1.c). 3D seismic analysis focused on the identification of possible fracture zones often associated with fault intersections and zones of structural flexion.

4.3.a Fault Presence

A thorough examination of the current 3D seismic data revealed no evidence of faults offsetting the injection zone or confining zones within the AoR. The 3D analysis involved meticulous techniques, including visual interpretation of faults and identification of discontinuities using seismic attributes like volume-based reflector curvature, coherency, dip, and azimuth. Additionally, historical well data underwent scrutiny for any fault indications, such as repeated sections, mudlogs, or driller notes. None of these analyses detected faults causing displacement in the injection or confinement layers within the AoR.

Analysis of the existing 3D seismic data identified reflector discontinuities that could be interpreted as discontinuous fault features roughly one mile to the northwest of the AOR boundary and approximately 1 mile southeast of the Camp Clarke 23-22 well as shown in Figure 23. Further refinement of the seismic imaging in this area would be needed to verify the presence of faulting. The required improvement in resolution could be achieved through reprocessing of the legacy data with likely further enhancement by the planned acquisition of a new 3D seismic survey to serve as a pre-injection, baseline survey. These hypothetical fault features are not anticipated to introduce risk to the project due to their isolated nature, lack of basement connectivity, and distance to the delineated AoR.

4.3.b Fault Sealing Potential

There are no interpreted faults present within the AoR; therefore, a fault seal analysis was not performed.

4.4 Injection and Confining Zone Details [40 CFR 146.82(a)(3)(iii)]

This section focuses on the details of the injection and confining zones in the vicinity of the AoR. The storage complex of the Voyager project consists of the overlying upper confining zone (Flowerpot Formation), the injection zone (Lyons Formation), and the lower confining zone (Salt Plain Formation) (Figures 28 and 29). The depositional history, stratigraphical characteristics, and tectonic framework of these units are described in detail in Section 4.1. Physical whole core will be taken through the primary upper confining zone, injection zone, and lower confining zone during pre-operational testing (see Section 3.2.c of **Attachment D: Pre-Operational Testing Program** for additional details). The secondary upper confining zone is excluded from the discussion below because the primary upper confining zone has sufficiently effective sealing capability. Both primary and secondary upper confining zones were evaluated for 3D porosity and permeability modeling, and were ultimately simplified as having no effective permeability, as described in later sections. Table 3 summarizes the elevations, areal extent, and thicknesses of the injection and confining zones. Each zone is pervasive across both static and dynamic model AOIs.

Table 3. Injection and Confining Zone Details within the Model Domains

Zone	Formation	Average Surface Elevation of Formation (ft relative to msl)	Average Thickness (ft)		Lithology
			Static Model	Dynamic Model	
Upper Confining Zone	Flowerpot Shale	-1,423	19.8	20.4	Shale
	Flowerpot Anhydrite	-1,443	14.1	12.0	Anhydrite
Injection Zone	Lyons	-1,455	63.6	61.2	Sandstone
Lower Confining Zone	Salt Plain	-1,516	169	175	Shale

msl = mean sea level

4.4.a Determination of Injection and Confining Zone

The project location was identified based on regional geologic context gathered from existing literature, available 3D seismic data, well log availability from legacy oil and gas development, and estimated petrophysical characteristics of prospective injection and confining zone sequences in the DJ Basin (Section 4.1). The Lyons Formation meets key injection zone criteria including (1) high porosity and permeability to allow sufficient injectivity, (2) sufficient depth, temperature, and pressure to keep CO_2 in a supercritical state, and (3) formation fluid salinity greater than 10,000 milligrams per liter (mg/L) total dissolved solids (TDS). The upper confining zone represents an effective seal as a laterally continuous anhydrite of consistent and sufficient thickness (greater than 12 ft on average) subsequently overlain by a similarly thick (approximately 20 ft average), laterally continuous, and low-permeability shale that exhibits high entry pressure and ductility in analog data from the same zone.

As detailed in **Attachment A: AoR and Corrective Action Plan**, geophysical log and 3D seismic data were integrated into SLB's Petrel Software to construct a structural geologic model to determine depth, areal extent, and thickness of the injection and confining zones. Well tops were correlated and interpreted from geophysical logs based on established stratigraphic definitions from literature and legacy oil and gas exploration. Structural surfaces were generated for key zones by combining depth-converted seismic horizons with interpreted tops to establish the static model zonation. Figures 28 and 29 illustrate the structural character of the storage complex and overlying stratigraphy beneath the AoR.

At the proposed Voyager 1 injection well, the estimated thicknesses of the lower confining zone, injection zone, primary upper confining zone are 167 ft, 62 ft, and 31 ft, respectively. Within the AoR, cross sections show lateral continuity of both the injection and confining zones (Figures 28 and 29). Figure 30 shows the isopach maps for the confining and injection zones. The lower confining zone has an estimated thickness range of 140 to 240 ft. The injection zone exhibits thinning to the west and north and grades into salt to the east and south with an estimated total thickness range of 27 to 93 ft across the static model domain. The primary upper confining zone has an estimated thickness range of 12 to 68 ft. Thickness variations within the proposed injection and confining zones are subtle across the project area and are not expected to impact injection capabilities. The following section further describes the spatial distribution of petrophysical properties for the injection and confining zones in greater detail.

4.4.b Injection and Confining Zone Properties

Well log data from historical oil and gas wells were gathered and integrated into the petrophysical analysis. Legacy well data were obtained from the NOGCC. Of those wells, 21 have complete or partial modern log suites (e.g., gamma ray [GR], neutron porosity [NPHI], density porosity [DPHI], bulk density [RHOB], photoelectric factor [PEF], shallow [RESS] and deep resistivity [RESD], and/or sonic slowness [DTC], etc.) suitable for 3D property modeling of porosity (POR) and permeability (K_SDR). Figure 10 displays wells with key log data. Table 4 lists the set of wells containing sufficient modern log suites used in calculating petrophysical properties. For logs requiring patching and repair and for wells lacking a complete suite of log data for estimating permeability, a neural network was used to generate synthetic equivalents, which are specified in the "Estimated/Repaired Logs" column. Establishing complete geophysical log suites for each well facilitates further evaluation of continuous mineralogical, lithological, and petrophysical characteristics vertically across the prospective injection and confining zones. Methodologies used for calibration and validation of geophysical logs are discussed below and are elaborated in Section 2.4 of **Attachment A: AoR and Corrective Action Plan.**

Table 4. Wells With Modern Logs Used to Characterize Petrophysical Porosity and Permeability Within the Static Model Domain

Well Name	UWI	Latitude (degree)	Longitude (degree)	Estimated/Repaired Logs
AF HOLT 1	26033223220000	41.3897	-103.1346	K
AURICH 1	26123215020000	41.4589	-102.8992	PEF, K
CIZEK 1	26033223620000	41.3786	-103.3599	K
CAMP CLARKE 23-22	26123215380000	41.6885	-103.1901	SP, PEF, DT, K
COOPS-LINBERG 1	26123214870000	41.47	-103.2558	K
CRANMORE 1	26123214040000	41.5004	-102.8836	PEF, K
GREENWOOD RANCH 15-1	26123214850000	41.4486	-103.0746	K
HART 1	26123215010000	41.5746	-102.9875	RHOB, K
LAPASEOTES 1	26123213650000	41.6139	-103.0451	RESD, PEF, DT, K
LEO A DURNAL 1	26123214950000	41.7264	-103.3642	K
LESSMAN 1	26123215230000	41.469	-102.9328	DT, K
LINDBERG RANCH 42X-6	26123215180000	41.4782	-103.2369	PEF, K
NORMAN E JOHNS 3-12	26157212950000	41.733	-103.5396	K
OLSEN ILER 1	26007217350000	41.6356	-103.6883	PEF, K
PETERS 11-12	26123215360000	41.4652	-103.2698	K
PETERSEN 2-24	26123214130000	41.7854	-103.1711	NPHI, PEF, DT, K
SCHNEIDER-SCOTT 1	26105214040000	41.3855	-103.4236	RHOB, NPHI, PEF, K
SINGLETON 17-A	26007069250000	41.4357	-103.4728	RESD, RHOB, NPHI, PEF, K
STATE OF NEBRASKA 1	26123214830000	41.4442	-102.8656	PEF, K
STEVENS 1	26123214120000	41.6648	-102.7466	PEF, DT, K
TOOF 1	26033221300000	41.385	-102.8187	PEF

DT = sonic; K = permeability; SP = spontaneous potential

Porosity and Permeability

Well logs from existing oil and gas wells were used to estimate effective porosity and permeability log curves, and were subsequently scaled up along the vertical well path and used to populate grid cells in the static model for the Voyager project area. The process of calibrating and upscaling porosity and permeability along with the calculation of relative permeability curves are discussed in Section 2.4 of **Attachment A: AoR and Corrective Action Plan**. Table 5 lists the average porosity and permeability for the injection and confining zones from the Camp Clarke 23-22 well and analog data from Carbon America's Denova Project static model.

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Table 5. Average Porosity and Permeability of the Injection and Confining Zones from Geophysical Log Analysis and Geocellular Modeling

Zone	Formation Division	Camp Clarke 23-22 Average Log Porosity (%)	Denova Project Average Dynamic Model Domain Porosity (%)	Camp Clarke 23-22 Average Log Permeability (mD)	Denova Project Average Dynamic Model Domain Permeability (mD)
Primary Upper Confining Zone	Flowerpot Shale	20.2%	10.8%	3.92 mD	6.18 mD
	Flowerpot Anhydrite	<1%	2.2%	<0.01 mD	0.62 mD
Injection Zone	Lyons	21%	12.1%	133.5 mD	169 mD
Lower Confining Zone	Salt Plain	10.7%	11.8%	1.42 mD	5.42 mD

The Injection zone exhibits high permeability and porosity values conducive to CO_2 injection and storage, and both the lower confining zone and the primary upper confining zone have sufficiently low porosity and permeability to ensure effective sealing of the injection reservoir.

Mineralogy

The mineralogy of the lower confining zone, the injection zone, and the primary upper confining zone was determined using geophysical log analysis (e.g., multimineral modeling and facies classification), with support from existing literature and analog core data from the Denova 1 well, located approximately 112 miles south of the Voyager project area. The lower confining zone, the Salt Plain Formation, is a reddish-brown shale with low permeability, and is more than 150 ft thick. The injection zone is primarily composed of silicate minerals, as it is quartz-dominated with minor components of feldspar, clays, dolomite, calcite, anhydrite, and hematite. The dolomite, clay, and feldspar content increase in the uppermost portion of the injection zone. As discussed in Section 4.1.b, the primary upper confining zone consists of the Flowerpot Anhydrite and the Flowerpot Shale. The Flowerpot Anhydrite is primarily anhydrite with trace amount of clay minerals, quartz, and pyrite. The Flowerpot Shale contains equal amounts of quartz and clay minerals, with variable amounts of dolomite, feldspar, hematite, and halite. Silicate minerals and evaporites are generally unreactive with CO_2 and CO_2 saturated brine. The CO_2 compatibility with formation fluids and minerals will be tested using permeability as a function of throughput during pre-operational testing (see Section 3.2.c of **Attachment D Pre-Operational Testing Plan**). Refer to Section 4.1.b for a detailed minerology discussion and Section 4.8 for additional detail on geochemistry and mineral compatibility with the proposed CO_2 stream.

Sealing Capacity and Integrity

Mercury injection capillary pressure (MICP) analyses will be performed on samples of the primary upper confining zone following drilling and core acquisition of the Voyager 1 well. The confining characteristics and pore system will be evaluated. The seal capacity will be characterized by the column height of CO_2, which will be calculated from MICP experimental results. An assessment of seal capacity shown in Table 6 modified from the Sneider Seal Classification (Sneider et al., 1997; Bolger and Reifenstuhl, 2008) was prepared to evaluate the seal type rank of each confining zone.

Table 6. CO_2 Seal Types Assessment Based on Air-Hg Entry Pressure and Range in CO_2 Column Height Using MICP Analysis Results

Seal Type	Entry Pressure (pounds per square inch)	CO_2 Column Height (feet)
A	>173	>1,000
B	86–173	500–1,000
C	17–86	100–500
D	9–17	50–100
E	2–9	<50
F	<2	Waste Zone

Modified from Sneider et al., 1997

Storage Capacity

Computational modeling at the proposed location of the Voyager 1 injection well was completed to delineate the CO_2 plume shape and extent, its projected lateral and vertical migration, the region of pressure elevation, and the project AoR. Based on the modeling results, the pore volume available for CO_2 storage totals 37 billion reservoir cubic feet. Final conditions of stored CO_2 should be reflective of those average conditions given by simulation statistics from model year 62, the end of the 50-year PISC period, for all model cells contacted by CO_2.

Using an average CO_2 saturation of 29.3% and a CO_2 density of 22.86 pounds per cubic foot (from simulation output), the dynamic model area has an effective CO_2 storage capacity of 248 billion pounds, or 112 mmt. The Voyager Project's planned storage of 2.1 mmt uses 1.87% of the effective CO_2 storage capacity defined within the dynamic model area. Unit storage calculations for the plume area based on the AoR plume size (4.83 sq mi, or 3,091 acres), under which 2.1 mmt of CO_2 is stored, yielded calculated values of 434,783 metric tons stored per sq mi, or 679.3 metric tons stored per acre.

Some uncertainty exists concerning the spatial distribution of petrophysical properties, as no existing wells penetrate through the injection and confining zone within the AoR. This uncertainty is addressed by a worst-case (low porosity) scenario sensitivity model run discussed in detail in Section 5 of **Attachment I: PISC and Closure Plan**.

4.5 Geomechanical and Petrophysical Information [40 CFR 146.82(a)(3)(iv)]

4.5.a *Fracture Gradient Estimation*

Saltwater disposal wells throughout Nebraska oil and gas operations are typically allowed to inject with bottomhole injection gradients as high as 0.7 pounds per square inch per foot (psi/ft). Generally, no injection or step-rate test data are required to provide support to confirm that the injection is occurring at a pressure below fracture gradient, so data for fracture pressure in the region are extremely limited.

The Voyager project Class VI permit application is submitted assuming that the fracture gradient in the Lyons Formation will be 0.6 psi/ft; therefore, all dynamic simulation and modeling used this value. This is further supported by the use of a 0.7 psi/ft fracture gradient by the NOGCC to dictate injection pressures in Nebraska (Hildebrandt and Meissner, 2015). At the site of the planned Voyager 1 injection well, where the depth to the top of the Lyons storage interval is anticipated to be 5,258 ft bgs, the calculated fracture pressure is estimated to be 3,155 psi (5,258 ft * 0.6 psi/ft = 3,155 psi). The maximum bottomhole injection pressure at the Voyager 1 well is then calculated by taking 90% of the estimated fracture pressure, resulting in an estimated maximum bottom hole injection pressure of 2,839 psi (0.9 * 3,155 psi = 2,839 psi).

In this data-poor area, even calculating estimates for fracture gradient requires further estimates for parameters such as pore pressure, overburden gradient, and Poisson's ratio. Pore pressure gradient was

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calculated from regional piezometric mapping which indicated a pressure of 1,718 psi at a depth of 5,258 ft bgs, defining a pore pressure gradient of 0.327 psi/ft. Using this value in the following equations from the Hulbert and Willis method (Hubbert and Willis, 1957), yields a range for an estimated fracture pressure gradient of 0.55 to 0.66 psi/ft:

$$G_{Frac,min} = \frac{1}{3}(1 + 2G_P)$$

$$G_{Frac,min} = \frac{1}{3}(1 + 2 * 0.327\ psi/ft)$$

$$G_{Frac,min} = 0.55\ psi/ft \tag{1a}$$

$$G_{Frac,max} = \frac{1}{2}(1 + G_P)$$

$$G_{Frac,max} = \frac{1}{2}(1 + 0.327\ psi/ft)$$

$$G_{Frac,max} = 0.66\ psi/ft \tag{1b}$$

In the above equations, G_{Frac} is fracture gradient, and G_P is pore pressure gradient.

Adding in an assumed range of estimates for Poisson's ratio of 0.20 to 0.35, appropriate for the region and lithology, and using the Denova 1 well overburden gradient of 1.02 psi/ft calculated from well logging data, a range of fracture gradients was calculated from Eaton's method using the following equation (Eaton, 1969). This method resulted in a range of 0.50 to 0.70 psi/ft.

$$G_{Frac} = (G_{OB} - G_P) \times \left(\frac{\upsilon}{1-\upsilon}\right) + G_P$$

$$G_{Frac,min} = (1.02\ psi/ft - 0.327\ psi/ft) \times \left(\frac{0.2}{1-0.2}\right) + 0.327\ psi/ft$$

$$G_{Frac,min} = 0.5\ psi/ft$$

$$G_{Frac,max} = (1.02\ psi/ft - 0.327\ psi/ft) \times \left(\frac{0.35}{1-0.35}\right) + 0.327\ psi/ft$$

$$G_{Frac,max} = 0.7\ psi/ft \tag{2}$$

In the above equation, G_{OB} is overburden gradient, $\boldsymbol{\upsilon}$ is Poisson's ratio.

From the totality of the data above, the fracture gradient value of 0.6 psi/ft was determined to be a conservative value for modeling.

However, based on dynamic model simulation results, the Voyager 1 injection well is anticipated to inject with a bottomhole injection pressure below the calculated maximum injection pressure of 2,839 psi. The dynamic model simulated a bottomhole injection pressure of ≤2,238 psi, with a bottomhole injection gradient ≤0.427 psi/ft. Therefore, the Voyager project, as presented, should be capable of unrestricted operations at its proposed injection rate even if future step-rate testing were to confirm a fracture gradient as low as 0.5 psi/ft in the Lyons Formation, making the allowable injection gradient 0.45 psi/ft (90% of the fracture gradient).

4.5.b Effective Horizontal Stress

A geomechanical analysis of effective horizontal stress will be conducted following the drilling of the Voyager 1 well. Dynamic geomechanical properties will be calculated from well logging data, and static geomechanical properties will be analyzed from rock mechanic lab measurements. Elastic constants, minimum and maximum horizontal stresses, vertical stress, and fracture gradient will be calculated from the geomechanical properties. Triaxial compressive strength testing was performed on Flowerpot Anhydrite core samples from the Denova 1 stratigraphic well. A Mohr-Coulomb failure envelope was constructed using the Mohr circles of compressive strength measurements from three Flowerpot Anhydrite core samples. Figure 31 shows the failure envelope for Flowerpot Anhydrite at the Denova 1 well. Mohr circles 1, 2, and 3 are from laboraroty compressive strength measurements. Mohr circle number 4 represents the stress state of Flowerpot Anhydrite at the end of injection at the Denova 1 well from past geomechanical simulation. Horizontal stress was used as confining stress, and vertical stress was used as compressive stress. This analysis shows that for Flowerpot Anhydrite at Denova 1 (an analog well for the Voyager project location), the stress state of the upper confining zone at its highest-pressure condition at the end of injection is well below the failure threshold from rock mechanic measurements. Therefore, these results provide a clear indication of being able to safely inject at the planned pressure levels without the risk of induced fracturing at Denova 1. Based on proximity, location in the DJ Basin and formation similarities, similar results are expected for the Voyager 1 well. The same workflow will be applied following drilling, core acquisition, and rock mechanic testing of the Voyager 1 well. The analyses and logging to occur as part of the Voyager 1 construction and preoperational testing are discussed in more detail in **Attachment D Pre-Operational Testing Plan.**

4.6 Seismic History [40 CFR 146.82(a)(3)(v)]

U.S. Geological Survey (USGS) earthquake data were queried to provide historical earthquake events that have occurred between 1960 and 2024. There have been no recorded seismic events within a 25-mile radius of the Voyager Project site. No earthquakes have occurred in the sedimentary column above the granitic basement or associated with known faults in the area.

Figure 32 displays the locations of earthquakes from the USGS that occurred from 1960 to January 2024. Identified faults are shown, along with the Voyager 1 injection well location. No significant seismicity has occurred proximally to identified faults or in the Voyager Project area.

4.7 Hydrologic and Hydrogeologic Information [40 CFR 146.82(a)(3)(vi), 146.82(a)(5)]

Regional hydrologic and hydrogeologic characteristics were compiled using resources from the Nebraska Groundwater Atlas (Korus et al., 2013) and multiple USGS and academic publications. Figure 33 illustrates a general chronostratigraphic geologic chart of the Nebraska aquifers (Korus et al., 2013).

Local geology was characterized using well logs, published water data, and analysis of data from the Camp Clarke 23-22 type well. The apparent water resistivity (RWA) method, also known as the resistivity-porosity (RP) method, was used to calculate salinity for zones where fluid was not collected. The RWA method uses Archie's equation to determine formation water resistivity to calculate salinity and has been documented as the most reliable method for estimating formation water resistivity in saturated zones (Lyle, 1988).

4.7.a Freshwater Aquifers

High Plains Aquifer – Quaternary Dunes and Ogallala Formation

Fresh water in the Voyager Project area primarily occurs within the High Plains Aquifer (Miller and Appel, 1997; Robson and Banta, 1995; McGovern, 1964). This aquifer is extensive across Nebraska, underlying roughly 84% of the state (Figure 34 and 35).

The High Plains Aquifer is composed of unconsolidated sand and gravel, sandstone, and lesser amounts of silt, siltstone, clay, and shale deposited within alluvial, eolian, lacustrine, and fluvial valley fill systems during the Oligocene, Miocene, Pliocene and Quaternary. The primary units of the High Plains Aquifer (oldest to youngest) are the upper Brule Formation, Arikaree Group, Ogallala Group, Broadwater Formation, and multiple younger, unconsolidated sand and gravel units ranging in age from 2.6 million to 10,000 years old.

The Ogallala Group is the principal unit of the High Plains Aquifer extending across most of Nebraska, and consists primarily of sand, sandstone, siltstone, and gravel deposited by rivers in paleo valleys and along broad alluvial plains. The High Plains Aquifer is generally thicker in western Nebraska in the region of the Sand Hills, ranging in thickness from approximately 600 to 1,000 ft. Elsewhere across the state, the High Plains Aquifer is generally thinner, ranging from 100 to 400 ft thick. Its thickness and permeability make it one of the largest aquifers in the United States, providing water to more than 130,000 high-capacity wells.

Alluvial Valley Aquifers

The valleys of many modern streams in Nebraska contain unconsolidated sediments, or alluvium, deposited during the Quaternary Period. Multiple episodes of activation and abandonment of stream channels resulted in broad deposits of sand and gravel underneath most of the state's major river valleys (Figure 36). The high permeability of these deposits makes them excellent aquifers. Most alluvial valley aquifers are unconfined and have shallow water tables, making them some of the most accessible aquifers in the state. Through Morrill

County in the Voyager Project area the North Platte River is the primary alluvial aquifer system crossing through the region.

USDW Zones

Chadron Formation Sandstones

The Chadron aquifer is composed of Eocene-age sands and gravels deposited by fluvio-lacustrine systems within paleovalleys. The Chadron aquifer sources several domestic supply, livestock, and irrigation water wells in the Nebraska panhandle area with an average depth of approximately 350 ft. The Chadron aquifer exhibits poor water quality, with high TDS and elevated salinity, as well as locally elevated arsenic and uranium concentrations, a result of mining (Figure 37).

Data from four local Chadron fresh water source wells indicate that in the vicinity of the Voyager project area, the top of the Chadron formation top should be at an approximate depth of 527 to 550 ft bgs and the base should be at an approximate depth of 640 ft bgs. Static water levels from the wells indicate an average depth of 88.5 ft bgs. Based on a surface elevation of 3,759 ft above mean sea level (ft msl), the elevation of the base of the Chadron is at 3,142 ft msl and the elevation of the free water surface is 3,670.5 ft msl. Although this formation is expected to meet the criteria for the definition of the Voyager project's lowermost USDW (<10,000 mg/L TDS), regional studies have generally concluded that the water within the aquifer is not fit for human consumption, often containing elevated levels of chlorides, sodium, uranium salts, and arsenic.

Hydrogeology of Non-USDW Zones

Cretaceous Niobrara Carbonates

The Niobrara consists of a thick succession of shales, limestones, and chalks that act primarily as confining units, but can include secondary aquifers in locations in northeast Nebraska where the chalks are weathered, fractured, and occur near the surface. The Voyager project location is in western Nebraska and not near Niobrara secondary aquifers.

Cretaceous Codell Sandstone

The Codell aquifer consists of isolated sandstones within the Carlile Shale and is a secondary aquifer in northeast Nebraska where the High Plains aquifer is absent (Souders, 1976). The Voyager project location is in western Nebraska and not near Codell secondary aquifers.

Cretaceous Dakota D and J Sandstones

The Early Cretaceous of Nebraska was dominated by widespread deposition of sands, silts, and clays on the coastal plain and in river valleys and near-shore environments. The Dakota Group was deposited across the DJ Basin, and is typically called the D Sandstone and the J or Muddy Sandstone of the Dakota Group. In Nebraska, the Dakota group nomenclature changes to the Great Plains Aquifer consisting of two main aquifers, the lower Apishapa aquifer and the upper Maha aquifer, separated by a confining layer, which is present throughout western and central Nebraska. The Apishapa aquifer is present in west-central and western Nebraska and contains mostly poor-quality water or oil and gas (Miller and Appel, 1997). The Maha aquifer, commonly known as the Dakota aquifer in Nebraska, contains highly variable water quality, but fresh water exists locally in eastern Nebraska where precipitation recharges the aquifer in the shallow subsurface (Lawton et al., 1984). The Dakota aquifer is an important secondary aquifer for municipal, domestic, and irrigation uses in parts of eastern Nebraska. The Dakota aquifer is not widely used as a source of water in central and western Nebraska because it is deeply buried by overlying strata, including units of the High Plains aquifer, and because the waters are generally too saline for most uses (Miller and Appel, 1997). Figure 38 illustrates where the Maha and Apishapa are present and the water quality of the aquifers. Where the Maha is present and has good water quality, it flows generally to the east (Figure 38).

In the DJ Basin, the Dakota D and J sand aquifers recharge at the Front Range outcrops and discharge in Kansas and Nebraska (Belitz and Bredenoeft, 1988). The faulting along the Front Range acts as a barrier separating the eastern Colorado Dakota D and J sands from recharge sources resulting in lower pressure conditions (Belitz and Bredenoeft, 1988). The faulting combined with the natural facies and permeability heterogeneity of the formation results in low conductivity. These low pressure and conductivity conditions have been confirmed with multiple drill-stem tests conducted in northeastern Colorado, southeastern

Wyoming, and the Nebraska panhandle where the D and J sandstones produce hydrocarbons. Water-well pump tests are available in South Dakota, southwestern Kansas, and southeastern Colorado where the Dakota is a water source and is relatively shallow (Belitz and Bredenoeft, 1988). Overall, the Dakota D and J aquifer flows to the northeast (Figure 39).

TDS measurements vary across the basin, likely due to the disconnected nature of the sands and the accumulation of oil and gas. Salinity calculations using the RWA method show the Dakota D and J sands ranging from 642 to 121,898 mg/L TDS with an average of 21,279 mg/L TDS. Low-end calculations appear to correspond to high resistivity signatures that can be attributed to hydrocarbons, and thus the Dakota D and J sands are not considered USDWs at the Voyager 1 well location.

Cretaceous Lakota Sandstone

In the DJ Basin, the Lakota Aquifer consists of the M Sand Unit (upper) and the O Sand Unit (lower), separated by an unnamed dark shale confining layer or aquitard. The M Sandstone and the O Sandstone of the two units are not typical oil and gas targets and are often water-bearing or are thin. Most oil and gas wells targeting the Dakota D and J do not continue drilling through the Lakota Formation; therefore, the amount of data for this formation is limited due to the lack of penetrations and drill stem tests. In the Nebraska Groundwater Atlas, the Lakota Aquifer is lumped in with the Great Plains Aquifer. The Lakota M and O aquifers are assumed to follow the same trend as the Dakota D and J aquifers and flow to the east-northeast.

Like the Dakota Formation aquifers, the Lakota sandstones recharge at the Front Range outcrops and discharge in Kansas (Belitz and Bredenoeft, 1988). The faulting along the Front Range disrupts flow paths and creates low pressure conditions within the basin for the Lakota Formation (Belitz and Bredenoeft, 1988).

RWA calculations on nearby wells estimated a salinity average of 48,199 mg/L. Similarly to the overlying D and J sands, low salinity estimates are likely produced by increased resistivity signatures that correspond to hydrocarbons in the reservoir. Historically, the Lakota Formation has been targeted for wastewater injection near the Voyager Project area.

Jurassic Sundance Sandstones

The Jurassic rocks do not outcrop in Nebraska; therefore, the subsurface Sundance Formation is correlated to outcrops through well logs. The Sundance can be separated into four units from oldest to youngest: Nugget, Twin Creek, Entrada, and Upper Marine (Candra and Reed, 1959). The low density of wells penetrating the Jurassic formations causes some uncertainty in naming and correlation. For simplicity, the sandstones and limestones will be referred to as the Sundance in this permit.

The Sundance is not described in the Nebraska Groundwater Atlas, as it is not categorized as a usable aquifer with good water quality due to high salinity. Belitz and Bredenoeft (1988) modeled the recharge from the Front Range, similar to the Lyons and Dakota formations with an overall northeast trending flow direction (Figure 40).

During the drilling of the Voyager 1 stratigraphic well, Carbon America will be testing the Sundance Formation to determine formation water quality and secondary injectivity potential.

Permian Lyons

The Permian Lyons Formation is the proposed injection zone and is described in detail in Section 4.1.b. The Lyons recharges through Front Range outcrops of the Lyons and Fountain Formations. Well data and drill stem tests are not common in the Lyons Formation; therefore, Belitz and Bredenoeft (1988) modeled the fluid flow of the waters within the Lyons Formation using mapping results and a 3D numerical flow model. They found that the flow direction of fluids in the Lyons aquifer is to the northeast (Figure 41).

Aquifer discharge occurs where the Lyons Formation rises from the basin and its waters begin to filter into shallow aquifers, the water table, and eventually surface water in the Kansas-Nebraska region.

The Lyons Formation heterogeneous lateral facies distribution coupled with the faulting along the Front Range creates low pressure conditions throughout the DJ Basin, similar to the shallower aquifers of the Cretaceous and Jurassic. Pressure measurements were taken at Carbon America's Denova 1 well using an SLB MDT tool. The reservoir pressure in the Lyons Formation was measured at 1,379 psi at an approximate depth of 4,840 ft bgs, resulting in a calculated pressure gradient of 0.285 psi/ft.

Near the planned Voyager 1 well, regional potentiometric mapping by Belitz and Bredenoeft (1988) indicate that the expected hydrostatic head in the Lyons Formation would balance a standing column of fluid (fresh water) at an elevation of 2,469 ft msl. At a planned drilling depth to the top of the Lyons Formation of 5,258 ft bgs, the elevation of the top of the Lyons is expected to be at -1,499 ft msl. The expected pressure calculated from the contoured regional hydrodynamic mapping at the top of the formation should be reflective of the hydrostatic head of fluid within the Lyons Formation supported above the top of the formation. The difference in elevation between a hypothetical static fresh-water Lyons fluid column level and the Lyons Formation elevation, multiplied by the pressure gradient of fresh water, results in an expected top of Lyons Formation pressure of 1,718 psi ([2,469 ft – (-1,499 ft)] * 0.433 psi/ft = 1,718 psi).

Fluid samples were collected in the Lyons Formation at the Denova 1 stratigraphic well. Pressurized samples were sent to Core Laboratories for full chemical analysis. The Denova 1 Lyons Formation sample results indicated a TDS value of 10,026 mg/L. Fluid analysis was also reported for fluid samples taken from the Tallgrass Eastern Wyoming Sequestration Hub project (Tallgrass project) in Laramie County, Wyoming, located approximately 100 miles west of the Voyager project area. There, the Lyons Formation fluids were reported to have a TDS concentration of 225,000 mg/L, with sodium and chlorine ions making up the predominant share of the TDS constituents. Further, mapping of the TDS and salinity values for the Tallgrass project indicated that salinity values should increase moving to the east in the direction of the Voyager project area. For that reason, and because offset logs support such high TDS/salinity estimates from Rwa and salinity calculations, the Voyager Project is modeled with an assumed TDS of approximately 330,000 mg/L. Simulation testing with this relatively high level of TDS provides a conservative assumption for analysis to ensure that neither salt nor other mineral precipitation will hinder injection performance.

4.7.b Water Wells within the AoR

Water well data and spatial information were obtained from the Nebraska DNR. There are currently no water wells present within the AoR (Figure 42). Voyager proposes to drill four new shallow water wells to monitor the Ogallala Formation (public-use aquifer) and one deep water well to monitor the Chadron Formation (lowermost USDW). Water well locations are presented in Figure 42 and construction diagrams are presented in Appendix F-4 of **Attachment F: Testing and Monitoring Plan**.

4.7.c Aquifer Depths

Table 7 shows the expected depths of aquifers at the Voyager 1 injection well, their corresponding thickness, and their TDS values. Figure 20 illustrates the thickness between the top of the injection zone and the base of the lowermost USDW.

Table 7. Depths of Aquifers at the Voyager 1 Well

Aquifer/Formation	Depth (ft MD)	Thickness (ft)	TDS (mg/L)
Quaternary Dunes	Surface	50–100	250-500
Ogallala Formation	50–100	250 (approximate)	250-500
Chadron (Lowermost USDW)	527	90	<1000
Niobrara Formation/Ft Hays	N/A	N/A	N/A
Codell Formation	N/A	N/A	N/A
Dakota D Sand	3,955	51	18,631
Dakota J Sand	4,091	78	23,926
Upper Lakota	4,292	215	48,338
Lower Lakota	4,506	222	48,059
Sundance	4,940	45	21,230
Lyons Formation (Injection Zone)	5,258	62	330,000 (estimated)

4.7.d Baseline Geochemistry

The principal public use aquifer surrounding the project area is the Ogallala Formation, as discussed in Section 4.7. According to Nebraska DNR, there are currently no water wells located within the AoR. Four shallow groundwater well locations and one lowermost USDW well location are proposed for baseline, operational, and post-injection groundwater monitoring within the AoR, and are presented in Appendices F-1 and F-2 of **Attachment F: Testing and Monitoring Plan**. Current water quality data are available for the Ogallala Formation outside of the AoR at nine well locations, and are presented in Appendix 4. Figure 43 shows the nine well locations in reference to the Voyager Project AoR.

4.7.e Oil and Gas Production

Oil and gas fields surrounding the project area are shown in Figure 44. There is one oil and gas field located within the project AoR, the Bridgeport Field. Oil and gas production in the Bridgeport Field is from the D Sand Unit of the Dakota Formation. Oil and gas production west and south of the AoR is primarily from the D and J Sand Units of the Dakota Formation.

There is one aquifer exemption surrounding the project area (Figure 45). It is associated with Class II wastewater injection into the Dakota Formation.

4.8 Geochemistry [40 CFR 146.82(a)(6)]

Geochemical modeling was conducted to evaluate the compatibility of the injectate with groundwater and mineralogy of both the injection zone and the primary upper confining zone. The intent of the modeling was to identify the major potential reactions that may affect injection or containment (U.S. EPA, 2013). Geochemical modeling using the PHREEQC (pH-REdox-Equilibrium) software was used to predict CO_2-water-mineral reactions based on chemical equilibrium conditions. Two geologic formations were considered:

- Lyons Formation (injection zone)
- Flowerpot Formation (primary upper confining zone)

4.8.a Injection Zone Fluid Geochemistry

Table 8 summarizes the fluid analysis for the injection zone.

Table 8. Comprehensive Fluid Analysis for the Injection Zone

Parameter	Result for Lyons Formation
pH	7.35
TDS (mg/L)	330,000
Total organic carbon (mg/L)	10.5
Total inorganic carbon (mg/L)	43.1
CO_2 (mg/L)	50
Dissolved O_2 (mg/L)	4.0
*Cations (mg/L)**	
Aluminum	0.62
Barium	0.90
Calcium	686.61
Cerium	—
Chromium	—
Iron (total)	6.88
Lithium	0.80
Magnesium	48
Manganese	0.16
Mercury	0.01
Molybdenum	9.87
Nickel	68.81
Potassium	3,507.95
Silicon	718.07
Sodium	143,984
Strontium	188.49
Tin	—
Titanium	4.37
Zinc	—
*Anions (mg/L)**	
Alkalinity (as bicarbonate)	380
Arsenic	—
Borate	33
Bromide	63
Chloride	178,471
Fluoride	60
Nitrate	—
Sulfate	4,876
Sulfide	6

*Levels are based on Carbon America's Denova 1 stratigraphic well, which also targeted the Lyons Formation (Appendix 5). Values were adjusted to reflect the local TDS and nearby available data. These values will be updated upon acquisition of site-specific samples, and geochemical analysis.

**While included in the sample analysis, brine chemistry did not return discrete levels of antimony, beryllium, cadmium, cobalt, copper, lead, phosphorous, selenium, silver, vanadium, iodide, nitrite, or phosphate.

4.8.b Injection Zone and Upper Confining Zone Mineralogy

Carbon America intends to drill the Voyager 1 stratigraphic well to obtain core samples, which will be used to provide detailed mineralogy via XRD analysis. See **Attachment D: Pre-Operational Testing Plan** for additional details. For this geochemical analysis, data from the Lyons and Flowerpot Formations acquired as part of Carbon America's Denova Class VI permit application will be applied. There is no indication, based on basin-wide geologic modeling and facies mapping, that the mineralogy will be significantly different from that measured in Carbon America's pervious stratigraphic well for the Denova project in Yuma, Colorado. While subtle differences are anticipated in minor mineralogic components, simplified mineralogy was used in the PHREEQC models as outlined in Table 9.

Table 9. Average Mineralogy of the Injection Zone and Upper Confining Zone

Mineral	Average Mineralogy	
	Injection Zone	Upper Confining Zone
Quartz	85	0.60
K-Feldspar	5	—
Dolomite	2	—
Anhydrite	2	98.1
Halite	2	—
Illite	2	0.80
Albite	2	—
Chlorite	—	0.4

4.8.c Injectate Chemistry

Stack Testing Accreditation Council (STAC) testing was completed on the unprocessed injectate from the upstream side of the proposed capture facility at the Bridgeport ethanol plant. Results from the STAC testing showed an unprocessed injectate consisting of approximately 99.0207% CO_2, with minor constituents making up the remaining 0.9793% (Appendix 2). The minor constituents of the unprocessed injectate are mostly oxygen, butane, and water, which will be separated by the proposed capture facility, routed to holding tanks, and trucked off-site for disposal prior to injection.

4.8.d Equilibrium Geochemical Modeling

PHREEQC, developed by USGS, is a robust geochemical program that enables the simulation of complex chemical reactions occurring between water and rock in various environmental settings. The program references thermodynamic databases and can handle diverse mineralogic compositions and a wide range of chemical species. Input data include mineralogy, water composition, and reservoir conditions, generating an output of anticipated mineral dissolution, precipitation, ion exchange, and complexation reactions. PHREEQC is a tool for understanding the effects of water-rock interactions on water quality and has been effectively used in water-rock-CO_2 applications.

Geochemical Database

The PHREEQC thermodynamic database serves as a reference library for the software, providing information to calculate equilibrium conditions and predict how chemical reactions will behave in different environmental settings. Key components of a thermodynamic database include the following:

- Thermodynamic Properties: Information on standard enthalpies of formation, standard entropies, heat capacities, standard Gibbs free energies of formation, and other thermodynamic constants that describe the energy changes associated with chemical reactions.

- Equilibrium Constants: Equilibrium constants (K-values) are provided at various temperatures and pressures for each chemical reaction in the database. These constants represent the ratio of the concentrations of the reactants and products at equilibrium and are used to determine the direction and extent of the reaction under specific conditions.
- Stability of Minerals: data on the stability of minerals, indicating whether they are stable or unstable under certain environmental conditions. This information is crucial in predicting mineral dissolution and precipitation reactions in water-rock interactions.
- Solubility Product Constants: Solubility product constants (K_{sp}) are included for various minerals, indicating the maximum concentration of dissolved ions that can exist in equilibrium with a solid mineral phase. These data help in understanding the solubility behavior of minerals.
- Ion Interaction Parameters: Provides ion interaction parameters, which account for interactions between ions in solution, particularly for systems where ion pairing, or complexation is significant.
- Redox Reactions: Provides data for calculating redox equilibrium conditions between different redox couples.

Saturation Indices

PHREEQC uses saturation indices to evaluate the thermodynamic stability of minerals under various conditions, aiding in the prediction of dissolution and precipitation reactions and providing insights into the evolution of water chemistry and mineralogical changes over time. The saturation index is calculated using the following equation:

$$SI = \log_{10}(IAP/K) \tag{3}$$

where SI is the saturation index, IAP is the ion activity product of the mineral in the solution, and K is the equilibrium constant for the mineral dissolution or precipitation reaction.

Saturation indices in dissolution and precipitation determinations are as follows:

- Dissolution ($SI < 0$): If the saturation index (SI) is negative, it indicates that the ion activity product (IAP) is lower than the equilibrium constant (K), suggesting that the mineral is undersaturated. This means that the mineral is in a state of disequilibrium with the solution and is likely to dissolve to reach equilibrium.
- Equilibrium ($SI = 0$): When the saturation index (SI) is zero, it signifies that the ion activity product (IAP) is equal to the equilibrium constant (K), indicating that the mineral is in equilibrium with the solution. There is no driving force for dissolution or precipitation.
- Precipitation ($SI > 0$): A positive saturation index (SI) indicates that the ion activity product (IAP) is greater than the equilibrium constant (K), suggesting that the mineral is oversaturated. This indicates that the solution is supersaturated with respect to the mineral, and the mineral is likely to precipitate until equilibrium is achieved.

In the context of CO_2-water-rock interactions, saturation indices are used to predict precipitation and dissolution reactions induced by the introduction of injectant into the existing equilibrated system.

Geochemical Model Input

PHREEQC models were constructed for the injection zone and the upper confining zone. With only approximate mineralogies for both intervals, only one model was constructed for each; however, the team recognizes that there may be mineralogically distinct units within both the Lyons and the Flowerpot Formations. Discrete models will be constructed for these as needed once site specific data is collected from the stratigraphic well. For both modeled formations, the geochemical processes of interest are mineral dissolution and precipitation and the impacts on injectability and seal. Geochemistry of the brine in the injection zone (Table 8) is assumed to be consistent with the brine at the injection interval-caprock interface and was used for the upper confining zone solution chemistry.

A consistent model workflow was applied across both intervals under consideration. The initial solution was established based on the approximate brine chemistry (Table 8). Following this, distinct mineralogies were incorporated using the EQUILIBRIUM PHASE block in PHREEQC. As a crucial first step, the brine and the formation mineralogy were allowed to equilibrate before initiating the CO_2 reaction.

To ensure uniformity across models, estimated mineral percentages were converted into mineral moles (Table 10). This conversion is done relative to each interval's porosity and assumes that 1 kilogram (kg) of water fills the porosity of each interval. The volume of rock was determined in relation to the porosity, with the consistency of 1 kg of water maintained across all models. For example, this means that the anhydrite interval of the upper confining zone, characterized by low porosity, necessitates a larger volume of rock to keep the water content consistent.

Table 10. Mineral Molar Ratios for the Lyons and Flowerpot Formations

Mineral	Mineral Molar Ratio	
	Injection Zone	Upper Confining Zone
Quartz	153.7	115.2
K-Feldspar	1.9	—
Albite	0.8	—
Dolomite	1.3	—
Anhydrite	1.8	9,283.1
Halite	1.8	—
Illite	0.6	24.9
Chlorite	—	6.4

After the initial equilibration between the brine and the matrix mineralogy, CO_2 was added to the system. To model the appropriate volume of injectate, moles of CO_2 were added to the system until a maximum pressure of 2,500 psi (the highest anticipated injection pressure) was reached (for PHREEQC, psi was converted to a partial pressure.)

Geochemical Modeling Results and Discussion

The PHREEQC models for each interval followed these steps:

- Input aqueous chemistry specific to the injection zone.
- Input % mineralogies per XRD analysis of the interval.
- Equilibrate the model with provided rock and solution parameters (including site specific reservoir conditions).
- Add CO_2 in 200 steps and allow to equilibrate.
- Observe relevant changes in mineral mass, and solution chemistry.

PHREEQC model results are presented in Table 11.

Table 11. PHREEQC Equilibrium Model Results

Mineral	Mineralogy Change (grams)	
	Injection Zone	Upper Confining Zone
Quartz	0	0
K-Feldspar	0	—
Dolomite	-0.552	—
Anhydrite	0.426	0
Illite	-0.105	0
Halite	1.946	—
Chlorite	—	-1.1934

PHREEQC model results indicate that the following mineral reactions are expected to occur with the injection of CO_2:

- Minor dissolution of dolomite and illite in the injection zone, while quartz and feldspar (that represent the majority of the Lyons Formation mineralogy) remain static.
- Minor precipitation of halite and, to a lesser degree, anhydrite, in injection zone.
- Minor dissolution of chlorite is the only impact predicted on the upper confining zone, the Flowerpot Anhydrite.

In terms of overall geochemically induced change, the model predicts less than 0.5% change in mass for both the Lyons and Flowerpot Formations, suggesting no material change in porosity and permeability.

The PHREEQC model does not predict dissolution or precipitation that represents a threat to injectivity or storage capacity of the Lyons Formation, or the seal integrity of the Flowerpot Formation. Once the Voyager 1 stratigraphic well is drilled and new site-specific data are collected, these models will be updated.

Model results from geochemical simulation using CMG indicate that the following mineral reactions are expected to occur with the injection of CO_2:

- CMG simulation geochemical model predicts minor precipitation of anhydrite and quartz through mineralizing chemical reactions within the injection zone.
- The CMG simulation geochemical model also predicts very slight dissolution of some dolomite, illite, and anhydrite from within the injection interval.
- Most importantly, the CMG simulation predicts significant precipitation of halite (salt) from the aquifer brine (especially in some near wellbore model cells) because of interactions between the reservoir brine with injected “dry” CO_2 into which the water from the brine can vaporize. As free water, or even capillary bound water, encounters continual injection volumes of fresh dry CO_2, the formation waters will continue to evaporate into the CO_2 to establish an equilibrium partial pressure of water vapor within the CO_2. Model cells containing the wellbore perforations are subjected to the injection and throughput of hundreds of pore volumes of CO_2, which continuously evaporates the capillary bound brine and reduces the residual water saturation through the evaporation process to a very low level. As water evaporates, the sodium and chlorine ions in the water become supersaturated and halite (salt) naturally begins to physically crystalize and precipitate. Although modeling does not suggest that the injection well will suffer plugging from this effect, over time some reduction in porosity of these model cells is noted due to this deposition. Porosity reduction between 1 and 4% are noted in some model cells, and injectivity and operational observation will be necessary to determine if occasional remedial fresh-water flushes might be necessary to keep the near wellbore area clear from heavy salt precipitation and to minimize injectivity reduction or injection pressure increases. These modeling results concerning halite deposition are in relative agreement with results from the PHREEQC modeling.

4.9 Site Suitability [40 CFR 146.83]

The proposed Voyager project site is suitable for the injection and containment of CO_2 as demonstrated in the sections above. Responses to recommended EPA questions are given below.

What is the subsurface distribution of lithological facies? What are the implications for carbon dioxide plume migration?

The facies distribution within the designated injection zone exhibits variability across both static and dynamic model AOIs. The proposed injection zone resembles an ancient dune field, akin to those found in desert regions bordering seas, such as those in the Middle East. Dune architecture and migration mechanisms promote water accumulation and subsequent evaporation in interdune areas, resulting in the deposition of impermeable evaporitic facies.

Examination of wells within the project area consistently reveals similar variations across the region, with some areas showcasing clean reservoir sands while others exhibit the presence of mineral halite southeast, southwest, and east of the proposed injection site. Proximity to the proposed injection well yields clear indications, as seen in well logs, of a quality reservoir conducive to injection activities. Notably, the reservoir tends to thin toward the north and west, while the presence of halite to the east serves to mitigate the potential for long-range updip plume migration.

How will carbon dioxide be confined to the injection zone? How do the site characterization data demonstrate the lack of potential leakage pathways?

The identification of mineral halite, coupled with regional thinning of the Lyons Formation toward the western extent, reduces the likelihood of unforeseen lateral migration of CO_2. The upper confining zone, the Flowerpot Anhydrite, is primarily composed of anhydrite, acts as the primary cap rock above the injection zone, and maintains continuity throughout the project area. Log data analysis confirms its high density and effectively zero porosity and permeability, establishing it as an optimal seal for injection activities (Tables 2 and 5).

Above the Flowerpot Anhydrite lies the thicker Flowerpot Shale, characterized by its low permeability and generally more ductile geomechanical properties (Tables 2 and 5). These properties contribute to additional confinement by inhibiting flow and dispersing energy and pressure upward through the section.

Through investigation of the seismic and tectonic history of the project area and surrounding areas within the DJ Basin in western Nebraska, minimal seismic activity and tectonic disturbances indicate a stable project area for CO_2 sequestration.

Detailed analysis, incorporating both 3D seismic data and a comprehensive study of seismic activity, has been conducted to assess the structural integrity of the proposed injection zone. An examination of the current 3D seismic data revealed no evidence of faults offsetting the injection zone or confining zones within the AoR. Moreover, the AoR maintains a substantial distance from identified faults that traverse shallower stratigraphic layers above the primary confining zones, minimizing the risk of unintended CO_2 migration. The computational modeling presented in **Attachment A: AoR and Corrective Action Plan** provides additional demonstration that CO_2 will be confined solely in the injection zone.

Furthermore, thorough investigation has confirmed that the proposed injection zone is situated comfortably above the basement, with no indications of faulting associated with basement structures. This absence of basement-involved faulting further contributes to the overall stability and suitability of the site for CO_2 injection activities.

These favorable geological conditions underscore the viability of the Lyons Formation as a reliable target formation for CO_2 Sequestration, offering a promising avenue for environmentally responsible carbon management initiatives within the DJ Basin.

How will the carbon dioxide stream interact with well materials and subsurface formations (injection and confining zones)?

The CO_2 stream is not expected to have any degenerative reactions with well materials, including well cement, casing, tubing, and packer. Special care was taken to select proper materials when designing the well. Corrosion-resistant cement and casing will be installed in the Voyager 1 well covering the injection and confining zones as detailed in **Attachment B: Construction Details**. The Voyager 1 well tubing and packer will also be constructed of Cr-13 material and will be corrosion resistant.

Geochemical modeling using PHREEQC and CMG, as summarized in Section 4.8, predicts minimal change in mass for both the Lyons and the Flowerpot Formations, suggesting that no material change in porosity or permeability should occur because of CO_2 injection. No threat to the injectivity or storage capacity of the Lyons Formation or to the seal integrity of the Flowerpot Formation is identified. Interaction of the injectate with formation fluids and mineralogy is not expected to affect injection or containment. Model results will be updated following the drilling of the Voyager 1 stratigraphic well.

What is the total storage capacity of the injection zone? How was this determined? How is this sufficient to receive the proposed amount of carbon dioxide?

The total storage capacity of the injection zone within the dynamic model area is 112 mmt. Computational modeling performed in CMG and presented in **Attachment A: AoR and Corrective Action Plan** demonstrates that the injected CO_2 will be contained within the delineated AoR. The stratigraphic and structural framework of the injection and confining zones supports that the injection zone has sufficient storage capacity that exceeds the total volume of CO_2 to be injected.

In the entire Voyager Project dynamic model area, the Lyons Formation contains 37 billion cubic feet of pore volume (from model simulation statistics). Simulation has indicated that at the end of the PISC period (January 2092), the model cells that have been contacted and have received CO_2 exhibit an average CO_2 saturation of 29.3%. The average density of that CO_2 at static reservoir conditions at that time is shown to be 22.86 pounds per cubic foot (pcf) (at an average reservoir pressure of 1,854 psi and temperature of 164°F). A total expected practical storage capacity within the dynamic model storage formation volume under these conditions is calculated to be 112,303,000 metric tons (37,000,000,000 ft^3 pore volume) * (29.3% CO_2 sat) * (22.86 lbs/ft^3 dens) * (1 metric ton/2,204.6 pounds).

Unit storage capacity per square mile for the 184.6 sq mi dynamic model area calculates to be 608,161 metric tons per sq mi, or 950 metric tons per acre (112,303,000 metric tons/184.6 sq mi), although these calculations do not fully account for potentially less efficient storage efficiency across areas with less structural closure.

The Voyager project is projected to store 175,000 mtpy throughout a 12-year injection period, eventually storing a total of 2.1 mmt, filling 1.87% of the available storage volume contained within the flow simulation dynamic model.

Computational modeling performed in CMG and presented in **Attachment A: AoR and Corrective Action Plan** demonstrates that the injected CO_2 will be contained within the delineated AoR. The stratigraphic and structural framework of the injection and confining zones supports that the injection zone has a sufficient storage capacity, and exceeds the total volume of CO_2 to be injected. Section 5.4 of **Attachment I: PISC and Site Closure Plan** details the trapping of the injected CO_2 at the end of the 12-year injection period and at 20 years post-injection. At 50 years post-injection, approximately 62.1% of the stored supercritical free-phase CO_2 is trapped structurally, 29.3% is trapped within pore space through the process of hysteresis and capillary trapping, 7.6 % is dissolved into the injection zone saline aquifer aqueous phase, and –0.5% is stored through net mineralization (Figure I-23 of **Attachment I: PISC and Site Closure Plan**).

Are there any potential concerns regarding confining zone integrity? What site characterization data support this determination?

As discussed above and in Section 4.4.b, the upper confining zone is thick, extensive, and exhibits low porosity and permeability values, as characterized by surrounding wellbores. Additionally, there are no transmissive faults or fractures observed in well or seismic data within the AoR that would result in fluid leakage into this zone. Although not required for permitting, secondary confinement is represented by the stacked Blaine, Opeche, and Minnekahta Formations, which offer an additional thick, low-porosity, low-permeability containment layer between the primary upper confining zone and the lowermost base of the USDW (Chadron).

5. AoR and Corrective Action

The Voyager Project AoR and Corrective Action Plan is provided as **Attachment A: AoR and Corrective Action Plan**. This attachment has been developed in compliance with 40 CFR §146.84, area of review and corrective action, which requires that the owner or operator of a Class VI well prepare, maintain, and comply with a plan to delineate the area of review for a proposed geologic sequestration project, as well as periodically reevaluate the delineation and perform corrective action if necessary. **Attachment A: AoR and Corrective Action Plan** has been submitted to the GSDT as follows:

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

6. Injection Well Construction

The Voyager Project will construct the Voyager 1 well as a Class VI injection well for CO_2 sequestration. Construction details are provided in **Attachment B: Construction Details**, which includes information about construction procedures, casing and cement, tubing and packer, and continuous monitoring. The injection well construction details have been developed in compliance with 40 CFR 146.86, injection well construction requirements. **Attachment B: Construction Details** has been submitted to the GSDT as follows:

Injection Well Construction GSDT Submissions
GSDT Module: Project Information Tracking ***Tab(s):*** Initial Permit Application Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☒ Injection Well Construction Requirements ***[40 CFR 146.86]***

7. Proposed Stimulation Program

A Stimulation Plan has been developed for the Voyager Project in compliance with 40 CFR 146.82(a)(9), and is provided as **Attachment C: Stimulation Plan**. A stimulation program is not necessary for the project at this time; however, a stimulation program is proposed in the case that stimulation is needed. The Stimulation Plan describes methods and procedures for stimulation, including fluids, additives, and diverters. Compatibility of the stimulation fluids with the injection and confining zones will be demonstrated if stimulation is deemed necessary. **Attachment C: Stimulation Plan** has been submitted to the GSDT as follows:

Stimulation Plan GSDT Submissions

GSDT Module: Project Information Tracking

Tab(s): Initial Permit Application

Please use the checkbox(es) to verify the following information was submitted to the GSDT:

☒ Proposed stimulation program ***[40 CFR 146.82(a)(9)]***

8. Pre-Operational Logging and Testing

A Pre-Operational Testing Program has been developed in compliance with 40 CFR 146.87, logging, sampling, and testing prior to injection well operation, and is provided as **Attachment D: Pre-Operational Testing Plan**. The Pre-Operational Testing Program describes deviation checks, tests and logs that will be performed during the drilling of Voyager 1, and the tests and logs to be performed during tubing and packer installation. Additionally, pre-operational tests and logs to be performed in the Voyager IZM 1 monitoring well are discussed in this plan. **Attachment D: Pre-Operational Testing Plan** has been submitted to the GSDT as follows:

Pre-Operational Logging and Testing GSDT Submissions

GSDT Module: Pre-Operational Testing

Tab(s): Welcome tab

Please use the checkbox(es) to verify the following information was submitted to the GSDT:

☒ Proposed pre-operational testing program ***[40 CFR 146.82(a)(8) and 146.87]***

9. Well Operation

The Voyager Project well operations are described in **Attachment E: Operating and Reporting Conditions**. Attachment E includes information that fulfills requirements for this Class VI permit application listed at 40 CFR 146.82(a)(7) and (10) and 40 CFR 146.88, injection well operating requirements. This includes proposed operating data such as average and maximum daily rate and volume and/or mass, total anticipated volume and/or mass, average and maximum injection pressure, source of the CO_2 stream, and an analysis of the chemical and physical characteristics of the CO_2 stream. It also describes overall operational procedures, routine shutdown procedures, and reporting requirements. **Attachment E: Operating and Reporting Conditions** has been submitted to the GSDT as follows:

Operating and Reporting Conditions GSDT Submissions
GSDT Module: Project Information Tracking ***Tab(s):*** Initial Permit Application Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☒ Proposed operating data ***[40 CFR 146.82(a)(7)]*** ☒ Proposed injection procedure ***[40 CFR 146.82(a)(10)]*** ☒ Injection well operating requirements ***[40 CFR 146.88]***

10. Testing and Monitoring

A Testing and Monitoring Plan prepared pursuant to 40 CFR 146.90, testing and monitoring requirements, is provided as **Attachment F: Testing and Monitoring Plan**. The Testing and Monitoring Plan will be used for ongoing project monitoring to verify that the CCS project is operating as permitted and is not endangering USDWs. Additionally, a Quality Assurance and Surveillance Plan (QASP) prepared pursuant to 40 CFR 146.90(k) is included as **Attachment G: QASP**. **Attachment F: Testing and Monitoring Plan** and **Attachment G: QASP** have been submitted to the GSDT as follows:

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

11. Injection Well Plugging

The Voyager Project Injection Well Plugging Plan is provided as **Attachment H: Injection Well Plugging Plan**, and has been prepared pursuant to 40 CFR 146.92(b), well plugging plan. The Injection Well Plugging Plan includes appropriate tests or measures for determining bottomhole reservoir pressure and ensuring external mechanical integrity, the type, number, placement, and method of placement of plugs, and the type, grade, and quantity of material to be used in plugging that is compatible with the CO_2 stream. **Attachment H: Injection Well Plugging Plan** has been submitted to the GSDT as follows:

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

12. Post-Injection Site Care (PISC) and Site Closure

The Voyager Project PISC and Site Closure Plan is provided as **Attachment I: PISC and Site Closure Plan**, and has been prepared pursuant to 40 CFR 146.93, post-injection site care and site closure. An alternative PISC time frame is proposed. **Attachment I: PISC and Site Closure Plan** has been submitted to the GSDT as follows:

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

13. Emergency and Remedial Response

The Voyager Project Emergency and Remedial Response Plan (ERRP) is provided as **Attachment J: ERRP** and has been prepared in accordance with 40 CFR 146.94, emergency and remedial response. The ERRP describes actions that the owner or operator must take to address movement of the injection or formation fluids that may cause an endangerment to a USDW during construction, operation, and post-injection site care based on potential risk scenarios. **Attachment J: ERRP** has been submitted to the GSDT as follows:

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

14. Financial Responsibility

The Voyager Project Financial Assurance Demonstration is provided as **Attachment K: Financial Assurance Demonstration** and has been prepared in accordance with 40 CFR 146.85, financial responsibility. This attachment describes the qualifying financial instrument(s) applicable to the proposed project that are sufficient to cover the cost of corrective action, injection well plugging, post-injection site care and site closure, and emergency and remedial response, as well as potential endangerment of USDWs. **Attachment K: Financial Assurance Demonstration** has been submitted to the GSDT as follows:

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

15. Optional Additional Project Information

This section summarizes additional project information based on 40 CFR 144.4, considerations under federal law, which lists the following laws that must be considered if applicable:

- Wild and Scenic Rivers Act
- National Historic Preservation Act
- Endangered Species Act
- Coastal Zone Management Act
- Fish and Wildlife Coordination Act

- Executive orders including the Clean Water Act, Safe Drinking Water Act, Clean Air Act, and the Resource Conservation and Recovery Act

The Coastal Zone Management Act does not apply due to the Voyager project's inland location. The analysis area is dominated by rangeland vegetation, cropland, and energy development. Allied Solutions performed a natural and cultural resources desktop review which included a 500-foot buffer around the project, and a raptor survey area that included a 0.5-mile buffer for raptor nests. The purpose of this desktop review was to identify any significant natural resource or cultural resource constraints or risks associated with the proposed development. Potential wetlands were identified in the pipeline area as well as a potentially jurisdictional water body, the Belmont Canal. Carbon America has contracted a consultant to evaluate the road and pipeline canal crossings. Meetings with the canal owner have been amicable and they were receptive to the project. Grassland, wetlands, and some open water areas within 0.5 mile of the project could provide suitable habitat for two state-listed species of concern, including foraging and den habitat for swift fox (*Vulpes velox*), and foraging habitat for whooping crane (*Grus americana*), as well as other migratory bird species. NDEE is requiring a biological survey shortly before dirt work commences.

There are currently no known historic resources within the AoR subject to the National Historic Preservation Act; however, Voyager met with the State Historic Preservation Office as a precaution due to nearby historical trails of the west. During the virtual meeting, the state archaeologist performed a desktop study for cultural resources in the area using the State's proprietary lidar data. No known areas of historical significance were identified in the area, though there is a lack of survey data locally. Carbon America offered to provide any archeological survey data to the state as a courtesy and will prepare an Inadvertent Discovery Plan (IDP) to provide instructions for on-site project staff in the event of an unexpected discovery of human remains or historic or prehistoric resources.

Carbon America also contracted Stantec to complete a Phase I ESA of the stratigraphic well pad area in June 2023, and a subsequent Phase II ESA soil sampling event in November 2023. The results of the soil sampling at the proposed stratigraphic test well pad suggest a historical release of crude oil and condensate from the site's former use as a crude petroleum and natural gas production facility. Carbon America has partnered with the NOGCC who is using federal orphan well remediation funding to remediate the site prior to the drilling of the Voyager 1 stratigraphic test well.

Should any of these resources be identified, Voyager has flexibility to reroute. Results of the surveys can be provided to EPA upon request.

15.1 National Historic Preservation Act

The National Historic Preservation Act of 1966, 16 U.S.C. 470 et seq. Identify properties listed or eligible for listing in the National Register of Historic Places that may be affected by the activities associated with the proposed project. If previous historic and cultural resource survey(s) have been conducted, provide the results of the survey(s).

An environmental and cultural resource survey will be conducted during pipeline construction. Results of the survey will be provided to EPA.

15.2 Wild and Scenic Rivers Act

The Wild and Scenic Rivers Act, 16 U.S.C. 1273 et seq. Identify any national wild and scenic river that may be impacted by the activities associated with the proposed project.

There are no national wild and scenic rivers that will be impacted by the proposed Voyager Project.

15.3 Endangered Species Act

The Endangered Species Act, 16 U.S.C. 1531 et seq. Identify any endangered or threatened species that may be affected by the activities associated with the proposed project. If a previous endangered or threatened species survey has been conducted, provide the results of the survey.

An environmental and cultural resource survey will be conducted during pipeline construction. Results of the survey will be provided to EPA.

15.4 Fish and Wildlife Coordination Act

An environmental and cultural resource survey will be conducted during pipeline construction. Results of the survey will be provided to EPA.

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Figures

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Appendix 1
Site Plans for Capture Facilities

Appendix 2
Injectate Composition

Appendix 3
Denova 1 Stratigraphic Well Testing and Results

Appendix 4
Baseline Geochemistry Data

Appendix 5
Lyons Formation Water Quality Data