Subpart RR Monitoring, Reporting, and Verification Plan for Juniper I-1 Facility

Laramie County, Wyoming

Version 3

November 22, 2024

Contents

List of Figures

List of Tables

1. Introduction

Tallgrass High Plains Carbon Storage, LLC (High Plains) has prepared this monitoring, reporting and verification (MRV) plan pursuant to 40 CFR (U.S. Code of Federal Regulations) § 98.440-449 (Subpart RR). High Plains is a subsidiary of Tallgrass Energy, L.P. (Tallgrass). This document describes the MRV activities for the proposed Juniper I-1 injection well of the planned High Plains East Wyoming Sequestration (EWS) Hub, located in Laramie County, Wyoming. The EWS Hub consists of six carbon dioxide (CO_2) injection facilities. The Juniper facility has one injection well (Juniper I-1).

High Plains plans to inject and store 1.5 million metric tons (MMT) of CO_2 annually for 5 years, not to exceed a total of 7 MMT. CO_2 will be sourced from a CO_2 collection pipeline from several industrial facilities.

The CO_2 will be injected into the Lyons Formation for geologic storage. An Underground Injection Control (UIC) Class VI permit has been issued by the State of Wyoming for the Juniper injection project (UIC Permit Number 2022-235, Facility Identification [ID] Number WYS-021-00149).

A stratigraphic test well, Juniper M-1 (American Petroleum Institute [API] #49-021-29548), has been drilled at the project area and will be converted into an above confining zone monitoring well.

This MRV plan is organized into the following sections:

- Section 1: Introduction
- Section 2: Facility Information
- Section 3: Project Description
- Section 4: Delineation of the Monitoring Areas
- Section 5: Identification and Assessment of Potential Surface Leakage Pathways
- Section 6: Monitoring and Considerations for Site-Specific Variables
- Section 7: Approach for Establishing the Expected Baselines
- Section 8: Considerations for Site-Specific Variables for the Mass Balance Equations
- Section 9: MRV Implementation Schedule
- Section 10: Quality Assurance and Quality Control
- Section 11: Records Retention

2. Facility Information

1. Greenhouse Gas Reporting Program (GHGRP) ID number – 589261
2. The Wyoming Department of Environmental Quality (WDEQ) issued a UIC Class VI permit under its Wyoming Statute (W.S.) Sections 3-11-101 through 2005 for the Juniper I-1 injection

well on September 11, 2024 (UIC Permit Number 2022-235, Facility Identification [ID] Number WYS-021-00149).

a. Oil- and gas-related wells around the Juniper I-1 well, including Class II injection wells and production wells, are regulated by the Wyoming Oil and Gas Conservation Commission (WOGCC). WDEQ is the responsible agency for all other UIC well classes.

3. Wells within the Juniper area of review (AoR) are identified by name, API number, status, and type. The list of planned wells associated with the Juniper project is provided in **Appendix A**. Any new wells or changes to well status will be indicated in the annual report.
4. Proposed date to begin collecting data for calculating the total CO_2 amount sequestered: June 1, 2025.

3. Project Description

Tallgrass, headquartered in Leawood, Kansas, is a committed leader at the forefront of decarbonization efforts in the United States (U.S.). Tallgrass is a pipeline and gas storage company that enables a high quality of life through the delivery of energy and services that fuel homes and businesses. As a demonstration of its decarbonization commitment, Tallgrass is developing the sequestration site in Laramie County, Wyoming. The EWS Hub is an innovative, multi-state decarbonization effort focused on permanently sequestering CO_2 from multiple emitters located in Nebraska, Colorado and Wyoming.

Tallgrass and predecessor companies have operated natural gas storage fields for more than 70 years. Tallgrass currently operates 90 wells with 74 billion cubic feet (bcf) of natural gas storage capacity and 20,470 compression horsepower across the Huntsman and East Cheyenne gas storage fields. These gas storage operations provide Tallgrass with critical subsurface working knowledge and skill sets that transfer directly to CO_2 sequestration, specifically the injection, monitoring, and storage of gaseous fluids in porous reservoirs.

The State of Wyoming previously recognized Tallgrass's commitment to decarbonization when the Wyoming Energy Authority (WEA) awarded High Plains a grant to help fund the development of the injection project. The grant is in addition to the proposed direct investment in the project by High Plains, designed to provide a cost-effective means of sequestering CO_2. "Wyoming is deeply committed to providing decarbonized solutions for the 21st century," said Dr. Glen Murrell, Executive Director of the WEA. "We are pleased to be able to fund Tallgrass's Eastern Wyoming Sequestration Hub project, which has the potential to add an important resource for our net-zero goals."[1]

[1] https://tallgrass.com/newsroom/press-releases/tallgrass-to-develop-a-commercial-scale-co2-sequestration-hub-in-wyoming

3.1 Project Characteristics

The Juniper I-1 injection project area, defined as the Class VI AoR, is ideally suited for CO_2 storage for the following reasons:

- The high permeability and porosity of the Lyons Formation (the injection zone)
- The continuity, low permeability, and ductility of the overlying Chugwater Formation/Goose Egg Formation (confining zone), and Satanka Formation (lower confining zone)
- The lack of any abandoned wells that penetrate the injection zone

Computational modeling to simulate CO_2 sequestration confirms anticipated containment of the injected mass. A robust monitoring program will be established to detect any CO_2 leakage so that any potential leakage may be mitigated.

The project will consist of one injection well, surface facilities, and above confining zone monitoring well (**Figure 1**). Ground water monitoring wells will be placed on the Juniper I-1 pad site.

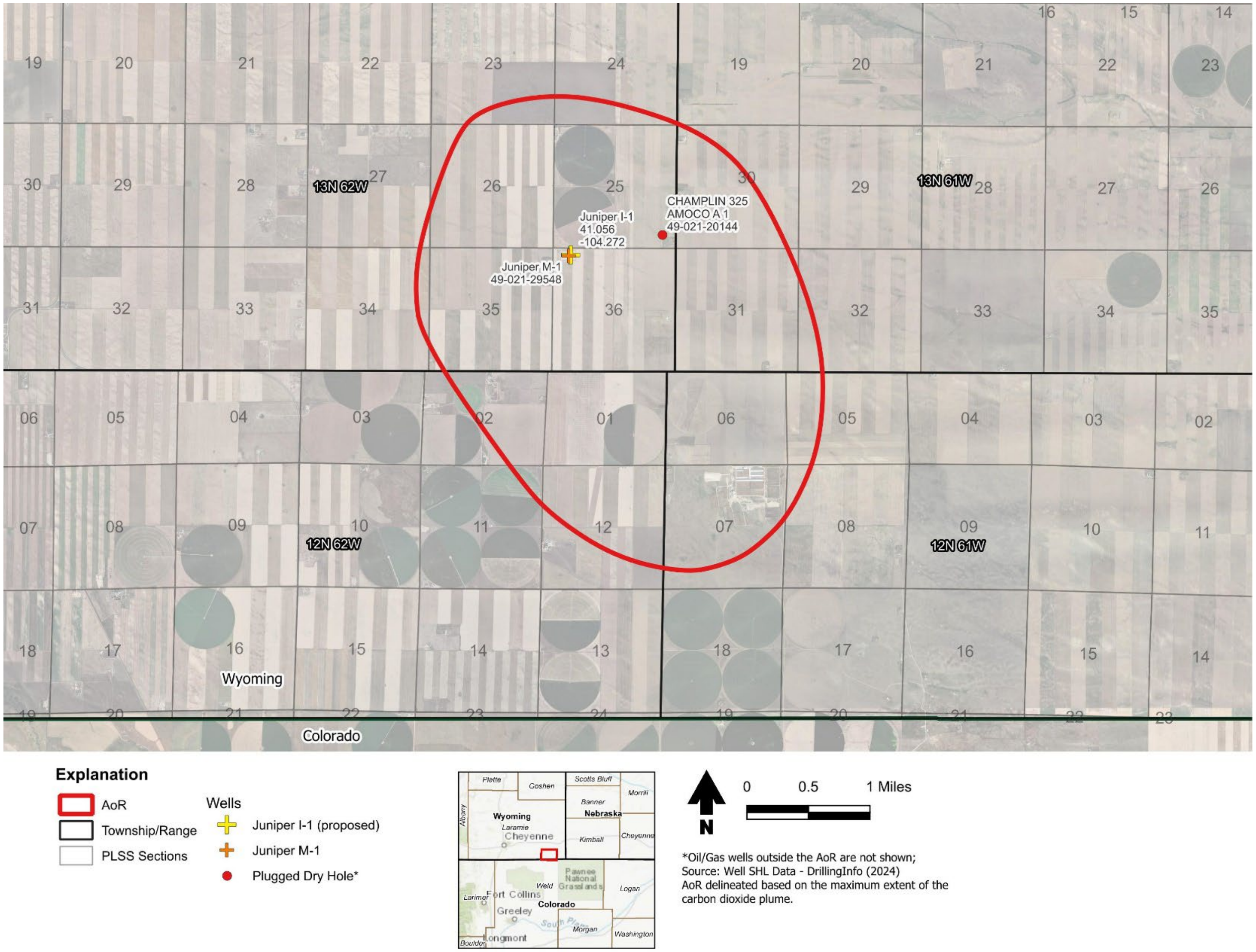

Figure 1. Juniper I-1 Project Location, Juniper M-1 proposed Above Confining Zone Monitoring Well, and Abandoned Oil And Gas Well within the AoR. The Champlin 325 A1 well does not penetrate the upper confining zone.

3.2 Project Area Geology

The Juniper I-1 AoR is located in Laramie County in southeastern Wyoming, near the town of Carpenter. The site is situated within the Denver Basin, commonly referred to as the Denver-Julesburg Basin, or "DJ Basin." The sequestration program entails injecting into the Lyons Formation, a geologic formation spanning approximately 50 to 100 net feet of high porosity and permeable sands at an approximate depth of 9,119 feet true vertical depth (TVD) at the project location.

The DJ Basin consists of more shallow Paleozoic through deeper Cenozoic sediments that were deposited unconformably over Precambrian crystalline basement rock. Deposition occurred in a predominantly marine shelf environment that was subject to subsidence for most of the Paleozoic and Mesozoic Eras. As a result, total sediment accumulation can reach thicknesses in excess of 13,000 feet along the synclinal axis. Sediment supply during Pennsylvanian time consisted primarily of shale and carbonate in the basin interior, with sand contribution along the Ancestral Rockies.

Permian through Triassic time was characterized by a broad, low-relief intermittent sea that exhibited depositional environments from fluvial, normal marine to hypersaline. Lithology within the Permian-Triassic strata is dominated by redbeds, evaporites, and anhydritic siltstones (Bethke and Lee, 1994). Triassic sediments were subsequently overlain by shale and sand deposition that dominated the Jurassic and Cretaceous periods. The Western Interior Seaway was relatively deep and present across a significant portion of western North America during the Cretaceous, including the DJ Basin. The Cretaceous was also subject to east-verging thrusts associated with Laramide tectonism.

The combination of the structural setting and depositional environment resulted in accumulation of up to 10,000 feet of Cretaceous shale, sandy shale, and carbonate over Jurassic and Triassic sediments throughout the basin (Sonnenberg and Weimer, 1981; Bethke and Lee, 1994; Taucher et al., 2013). These shales and tight carbonate formations have been identified by the Wyoming State Geological Survey (WSGS) as confining intervals between the injection formation and lowermost potential potable water aquifer.

Figure 2 depicts the stratigraphy of the DJ Basin. The geologic sequence of the Juniper I-1 includes the following formations, from most shallow to deepest (approximate depths are given at the project location):

- *Above Confining Zone:* Sundance Formation (8,518 feet TVD). The Sundance Formation includes well-sorted, well-rounded sandstone intervals that are sufficiently permeable to serve as a groundwater aquifer (Lowry and Crist, 1967; Love and Christiansen, 1985; Taucher et al., 2013).
- *Upper Confining Zone:* Chugwater Formation/Goose Egg Formation.
    - *Chugwater Formation* (8,610 feet TVD)*:* The formation consists of reddish-orange shale and siltstone with thin gypsum partings near the base. Based on data collected from the Juniper M-1 monitoring well, the thickness of the Chugwater Formation within the Juniper project area is approximately 250 feet.

- ◇ *Goose Egg Formation* (8,844 feet TVD): This geologic section consists of red shale and silt interbedded with gypsum, anhydrite, limestone, and dolomite. Based on data collected from the Juniper M-1 monitoring well, the thickness of the Goose Egg Formation within the Juniper project area is approximately 250 feet.

- *Injection Zone*: Lyons Formation (9,119 feet TVD). The Lyons Formation is described as a well-sorted, fine-grained, eolian quartzose sandstone from outcrops near Lyons, Colorado (Sonnenberg and Weimer, 1981). Based on data collected from the Juniper M-1 monitoring well and offset correlations, the Lyons Formation has an approximate thickness of 62 to 74 feet in the vicinity of the Juniper project area.

- *Lower Confining Zone*: Satanka Formation. The Satanka Formation contains interbedded red and gray sandstones, gray siltstone, red mudstone, and red anhydritic siltstones. The sandstones contain feldspar and are commonly fine-grained to very fine-grained. The anhydrite-rich upper Satanka provides an impermeable barrier, inhibiting vertical fluid migration (Clayton and Swetland 1980).

Figure 3 is a schematic representing the regional stratigraphy in the vicinity of the Juniper project area. The figure also shows the proposed above confining zone monitoring well (Juniper M-1) location. The injection zone is shown in red as the Lyons Formation.

ERATHEM	SYSTEM AND SERIES		Lithostratigraphic units of Love et al. (1993) in the DJ Basin (MODIFIED)		Hydrogeologic unit for DJ Basin		
CENOZOIC	QUATERNARY	Holocene and Pleistocene	Alluvium and terrace deposits		Quaternary unconsolidated-deposit aquifers		High plains aquifer system
	TERTIARY	Pliocene	*section absent due to erosion or nondeposition*				
		Miocene	Ogallala Formation		Ogallala aquifer		
			Arikaree Formation		Arikaree aquifer		
		Oligocene	White River Formation	Conglomerate	White River Group		
				Lower part	White River aquifer/confining unit		
			White River Group	Brule Formation		Brule	
				Chadron Formation		Chadron	
		Eocene	*section absent due to erosion or nondeposition*				
		Paleocene					
MESOZOIC	CRETACEOUS	Upper Cretaceous	Lance Formation		Lance aquifer		Lance-Fox Hills aquifer
			Fox Hills Sandstone		Fox Hills aquifer		
			Pierre Shale		Pierre confining unit		
			Niobrara Formation		Niobrara confining unit		
			Carlile Shale		Carlile confining unit		
			Greenhorn Formation		Greenhorn confining unit		
			Belle Fourche Shale		Belle Fourche confining unit		
			Mowry Shale		Mowry-Thermopolis confining unit		
		Lower Cretaceous	Muddy Sandstone			Muddy Sandstone aquifer	
			Thermopolis Shale				
			Inyan Kara Group	Fall River Formation	Inyan Kara aquifer		
				Lakota Formation			
	JURASSIC	Upper Jurassic	Morrison Formation		Morrison aquifer and confining unit		
		Middle Jurassic	Sundance Formation		Sundance aquifer		
	JURASSIC (?) AND TRIASSIC (?)		*section absent due to erosion or nondeposition*				
	TRIASSIC	Upper Triassic	Chugwater Formation of Darton (1908)		Chugwater confining unit		
		Lower Triassic	Lykins Formation		Goose Egg Formation		
PALEOZOIC	PERMIAN		Lyons Sandstone		Hydrogeologic role/unit not defined for study area		
			Satanka Shale		Satanka confining unit		
	PENNSYLVANIAN	Upper Penn	Casper Formation	Hartville Formation	Casper aquifer	Hartville aquifer	Paleozoic aquifer system
		Middle Penn					

Figure 2. Stratigraphic Column of the DJ Basin. The shading indicates freshwater aquifers (underground sources of drinking water [USDWs]) in blue, the proposed injection interval in red, primary confining layers in dark gray, and additional confining layers in light gray (adapted and modified from Taucher et al., 2013).

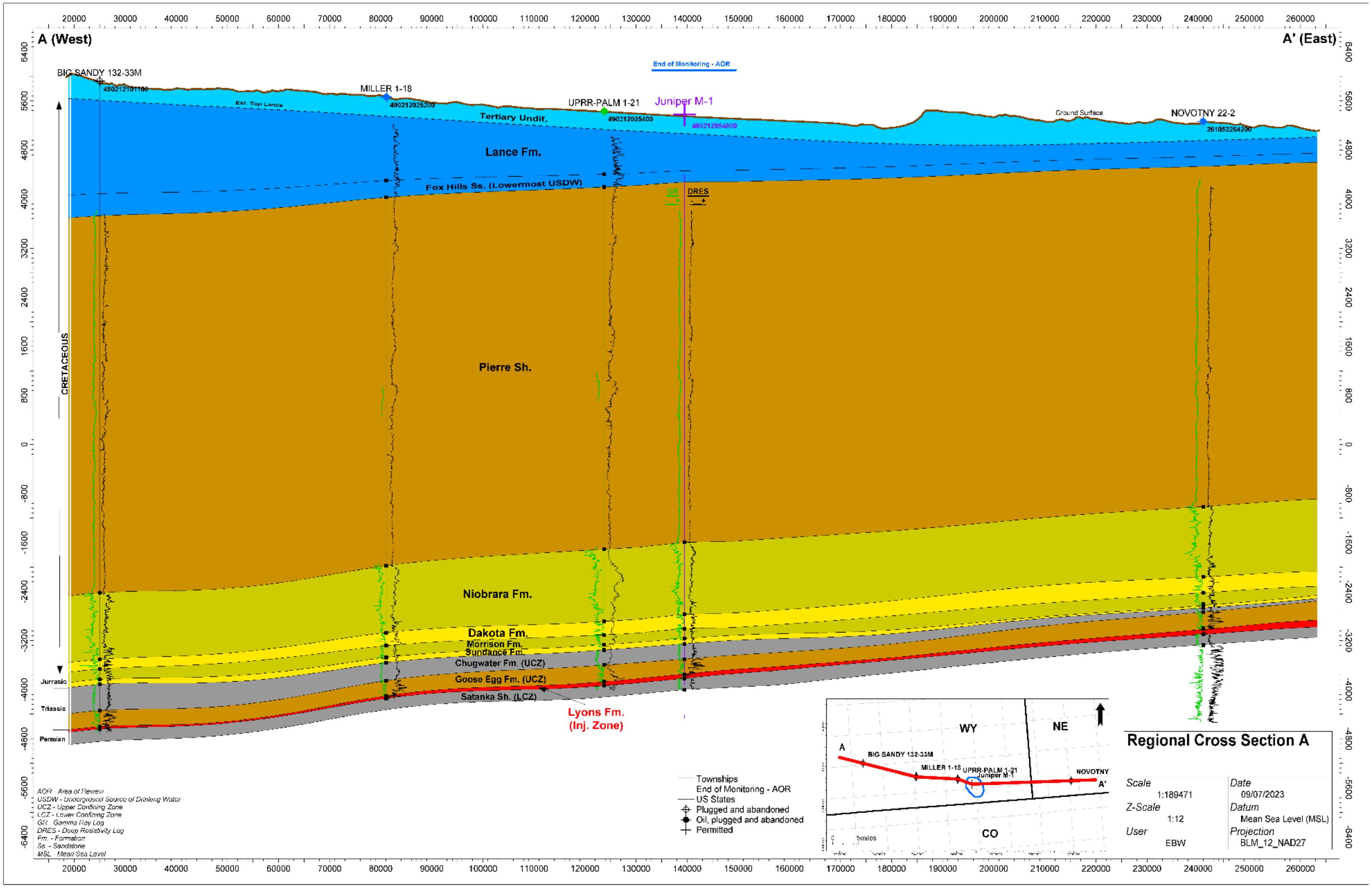

Figure 3. Regional West-East Cross Section A-A'. Gamma ray (left, green) and deep resistivity (right, black) logs are shown.

3.3 Surface Facilities and Injection Process

A simplified flow diagram of surface facilities is provided in **Figure 4**. All facilities will be designed and built to ensure integrity and compatibility with CO_2. The injection well will be designed and operated in a manner that meets the requirements of WDEQ Chapter 24. Once injection activity is complete, the well will be plugged according to WDEQ Chapter 24 §23.

The monitoring program (see Section 6) is designed to meet the requirements of Subpart RR and WDEQ Chapter 24 §20, with advanced technologies that allow for the tracking of the injectate plume migration while minimizing the artificial creation of potential pathways for sequestered fluids to escape confinement. The extent of the CO_2 plume will be monitored using two-dimensional (2D) seismic surveys to understand CO_2 saturation changes through time. A monitoring well (Juniper M-1) has been drilled and will be utilized to detect migration above the confining zone.

Subsections will review:

- CO_2 source (Section 3.3.1)
- CO_2 transportation and injection (Section 3.3.2)
- Wells in the Class VI AoR penetrating the upper confining zone (Section 3.3.3)

3.3.1 CO_2 Source

CO_2 will be sourced from a CO_2 collection pipeline from several industrial facilities in Nebraska and surrounding states. Chemistry of the injectate stream will consist of 95 percent or higher CO_2 purity and less than 150 parts per million (ppm) water. **Table 1** shows the planned composition of the injectate stream, per the pipeline specifications.

High Plains will demonstrate the compatibility of the CO_2 stream with the fluids in the injection zone and minerals in both the injection and confining zones based on the results of the formation testing program. The CO_2 streams that High Plains proposes to inject through the Class VI permit are exempt from the U.S. Environmental Protection Agency (EPA) definition of hazardous waste in CFR 40 CFR § 261.4(h). Similarly, the injected CO_2 is not a hazardous or toxic waste or other material under Chapter 8 of WDEQ Water Quality Rules in the Wyoming Code of Regulations (WCR) (020-0011-8 WCR 6). As such, the CO_2 stream that High Plains proposes to inject is not subject to the restrictions in 020-0011-8 WCR 6(c)(ii).

3.3.2 CO_2 Transportation and Injection

CO_2 from the collection pipeline will be distributed to the injection well with new infrastructure. This distribution infrastructure will allow CO_2 to be injected into the CO_2 injection well completed within the Lyons Formation.

The CO_2 injection well will have automated controls that provide for both control and measurement of the mass flow rate and pressure.

3.3.3 Wells in the AoR Penetrating the Upper Confining Zone

The Juniper M-1 (API #49-021-29548) is the only well in the AoR that penetrates the upper confining zone but will be converted into an above confining zone monitoring well.

Remaining active or abandoned oil and gas wellbores within the AoR were identified using the WOGCC online data explorer. One plugged dry hole (Amoco Champlin 325 A1) was identified, and does not penetrate the upper confining zone (**Figure 1**). The Amoco Champlin 325 A1 vertical well (API #49-021-20144) is located approximately 1 mile east-northeast of Juniper I-1. The well was drilled to a total depth of 7,990 feet, completed in the Lower Cretaceous Muddy Sandstone (**Figure 2**) and contains no reported production in the WOGCC database. The approximate distance between the Amoco Champlin 325 A1 well maximum depth and the top of the Lyons injection zone is 1,042 feet. Amoco Champlin 325 A1 does not penetrate the injection zone; therefore, the well does not pose a risk of fluid leakage and no corrective action is needed.

The Amoco Champlin 325 A1 and Juniper M-1 wells are the only existing active or abandoned oil and gas or carbon capture and storage (CCS) wells in the maximum monitoring area (MMA; see Section 4).

Table 1. Composition of the injectate stream

Constituent	Limit
CO_2	$\geq$ 95 mol%
Carbon monoxide (CO)	$\leq$ 0.4 mol%
Hydrogen (H_2)	$\leq$ 0.5 mol%
Hydrogen Sulfide (H_2S)	$\leq$ 20 ppm
Total Sulfur	$\leq$ 35 ppm
Total nitrogen oxides (NO_x)	$\leq$ 10 ppm
Oxygen (O_2)	$\leq$ 1 mol%
Water (H_2O)	$\leq$ 150 ppm
Hydrocarbons	$\leq$ 4 mol %
Glycol	0.3 gallons/MMCF
Maximum dew point at 400 psig	30°F
Non-condensable gases	$\leq$ 5% mol%

psig = pounds per square inch gauge
MMCF = million cubic feet

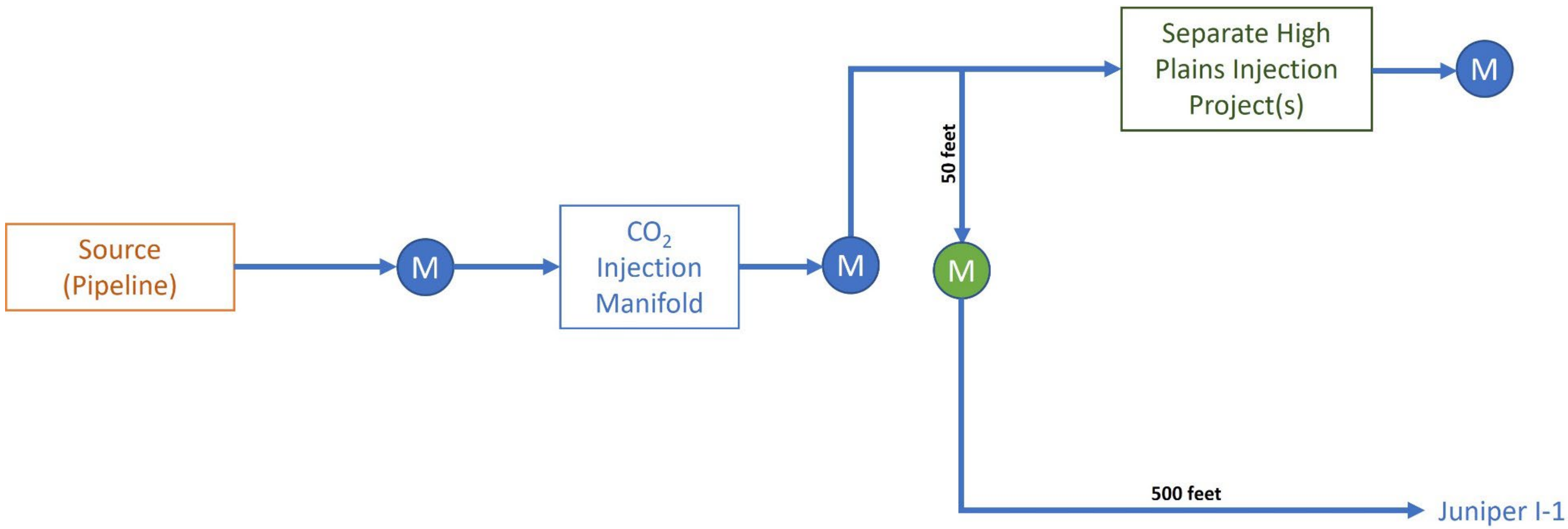

Figure 4. **Simplified Facilities Flow Diagram for Juniper Injection Project.** Green "M" symbol denotes Juniper project meter location. Blue "M" symbols denote additional meter locations. Figure not to scale; distances given are approximate.

3.4 Reservoir Simulation Model

Reservoir modeling included development of a static geologic model and dynamic reservoir model. The reservoir simulation model was used to define the site AoR (CO_2 plume) and the MRV monitoring areas (Section 4).

Subsections further describe the follow topics:

- Data Sources (Section 3.4.1)
- Model Platform (Section 3.4.2)
- Structural Framework (Section 3.4.3)
- Initial Conditions (Section 3.4.4)
- Fracture Gradient (Section 3.4.5)
- CO_2 (Section 3.4.6)
- Injection (Section 3.4.7)
- Boundary Conditions (Section 3.4.8)
- Modeling Results (Section 3.4.9)

3.4.1 Data Sources

Data sources used to build the geologic model include well logs, 2D seismic data, core, and publicly available literature. Publicly available open-hole log data including gamma-ray, spontaneous potential, resistivity, porosity (sonic, neutron, density), photoelectric factor, and the caliper log were used to pick stratigraphic tops and perform petrophysical analyses. Petrophysical analyses were performed on a total of 47 wells with triple combo log suites (gamma ray, porosity, and resistivity logs) within the southeastern Wyoming area of interest (EWS Hub area). Well logs were also used as control points in the geologic model to distribute rock property values.

2D seismic data was tied in with well log formation tops to model the geologic structure. The seismic analysis was further used to identify any faulting, structural changes, or reservoir thickness not identified from well logs. No faults were identified in the project area.

3.4.2 Model Platform

Schlumberger's Petrel™ Software was chosen to build the geologic model. Petrel is a state-of-the-art software package that is used worldwide, incorporating log and seismic data to create a geostatistical representation of the reservoir. The geologic model developed using Petrel represents the subsurface characteristics of the proposed carbon sequestration site. It consists of the Chugwater (upper seal), Goose Egg (upper seal), and Lyons (injection zone).

The geologic model was then used as an input into Computer Modeling Group's (CMG's) GEM 2022.10 (GEM) simulator, which is one of the most accurate and technically sound reservoir simulation software packages for conventional, unconventional, and secondary recovery. GEM uses equation-of-state (EOS) algorithms, along with some of the most advanced computational methods, to evaluate compositional, chemical, and geochemical processes and characteristics to produce highly accurate and reliable simulation models for carbon sequestration. GEM was used to accurately simulate the movement of supercritical CO_2 and the increase in reservoir pressure due to injection operations.

3.4.3 Structural Framework

The structure model was built from formation tops as determined from log analysis and seismic interpretation. A three-dimensional (3D) model was constructed in Petrel from interpreted geologic horizons and mapped regional faulting. Petrel employs simple kriging methods, with the well logs as control points, to distribute property values across the modeled formations. The primary distributed properties were permeability and porosity estimates.

The geocellular model consists of 500-foot by 500-foot hexahedral grid cells. The model covers an area of 40 miles by 70 miles. Model layers for the five primary zones of interest (Dakota, Morrison, Sundance, Chugwater and Goose Egg, Lyons, and Satanka) were obtained from the static geologic model (**Figure 5**).

Additional layering for the model was defined through isopach maps and well tops, resulting in vertical cells of varying thickness ranging from 2 to 40 feet. The isopach maps honored significant features observed from seismic data including facies changes. Because no faults were observed in the area of interest, the model contains no fault planes.

Petrophysical analyses conducted on 45 wells within the model boundary were used to determine porosity and permeability for each stratigraphic zone. Using the values derived from log analysis, properties in the geocellular static model were assigned by taking the continuous range of the property and upscaling the value to match the final grid cell resolution using the arithmetic average over each cell. Property distribution in the Lyons Formation consisted of applying a kriging algorithm from upscaled logs, guided by an experimental spherical variogram, with major and minor range of 100,000 feet and a vertical range of 50 feet for each zone. Property distribution consisted of applying the kriging algorithm from upscaled porosity logs, guided by variograms for each zone as seen in **Figure 6**.

3.4.4 Initial Conditions

The model is a pseudo-infinite acting reservoir that is 100 percent brine filled. Based on 2D seismic interpretation and log information collected at the Juniper M-1, the sands within the Lyons Formation have an average gross thickness of 55 feet. From drill stem test data in adjacent wells, High Plains determined that the Lyons Formation has a pressure gradient of 0.3 pounds per square inch per foot (psi/ft) and a fracture gradient of 0.47 psi/ft. A reservoir temperature gradient of 1.34°F per 100 feet with a mean surface temperature of 75°F was used.

A regional review of the Lyons Formation and the DJ Basin was conducted to determine salinity estimates for input into the model. All regional data were acquired from a national produced-water database generated by the U.S. Geological Survey (USGS). The review concluded that salinity increased with depth and higher values trended along the eastern flank of the reservoir. A total dissolved solids (TDS) value of 150,000 ppm was chosen based on the location of the CO_2 injector relative to the salinity data that was reviewed.

3.4.5 Permeability and Porosity

Permeability was distributed along corresponding porosity values. Air permeability was correlated to ambient porosity. The correlation of porosity to permeability is defined by the best-fit trend line of the measured data taken from Razor 26J-2633L (API #051233749500) and Marathon-Avalo 1-32 (API #05123106700), as shown in **Figure 7**. An equation was created with a best-fit trend line to calculate permeability based on the distributed porosity. These values were then converted into brine permeability based on the Swanson K_{air}/K_{brine} relationship (Swanson, 1981). If the brine permeability was greater than the air permeability, the study authors chose the air permeability to provide a more conservative estimate in the model.

3.4.6 Fracture Gradient

A value of .47 psi/ ft was calculated and utilized as the fracture gradients of the Lyons Formation. 90 percent of the gradient was applied to the wellbore model as a maximum injection pressure constraint. Using 90 percent of the fracture gradient results in a pressure constraint gradient of 0.42 psi/ft.

3.4.7 CO_2 Phase

The CO_2 will be injected in a supercritical state, and separate-phase CO_2 will remain as a supercritical fluid due to the pressure and temperature of the Lyons Formation. There are numerous advantages to storing CO_2 under supercritical conditions. Supercritical fluids have significantly higher density that allows for a greater mass of molecules to be stored in the same space. CO_2 also has a low viscosity that lowers the pressure required to store it. Based on the pressure and temperature assumptions, separate-phase CO_2 will continue to remain as a supercritical fluid throughout the life of the project and some CO_2 will dissolve into the brine.

3.4.8 Injection

The injection rate was held constant for approximately 5 years at 1.5 MMT not to exceed 7 MMT of CO_2 stored.

3.4.9 Boundary Conditions

From well log and seismic analyses, the Lyons Formation was determined to pinch out to the northwest and to the southeast of our area of interest. Therefore, the northwest and southeast edges have been established as no-flow boundaries for modeling purposes. Conversely, the northeast and southwest edges of the model have volume modifiers in place, allowing them to act as open boundaries.

3.4.10 Modeling Results

Once all variables were input, the simulation model was run with the primary objective to maximize storage capacity and minimize the lateral extent of CO_2 plume. The objectives were achieved by optimizing injection patterns and well placement, as well as performing sensitivity analyses. The maximum extent of the plume is assumed to be the point where the concentration of supercritical-phase CO_2 reaches below 2 percent saturation.

The Lyons Formation sands were upscaled into eight distinct 7-foot layers that were all simultaneously perforated and injected with supercritical CO_2. The Lyons Formation is bounded by an upper shale (Chugwater) that is a physical trap preventing the upward migration of CO_2. Supercritical CO_2 is more buoyant than water; thus, the CO_2 migrates to the upper 7-foot Lyons Formation layer. The maximum extent of the plume was taken from the uppermost of these layers (Layer 11).

Figure 8 shows modeling results of the predicted CO_2 plume radius over time. As indicated by negligible change after 2035 (6 years after the end of injection), the plume is considered stabilized by that time.

The increase in pressure experienced from injection operations was also modeled. The pressure buildup is monitored by the rise of reservoir pressure, as well as its associated gradient based on the top of the perforated interval. **Figure 9** represents the maximum pressure buildup and maximum pressure gradient seen within the reservoir at any given time. In the model, the reservoir experiences a maximum pressure buildup of 976 pounds per square inch (psi). This buildup does not exceed 90 percent of the fracture pressure, allowing for safe injection of supercritical CO_2.

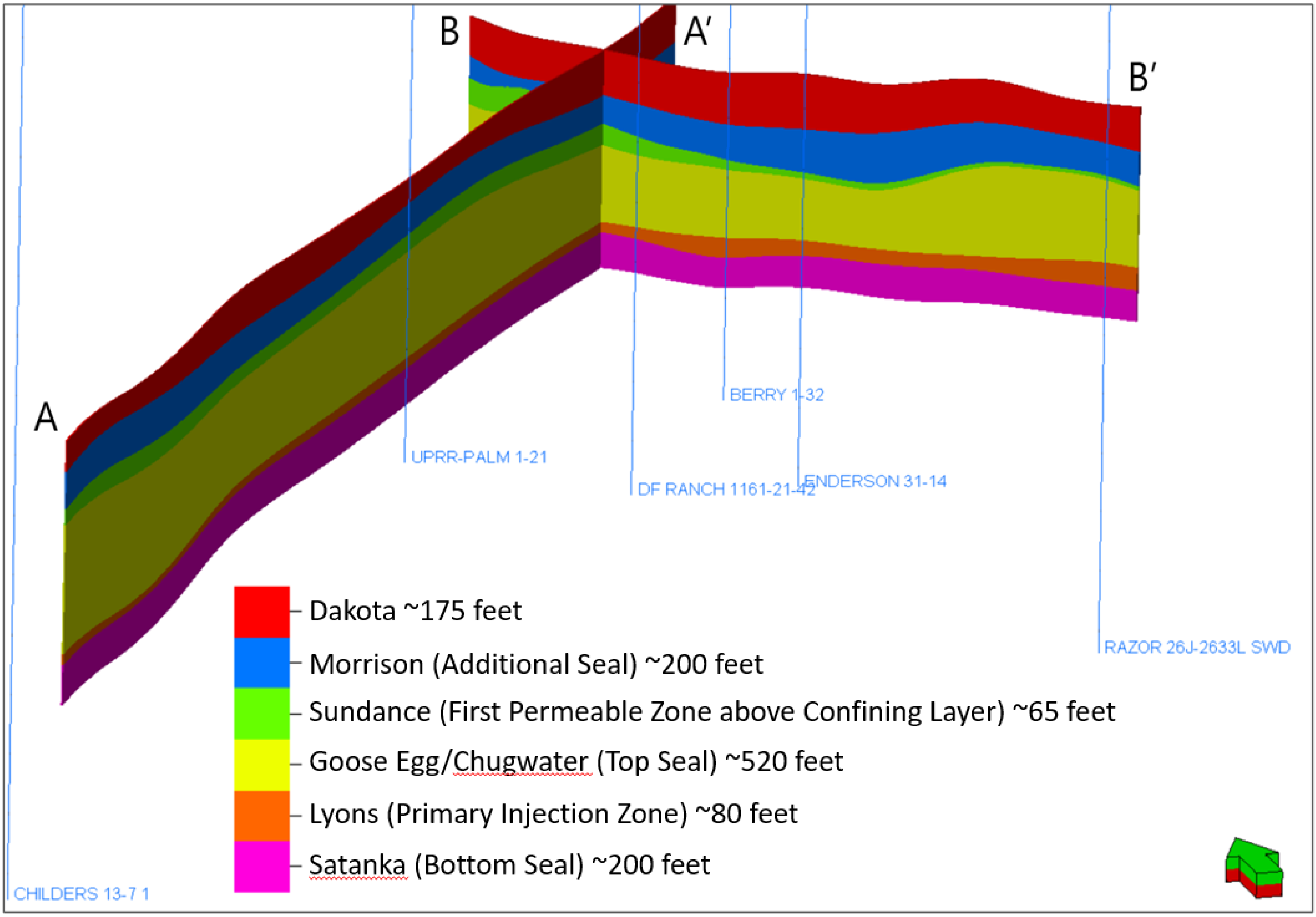

Figure 5. Model Layers.

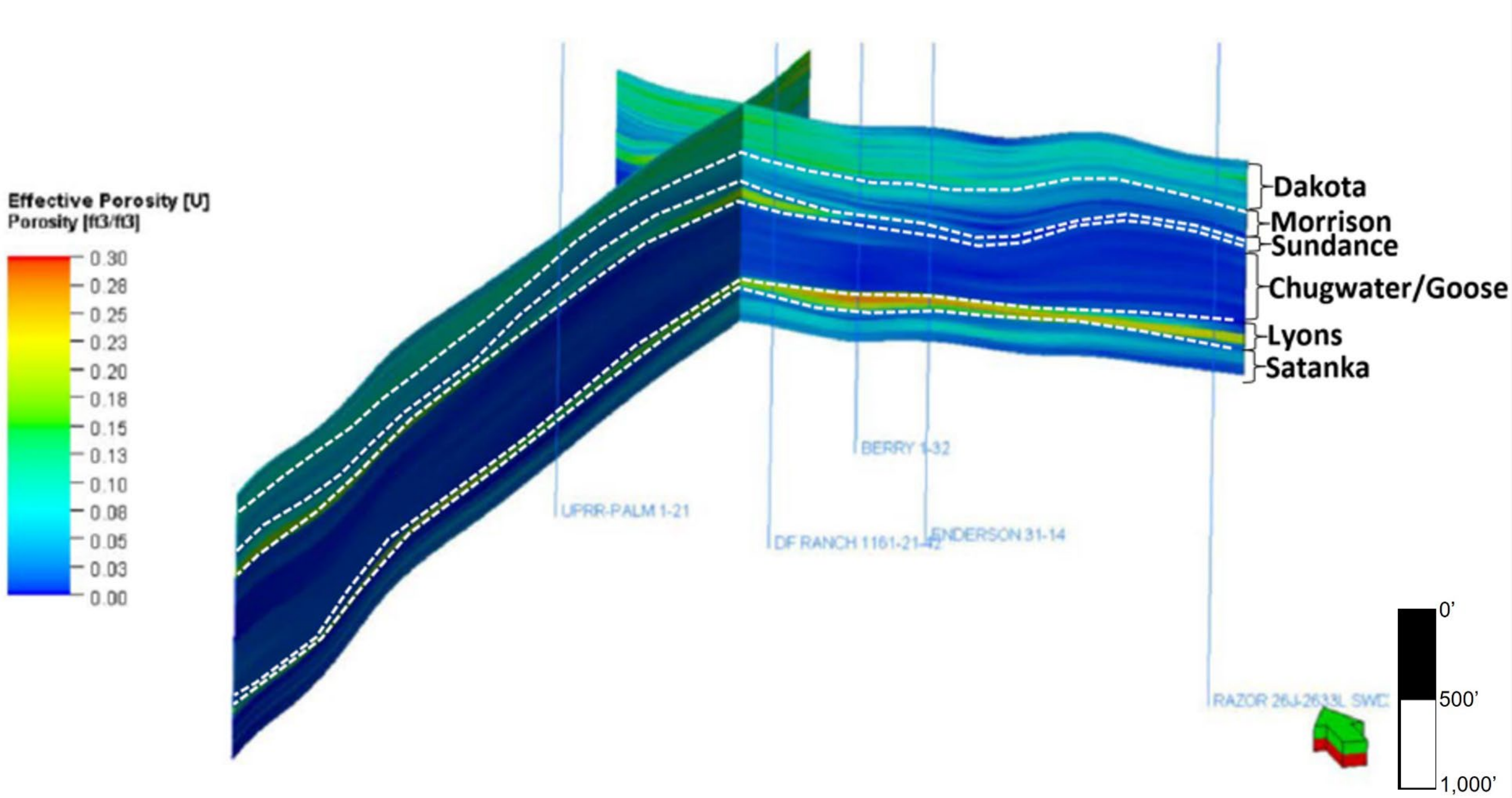

Figure 6. Distribution of Porosity Using Simple Kriging Methodology.

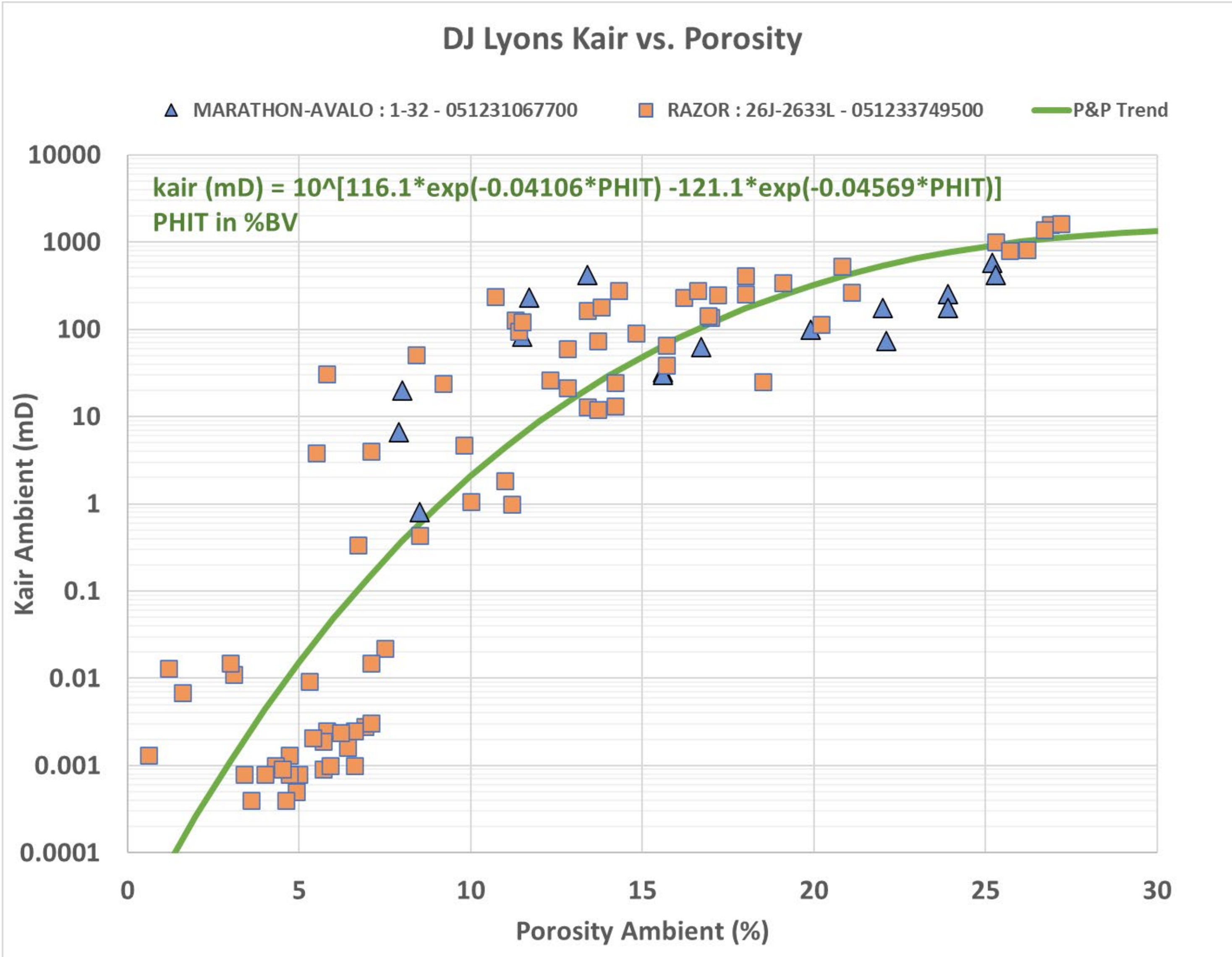

Figure 7. **Porosity and Permeability Relationship.**

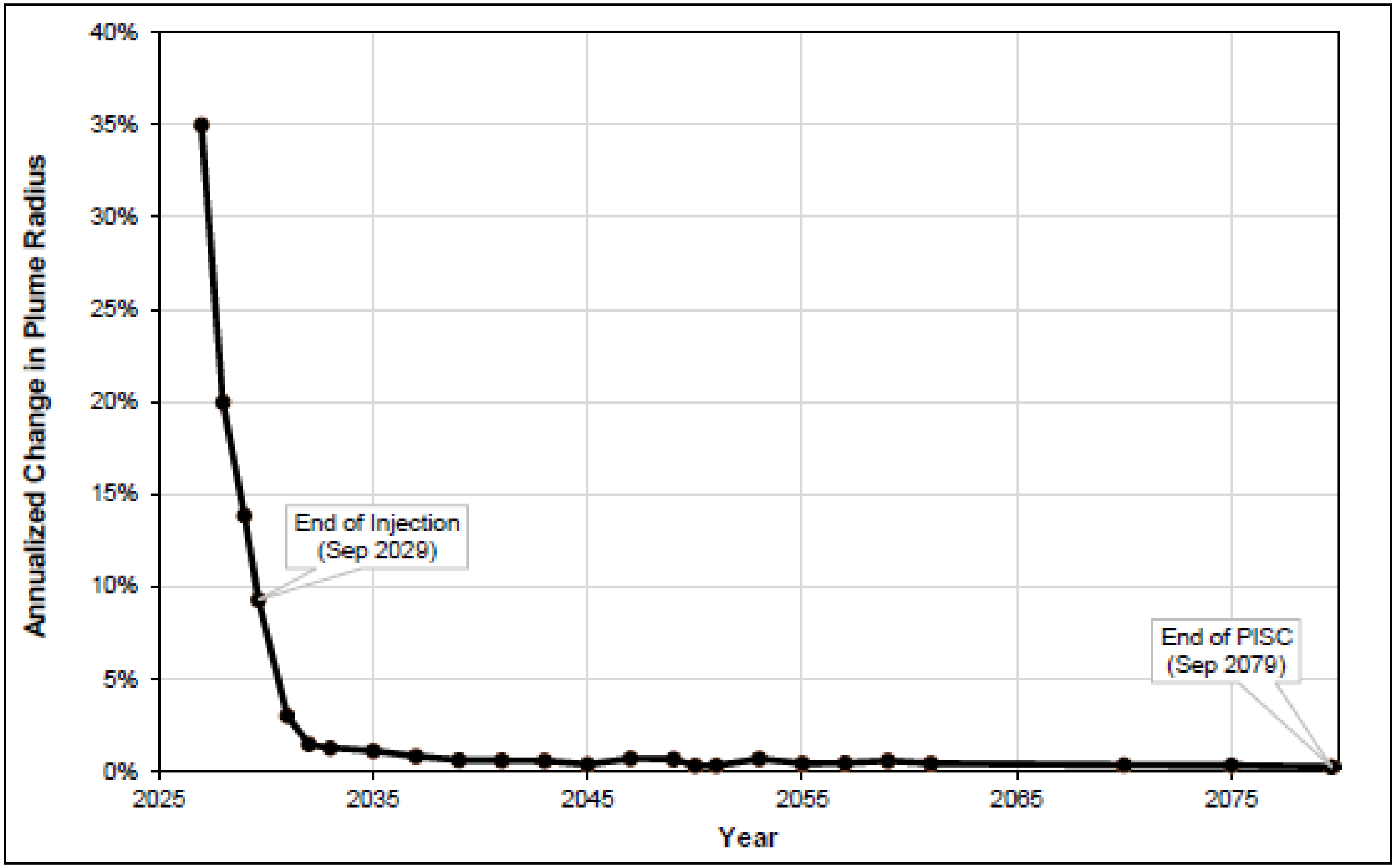

Figure 8. Juniper I-1 CO_2 Plume Stabilization. This figure shows modeling results of the predicted CO_2 plume stabilization.

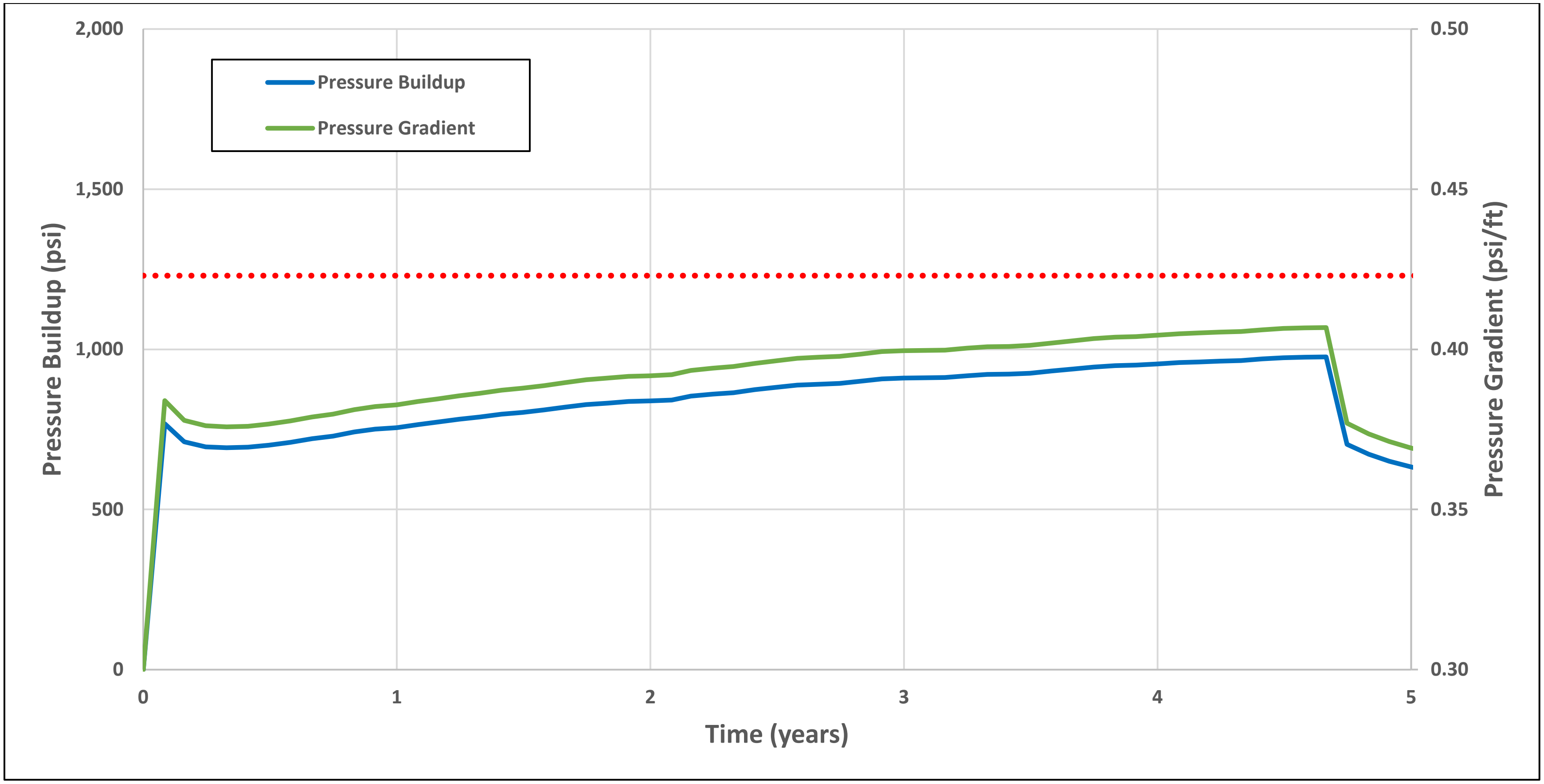

Figure 9. Pressure Buildup During Injection Operations. Red line indicates the threshold of 90 percent of the fracture gradient.

4. Delineation of the Monitoring Areas

Reservoir simulation modeling (Section 3.4) was used to define the MMA and the active monitoring area (AMA), as described in subsections 4.1 and 4.2. In determining the monitoring areas, the extent of the separate-phase CO_2 plume is equal to the point where the concentration of supercritical-phase CO_2 reaches below 2 percent saturation.

The monitoring timeframe will be the same as the Post-Injection Site Care (PISC) timeframe in the Class VI permit. At the conclusion of the PISC period, a request for discontinuation of Subpart RR reporting will be submitted including a demonstration that current monitoring and modeling show that the cumulative mass of CO_2 reported as sequestered is not expected to migrate in the future or encounter leakage pathways.

4.1 Maximum Monitoring Area

As defined in Subpart RR, the MMA is equal to or greater than the area expected to contain the free-phase CO_2 plume until the CO_2 plume has stabilized plus an all-around buffer zone of at least 0.5 mile. **Figure 10** shows the MMA as defined by the final extent of the stabilized CO_2 plume (50 years after the end of injection) plus a 0.5-mile buffer.

4.2 Active Monitoring Area

The AMA boundary was established by superimposing two areas (40 CFR § 98.449):

- *Area #1:* The area projected to contain the free-phase CO_2 plume at the end of year *t*, plus an all-around buffer zone of 0.5 mile or greater if known leakage pathways extend laterally more than 0.5 mile.
- *Area #2:* The area projected to contain the free-phase CO_2 plume at the end of year $t + 5$.

The AMA boundary was determined for the time period ("*t*") corresponding to 50 years after the end of injection (55 years after the beginning of injection). Area #1 was taken as the plume area plus an all-around buffer zone of 0.5 mile. Area #2 is smaller or equal in all directions; therefore, the final AMA was defined as Area #1 (**Figure 10**).

High Plains has established one AMA boundary for 55 years and does not anticipate any expansion of the monitoring area under 40 CFR § 98.448 under the currently planned project operating conditions. Given the definitions used to define the MMA and AMA, the AMA is functionally equivalent to the MMA. Instituting monitoring throughout the entire MMA boundary provides maximum operational flexibility.

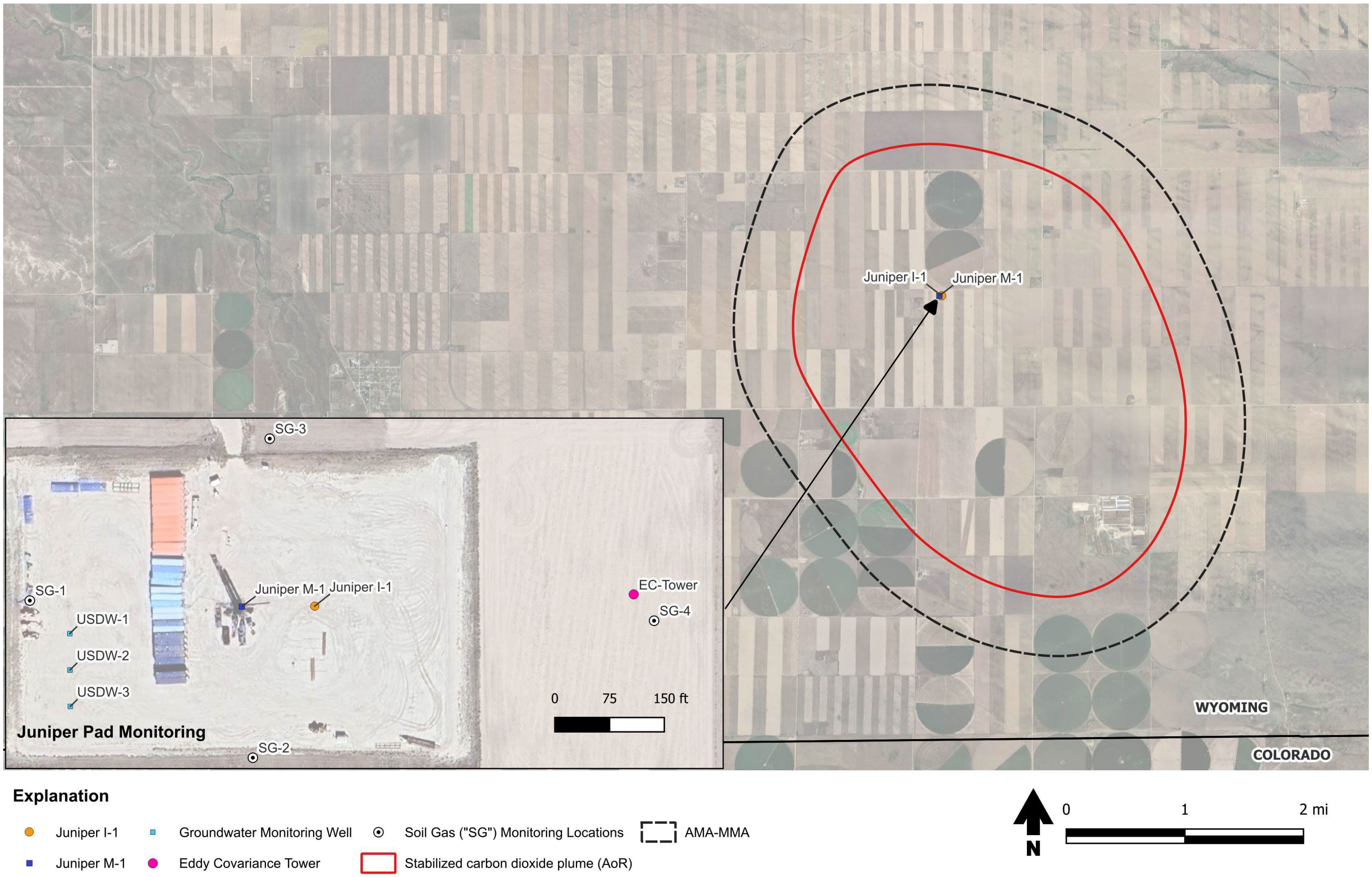

Figure 10. Project Location, Monitoring Locations, and AMA-MMA. Eddy covariance monitoring discussed in Section 6.4.2, and soil gas monitoring discussed in Section 6.5.2.

5. Identification and Assessment of Potential Surface Leakage Pathways

This section assesses potential pathways for leakage of stored CO_2 to the surface. Monitoring protocols that will be in place for each potential pathway are discussed. Section 6 describes how High Plains will develop the inputs used in the Subpart RR mass-balance equation (Equation RR-12). Any incidents that result in CO_2 leakage through the wellbore and into the atmosphere will be quantified as described in Section 6.

5.1 Pipelines/Surface Equipment

The Juniper I-1 wellhead and the pipeline that carries CO_2 to it are a potential pathway to allow CO_2 to leak to the surface. Leakage is most likely to be the result of aging and use of the surface components over time. The accumulation of wear and tear on the surface components, especially at the flanged connection points, is the most probable cause of the leakage. Another possible cause of leakage is the release of air through relief valves, which are designed to alleviate pipeline overpressure. Leakage can also occur when the surface components are damaged by an accident or natural disaster, causing CO_2 to be released. Therefore, High Plains infers that there is minor potential for leakage via this route.

There is a possibility of fugitive emissions from surface equipment in the event of equipment failure. CO_2 will occasionally need to be vented from surface equipment for operational maintenance. High Plains will monitor and report this CO_2 as part of its reporting requirements under 40 CFR § 98.446(f)(3).

Likelihood: Compliance with applicable pipeline and UIC regulations ensures that likelihood of leakage via this pathway is minor.

Timing*:* Surface component leakage is only a concern during the injection operation phase. Once the injection phase is complete, the surface components will no longer be able to store or transport CO_2, eliminating any potential risk of leakage.

Magnitude*:* Depending on the component's failure mode, the magnitude of the leak can vary greatly. For example, a rapid break or rupture could release large amounts of CO_2 into the atmosphere almost instantly, while a slowly deteriorating seal at a flanged connection could release only a small volume of CO_2 over several hours or days.

Should leakage be detected between the flow meter used to measure injection quantity and the injection wellhead, then the mass of released CO_2 will be quantified following the requirements of EPA's GHGRP as referenced at 40 CFR § 98.444(d).

Monitoring*:* Routine field inspection and remote pipeline monitoring will be conducted to detect any potential leakage from pipelines and surface facilities. Continuous surface air monitoring (eddy covariance tower) and semi-annual soil gas monitoring will also be in place to detect any surface leakage.

5.2 Wellbores

Importantly, no abandoned wells are present within the MMA that penetrate the upper confining zone or below. The project-related injection and monitoring well will be monitored and maintained to prevent wellbore integrity issues. CO_2 migration could occur along an injection or monitoring well due to a degraded cement bond or corrosion of the casing and completion. Any well that penetrates the injection zone creates a possible migration pathway if the CO_2 plume reaches its position.

All of the injection and monitoring wells involved in the project will be permitted by the State of Wyoming in accordance with Chapter 24 of the WDEQ regulations. High Plains is required to demonstrate to WDEQ that Class VI wellbores do not pose a threat of leakage. Injection well tubing and casing pressures will be monitored continuously. Designs for each injection well are engineered to govern the rate and pressure of CO_2 injection. Pressure monitors on the injection well is programmed to flag pressures that statistically deviate from design. Leakage on either the inside or outside of the injection wellbore would cause pressure inflections that would be detected through this approach. Injectors will also be monitored with mechanical integrity tests (MITs) and pressure tests to ensure internal and external integrity. If monitoring data leads to identification of a well integrity issue, High Plains will address the issue with corrective actions.

***Likelihood**:* The probability that an existing or new well causes leakage to surface is minor. There are no abandoned wells within the CO_2 plume area that penetrate the injection zone, and the injection and monitoring well are designed, operated, and monitored according to WDEQ regulations. The monitoring program assesses the mechanical integrity of wells to ensure that well integrity is maintained.

***Timing**:* Wellbore leakage risk from project wells will be highest during the injection phase. Risk will decrease after injection, most notably when the injection well is plugged. The well will be plugged to WDEQ Class VI standards.

***Magnitude**:* Leakage of CO_2 mass from project wellbores is considered to be negligible for the reasons previously described in this section (Section 5.2).

***Monitoring**:* Wellbore monitoring will include MITs, injection well pressure and rate monitoring, annulus pressure monitoring, surface and near-surface (USDW) monitoring, and inspections. An annual temperature log will be conducted in Juniper I-1. Permanent, continuous pressure and temperature monitoring will be conducted in Juniper M-1. Annual pulsed neutron logs (PNLs) will be conducted in Juniper M-1. Surface air (eddy covariance tower), soil gas, and USDW groundwater monitoring will also be instituted in the vicinity of the injection well and Juniper M-1 (above confining zone monitoring well).

5.3 Leakage through the Confining Zone

Leakage out of the Lyons Formation could result in elevated concentrations of indicator parameter(s) in groundwater sample(s) or other evidence of CO_2 leakage into shallow groundwater. Fluid leakage risk is low due to the significant thickness (>7,500 feet) of intervening geologic units above the sequestration zone.

High Plains conducted a seismic evaluation of 10 quality 2D lines within the region of the project area to confirm structural mapping and locate any potential faulting or fracturing within the area. The review also incorporated published public domain interpretations of surrounding 3D surveys for Silo Field, North Mustang Field, and Hereford Field. The 3D surveys were not licensed or purchased, as the surveys do not cover the project area. No faults that intersect the CO_2 plume were identified in the 2D seismic evaluation. Faulting was observed in Hereford Field, located 7 to 8 miles south of the Juniper project area, with a general orientation of east to west. These subsurface features have been evaluated and do not appear to intersect the modeled plume migration or modeled pressure of Juniper I-1. No transmissive fractures were identified based on a wireline image log of Juniper M-1.

Diffusion of CO_2 through the upper confining zone (Goose Egg and Chugwater Formations) is not expected to result in significant loss from the storage reservoir given the low permeability (0.00001 millidarcy [mD]) and thickness (>480 feet) of these zones.

High Plains will operate the project to ensure containment of CO_2. Leakage will be avoided by ensuring injection well integrity through the following means:

- Conducting well maintenance and MITs
- Maintaining the injection pressure below 90 percent of the fracture gradient of the confining unit
- Assessing monitoring data to ensure competency of the confining layer
- Monitoring the Sundance Formation interval that overlies the confining unit to identify leakage before migration to shallower aquifers

Likelihood: Negligible for the reasons previously described in this section (Section 5.3).

Timing: Leakage risk will be similar via this pathway during the operation and post-injection project phases.

Magnitude: For reasons previously given in this section (Section 5.3), anticipated leakage magnitude is negligible.

Monitoring: Monitoring for leakage through the confining zone will include groundwater monitoring above the confining zone, annual PNLs in Juniper M-1, annual temperature log in Juniper I-1, surface air monitoring (eddy covariance tower), soil gas monitoring, and continuous injection-well pressure monitoring.

5.4 Induced or Natural Seismic Event

In 2002, the WSGS published a report on basic seismological characterization of Laramie County, Wyoming. The study analyzed historical seismicity, short- and long-term seismic probability, nearby faulting, and the Uniform Building Code to improve understating of potential risks of seismicity in Wyoming and their potential to incur damage. Findings from the study suggest that the 2,500-year probabilistic map of Wyoming should be referenced for Laramie County seismic analyses, as the map represents a conservative approach in the interest of public safety. The probabilistic acceleration map, shown in **Figure 11**, illustrates that the Juniper project area is located in one of the lowest-risk areas of Wyoming. Historical earthquake data were obtained from the USGS Earthquake Hazards database (USGS, 2022) for recorded earthquakes in the regional vicinity of the Juniper project area in the last 100 years. The search results, shown in **Figure 12**, identified no events within 40 miles of the Juniper project area. No faults that intersect the CO_2 plume were identified in the 2D seismic evaluation. No transmissive fractures were identified based on a wireline image log of Juniper M-1.

Average depth of prior seismic hazard in the region based on reviewed historical seismicity has been approximately 3.7 miles, which is significantly deeper than the proposed injection zone.

***Likelihood**:* A probabilistic analysis indicates that the project is located in one of the lowest-risk areas of Wyoming for natural seismicity. Based on project operating conditions, it is highly unlikely that injection operations would ever induce a seismic event.

***Timing**:* Seismicity risk is negligible; however, pressures will be highest during the injection phase of the project. As a result, if induced seismicity were to occur it would likely correspond to the injection phase of the project.

***Magnitude**:* For reasons previously given in this section (Section 5.4), anticipated leakage magnitude is negligible.

***Monitoring**:* High Plains will monitor the USGS Intermountain West Seismic Network for seismic events.

5.5 Lateral Migration

It is highly improbable that injected CO_2 will migrate laterally outside the modeled plume area due to the buoyant properties of supercritical CO_2, the nature of the geologic structure, and the planned injection approach. As displayed in **Figure 3**, there is a structural dip in the injection zone (Lyons Formation) towards the west. This structural dip was accounted for in the computational modeling used to define the area of the stabilized CO_2 plume. Although CO_2 is predicted to migrate in the updip direction, it is slowed and eventually stopped by capillary trapping mechanisms within the predicted boundaries of the AMA-MMA (e.g., Zhao et al., 2014).

***Likelihood**:* Leakage via the lateral migration pathway is not anticipated.

***Timing**:* Although leakage via lateral migration is not anticipated, the risk is greatest when pressures are highest (generally at the end of the injection period).

***Magnitude**:* Magnitude of any leakage is considered negligible, as leakage via lateral migration is not anticipated.

***Monitoring**:* The CO_2 plume will be monitored indirectly through time-lapse 2D seismic, as approved in the Class VI permit. The 2D seismic will be used to detect any risk of lateral migration outside of the Juniper modeled plume area.

5.6 Drilling Through the CO_2 Area

It is possible that at some point in the future, drilling through the confining zone and into the Lyons Formation may occur.

Likelihood: The possibility of this activity creating a leakage pathway is extremely low because no oil and gas resources are identified and future well drilling would be regulated by WOGCC (oil and gas wells, Class II injection wells) or WDEQ (Class VI injection wells, all other UIC well classes), and will, therefore, be subject to requirements that fluids are contained in strata in which they are encountered.

Timing: Leakage via this pathway is not anticipated; however, leakage risk is greatest during future time periods if drilling through the confining zone and into the injection zone were to occur.

Magnitude: Leakage via this pathway is not anticipated to occur; therefore, magnitude of any leakage is considered negligible.

Monitoring: In the state of Wyoming, High Plains will receive a unitization order from the WOGCC for a unit area that encompasses the AOR (CO_2 Area), which will also be mapped in their records. If there is an application for a permit to drill a well (APD) proposed within a High Plains unit area that is proposed to penetrate the caprock, then High Plains will be notified by either or both the APD applicant and the WOGCC. High Plains will also assess potential drilling activity via the WOGCC online data explorer. In the unlikely event that third party drilling is conducted through the Lyons formation High Plains will coordinate with the operator regarding wellbore monitoring (Section 5.2) and if the site is accessible wellheads will be added to surface monitoring (Section 5.1).

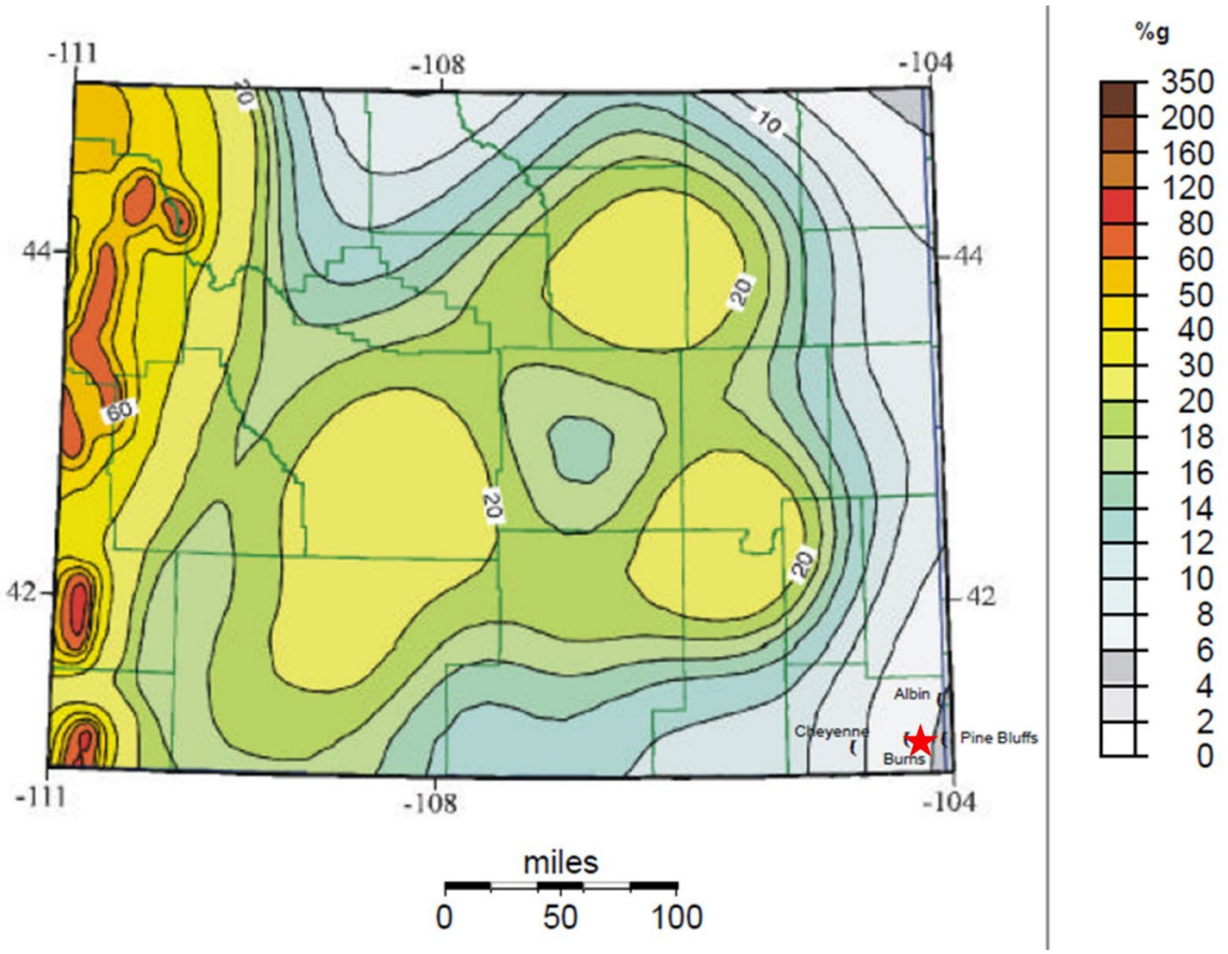

Figure 11. USGS 2,500-Year Probabilistic Acceleration Map of Wyoming. The contours represent a 2 percent probability of exceedance in 50 years. The red star is the approximate location of the Juniper project area (USGS, 2002).

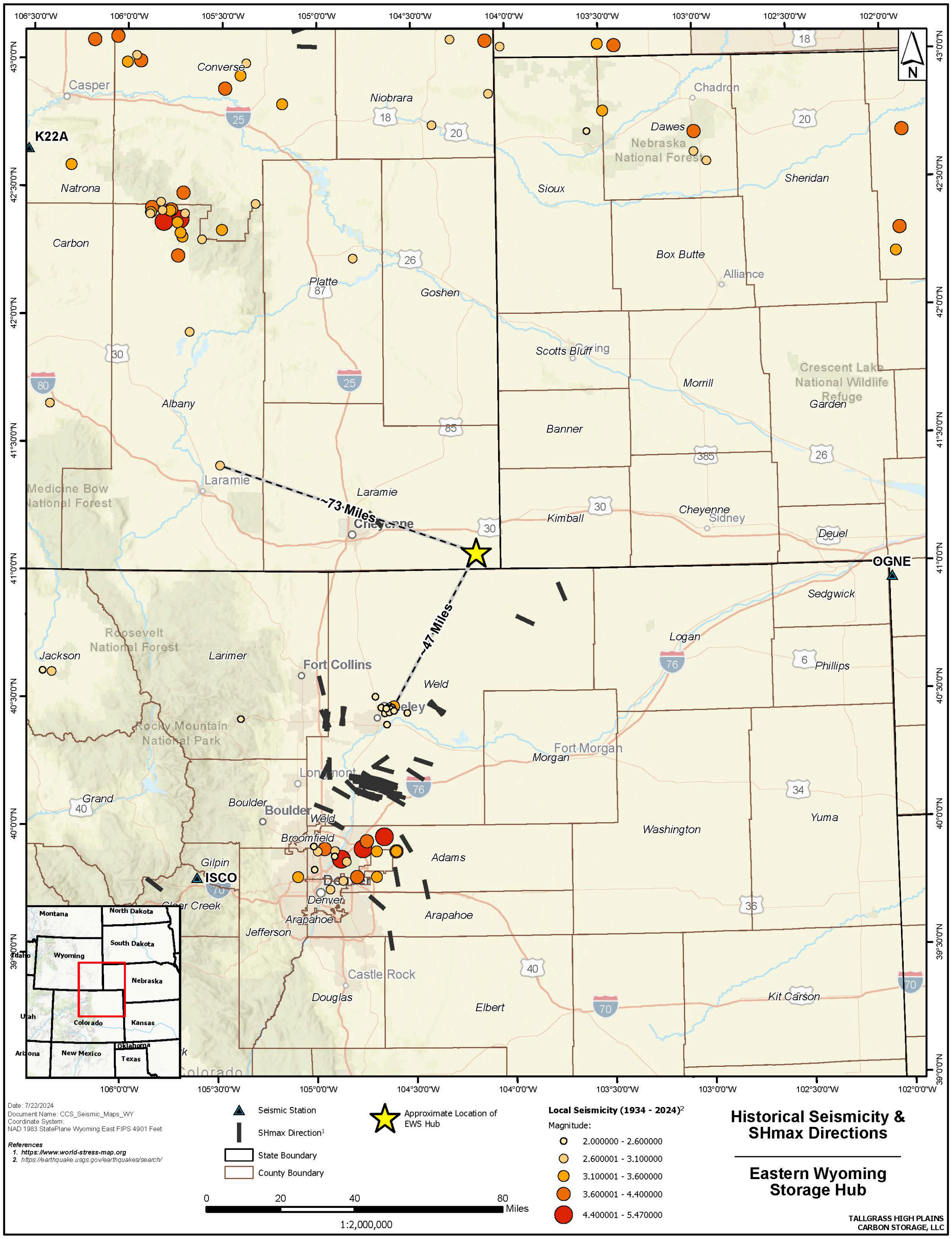

Figure 12. USGS-Reported Earthquakes Over the Past 100 Years. The yellow star is the approximate location of the Project Area.

6. Monitoring and Considerations for Calculating Site-Specific Variables

High Plains will establish a Central Control Center to ensure that personnel have access to the continuous data being acquired during operations. The Central Control Center will receive CO_2 metering data and continuous surface-air monitoring data (eddy covariance tower). **Figure 4** identifies the meters that will be used to evaluate, monitor, and report on the injection project.

6.1 CO_2 Received

A custody-transfer meter will be used at the CO_2 source (pipeline) to continuously measure the mass and composition of CO_2 received at Juniper I-1. Metering protocols will follow the prevailing industry standard(s).

6.2 CO_2 Injected into the Subsurface

Injected CO_2 associated with geologic sequestration will be calculated using the flow meter at the Juniper I-1 wellhead.

6.3 CO_2 Produced, Entrained in Products, and Recycled

No CO_2 will be produced, entrained in products, or recycled.

6.4 CO_2 Emitted by Surface Leakage

As discussed in Section 5.1, standard GHGRP procedures as referenced at 40 CFR § 98.444(d) will be used to estimate surface leaks from equipment if leakage is detected between the flow meter used to measure injection quantity and the injection wellhead. In addition, an event-driven process will be used to assess, address, track, and, if applicable, quantify potential CO_2 leakage to the surface. Reporting will be completed in accordance with 40 CFR § 98.446(f)(3).

6.4.1 Injection Well Monitoring

Injection well pressure, temperature, and injection rate will be continuously monitored. If the measurements of injection pressure or rate exceed the specified set-points determined for Juniper I-1, a data flag will automatically trigger, and field personnel will investigate and resolve the issue. These deviations will be reviewed by well management personnel to determine if CO_2 leakage may be occurring. Deviations are not necessarily indicators of leaks, but they indicate that injection rates and pressures are not conforming to the planned pattern of injection. In many cases, problems are straightforward to fix (e.g., recalibrating a meter), and there is no CO_2 leakage. If issues that are not readily resolved arise, a more detailed investigation and response will be initiated. To quantify leakage to the surface, an estimate of the relevant parameters (e.g., the rate, concentration, and duration of leakage) will be made to quantify the leakage mass. Depending on specific circumstances, these determinations may rely on engineering estimates. An example methodology that may be used for early detection and rate estimation of CO_2 wellbore leakage, based on temperature analysis, is outlined in Mao et al. (2017).

6.4.2 Broad Continuous Surface Air Monitoring

Broad aerial surface air monitoring will be conducted with a permanently installed eddy covariance tower (**Figure 10**). The eddy covariance tower will consist of a solar-powered 3D sonic anemometer and open-path gas analyzer installed on a stationary tower. The tower will be installed downwind of the prevailing wind direction from the injection well and injection zone monitoring well. Annual average prevailing wind direction in the vicinity is from the west (WRCC, 2022; Cheyenne AP KCYS station). The location was chosen to be downwind (east) of the injection well and injection zone monitoring well and in a location with access for equipment installation and servicing.

Monitoring equipment will be installed at a height of approximately 4 to 5 meters (13 feet). In general, the upwind distance represented by the tower height can be determined by the 1:100 rule. In this case, with a 4-meter tower height, the majority of measured flux will come from an oval-shaped area from near the tower to 400 meters (1,312 feet) upwind (Burba, 2013).

Gas emission rate is calculated from air density, vertical wind speed, and dry CO_2 mole fraction. Air density fluctuation is assumed to be negligible (Burba, 2013). Wind speed will be measured with the sonic anemometer. CO_2 mole fraction will be measured with the gas analyzer. Eddy covariance tower instrumentation will be installed consistent with protocols listed in Burba (2013). The sonic anemometer will be a Campbell Scientific CSAT3 or equivalent. The CO_2 gas analyzer will be a LI-COR Biosciences LI-7500A or equivalent. The gas analyzer will be positioned at or slightly below the sonic anemometer level, with a separation distance less than 20 centimeters. Vibration will be minimized by the use of several guy wires attached at the middle of the tower.

Manual cleaning of the gas analyzer will be performed on an as-needed basis when anomalous readings or excessive zero-drift in the data is observed. Factory calibration is assumed to be stable for at least several years, and will be checked once every six months as a precaution.

Data processing will be conducted with the automated open-source package EddyPro (LI-COR Biosciences, 2021), and will be presented as hourly averaged CO_2 concentrations and gas emission rates. Detection of anomalous and increasing CO_2 concentrations will lead to eddy covariance tower equipment testing and further targeted surface air investigation (described in subsections 6.4.3 and 6.4.4). In the event of leakage detected by the eddy covariance tower, mass will be calculated based on the increased CO_2 subsurface flux rate.

6.4.3 Targeted Point Source Monitoring

Targeted monitoring of potential CO_2 point sources will be conducted at injection well wellheads, as well as at pipelines/delivery systems within the MMA. No abandoned wells within the project area penetrate the confining zone. Therefore, these wellheads will not be specifically monitored. Juniper M-1 was drilled through the injection zone, but will be plugged back to serve as an above confining zone monitoring well.

Intermittent point-source monitoring will occur at a minimum of once per quarter at the injection well and above confining zone monitoring well, and once per year at other locations. Targeted point-source monitoring will also be triggered by indications of leakage from eddy covariance monitoring and/or other monitoring results. Point-source measurement will be conducted with a portable non-dispersive infrared (NDIR) CO_2 meter. CO_2 concentration, relative humidity, and temperature will be recorded at each location and collected with an attached USB Data Logger. Measurement location will be recorded with a handheld global positioning system (GPS) unit, and corresponding wellhead or other infrastructure location will also be recorded. Leakage will be quantified based on leak flow rate and CO_2 gas concentration.

6.4.4 Inspection and Leak Detection

High Plains will perform inspection of wellheads, valves, and piping, including the following:

- Field inspections will be conducted on a routine basis by field personnel. Field personnel will be trained to identify visual indications of leaking CO_2 and other potential problems in the field.
- Injection well wellheads will be inspected on a quarterly basis, which will include the following and will be recorded on a well inspection data sheet:
    - ◇ Visual inspection for general condition of the wellhead system, including for external corrosion/coating damage and mechanical damage
    - ◇ Inspection of all bolts for needed replacement
    - ◇ Reenergizing wellhead seals as needed, reapplying screw and nut torque as needed, replacement of any needed fittings, packing, hand wheels, pins, or bearings
    - ◇ Visual inspection of all pipelines within 100 feet of the injection well
    - ◇ Identification of faulty valves or gasket leaks
    - ◇ Verification of adequate fittings for wireline equipment and CO_2 injection
    - ◇ CO_2 gas analysis with a handheld meter at the wellhead and pipelines within 100 feet of the wellhead (pSense High Accuracy portable CO_2 meter or equivalent, with CO_2 measurement range of 0 to 9,999 ppm and accuracy of 30 ppm).
- Instrumentation will be installed on pipelines and facilities that allow the 24/7 operations staff to monitor the process and potentially spot leaks. High Plains will use a supervisory control and data acquisition (SCADA) software system to implement operational control decisions on a real-time basis throughout the project area to assure the safety of field operations and compliance with monitoring and reporting requirements in existing permits. Both manual and automatic shutdowns will be installed in the MMA to ensure that leaks are addressed in a timely manner. Potential leakage identified with dynamic modeling will be assessed in the field, including by visual inspection and gas analysis, as well as by soil gas analysis in the case of buried pipelines.
- Biannual testing of surface safety valve systems will be conducted to ensure their ability to hold anticipated pressure. Surface valve testing will be consistent with API Specification 6AV1. Annual testing of master valve and wellhead isolation valves will be conducted for proper function and verification of the valves' ability to isolate the well.

Upon finding that a surface safety valve is inoperable, High Plains will immediately shut in the well and repair the valve within 90 days, or will determine an appropriate alternative time frame for testing a valve or addressing an inoperable surface or subsurface safety valve. Documentation of all inspections, tests, and results will be maintained by High Plains and will be available for EPA review during the active life of the project.

6.5 Monitoring for Potential Leakage from the Injection/Production Zone

In addition to the surface-based monitoring previously described in Section 6.4, additional monitoring for potential leakage from the subsurface will include groundwater and soil gas monitoring, permanent fiber optic sensing in Juniper M-1, annual PNL logs in Juniper M-1, and annual temperature logging in Juniper I-1.

6.5.1 Groundwater Monitoring

Monitoring wells to measure pressure, temperature, and fluid composition will be dedicated to geologic sequestration. These dedicated wells will monitor above the confining zones and overlying USDWs (monitoring wells Juniper M-1, USDW-1, USDW-2 and USDW-3; locations shown on **Figure 10**). Indirect monitoring above the confining zone will include annual PNLs in Juniper M-1. Baseline analysis will be established for each of these wells. Any deviation from the baseline analysis will be assessed for potential indications of leakage. CO_2 leakage rates will be quantified based on measured increases in CO_2 concentration in formation fluids above the AoR

Monitoring well locations are shown on **Figure 10** and are listed in **Appendix A**. Monitoring well details including depth and chemistry monitoring parameters are listed in **Appendix B**. Monitoring well data collection procedures will be consistent with protocols listed in the Class VI permit.

6.5.2 Soil Gas Monitoring

High Plains will perform soil gas monitoring including sampling of CO_2 and ratio of CO_2 to methane (CH_4) during the injection period. Soil gas composition monitoring will also be performed prior to injection to establish a baseline.

Soil gas monitoring will be performed with the portable flux accumulation chamber method, which offers the advantage of flexibility in sampling locations if leak detection survey monitoring is required, as well as real-time data collection. Baseline soil gas sampling locations are shown on **Figure 10**. If potential leakage is detected during the injection phase, soil gas monitoring locations will be determined based on the available data regarding the location of the potential leakage. In the case of potential leakage via an active well or buried pipeline, soil gas flux will be assessed in within 10 feet of the wellbore/pipeline. For potential leakage indicated by broad aerial monitoring, soil gas measurements will be located within the area indicated by the atmospheric monitoring data.

Soil gas monitoring will be conducted with a portable self-powered flux accumulation chamber (LI-COR 8200-01S or equivalent) paired with a CO_2 and CH_4 gas analyzer (LI-7810 $CH_4/CO_2/H_2O$ Trace Gas Analyzer or equivalent). The flux chamber computes real-time soil gas flux. Data will be digitally collected and integrated with GPS coordinates, soil moisture, and soil temperature (Stevens HydraProbe or equivalent). Soil gas flux will be measured at each location until steady-state flux is observed in the real-time observed data. Flux-accumulation chamber collars will be field deployed at each sampling location at least 24 hours prior to sample collection. Data will be processed and digitally stored with the SoilFluxPro software or equivalent. CO_2 flux and gas ratios will be compared to data collected during the baseline period to evaluate potential atmospheric leakage through the soil profile.

6.6 CO_2 Plume Tracking

The extent of the CO_2 plume will be monitored using 2D seismic surveys to understand CO_2 saturation changes through time. The existing 2D surveys will establish a baseline view of the injection interval. One survey will be performed during the injection phase to confirm plume movement and direction. One survey will be performed to confirm plume stabilization after downhole pressure and temperature measurements indicate that the plume has stabilized. The results will be compared to those from the baseline surveys to determine the extent of the CO_2 plumes within the project area.

6.7 Seismicity Monitoring

High Plains will monitor the Intermountain West Seismic Network for seismic events. Historical seismicity within the area will be accounted for in the baseline assessment.

6.7.1 Baseline Analysis

Historical seismicity data from the Intermountain West Seismic Network will be reviewed to establish the baseline. This data will help establish historical natural seismic event depth, magnitude, and frequency to distinguish between naturally occurring seismicity and induced seismicity resulting from CO_2 injection.

6.7.2 Seismic Monitoring Analysis

Throughout the injection phase, monitoring for natural and induced seismic activity will be performed by monitoring data from the USGS Intermountain West Seismic Network.

6.8 Vented Emissions of CO_2 from Surface Equipment

Monitoring efforts will evaluate and estimate leaks from equipment and vented CO_2 as required under 40 CFR § 98.444(d).

7. Approach for Establishing the Expected Baselines

High Plains will use the Central Control Center to continuously monitor operating parameters and to identify any excursions from normal operating conditions that may indicate leakage of CO_2. The following bullets describe the High Plains strategy for collecting baseline information:

- *Visual Inspection:* High Plains field personnel conduct frequent periodic inspections of all surface equipment, providing opportunities to ensure facility and well integrity as described in Section 6.4.
- *Handheld CO_2 Monitors:* High Plains will perform leakage detection at wellheads, valves, and piping in the MMA as defined in Section 6.4.

- *Field Sampling:* Field sampling activities to monitor CO_2 at the Juniper I-1 well will include periodic well (groundwater and gas) and atmospheric sampling from the MMA around the injection well. Pre-injection data will be collected for one year prior to injection to establish baselines.
- *Continuous Parameter Monitoring:* The Central Control Center will monitor injection rates, pressures, and composition on a continuous basis. High and low set points are programmed, and engineering and operations are alerted if a parameter is outside the allowable window. If a parameter is outside the allowable window, this will trigger further investigation to determine if the issue poses a leak threat.
- *Well Surveillance:* High Plains will adhere to the requirements of WDEQ governing the construction, operation, and closing of a Class VI well, including the requirement for testing and monitoring to ensure mechanical integrity. High Plains routine operation and maintenance procedures for the Juniper I-1 well will ensure frequent periodic inspection of the wells and opportunities to detect leaks and implement corrective action.
- *Seismic Monitoring Stations:* High Plains will perform seismic monitoring as listed in Section 6.7, including pre-injection data collection from the USGS Intermountain West Seismic Network to establish baselines.

8. Considerations for Site-Specific Variables for the Mass Balance Equations

The following subsections describe how each element of the mass-balance equation (Equation RR-12) will be calculated.

8.1 Mass of CO_2 Received

High Plains will use Equation RR-1 as indicated in 40 CFR § 98.443 to calculate the mass of CO_2 received from the custody-transfer meter immediately downstream of the source (pipeline).

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

where
$CO_{2T,r}$ = Net annual mass of CO_2 received through flow meter r (metric tons)
$Q_{r,p}$ = Quarterly mass flow through a receiving flow meter r in quarter p (metric tons)
$S_{r,p}$ = Quarterly mass flow through a receiving flow meter r that is redelivered to another facility without being injected into your well in quarter p (metric tons)
$C_{CO_{2,p,r}}$ = Quarterly CO_2 concentration measurement in flow for flow meter r in quarter p (wt. percent CO_2, expressed as a decimal fraction)
p = Quarter of the year
r = Receiving flow meter

Given the method by which High Plains will receive CO_2 and the requirements of 40 CFR § 98.444(a):

- All delivery to Juniper is used, so quarterly flow redelivered, $S_{r,p}$, is zero (0), and will not be included in the equation.
- Quarterly CO_2 concentration will be taken from the gas measurement database.

High Plains will sum to total mass of CO_2 received using Equation RR-3 in 40 CFR § 98.443:

$$CO_2 = \sum_{r=1}^{R} CO_{2T,r} \text{ (Eq. RR-3)}$$

where CO_2 = Total net annual mass of CO_2 received (metric tons)

$CO_{2T,r}$ = Net annual mass of CO_2 received (metric tons) as calculated in Equation RR-1 for flow meter r

r = Receiving flow meter

8.2 *Mass of CO_2 Injected into the Subsurface*

Mass of CO_2 injected into the subsurface at the injection well will be calculated with Equation RR-4:

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

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

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

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

p = Quarter of the year

u = Flow meter

Figure 4 displays the location of the Juniper I-1 flow meter (green color).

8.3 *Mass of CO_2 Emitted by Surface Leakage*

High Plains will calculate and report the total annual mass of CO_2 emitted by surface leakage using an approach that is tailored to specific leakage events and relies on standard GHGRP procedures as listed at 40 CFR § 98.444(d). Operators will be prepared to address the potential for leakage in a variety of settings. Estimates of the amount of CO_2 leaked to the surface will depend on several site-specific factors, including measurements, engineering estimates, and emission factors, depending on the source and nature of the leakage.

The process for quantifying leakage will entail using industry standard engineering principles or emission factors. Some approaches for quantification of potential types of leaks that may occur are discussed in Section 6.4. In the event leakage to the surface occurs, the quantity and leakage amounts will be reported, and records will be retained that describe the methods used to estimate or measure the mass leaked as reported in the annual Subpart RR report.

Equation RR-10 in 40 CFR § 98.443 will be used to calculate and report the mass of CO_2 emitted by surface leakage:

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

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

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

x = Leakage pathway

8.4 Mass of CO_2 Sequestered in Subsurface Geologic Formations

Equation RR-12 in 40 CFR § 98.443 will be used to calculate the mass of CO_2 sequestered in subsurface geologic formations in the reporting year as follows:

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

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

CO_{2I} = Total annual CO_2 mass injected (metric tons) in the well or group of wells covered by this source category in the reporting year

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

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

Figure 4 illustrates that CO_2 supplied for geological storage will be metered between the CO_2 source and the injection meter.

8.5 Cumulative Mass of CO_2 Reported as Sequestered in Subsurface Geologic Formations

A sum of the total annual mass obtained using RR-12 in 40 CFR § 98.443 will be used to calculate the cumulative mass of CO_2 sequestered in subsurface geologic formations.

8.6 Data Reporting

High Plains will report all data per regulations listed in 40 CFR § 98.446, including the CO_2 facility source(s) to the pipeline per the following categories: (1) CO_2 production wells, (2) electric generating unit, (3) ethanol plant, (4) pulp and paper mill, (5) natural gas processing, (6) gasification operations, (7) other anthropogenic source, (8) discontinued enhanced oil and gas recovery project, or (9) unknown.

9. MRV Implementation Schedule

The final MRV plan will be implemented upon receiving approval from the EPA, and no later than the day after the day on which the plan becomes final, as described in 40 CFR § 98.448(c). After Juniper I-1 is drilled, High Plains will reevaluate the MRV plan and, if any modifications are a material change per 40 CFR § 98.448(d)(1), High Plains will submit a revised MRV plan as required by 40 CFR § 98.448(d).

10. Quality Assurance and Quality Control

High Plains will meet the monitoring and quality assurance and quality control (QA/QC) requirements of 40 CFR § 98.444 of Subpart RR.

10.1 Greenhouse Gas Monitoring

As required by 40 CFR § 98.3(g)(5)(i), High Plains internal documentation regarding the collection of emissions data includes the following:

- Identification of positions of responsibility (i.e., job titles) for collection of the emissions data
- Explanation of the processes and methods used to collect the necessary data for the greenhouse gas (GHG) calculations
- Description of the procedures and methods that are used for quality assurance, maintenance, and repair of all continuous monitoring systems, flow meters, and other instrumentation used to provide data for the GHGs reported

10.2 Measurement of CO_2 Concentration

All measurements of CO_2 concentrations of any CO_2 quantity will be conducted according to an appropriate standard method published by a consensus-based standards organization or an industry standard practice. All measurements of CO_2 concentrations of CO_2 received will meet the requirements of 40 CFR § 98.444(a)(3).

10.3 Measurement of CO_2 Mass

Daily CO_2 received is recorded by totalizers on the mass flow meters on each of the pipelines listed in Section 8 using accepted flow calculations for CO_2. Daily CO_2 injected is recorded by totalizers on the mass flow meters using accepted flow calculations for CO_2.

High Plains does not produce CO_2 at the surface facility; therefore, no QA/QC procedures are necessary for produced CO_2 mass.

As required by 40 CFR § 98.444(d), High Plains will follow the monitoring and QA/QC requirements specified in the GHGRP for equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead.

As required by 40 CFR § 98.444(e), High Plains will ensure that:

- All flow meters are operated continuously except as necessary for maintenance and calibration.
- All flow meters used to measure quantities reported are calibrated according to the calibration and accuracy requirements in 40 CFR § 98.3(i), Subpart A of the GHGRP.
- All measurement devices are operated according to an appropriate standard method published by a consensus-based standards organization or an industry standard practice. Consensus-based standards organizations include, but are not limited to, the following:
  - ASTM International
  - American National Standards Institute (ANSI)
  - American Gas Association (AGA)
  - American Society of Mechanical Engineers (ASME)
  - API
  - North American Energy Standards Board (NAESB)
- All flow meter calibrations performed are National Institute of Standards and Technology (NIST) traceable.

10.4 QA/QC Procedures

High Plains will adhere to all QA/QC requirements in Subpart RR as required in the development of this MRV plan under Subpart RR. Any measurement devices used to acquire data will be operated and maintained according to the relevant industry standards.

10.5 Estimating Missing Data

High Plains will estimate any missing data according to the following procedures in 40 CFR § 98.445, Subpart RR of the GHGRP, as required:

- A quarterly flow rate of CO_2 received that is missing would be estimated using invoices, purchase statements, or a representative flow rate value from the nearest previous time period.
- A quarterly CO_2 concentration of a CO_2 stream received that is missing would be estimated using invoices, purchase statements, or a representative concentration value from the nearest previous time period.
- A quarterly quantity of CO_2 injected that is missing would be estimated using a representative quantity of CO_2 injected from the nearest previous period of time at a similar injection pressure.
- For any values associated with CO_2 emissions from equipment leaks and vented emissions of CO_2 from surface equipment at the facility that are reported in Subpart RR, standard GHGRP missing data estimation procedures specified in 40 CFR § 98.445(e) would be followed.

10.6 Revisions of the MRV Plan

High Plains will revise the MRV plan as needed for any of the following reasons:

- To reflect changes in monitoring instrumentation and quality assurance procedures

- To improve procedures for the maintenance and repair of monitoring systems to reduce the frequency of monitoring equipment downtime
- To address additional requirements as directed by U.S. EPA or the State of Wyoming

If any operational changes constitute a material change as described in 40 CFR § 98.448(d)(1), High Plains will submit a revised MRV plan addressing the material change.

11. Records Retention

High Plains will meet the recordkeeping requirements of paragraph 40 CFR 98.3(g), Subpart A of the GHGRP. As required by 40 CFR § 98.3(g) and 40 CFR § 98.447, High Plains will retain the following documents:

- A list of all units, operations, processes, and activities for which GHG emissions were calculated.
- The data used to calculate the GHG emissions for each unit, operation, process, and activity. These data include:
  - ◇ The GHG emissions calculations and methods used
  - ◇ Analytical results for the development of site-specific emissions factors, if applicable
  - ◇ The results of all required analyses
  - ◇ Any facility operating data or process information used for the GHG emission calculations
- The annual GHG reports.
- Missing data computations. For each missing data event, High Plains will retain a record of the cause of the event and the corrective actions taken to restore malfunctioning monitoring equipment.
- A copy of the most recent revision of this MRV plan.
- The results of all required certification and quality assurance tests of continuous monitoring systems, fuel flow meters, and other instrumentation used to provide data for the GHGs reported.
- Maintenance records for all continuous monitoring systems, flow meters, and other instrumentation used to provide data for the GHGs reported.
- Quarterly records of CO_2 received, including mass flow rate of contents of container at standard conditions and operating conditions, operating temperature and pressure, and concentration of these streams.
- Quarterly records of injected CO_2 including mass flow at standard conditions and operating conditions, operating temperature and pressure, and concentration of these streams.
- Annual records of information used to calculate the CO_2 emitted by surface leakage from leakage pathways.

- Annual records of information used to calculate the CO_2 emitted from equipment leaks and vented emissions of CO_2 from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead.
- Any other records as specified for retention in this EPA-approved MRV plan.

References

Bethke, C.M. and M.K. Lee. 1994. Groundwater flow, late cementation, and petroleum accumulation in the Permian Lyons sandstone. *Denver Basin: AAPG Bulletin* 78(2): 221-241.

Burba, G. (2013). *Eddy covariance method for scientific, industrial, agricultural and regulatory applications: A field book on measuring ecosystem gas exchange and areal emission rates*. LI-Cor Biosciences.

Clayton, J.L. and P.J. Swetland. Petroleum Generation and Migration in Denver Basin. AAPG Bulletin (1980) 64 (10) p.1613-1633.

LI-COR Biosciences. 2021. Eddy covariance processing software (Version 7.0.8) [Software]. Available at <www.licor.com/EddyPro>.

Love J.D. and A.C. Christiansen. 1985. *Geologic map of Wyoming*. U.S. Geological Survey. Scale 1:500,000.

Lowry, M. and M. Crist. 1967. *Geology and ground-water resources of Laramie County, Wyoming*. U.S. Geological Survey Report.

Sonnenberg, S.A. and R.J. Weimer. 1981. Tectonics, sedimentation, land petroleum potential, northern Denver basin, Colorado, Wyoming, and Nebraska. *Colorado School of Mines Quarterly* (76): 35–36.

Swanson, B.F. 1981. A simple correlation between permeabilities and mercury capillary pressures. *Journal of Petroleum Technology* 33(12): 2498–2504.

Taucher, P., T.T. Bartos, and K.G. Taboga. 2013. *Platte River Basin water plan update, level I (2009–2013), available groundwater determination*. WSGS Technical Memorandum 5.

U.S. Geological Survey (USGS). 2022. Earthquake Hazards Program. <https://earthquake.usgs.gov/>.

Western Regional Climate Center (WRCC). 2023. Prevailing wind direction. <https://wrcc.dri.edu/Climate/comp_table_show.php?stype=wind_dir_avg>. Accessed June 2023.

Mao, Y., M Zeidouni, I. Duncan, 2017. Temperature analysis for early detection and rate estimation of CO_2 wellbore leakage, International Journal of Greenhouse Gas Control, Volume 67, 2017, https://doi.org/10.1016/j.ijggc.2017.09.021.

Zhao, B., C.W. MacMinn, and R. Juanes. 2014. Residual trapping, solubility trapping and capillary pinning complement each other to limit CO_2 migration in deep saline aquifers. Energy Procedia 63, p.3833-3839.

Appendix A Project Well List

Injection well	Juniper I-1	
Monitoring wells	Juniper M-1	Above confining-zone monitoring
	Juniper USDW-1	USDW monitoring, Fox Hills
	Juniper USDW-2	USDW monitoring, Ogallala
	Juniper USDW-3	USDW monitoring, Alluvium

Appendix B Groundwater Monitoring Details

Table B-1. Project Monitoring of Groundwater Quality and Geochemical Changes Above the Confining Zone

Activity	Location(s)	Method	Analytical Technique	Pre-injection Baseline	Operation Period	PISC Period	Purpose
Fluid sampling (freshwater aquifers above confining zone)	Alluvial USDW Monitoring Well Ogallala USDW Monitoring Well Fox Hills USDW Monitoring Well	Direct sampling	Chemical analysis	Semi-annual	Semi-annual	Annual	Monitor water quality
Pressure/Temperature (Above Confining Zone)	Juniper M-1	Gauge	Direct measurement	Continuous	Continuous	Continuous	Monitor pressure / temperature
Indirect Monitoring	Juniper M-1	Pulsed Neutron Logging (PNL)	Direct measurement	Once	Annual	Annual	Gas saturations, verify absence of fluid migration

Table B-2. Analytical and Field Parameters for Fluid Samples

Parameters	Analytical Methods
Cations: Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Sb, Se, and Tl	ICP-MS EPA Method 6020
Cations: Ca, Fe, K, Mg, Na, and Si	ICP-OES EPA Method 6010B
Anions: Br, Cl, F, NO_3, and SO_4	Ion Chromatography EPA Method 300.0
Dissolved CO_2	Coulometric titration ASTM D513-11
Hydrogen Sulfide	SM4500_S2_H
Total Dissolved Solids	Gravimetry APHA 2540C
Alkalinity	APHA 2320B
pH (field)	EPA 150.3
Specific conductance (field)	APHA 2510
Temperature (field)	Thermocouple

Note: Once the analytical laboratory is confirmed, all analytical methods will meet or exceed the above. An equivalent method may be employed with the prior approval of the UIC Program Director.