June 27, 2025

Tallgrass High Plains Carbon Storage, LLC
Attn: Mr. Craig Spreadbury
370 Van Gordon St.
Lakewood, CO 80228

Sent Via Email: craig.spreadbury@tallgrass.com

RE: Tallgrass High Plains Carbon Storage, LLC, Eastern Wyoming Sequestration Hub
Underground Injection Control Class VI Permit 2022-235v1.1-Juniper I-1
Facility Number WYS-021-00149
Laramie County, Wyoming

Dear Mr. Spreadbury:

The Wyoming Department of Environmental Quality Water Quality Division (WDEQ/WQD), Underground Injection Control (UIC) Program received a permit modification application for Authorization to Inject for the Juniper I-1 Class VI injection well, located in Laramie County, Wyoming, on February 21, 2025, with supplemental information submitted on the dates listed in the associated Administrative Record. WDEQ determined that this permit modification for Authorization to Inject is a minor modification, as the data collected during drilling and testing of the Juniper I-1 Class VI injection well confirmed the data provided in the Permit to Construct, UIC Permit 2022-235v1.0.

On June 23, 2025, WDEQ approved surety bonds EACX404408, EACX4044409, DUA03747, and wire transfer 250604456678 in the total amount of $21,413,120 submitted by Tallgrass High Plains Carbon Storage, LLC. Additionally, WDEQ received Certificates of Liability Insurance on June 26 and 27, 2025; therefore, WDEQ hereby issues Tallgrass High Plains Carbon Storage, LLC a UIC Class VI Permit for the facility referenced above. A copy of the Final Class VI UIC Permit will be available at https://deq.wyoming.gov/water-quality/groundwater/uic/class-vi/. This Permit provides authorization to inject and operate the Juniper I-1.

Permit 2022-235v1.1 lists monitoring, recordkeeping, and reporting requirements in Section 9. Please be aware that the permittee must report any noncompliance which may endanger health or the environment within 24 hours from the time the operator becomes aware of the circumstances as required in Section 9(B) and Table 2 Permit 2022-235v1.1. This includes any monitoring or other information indicating that any contamination may cause endangerment to an underground source of drinking water. All reports associated with this permit, including all monitoring and testing reports, shall be submitted electronically to the Electronic Documents Submittal tab located at the link identified above.

After you have had a chance to review the Permit, please contact me to set up a permit issuance meeting to discuss permit requirements and next steps. If you have any questions regarding the permit or monitoring requirements, please contact me at (307) 777-8275 or tyler.harris@wyo.gov.

Sincerely,

Tyler Harris, P.G.
Geology Supervisor – UIC Class VI Program
Water Quality Division
Wyoming Department of Environmental Quality

cc: Karin Quigley, Administrative Assistant to the DEQ Director, WDEQ
Randall Luthi, Chief Energy Advisor, Office of the Governor, Wyoming (randall.luthi@wyo.gov)
Jennifer Zygmunt, WQD Administrator, WDEQ
Lily R. Barkau, P.G., Groundwater Section Manager, WDEQ/WQD
Wendy Cheung, USEPA, Region VIII (cheung.wendy@epa.gov)
Rick Arnold, USEPA, Region VII (Arnold.rick@epa.gov)
Jessica Gregg, Director, Geoscience Compliance, Tallgrass Energy (jessica.gregg@tallgrass.com)
Katy Larson, Geoscience Compliance Manager, Tallgrass Energy (katy.larson@tallgrass.com)
file

STATE OF WYOMING
DEPARTMENT OF ENVIRONMENTAL QUALITY
UNDERGROUND INJECTION CONTROL PERMIT ISSUED UNDER WYOMING WATER QUALITY RULES
CHAPTER 24

Final Permit No. 2022-235
Version 1.1

Eastern Wyoming Sequestration Hub
Class VI Carbon Sequestration Injection Well

Juniper I-1

Facility ID No. WYS-021-00149

Issued to:

Tallgrass High Plains Carbon Storage LLC
4200 West 115th Street, Leawood, KS 66211
303-763-3319

June 2025

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ATTACHMENT B: FINAL PLANS
- **ATTACHMENT B-1: AREA OF REVIEW AND CORRECTIVE ACTION PLAN**
- **ATTACHMENT B-2: EMERGENCY AND REMEDIAL RESPONSE PLAN**
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ATTACHMENT C
- **ATTACHMENT C- 1: UNITIZATION ORDER**
- **ATTACHMENT C- 2: TITLE TO SEQUESTERED AND INJECTED CARBON DIOXIDE**

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ACRONYMS AND ABBREVIATIONS

ANSI	American National Standards Institute
AoR	Area of Review
ºC	degrees Celsius
CAP	Corrective Action Plan
CFR	Code of Federal Regulations
cm^3	Cubic centimeters
CO_2	Carbon Dioxide
e.g.	For Example
ENS	Earthquake Notification Service
ERR	Emergency and Remedial Response
ºF	degrees Fahrenheit
ft	Feet
ft-bgs	feet below ground surface
g/cm^3	Grams per cubic centimeter
in	Inches
in^3	Cubic inches
km	kilometers
lb	pound
LSIP	Limiting Surface Injection Pressure
M	Moment Magnitude
µmhos/cm	Micromhos per centimeter
mg/L	milligrams per liter
MIT	Mechanical Integrity Test
Mmscf/d	million standard cubic feet per day
MMT	Million metric tons
Mol%	Mole percent
%	Percent
PISC	Post-Injection Site Care

ACRONYMS AND ABBREVIATIONS (cont.)

ppmv	Parts per million per volume
psi	pounds per square inch
psi/ft	pounds per square inch per foot
psig	pounds per square inch - gage
§	Section
SDWA	Safe Drinking Water Act
SIP	Surface Injection Pressure
s.u.	Standard Unit
t/d	Tonnes per day
TDS	Total Dissolved Solids
UIC	Underground Injection Control
USDW	Underground Source of Drinking Water
USEPA	United States Environmental Protection Agency
USGS	United States Geological Survey
WQD	Water Quality Division
WDEQ	Wyoming Department of Environmental Quality
WEQA	Wyoming Environmental Quality Act
WOGCC	Wyoming Oil and Gas Conservation Commission
W.S.	Wyoming Statute
WWQR	Wyoming Water Quality Rules

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OVERVIEW

This permit is for the operation of one (1) Underground Injection Control (UIC) Class VI carbon sequestration well and associated monitoring wells. This UIC Class VI carbon sequestration well is one of six (6) total injection wells associated with the Eastern Wyoming Sequestration Hub, which is anticipated to inject 137 million metric tons (MMT) over a 30-year operating period. A Certificate of Project consisting of six (6) Class VI injection wells, if requested, will be issued in accordance with Wyoming Statute (W.S.) § 35-11-313(n).

This permit consists of 10 Sections as follows: Section 1. Permit Issuance; Section 2. Permit Conditions; Section 3. Area of Review and Corrective Action Plan; Section 4. Emergency and Remedial Response; Section 5. Financial Assurance; Section 6. Drilling, Constructing, and Testing; Section 7. Plugging and Abandonment; Section 8. Well Operation; Section 9. Monitoring, Recordkeeping, and Reporting of Results; and Section 10. Post Injection Site Care and Site Closure.

The permitted injection well, Juniper I-1, was constructed between October 31, 2024 and December 5, 2024, and completed pre-injection testing on June 11, 2025. Data collected during the injection well construction and pre-injection testing confirmed information submitted under UIC Permit No. 2022-235v1.0 (Attachment A) and therefore, an Authorization to Inject (ATI) Request was submitted by the Permittee on February 21, 2025 with supplemental information submitted on the dates listed in the associated Administrative Record. An Administrative Record has been developed to index all data, records, and correspondences associated with the permitting of this injection well. Modifications to UIC Permit No. 2022-235v1.0 have been determined to be minor permit modifications in accordance with Wyoming Water Quality Rules (WWQR) Chapter 24 Section 6(b) and therefore, have been processed as such in this UIC Permit No. 2022-235v1.1.

The final location of the Juniper I-1 and associated monitor wells is presented in Table 1.

A Reporting and Notification Summary is included in Table 2 which provides a summary of all notification, reporting, and reporting frequency requirements for this permit.

Based on the information collected to date, a Depth Waiver (WWQR Chapter 24, Section 15) is not required for this well. Therefore, ATI is not contingent on receipt of a Depth Waiver. If future information is identified that an Underground Source of Drinking Water (USDW) is located below the injection interval, a Depth Waiver will be required.

In accordance with WWQR Chapter 24, Section 4(d), prior to issuing a final permit to authorize injection for a Class VI well, the Director shall consider:

i. The final Area of Review (AoR) based on modeling, using data obtained during logging and testing of the well and the formation as required under WWQR Chapter 24, Section 10.

ii. Any relevant updates, based on data obtained during logging and testing of the well and the formation, to the information on the geologic structure and hydrogeologic properties of the proposed storage site and overlying formations, as required under WWQR Chapter 24, Section 10.

iii. The results of the formation testing program, as required under WWQR Chapter 24, Section 10.

iv. Final injection well construction procedures that meet the requirements of WWQR Chapter 24, Section 14.

v. Any updates to the proposed *AoR and Corrective Action Plan (CAP), Injection Well-Plugging Plan, Post-Injection Site Care (PISC) and Site Closure Plan, Emergency and Remedial Response (ERR) Plan, and the Financial Assurance Demonstration Plan* that are necessary to address new information collected during logging and testing of the well and the formation. The *AoR and CAP, Injection Well-Plugging, PISC and Site Closure, ERR, and Financial Assurance Demonstration Plans* were submitted as part of the UIC Class VI Permit Application (dated March 29, 2023). Amendments to these Plans must meet the requirements of WWQR Chapter 24, and upon approval of amendments by the Administrator or a Permit Modification by the Director, all plans are incorporated into the permit as a permit condition and are enforceable (Attachment B). If no amendments or modifications are required for a proposed Plan(s), the Plan(s) becomes final upon issuance of the Final UIC Class VI Permit authorizing injection.

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SECTION 1. PERMIT ISSUANCE

In compliance with the Wyoming Environmental Quality Act (WEQA), Wyoming Statute (W.S). § 35-11-101 through 1104, specifically 301(a)(i) through 301 (a)(iv), Laws 1973, Ch. 250, Section 1; W.S. § 31-11-313, Laws 2008, Ch. 30, Section 1; and WWQR, Chapters 24 and 29

Tallgrass High Plains Carbon Storage LLC, 4200 West 115th Street, Leawood, KS 66211

is hereby authorized, contingent upon permit conditions, to operate one (1) UIC Class VI Carbon Sequestration injection well, the Juniper I-1 (Facility ID No. WYS-021-00149) and four (4) monitoring well(s), the Juniper M-1, Juniper-USDW-1-FH, Juniper-USDW-2-LN and Juniper-USDW-3-HP, as part of the Eastern Wyoming Sequestration Hub located in the NW¼ NW¼ of Section 36, Township 13 North, Range 62 West of the 6th Principal Meridian, in Laramie County, Wyoming for the injection of the carbon dioxide (CO_2) stream generated by ethanol plants, ammonia plants, and power plants. The permittee may construct additional monitoring wells under Section 6. Drilling, Constructing, and Testing of this permit. No additional injection wells shall be constructed under this permit.

The CO_2 stream is characterized as a supercritical fluid to be injected into the Lyons Sandstone at depths between 9,124 feet and 9,175 feet below ground surface (ft-bgs) upon the express condition that the Permittee meet the restrictions set forth herein. This injection well shall not exceed **seven (7) MMT**. An increase in injection volume shall not occur without a major permit modification completed in accordance with WWQR Chapter 24 Section 6.

This permit consists of 47 pages plus the tables and attachments and includes all items listed in the Table of Contents. Further, it is based upon representations made by Tallgrass High Plains Carbon Storage LLC through their request for ATI submitted on February 21, 2025, and all additional information submitted by the company and other state and federal agencies as identified in the Administrative Record. This permit modification replaces and supersedes the original sections of UIC Permit No. 2022-235V1.0 as follows:

- Correction for typos, formatting, and section and table numbering.
- Section 6. Drilling, Constructing, and Testing
  - Revised from UIC Permit No. 2022-235v1.0 to remove injection well drilling, construction, and testing requirements as no additional injection wells are authorized under this permit.
- Section 8. Well Operation
  - Revised from UIC Permit No. 2022-235v1.0 to incorporate operating parameters collected during pre-injection testing.
- Financial Assurance Demonstration Plan
  - Incorporates the final public liability insurance policy, control of well insurance policy, and updated cost estimate following construction of the Juniper I-1.
- Testing and Monitoring Plan
  - Revised to incorporate updated sampling design for the Juniper M-1.

Amendments to the *Financial Assurance Demonstration* and *Testing and Monitoring Plans* has met the requirements of WWQR Chapter 24 and is incorporated into the permit as a permit condition and is enforceable. No amendments or modifications were required for the *AoR and CAP*, *ERR*, *Well Plugging*, or the *PISC and Site Closure Proposed Plans*; therefore, these Plans become final upon issuance of this ATI.

A Unitization Order was issued on March 14, 2025 by the Wyoming Oil and Gas Conservation Commission (WOGCC) in accordance with W.S. § 35-11-314 through 35-11-317 (Attachment C-1). The Permittee has also provided title to CO_2 in accordance with W.S. § 35-11-318 (Attachment C-2).

All other sections, subsections, and requirements of the UIC Permit No. 2022-235v1.0 (issued on September 11, 2024) remain unchanged. The modifications are processed as a minor modification in accordance with WWQR Chapter 24, Section 6(b) and become final twenty (20) days from the date of receipt of this notice. It is the responsibility of the Permittee to read, understand, and comply with all terms and conditions of this permit. The permit is issued for the operating life of the facility and extended through the PISC period until the Administrator certifies site closure pursuant to WWQR Chapter 24, Section 24(b)(iii) unless this permit is revoked and reissued, terminated, or modified pursuant to WWQR Chapter 24, Sections 6 and 7.

Jennifer Zygmunt, Administrator
Water Quality Division

6/27/25
Date

Todd Parfitt, Director
Department of Environmental Quality

6/27/2025
Date

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SECTION 2. PERMIT CONDITIONS

A. EFFECT OF PERMIT

Any underground injection activity not specifically authorized by this permit or rule is prohibited. The Permittee must comply with all applicable provisions of the Safe Drinking Water Act (SDWA) and Code of Federal Regulations (CFR) Title 40 §§ 124, 144, 145, and 146. Such compliance does not constitute a defense to any action brought under Section 1431 of the SDWA, U.S. Code, Title 42. § 300(i), or any other common law, statute, or regulation other than Part C of the SDWA. Notwithstanding any other provisions of this permit, the Permittee authorized by this permit must not construct, test, operate, maintain, convert, plug, abandon, or conduct any other injection activity in a manner that allows the movement of injection, annulus, or formation fluids into USDWs or any unauthorized injection zones. The objective of this permit is to prevent the movement of fluids into or between USDWs or into any unauthorized injection zones consistent with the requirements of WWQRs Chapter 24.

B. DEFINITIONS

All terms used in this permit shall have the meaning set forth in WWQR Chapter 24, Section 2. Unless specifically stated otherwise, all references to "days" in this permit should be interpreted as calendar days.

C. DUTY TO COMPLY

The Permittee shall comply with all conditions of this permit. Any permit noncompliance constitutes a violation of the WWQR and is grounds for enforcement, permit termination, revocation, or modification. Nothing in this permit shall be construed to relieve the Permittee of any duties under applicable regulations.

D. PERMIT ACTIONS

i. Any modification that may result in a violation of a permit condition shall be reported to the Administrator.

ii. Any modification that will result in a violation of a permit condition shall be reported to the Administrator through the submission of a new or amended permit application.

iii. The Permittee shall give advance notice to the Administrator as soon as possible of any planned physical alterations or additions, other than authorized operation and maintenance, to the permitted facility and receive authorization from the Administrator prior to implementing the proposed alteration or addition.

iv. The Permittee shall notify the Administrator before the conversion or abandonment of the facility. Conversion refers to converting a Class VI well to a Class I, II, or V well. The Permittee shall apply for a permit for Class I and V as specified in WWQR Chapter 27 or Class II through the WOGCC. Upon receipt of the Class I, II, or V permit, the Permittee shall request the permit be terminated as outlined in WWQR Chapter 24 Section 4(d).

v. The Administrator shall review each permit at least once every five (5) years to determine whether it should be modified, revoked and reissued, or terminated.

vi. Filing of a request by the Permittee, or at the instigation of the Administrator, for a permit modification, revocation, termination, or notification of planned changes or anticipated noncompliance, shall not stay any permit condition.

vii. Modification, Revocation and Reissuance, or Termination

1. Permits may be modified, revoked and reissued, or terminated either at the request of any interested person (including the Permittee or licensee) or upon the Administrator's initiative.
2. The Director may modify a permit as identified in WWQR Chapter 24, Section 6.
3. Upon the consent of the Permittee, the Director may modify a permit to make corrections or allowances for minor modifications pursuant to WWQR Chapter 24, Section 6(b). Any permit modification not processed as a minor modification under WWQR Chapter 24, Section 6(b), shall modify the permit pursuant to WWQR Chapter 24, Section 6(a) and conduct public notice as required under WWQR Chapter 24, Section 27.
4. The Director may terminate, revoke and reissue a permit as identified in WWQR Chapter 24, Section 7.

viii. Permit Transfer

1. Transfer of a permit is allowed only upon approval by the Director. The proposed permit transferee shall apply in writing as though that person were the original applicant of the permit, and the proposed permit transferee shall agree to be bound by all of the terms and conditions of the permit.
2. The notice shall be sent at least forty-five (45) days prior to transfer.
3. The Permittee is solely responsible for the operation of the facility covered by this permit. Operation of this facility by another entity is a violation of this permit unless a transfer of this permit has first been authorized.
4. Any transfer of a permit shall be approved by the Director, and no transfer will be approved if the facility is not in compliance with the existing permit unless the proposed Permittee agrees to bring the facility into compliance prior to transfer.
5. A permit may be transferred by modifying the permit or by revoking and reissuing the permit to identify the new Permittee and incorporate the requirements of WWQR Chapter 24 and the WEQA, W.S. § 35-11-101 *et seq.*

ix. When the Permittee becomes aware of the failure to submit any relevant facts in the permit application or that incorrect information was submitted in a permit application or any report to the Administrator, the Permittee must submit such facts or corrected information within ten (10) days of discovery.

E. PENALTIES FOR VIOLATIONS OF PERMIT CONDITIONS

Any person who violates a permit requirement is subject to civil penalties, fines, and other enforcement actions. Any person who willfully violates a permit condition may be subject to criminal prosecution under the SDWA and other applicable statutes and regulations.

F. NEED TO HALT OR REDUCE ACTIVITY NOT A DEFENSE

It shall not be a defense for the Permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of the permit.

G. DUTY TO MITIGATE

The Permittee shall take all reasonable steps to minimize and correct any adverse impact on the environment resulting from noncompliance with this permit.

H. PROPER OPERATION AND MAINTENANCE

The Permittee shall at all times properly operate and maintain all facilities and systems of treatment and control (and related appurtenances) that are installed or used by the Permittee to achieve compliance with the conditions of this permit. Proper operation and maintenance include effective performance, testing, equipment calibration, adequate funding and operator staffing and training, and adequate laboratory and process controls, including appropriate quality assurance procedures. This provision requires the operation of backup or auxiliary facilities or similar systems only when necessary to achieve compliance with the conditions of the permit.

I. PROPERTY RIGHTS

This permit does not convey any property rights or any exclusive privileges. This permit does not authorize any damage to private property or any invasion of personal rights, nor any infringement of federal, state, or local laws or regulations. Proof of notice to surface owners, mineral claimants, mineral owners, lessees and other owners of record of subsurface interests as to the contents of such notice was completed in accordance with W.S. § 35-11-313(ii)(N) and were included in Attachments A-1 and A-2 of the UIC Permit No. 2022-235v1.0.

J. DUTY TO PROVIDE INFORMATION

The Permittee shall furnish to the Wyoming Department of Environmental Quality (WDEQ), Water Quality Division Administrator (WQD) within a time specified, any information which WDEQ may request to determine whether cause exists for modifying, revoking and reissuing, or terminating this permit or to determine compliance with this permit. The Permittee shall also furnish to WDEQ, upon request, copies of records required to be kept by this permit. The Permittee must also comply with all reporting requirements of this permit, and as required by WWQR Chapter 24.

K. INSPECTION AND ENTRY

i. The Permittee shall allow the Administrator, or an authorized representative of the Administrator, upon the presentation of credentials, during normal working hours, to enter the premises where a regulated facility (comprising an injection facility, monitoring facilities, and all associated appurtenances) is located, or where records are kept under the conditions of this permit, and:

1. Inspect the injection and related facilities, practices, or operations regulated or required under this permit;
2. Review and copy reports and records required by this permit;
3. Collect fluid samples for analysis for the purposes of ensuring permit compliance or as otherwise authorized by the WEQA of any substances or parameters at any location;
4. Measure and record water levels, injection pressures, injectate temperatures, and annulus pressures;
5. Collect resource data as defined by W.S. § 6-3-414; and
6. Perform any other function authorized by law or regulation.

ii. If the facility is located on property not owned by the Permittee, the Permittee shall also secure from the landowner upon whose property the facility is located permission for WDEQ personnel and their invitees to enter the premises where the facility is located or where records are kept under the conditions of this permit, and collect resource data as defined by W.S. § 6-3-414, inspect and photograph the facility, collect samples for analysis, review records, and perform any other function authorized by law or regulation. The Permittee shall secure and maintain such access for the duration of the permit and the post-injection site care and site closure period.

iii. If the facility cannot be directly accessed using public roads, the Permittee shall also secure and maintain permission for WDEQ personnel and their invitees to enter and cross all properties necessary to access the facility. The Permittee shall secure and maintain such access prior to spudding wells and for the duration of the permit.

iv. The Permittee shall also maintain in its records a current map of the access route(s) to the facility and contact information for the owners or agents of all properties that must be crossed to access the facility. The Permittee shall ensure that the documentation, map, and contact information are current at all times.

v. Inspectors shall not be required by the Permittee to sign any waiver of liability.

L. SIGNATORY REQUIREMENTS

All applications, reports, and other information submitted to the Administrator shall contain the certifications required in WWQR Chapter 24, Section 10(d) by a responsible corporate officer.

M. SEVERABILITY

The provisions of this permit are severable, and if any provision of the permit, or the application of any provision of this permit to any circumstance, is held invalid, the application of such provision to other circumstances, and the remainder of this permit shall not be affected.

N. CONFIDENTIALITY

In accordance with 40 CFR Part 2 and §144.5, and W.S. § 16-4-203(d)(v), any information submitted to WDEQ pursuant to this permit may be claimed as confidential by the submitter. Any such claim must be asserted at the time of submission by stamping the words "confidential business information" on each page containing such information. If no claim is made at the time of submission, WDEQ may make the information available to the public without further notice. If a claim is asserted, the validity of the claim will be assessed and processed in accordance with the provisions of the Wyoming Public Records Act, W.S. §§ 16-4-201 through 205. Claims of confidentiality for the following information will be denied:

i. Name and address of the Permittee, or

ii. Information dealing with the existence, absence, or level of contaminants in drinking water.

O. PROHIBITIONS

Pursuant to the provisions of W.S. § 35-11-301(a), the Permittee shall not conduct any activities that are identified as prohibited under WWQR Chapter 24, Section 11.

P. WYOMING CONSERVATION EXECUTIVE ORDERS 2019-3 and 2020-1

i. Executive Order 2019-3 Sage Grouse

The Permittee shall ensure that all activities and habitat disturbances related to injection well(s) authorized by this permit comply with stipulations under the Governor's Executive Order 2019-3 on Greater Sage-Grouse Core Area Protection and are conducted in accordance with Wyoming Game and Fish Department Wildlife Environmental Review recommendations to protect sage-grouse habitat.

<u>No portion of the project authorized by this permit falls within a Sage Grouse Core Area.</u>

ii. Executive Order 2020-1 Migration Corridors

The Permittee shall ensure that all activities and habitat disturbances related to injection well(s) authorized by this permit comply with stipulations under the Governor's Executive Order 2020-1 on Migration Corridors and are conducted in accordance with Wyoming Game and Fish Department Wildlife Environmental Review recommendations to protect migration corridors.

<u>No portion of the project authorized by this permit falls within a Migration Corridor.</u>

SECTION 3. AREA OF REVIEW AND CORRECTIVE ACTION PLAN

The *AoR and CAP* is included as Attachment B-1 of this permit. The AoR model has been updated with data collected during the drilling and testing of the injection and monitoring wells. This updated model demonstrated that no modifications to the *AoR and CAP* are required at this time as all information remained the same as information presented in UIC Permit No. 2022-235 v1.0. The Permittee must comply with the approved *AoR and CAP,* requirements of WWQR Chapter 24 Section 13, and any modifications required by the Administrator after the effective date of the permit. The AoR and CAP is an enforceable condition of the permit. Any deviations from the WDEQ-approved *AoR and CAP* must receive WDEQ approval prior to implementation.

A. AREA OF REVIEW

i. The AoR for an injection well is the subsurface three-dimensional extent of the CO_2 plume, associated pressure front, and displaced fluids, as well as the overlying formations, and surface area above that delineated region. The AoR for this injection well is based on computational modeling that accounts for the physical and chemical properties of all phases of the injected CO_2 stream. The *AoR and CAP* shall include all requirements listed in WWQR Chapter 24 Section 13.

ii. One (1) well located within the AoR penetrated the receiver and was identified in *Specific Comment 35* in the initial response to comments, dated September 8, 2023 (Attachment A-4 of Permit 2022-235v1.0). Corrective action operations have been conducted on this well following the procedures outlined in Section 3.B of this Part. A plugback report describing this corrective action is included in Attachment B-1 of this permit.

iii. The AoR is depicted in *Figure 1 Map showing the updated Juniper I-1 AoR* of Attachment B-1 of this permit.

1. The final AoR is based on modeling, using data obtained during logging and testing of the well and the formation as required by WWQR Chapter 24 Sections 10(b)(xviii) – (xxviii). The AoR is further described in Specific Comments 1 and 2 of Tallgrass' Response to Comments dated May 2, 2025, included in Attachment B-1 of this permit.
2. At a fixed frequency, not to exceed two (2) years during the operational life of the facility or five (5) years during the post-injection site care period (until site closure) as specified in the *AoR and CAP*, or when monitoring and operations conditions warrant, the Permittee shall:

    a. Re-evaluate the AoR in the same manner specified in WWQR Chapter 24 Section 13(b)(i);
    b. Identify all wells in the re-evaluated AoR that require corrective action in the same manner specified in WWQR Chapter 24 Section 13(b)(iv);

c. Perform corrective action on wells requiring corrective action in the reevaluated AoR in the same manner specified in WWQR Chapter 24 Section 13(b)(v); and
d. Submit an amended *AoR and CAP* or demonstrate to the Administrator through monitoring data and modeling results that no change to the *AoR and CAP* is needed.

iv. Following each AoR reevaluation or a demonstration that no evaluation is needed, the Permittee must submit a report of the resultant information to the Administrator for review and approval.

v. Revisions to the *AoR and CAP* following AoR reevaluations will become an enforceable condition of this permit, once approved by the Administrator.

vi. Amendments to the AoR are subject to the permit modification requirements of Section 2.D.viii of this permit.

B. CORRECTIVE ACTION PLAN

i. If any additional wells requiring corrective action are found within the modified AoR, a list of these wells along with their locations and construction data shall be provided to WDEQ within thirty (30) days of their identification.

ii. For any additional wells identified in Section 3.B.i of this Part, the Permittee shall submit a plan to re-enter, plug, and abandon the wells in a way that prevents the migration of fluids into a USDW. This plan must meet WOGCC plugging requirements.

iii. The Permittee may not commence corrective action activities without prior written approval from WDEQ.

iv. Amendments to a WDEQ-approved *CAP* are subject to the permit modification requirements of Section 2.D.viii of this permit.

v. Amendments to a WDEQ-approved *CAP* will become an enforceable condition of this permit, once approved by the Administrator.

SECTION 4. EMERGENCY AND REMEDIAL RESPONSE

The *ERR Plan* describes actions the Permittee must take to address the movement of the injection or formation fluids that may cause an endangerment to a USDW during construction, operation, and PISC periods. The *ERR Plan* is included as Attachment B-2 of this permit. No modifications to the *ERR Plan* are required at this time as all information remained the same as information presented in UIC Permit No. 2022-235v1.0. The Permittee must maintain and comply with the approved *ERR Plan*, requirements of WWQR Chapter 24 Section 25, and any modifications required by the Administrator after the effective date of the permit.

i. The *ERR Plan* shall be reviewed and updated, as necessary, on the same schedule as the update to the AoR delineation.

ii. Any amendments to the *ERR Plan* shall be subject to approval by the Administrator, shall be incorporated into the permit, and are subject to the permit modification requirements of Section 2.D.viii of this permit. Amendments shall be submitted pursuant to WWQR Chapter 24 Section 25(a)(ii)(A) – (C).

iii. The *ERR Plan* shall account for the entire AoR delineated pursuant to Section 3.A.iii of this permit.

iv. If any monitoring data or other information indicates that any contaminant, including corrosion or precipitation of minerals, the injected CO_2 stream, displaced formation fluids, annulus fluids, or associated pressure front may endanger a USDW or threaten human health, safety, or the environment, the Permittee shall:

1. Immediately cease injection;
2. Take all steps reasonably necessary to identify and characterize any release;
3. Orally notify the Administrator within twenty-four (24) hours of discovering the condition; and
4. Provide a written report to the Administrator within five (5) days of discovering the condition. The written report shall contain:

    a. A description of the noncompliance and its cause;
    b. The period of noncompliance, including exact dates and times, and, if the noncompliance has not been controlled, the anticipated time it is expected to continue; and
    c. Steps taken or planned to reduce, eliminate, and prevent reoccurrence of the noncompliance.

v. If the Permittee discovers any noncompliance with a permit condition or a requirement of WWQR Chapter 24 that may cause fluid migration into or between USDWs, and malfunction of the injection system that may cause fluid migration into or between USDWs or any excursion, the Permittee shall:

1. Orally notify the Administrator within twenty-four (24) hours of discovering the condition;
2. Provide a written report to the Administrator within five (5) days of discovering the condition, which shall contain:

    a. A description of the noncompliance, malfunction, or excursion, and its cause;

b. The period of noncompliance, malfunction, or excursion, including exact dates and times, and, if the noncompliance, malfunction, or excursion has not been controlled, the anticipated time it is expected to continue; and
c. Steps taken or planned to reduce, eliminate, and prevent reoccurrence of the noncompliance, malfunction, or excursion.

vi. If an excursion is discovered, the Permittee shall provide written notice to all surface owners, mineral claimants, mineral owners, lessees, and other owners of record of subsurface interest within thirty (30) days of discovering the excursion.

vii. Amendments to a WDEQ-approved *ERR Plan* will become an enforceable condition of this permit, once approved by the Administrator.

viii. Any deviations from the WDEQ-approved *ERR Plan* must receive WDEQ approval prior to implementation.

SECTION 5. FINANCIAL ASSURANCE

The *Financial Assurance Demonstration Plan* is included as Attachment B-3 of this permit. Minor modifications to the cost estimates were received on February 13, 2025, with subsequent information received on the dates listed in the Administrative Record, and approved June 20, 2025 and therefore updated below. All other information in this section remains the same as information presented in UIC Permit No. 2022-235v1.0. The Permittee must maintain and comply with the approved *Financial Assurance Plan*, requirements of WWQR Chapter 24 Section 26, and any modifications required by the Administrator after the effective date of the permit. The *Financial Assurance Plan* is an enforceable condition of the permit. Any deviations from the WDEQ-approved *Financial Assurance Plan* must receive WDEQ approval prior to implementation.

i. The Permittee shall establish, demonstrate, and maintain financial assurance compliant with WWQR Chapter 24 Section 26 for all phases of the geologic sequestration project, including complete site reclamation in the event of default. The phases of a geologic sequestration project are:

1. Permitting/characterization;
2. Testing and monitoring, pursuant to WWQR Chapter 24, Section 20;
3. Operations, including injection and well-plugging, pursuant to WWQR Chapter 24, Sections 18 and 23.
4. PISC, including plume stabilization, monitoring, measurement, verification, corrective action, and other actions needed to ensure that USDWs are not endangered from the time of well-plugging until site closure is certified by the Administrator and above ground-reclamation is completed, pursuant to WWQR Chapter 24, Section 24; and
5. Emergency and remedial response pursuant to WWQR Chapter 24, Section 25.

Financial assurance instruments to be utilized to demonstrate financial responsibility were submitted to WDEQ and approved on June 20, 2025.

ii. The Permittee shall develop and annually update in accordance with WWQR Chapter 24, Section 26(f), a written financial assurance cost estimate. The Permittee shall submit the updated financial assurance cost estimate to the Administrator annually within thirty (30) days of the anniversary date when the original financial assurance cost estimate was submitted.

iii. The financial assurance cost estimate shall include the cost in current dollars and must cover the cost of:

1. Performing corrective action on other wells in the AoR that require corrective action under Chapter 24, Section 13;
2. Plugging the injection wells under Chapter 24, Section 23;
3. PISC and Site Closure under Chapter 24, Section 24;
4. Testing and monitoring under Chapter 24, Section 20; and
5. ERR under Chapter 24, Section 25.

iv. The financial responsibility instruments used shall be from the list of qualifying instruments identified in WWQR Chapter 24 Section 26(c) and submitted on a WDEQ form. Qualifying financial responsibility instruments are subject to approval by the Director.

v. Total financial responsibility for the injection well is summarized in Table 3. A complete breakdown of the costs to establish financial assurance and used to assess the appropriate coverage is presented in the *Financial Assurance Demonstration Plan*, Attachment B-3.

vi. The Permittee estimates the corrective action cost pursuant to WWQR Chapter 24 Section 13 to be **$256,000**. Corrective action is required for one (1) well identified within the AoR that penetrated the injection receiver (*Specific Comment 35* in the initial response to comments, dated September 8, 2023, Attachment A-4 of Permit 2022-235v1.0). Corrective action operations have been conducted on this well following the procedures outlined in Section 3.B of this permit. A plugback report describing this corrective action is included in Attachment B-1 of this permit. As corrective action has been completed for the well identified, financial assurance is not required to be submitted by the Permittee.

vii. The Permittee estimates the injection well-plugging cost pursuant to WWQR Chapter 24 Section 23 to be **$611,328**. Surface reclamation for the injection well, removal of the flow line, ancillary surface structures associated with the well, and soil grading and seeding will be covered under PISC. Surety bond, EACX4044408, in the amount of $611,328 was approved by WDEQ on June 23, 2025.

viii. The Permittee estimates the PISC and Site Closure to be **$11,200,205**. The PISC will cover the costs associated with monitoring during the post-injection phase, the surface reclamation and plugging of monitoring well(s), surface reclamation activities associated with the injection well, and the plugging and surface reclamation of soil gas monitoring points. A surety bond, EACX4044409, in the amount of $534,528 was approved by WDEQ on June17, 2025. An additional surety bond, DUA003747, in the amount of $10,665,677 was approved by WDEQ on June 20, 2025. The two surety bonds total $11,200,205.

ix. The Permittee estimates the Testing and Monitoring to be **$6,522,035**. Testing and monitoring is required to verify that the geologic sequestration project is operating as permitted and is not endangering USDWs as specified in WWQR Chapter 24 Section 20 and W.S. § 35-11-313. Financial Assurance is not required to be submitted by the Permittee for testing and monitoring, but the Permittee must demonstrate that testing and monitoring will be fully funded during the 25-year operational period.

x. The Permittee estimates the ERR costs pursuant to WWQR Chapter 24 Section 25, by considering the cost of emergency and remedial response actions and WWQR event-based risk activities (WWQR Chapter 24, Appendix A). Technical manuscripts by Trabucchi and others (2014) were used to identify and estimate the costs of mitigation and remediation technologies to address the undesired migration of CO_2 from a geological storage reservoir. The dollar amount was calculated by evaluating the probability of CO_2 leakage from the wellbore, and/or through the caprock and fault(s). The Permittee's estimate for ERR actions is **$9,601,587**. A cash bond, 250604456678, in an amount of $9,601,587 was approved by WDEQ on June 20, 2025

xi. The Permittee shall obtain and maintain public liability insurance for the geologic sequestration project. The requirements for public liability insurance are listed in WWQR Chapter 24 Section 26(l). Certificate of Insurance for the public liability insurance policy (submitted to WDEQ on June 27, 2025) is presented in the *Financial Assurance Demonstration Plan*, Attachment B-3.

xii. In accordance with WWQR Chapter 24 Section 26, the Director may require modifications or update to the public liability insurance upon review of the annual update.

SECTION 6. DRILLING, CONSTRUCTING, AND TESTING

The design and specifications for the injection well, injection zone monitoring wells, confining zone monitoring wells, groundwater monitoring wells, and any other monitoring system were included Attachments A-1 and A-4 of UIC Permit No. 2022-235v1.0. A Final Report including a notice of completion of the injection well was submitted to WDEQ on June 13, 2025. No additional injection wells are authorized under this permit.

A. SITING

i. The Permittee has demonstrated that the well is in an area with suitable geology in accordance with WWQR Chapter 24, Section 12 requirements.

ii. The groundwater in the Lyons Sandstone is classified as Class VI (unusable/unsuitable) in accordance with WWQR, Chapter 8 Section 4 (d)(ix). This classification is made as a baseline sample was collected from the formation confirmation:

1. The depths of these formations are such that the production of water from them is not economically nor technically practical.
2. Total Dissolved Solids (TDS) concentrations were identified as 213,000 milligrams per Liter (mg/L); formations with TDS greater than 10,000 mg/L do not meet the definition of a USDW.

   A USDW means an aquifer or portions thereof that is not an exempted aquifer and:

   a. Supplies any public water system; or
   b. Contains a sufficient quantity of groundwater to supply a public water system, and
   c. Currently supplies drinking water for human consumption; or
   d. Contains fewer than 10,000 mg/L TDS.

iii. The aquifer Class VI designation is limited to the AoR as defined in Section 3.A.iii of this permit.

iv. Data obtained during logging and testing of the well and the formation confirm that the injection zone proposed in UIC Permit No. 2022-235v1.0 is as follows:

1. The Lyons Sandstone is approximately fifty-one (51) foot (ft) thick zone encountered below 9,124 ft-bgs.

v. Data obtained during logging and testing of the well and the confining zones confirm that the that the confining zones proposed in UIC Permit No. 2022-235v1.0 is as follows:

1. The Chugwater and Goose Egg Formations overlie the Lyons Sandstone and consist of interbedded shale and siltstones with an average combined thickness of 506 feet in the area of the injection well.
2. The Satanka and Wolfcamp Formations underlie the Lyons Sandstone and consist of interbedded sandstone, siltstone, mudstone, marlstone, and anhydrite, with an average thickness of 295.8 feet in the area of the injection well.

vi. Data obtained during logging and testing of the well or monitoring wells for the project confirm that a USDW is currently located above the proposed injection zone and therefore does not require an Injection Depth Waiver in accordance with WWQR Chapter 24, Section 15.

B. WELL CONSTRUCTION

i. INJECTION WELL CONSTRUCTION

1. The injection well covered by this permit was constructed in accordance with the construction requirements outlined in WWQR Chapter 24 Section 14. The design and construction allow for continuous monitoring of the annulus between the long string casing and the injection tubing from the packer to the surface and accommodate testing devices and workover tools.
2. During the construction, no changes to the design of the injection well occurred.
3. Final, as-built construction specifications and diagrams were submitted to WDEQ on March 13, 2025.

ii. WELL LOCATION

1. The injection well authorized under this permit will be located in Laramie County, Wyoming. The locations for the injection well and associated monitoring wells are located in Table 1 of this permit.

iii. CASING AND CEMENTING

The well was cased and cemented in accordance with WWQR Chapter 24 Section 14(b). Casing and cement or other materials used in the construction of the Class VI well shall have sufficient structural strength and be designed for the life of the well. All well materials shall be compatible with fluids with which the materials may be expected to come in contact and shall meet or exceed the standards identified in WWQR Chapter 24 Section 14(b)(i)(A) – (H).

iv. TUBING AND PACKER SPECIFICATIONS

The tubing and packer design must meet the requirements in accordance with WWQR Chapter 24 Section 14(c). The Permittee shall inject fluids through tubing with a packer set at a depth opposite a cemented interval at the location approved by the Administrator. Tubing and packer materials used in the construction of the Class VI well shall be compatible with fluids with which the materials may be expected to come into contact and shall meet or exceed the standards identified in WWQR Chapter 24 Section 14(c)(i)(A) – (H). <u>**The injection must only take place through the tubing, with a packer set in the long string casing within or below the nearest cemented and impermeable confining system no more than 100 feet above the injection zone.**</u>

v. MONITORING WELL CONSTRUCTION

1. Monitoring of the groundwater quality and geochemical changes above the confining zones that may be a result of CO_2 movement or displaced formation fluid movement through the confining zones or additional zones is required per WWQR Chapter 24 Section 20.

Monitoring includes **monitoring for all USDWs above the confining zone**. Groundwater, confining zone, and injection zone monitoring wells must be constructed as depicted in Attachments A-1 and A-4 of UIC Permit No. 2022-235v1.0. Additional monitoring wells beyond what is depicted in Section 4.4 *Well Casing and Cementing Program* (Attachment A-1 of UIC Permit No. 2022-235v1.0) may be required based on site-specific data collected during operation at the facility.

2. All monitoring wells must be constructed in a manner to provide representative samples that can be analyzed for the monitoring parameters required by this permit.
3. Once the construction of the monitoring wells has been completed, the as-built construction diagrams must be submitted to the Administrator with a Final Well Construction Report, including a narrative description and timeline for the well construction and completion activities, summary of any deviation(s) from the approved well drilling and completion plan, report of formation tops from surface to the total depth of the well, schematic diagrams, and detailed description of construction, including driller's log, materials used (i.e., tubing tally, particulate filters), if any, and cement (and other) volumes.
4. Final Well Construction Report shall be submitted to WDEQ within thirty (30) days after completion of any of the permitted monitoring well(s) or with the next quarterly report, whichever is later.
5. Additionally, for monitoring wells that will penetrate the upper confining zone, analysis of the Cement Bond Log, daily reports, logging, coring, and other results, and Part I Mechanical Integrity Tests (MIT) results, if applicable, shall also be submitted.

SECTION 7. PLUGGING AND ABANDONMENT

The *Well Plugging Plan* is included as Attachment B-4 of this permit. No modifications to the *Well Plugging Plan* are required at this time as all information remained the same as information presented in UIC Permit No. 2022-235v1.0. The Permittee must maintain and comply with the approved *Well Plugging Plan,* requirements of WWQR Chapter 24 Section 23, and any modifications required by the Administrator after the effective date of the permit.

i. The Permittee shall prepare, maintain, and update on the same schedule as the update to the AoR delineation, and comply with a well-plugging plan that is approved by the Administrator. The well-plugging plan shall include the information pursuant to WWQR Chapter 24 Section 23(b)(i) – (vi).

ii. Prior to well plugging, the Permittee shall flush each injection well with a buffer fluid, determine bottom hole reservoir pressure, and perform a Part I MIT in accordance with WWQR Chapter 24 Section 19.

iii. The Permittee shall notify the Administrator, in writing, of at least sixty (60) days before plugging a well.

iv. Within sixty (60) days after completion of plugging and abandonment of a well, the Permittee shall submit to the Administrator a final report that includes the information pursuant to WWQR Chapter 24 Section 23(e)(i) – (ii).

v. If the plugging differed from the approved plan, the Permittee shall submit a statement describing the actual plugging and an updated plan specifying the differences from the plan previously submitted and explaining why the Administrator should approve the deviation. If the Administrator determines that a deviation from the plan incorporated in the permit may endanger the USDW, the Permittee must re-plug the well as required by the Administrator.

vi. The well-plugging report required under WWQR Chapter 24 Section 23 shall be retained for ten (10) years following site closure.

vii. The Permittee must deliver the records to the Administrator at the conclusion of the retention period.

viii. Any amendments to the *Well Plugging Plan* must be approved by the Administrator and must be incorporated into the permit and are subject to the permit modification requirements of WWQR Chapter 24 Section 6.

ix. Amendments to a WDEQ-approved *Well Plugging Plan* will become an enforceable condition of this permit, once approved by the Administrator.

x. Any deviations from the WDEQ-approved *Well Plugging Plan* must receive WDEQ approval prior to implementation.

SECTION 8. WELL OPERATION

ATI may only occur after all conditions and requirements of WWQR Chapter 24, and this permit has been met. Section 8.A establishes the maximum injection volumes and pressure necessary to ensure that fractures are not initiated in the confining zone, to ensure that injected fluids do not migrate into any USDW, to ensure that formation fluids are not displaced into any USDW, and to ensure compliance with the operating requirements. Modifications to operations of the Class VI injection well shall not occur until a modified permit is issued.

A. INJECTION PRESSURE LIMITATION

i. Except at specific times as approved by the Administrator, the Permittee must maintain on the well a pressure that will prevent the return of the injection fluid to the surface. The well bore must be filled with a fluid of sufficient specific gravity during workovers to maintain a positive (downward) pressure gradient and/or a plug shall be installed which can resist the pressure differential. A blowout preventer must be installed and kept in proper operational condition whenever the wellhead is removed to work on the well. The Permittee must follow procedures such as those below to ensure that a backflow or blowout does not occur:

1. Limit the temperature and/or corrosivity of the injectate; and
2. Develop procedures necessary to assure that pressure imbalances do not occur.

ii. The Permittee shall ensure that injection pressure does not exceed ninety percent (90%) of the fracture pressure of the injection zone(s) to ensure that the injection does not initiate new fractures or propagate existing fractures in the injection zone(s). In no case may injection pressure cause movement of injection or formation fluids in a manner that endangers a USDW, or otherwise threatens human health, safety, or the environment, or initiate fractures in the confining zones or cause the movement of injectate or formation fluids that endanger a USDW, or otherwise threaten human health, safety, or the environment.

iii. During operation, the injection pressure will be measured at the wellhead and at the injection interval.

iv. The pressure limitations are presented in Table 4 of this permit and are based on the results of injection tests conducted on the injection well, and on the American National Standards Institute (ANSI) 900 limitations for the piping used.

B. STIMULATION PROGRAM

All stimulation activities must be approved by the Administrator prior to conducting stimulation. The Permittee must carry out the Stimulation Program in accordance with *Specific Comment 26* in the first response to comments, dated September 8, 2023 (Attachment A-4 of UIC Permit No. 2022-235v1.0). If additional stimulation activities are required in the injection well, a new Stimulation Program shall be submitted to the Administrator for review and approval prior to stimulation activities being conducted.

C. ADDITIONAL INJECTION LIMITATIONS

No injection fluid other than that identified in Section 1 of this permit may be injected except fluids used for stimulation, rework, and well tests as approved by the Administrator. Injection must occur within the injection tubing.

D. ANNULUS FLUID

The Permittee must fill the annulus between the tubing and the long string casing with a non-corrosive fluid approved by the Administrator.

E. ANNULUS/TUBING PRESSURE DIFFERENTIAL

Except during workovers or times of annulus maintenance, the Permittee must maintain pressure on the annulus that exceeds the operating injection pressure as specified in Table 4, unless the Administrator determines that such requirement might harm the integrity of the well or endanger USDWs.

F. AUTOMATIC ALARMS AND AUTOMATIC SHUT-OFF SYSTEM

The Permittee shall install, test, and use alarms and automatic surface shut-off systems or, at the discretion of the Administrator, use down-hole shut-off systems (e.g., automatic shut-off, check valves) or other mechanical devices that provide equivalent protection, designed to alert the Permittee and shut-in the well when operating parameters such as injection rate, injection pressure, annulus pressure, or other parameters approved by the Administrator diverge beyond ranges or gradients specified in the permit.

If an automatic shutdown is triggered or a loss of mechanical integrity is discovered, the Permittee shall immediately investigate and identify as expeditiously as possible the cause. If, upon such investigation, the well appears to be lacking mechanical integrity, or if monitoring required under WWQR Chapter 24 Section 18(e) – (g) otherwise indicates that the well may be lacking mechanical integrity, the Permittee shall:

i. Immediately cease injection;

ii. Take all steps reasonably necessary to determine whether there may have been a release of the injected CO_2 stream or formation fluids into any unauthorized zone;

iii. Notify the Administrator within twenty-four (24) hours;

iv. Restore and demonstrate mechanical integrity to the satisfaction of the Administrator as soon as practicable and prior to resuming injection; and

v. Notify the Administrator when injection can be expected to resume. Approval to resume injections is required from the Administrator.

G. MECHANICAL INTEGRITY

i. The Permittee shall establish mechanical integrity prior to commencing injection and maintain mechanical integrity as defined in WWQR Chapter 24 Section 19.

ii. To evaluate the absence of significant leaks (in the casing, tubing, or packer), the Permittee shall continuously monitor injection pressure, rate, injected volumes, and pressure on the annulus between tubing, long string casing, and annulus fluid volume as specified in WWQR Chapter 24 Section 18(e) – (f).

iii. The Permittee shall maintain mechanical integrity, as defined in WWQR Chapter 24, Section 19, of the injection well at all times except during periods of well workover or maintenance approved by the Administrator in which the sealed tubing-casing annulus is, by necessity, disassembled for maintenance or corrective procedures.

iv. The Permittee shall use one (1) of the following methods to determine the absence of significant fluid movement under subparagraph (a)(ii) of WWQR Chapter 24 Section 19 at least once per year:

1. An approved tracer survey, such as an oxygen-activation log; or
2. A temperature log or a noise log such as pulse echo, ultrasonic image, or equivalent.

v. If the Administrator determines that a Class VI well lacks mechanical integrity and gives written notice of the determination to the Permittee, the Permittee shall:

1. Cease injection in the well within forty-eight (48) hours of receipt of the Administrator's determination unless the Administrator requires immediate cessation;
2. Perform any construction, operation, monitoring, reporting, and corrective action that the Administrator requires to prevent the movement of fluid into or between USDWs caused by the lack of mechanical integrity, or plug the well pursuant to the requirements of WWQR Chapter 24 Section 23 if allowed by the Administrator; and
3. Not resume injection into the well until the Administrator provides written notice that the Permittee has demonstrated mechanical integrity pursuant to WWQR Chapter 24 Section 19.

vi. The Permittee shall run a casing inspection log to determine the presence or absence of corrosion in the long-string casing as specified in the *Testing and Monitoring Plan* (Attachment B-5 of this permit).

vii. For any Class VI well that lacks mechanical integrity, injection operations are prohibited until the Permittee shows to the satisfaction of the Administrator under WWQR Chapter 24 Section 19 that the well has mechanical integrity.

H. SEISMIC EVENT RESPONSE

i. All seismic work to be completed requires a permit from the WOGCC.

ii. The United States Geological Survey (USGS) Earthquake Hazards Program operates an email notification service that reports real-time earthquake events for any events for any area specified by the user. The Permittee is required to subscribe to this service, known as the Earthquake Notification Service (ENS). Details for the ENS can be found at https://earthquake.usgs.gov/ens/, and a subscription can be initiated at https://earthquake.usgs.gov/ens/register.

iii. All seismicity recorded by the seismic array above Moment Magnitude (M) 2.0 shall be recorded, with hypocenters resolved as accurately as possible, and reported to WDEQ on a quarterly basis.

iv. Information obtained during logging, reservoir testing, and seismicity investigations shall be used to update the reservoir model. Permit actions due to seismicity are included in Table 5.

SECTION 9. MONITORING, RECORDKEEPING, AND REPORTING OF RESULTS

The specific measurements and reporting frequencies are listed in Table 2. All data and reports required by this permit are to be submitted in an electronic format as approved by the Administrator.

A. TESTING AND MONITORING PLAN

i. The *Testing and Monitoring Plan* is included as Attachment B-5 of this permit.

ii. Minor modifications to the *Testing and Monitoring Plan* were made to the sampling design of the Juniper M-1 well, no other modifications are required at this time as all information remained the same as information presented in UIC Permit No. 2022-235v1.0.

iii. The Permittee must maintain and comply with the approved *Testing and Monitoring Plan*, requirements of WWQR Chapter 24 Section 20, and any modifications required by the Administrator after the effective date of the permit. Samples and measurements taken for the purpose of monitoring must be representative of the monitored activity.

iv. The Permittee shall prepare, maintain, and comply with the *Testing and Monitoring Plan* to verify that the geologic sequestration project is operating as permitted and is not endangering USDWs as specified in WWQR Chapter 24 Section 20 and W.S. § 35-11-313.

v. Amended plans or demonstrations shall be submitted to the Administrator as specified in WWQR Chapter 24 Section 20(b)(xi) – (xii).

vi. The Permittee shall create and retain records of all monitoring information as specified in WWQR Chapter 24 Section 20(c).

vii. The Permittee shall review the *Testing and Monitoring Plan* to incorporate monitoring data, operational data, and the most recent AoR reevaluation performed under this permit. The Permittee shall review the *Testing and Monitoring Plan* every five (5) years. Based on this review, the Permittee shall submit an amended *Testing and Monitoring Plan* or demonstrate to the Administrator that no amendment to the *Testing and Monitoring Plan* is needed. Amended plans or demonstrations shall be submitted to the Administrator as follows:

1. Within one (1) year of an AoR reevaluation;
2. Following any significant changes to the facility, such as the addition of monitoring wells or newly permitted injection wells within the AoR; or
3. When required by the Administrator.

viii. Any amendments to the *Testing and Monitoring Plan* must be approved by the Administrator and must be incorporated into the permit and are subject to the permit modification requirements of WWQR Chapter 24 Section 6.

ix. Amendments to a WDEQ-approved *Testing and Monitoring Plan* will become an enforceable condition of this permit, once approved by the Administrator.

x. Any deviations from the WDEQ-approved *Testing and Monitoring Plan* must receive WDEQ approval prior to implementation.

xi. CO_2 STREAM ANALYSIS
The Permittee must analyze the CO_2 stream with sufficient frequency to yield data representative of its chemical and physical characteristics, as described in the *Testing and Monitoring Plan* and WWQR Chapter 24 Section 20 (Table 6 of this permit). **The CO_2 purity has been determined to be >95%.** The Permittee has submitted its certification that no hazardous waste will be mixed or otherwise co-injected with the CO_2 stream and the CO_2 stream is excluded as a hazardous waste under 40 CFR § 261.4(h).

xii. CONTINUOUS MONITORING
The Permittee must install and use, except during well workovers, continuous recording devices to monitor injection pressure, injection rate and volume, pressure on the annulus between the tubing and the long string casing, and the annulus fluid volume added. The monitoring must be performed as described in the *Testing and Monitoring Plan,* WWQR Chapter 24 Section 20, and Table 6 of this permit. The Permittee must maintain for WDEQ's inspection at the facility an appropriately scaled, continuous record of these monitoring results as well as original files of any digitally recorded information pertaining to these operations.

xiii. CORROSION MONITORING
The Permittee shall perform corrosion monitoring of the well materials for loss of mass, loss of thickness, cracking, pitting, and other signs of corrosion, which shall be performed and recorded at least quarterly to ensure that the well components meet the minimum standards for material strength and performance as set forth in WWQR Chapter 24 Section 14(b).

xiv. GROUNDWATER MONITORING ABOVE THE CONFINING ZONE
Periodic monitoring of the groundwater quality and geochemical changes above the confining zones that may be a result of CO_2 movement or displaced formation fluid movement through the confining zones or additional zones is required. All monitoring conducted must be performed for the parameters identified in the approved *Testing and Monitoring Plan* at the locations and depths and at the frequencies described in the *Testing and Monitoring Plan* and Tables 7 and 8 of this permit.

xv. CARBON DIOXIDE PLUME AND PRESSURE FRONT TRACKING

The Permittee must track the extent of the CO_2 plume and pressure front using direct and indirect monitoring methods as described in the *Testing and Monitoring Plan*. The Permittee is required to conduct this monitoring in order to detect and locate the CO_2 pressure front and the dissolved CO_2 plume, and the data will be used to calibrate the AoR model to determine whether modifications to the AoR are needed. Data collected by the following methods will be used to monitor the location of the plume and pressure front, evaluate its movement through time, and to compare to the plume and pressure front predictions of the AoR model:

1. Direct Methods in the injection zone(s); and
2. Indirect Methods in the injection zone (e.g., seismic, electrical, gravity, or electromagnetic surveys and/or down-hole carbon dioxide detection tools) unless the Administrator determines based on site-specific geology, that such methods are not appropriate.
3. Direct and Indirect Methods described in the *Testing and Monitoring Plan* shall be followed.

viii. PART II MECHANICAL INTEGRITY TESTING

The Permittee must demonstrate Part II MIT pursuant to the *Testing and Monitoring Plan* at least once per year until the well is plugged.

ix. PRESSURE FALL-OFF TEST

The Permittee must conduct a Pressure Fall-Off Test that identifies reservoir conditions with respect to flow dynamics at least once every five (5) years, unless more frequent testing is required by the Administrator based on site-specific data.

x. SURFACE AIR AND/OR SOIL GAS MONITORING

The Permittee must conduct soil gas monitoring pursuant to the *Testing and Monitoring Plan*. The frequency and spatial distribution of soil gas monitoring shall be based on baseline data to be collected during the drilling and testing of the injection well.

xi. PROPOSED CHANGES AND WORKOVERS

1. Demonstration of mechanical integrity shall be performed within thirty (30) days of completion of workovers or alterations and prior to resuming injection activities, in accordance with Section 8.G of this Permit.
2. The Permittee shall provide a procedure for completing workovers or changes to WDEQ for review and approval prior to initiating the proposed work.
3. The Permittee shall provide all records of well workovers, logging, or other subsequent test data, including required MIT, to WDEQ within thirty (30) days of completion of the activity or with the next quarterly report, whichever is later.

B. REPORTING AND NOTICE REQUIREMENTS

The Permittee must submit reports at frequencies described in the approved *Testing and Monitoring Plan* and as required by the permit. Reports must contain all data and information required to be monitored, gathered, and reported by this permit and meet the requirements of WWQR Chapter 24 Section 21. A summary of all reporting requirements, frequency, and submittal due dates is identified in Table 2.

i. The Permittee shall submit all required reports, submittals, and notifications to the Administrator in a format acceptable to WDEQ.

ii. The Permittee shall report all instances of noncompliance not already required to be reported under 9.B.v of this permit, at the time monitoring reports are submitted. The reports shall contain the information in Section 9.B.v of this permit.

iii. Semi-annual Reports
The Permittee shall submit semi-annual reports to the Administrator thirty (30) days following the end of the period covered in the report and shall contain:

1. Any changes to the physical, chemical, and other relevant characteristics of the CO_2 stream from the proposed operating data;
2. Monthly average, maximum, and minimum values for injection pressure, flow rate and volume, and annular pressure;
3. A description of any event that exceeds operating parameters for annulus pressure or injection pressure as specified in the *Testing and Monitoring Plan*;
4. A description of any event that triggers an automatic alarm or shut-off system required pursuant to WWQR Chapter 24 Section 18(g) and Section 8.F of this permit and the response taken;
5. The monthly volume of the CO_2 stream injected over the reporting period and project cumulatively;
6. Monthly annulus fluid volume added; and
7. The results of the monitoring required by WWQR Chapter 24 Section 20 and the *Testing and Monitoring Plan*.

iv. Reports
The Permittee shall submit a Report within thirty (30) days, the results of:
1. Periodic test of mechanical integrity;
2. Any other test of the injection well conducted by the Permittee if required by the Administrator; and
3. Any well workover.

v. Twenty-Four (24) Hour Reporting
1. The Permittee must report to the Administrator any permit noncompliance which may endanger human health or the environment and any events that require implementation of

actions in the *ERR Plan*. Any information must be provided orally within twenty-four (24) hours from when the Permittee becomes aware of the circumstances. Such verbal reports must include, but not be limited to, the following information:

a. Any evidence that the injected CO_2 stream or associated pressure front may cause an endangerment to a USDW;
b. Any noncompliance with a permit condition or malfunction of the injection system, which may cause fluid migration into or between USDWs;
c. Any triggering of a shut-off system, either down-hole or at the surface;
d. Any release of CO_2 to the atmosphere or biosphere indicated by the surface air or soil gas monitoring or other monitoring technologies required by WWQR Chapter 24 Section 20(b)(ix) and Section 9.A.x of this permit; and
e. Any failure to maintain mechanical integrity.

2. The Permittee must report to the Administrator actions taken to implement appropriate protocols outlined in the *ERR Plan*.
3. A written submission must be provided to the Administrator within five (5) days of the time that the Permittee becomes aware of the circumstances described in Section 9.B.v.1 of this permit. The submission must contain a description of the noncompliance or emergency, or remedial response and its cause; the period of noncompliance, emergency, or remedial response, including exact dates and times, and, if the noncompliance has not been corrected, the anticipated time it is expected to continue as well as actions taken to implement appropriate protocols outlined in the *ERR Plan*; and steps taken or planned to reduce, eliminate and prevent recurrence of the noncompliance or emergency or condition requiring remedial response.

vi. Written Notice
The Permittee shall notify the Administrator, in writing, thirty (30) days in advance of:
1. Any planned well workover;
2. Any planned stimulation activities, other than stimulation for formation testing conducted under WWQR Chapter 24 Section 17; and
3. Any other planned test of the injection well conducted by the Permittee.

vii. The Permittee shall submit a written report to the Administrator of all remedial work concerning the failure of equipment or operational procedures that resulted in a violation of a permit condition at the completion of the remedial work.

viii. For any aborted or curtailed operation, the Permittee shall submit to the Administrator a complete report within thirty (30) days of complete termination of the discharge or associated activities.

ix. Compliance Schedules – Reports of compliance or noncompliance with, or any progress reports on, interim and final requirements contained in any compliance schedule of this permit must be submitted in an electronic format as approved by the Administrator by the Permittee no later than thirty (30) days following each schedule date. The Permittee shall submit progress reports no later than thirty (30) days following each interim date and the final date of compliance.

x. Other Noncompliance – The Permittee must report all other instances of noncompliance not otherwise reported within the next monitoring report. The reports must contain the information listed in Section 9.B.v.1 of this permit.

xi. Report on permit Review – Within thirty (30) days of receipt of this permit, the Permittee must certify to the Administrator that he or she has read and is personally familiar with all terms and conditions of this permit.

C. RECORDKEEPING

i. The Permittee must retain all records as identified in this section and Table 9.

ii. Records of monitoring information must include:

1. The date, exact place, and time of sampling or measurements;
2. The name(s) of the individual(s) who performed the sampling or measurements;
3. A precise description of both sampling methodology and the handling of samples;
4. The date(s) analyses were performed;
5. The name(s) of the individual(s) who performed the analyses;
6. The analytical techniques or methods used; and
7. The results of such analyses.

iii. The Permittee must deliver the records to the Administrator at the conclusion of the retention period.

D. INJECTION FEE SCHEDULE

i. Once injections begin, the Permittee shall pay a fee into the geologic sequestration special revenue account in accordance with WWQR Chapter 29, Section 4. Payment into the special revenue account terminates once injections cease and the injection well is plugged and abandoned.

ii. Failure to pay fees is a violation of WWQR Chapter 29 and may be cause for the revocation of this Class VI permit.

iii. Notice and payment of fees shall be made in accordance with WWQR Chapter 29, Section 4.

SECTION 10. POST-INJECTION SITE CARE AND SITE CLOSURE

The *PISC and Site Closure Plan* is included as Attachment B-6 of this permit. No modifications to the *PISC and Site Closure Plan* are required at this time as all information remained the same as information presented in UIC Permit No. 2022-235v1.0. The Permittee must maintain and comply with the approved *PISC and Site Closure Plan*, requirements of WWQR Chapter 24 Section 24, and any modifications required by the Administrator after the effective date of the permit. The *PISC and Site Closure Plan* is an enforceable condition of the permit. Any deviations from the WDEQ-approved *PISC and Site Closure Plan* must receive WDEQ approval prior to implementation.

The Permittee must maintain and comply with the approved *PISC and Site Closure Plan* and requirements of WWQR Chapter 24 Section 24. The PISC period is the length of time anticipated to demonstrate that the CO_2 injection poses no threat to USDWs and is an enforceable condition of this permit.

i. The *PISC and Site Closure Plan* shall include the information pursuant to WWQR Chapter 24 Section 24(a)(ii) – (iii).

ii. Upon cessation of injection, the Permittee shall either submit an amended *PISC and Site Closure Plan* or demonstrate to the Administrator through monitoring data and modeling results that no amendment to the plan is needed. Any amendments to the *PISC and Site Closure Plan* shall be subject to the provisions identified in WWQR Chapter 24 Section 24(a)(iv)(A) – (C).

iii. The Permittee may amend the *PISC and Site Closure Plan* during the life of the project. The Permittee shall re-submit the *PISC and Site Closure Plan* for the Administrator's approval within thirty (30) days of amending the plan. Once approved, the *PISC and Site Closure Plan* is amended to the permit. Upon receipt of the Administrator's approval, the Permittee shall submit the proposed cost estimate for measurement, monitoring, and verification of the plume stabilization.

iv. Any amendments to the *PISC and Site Closure Plan* must be approved by the Administrator and must be incorporated into the permit and are subject to the permit modification requirements of WWQR Chapter 24 Section 6.

v. PISC shall continue for a period that meets the criteria of W.S. §35-11-313(f)(vi)(F).

vi. The Permittee shall continue to conduct monitoring as specified in the Administrator-approved *PISC and Site Closure Plan* until the Administrator certifies site closure pursuant to WWQR Chapter 24 Section 24(b)(iii).

vii. Prior to certification of site closure, the Permittee shall demonstrate to the Administrator, based on monitoring, other site-specific data, and modeling that is reasonably consistent with site performance, that no additional monitoring is needed to ensure the geologic sequestration project does not and is not expected to endanger a USDW or otherwise threaten human health, safety, or the environment. In addition, the Permittee shall demonstrate, based on the best available understanding of the site, including monitoring data and modeling, that all other site closure standards and requirements have been met.

viii. If the Permittee cannot demonstrate that the requirements of WWQR Chapter 24 Section 24(b)(iii) have been met, the Permittee shall continue post-injection site care.

ix. The Permittee shall notify the Administrator, in writing, at least one hundred and twenty (120) days before filing a request for site closure. At that time, if any changes have been made to the original *PISC and Site Closure Plan*, the Permittee shall also provide the revised plan.

x. After the Administrator has certified site closure, the Permittee shall plug monitoring wells in a manner approved by the Administrator that will not allow the movement of injection or formation fluids. The Permittee must also restore the site to its pre-injection condition.

xi. The Permittee shall submit a site closure report within ninety (90) days after completion of all closure operations. The report must include all information specified in WWQR Chapter 24 Section 24(d)(i) – (v).

xii. The Permittee shall submit a proposed cost estimate with the site closure report as specified in WWQR Chapter 24 Section 26(i).

xiii. If the Director determines that there are insufficient monies available in the special revenue account, including accumulated interest, based on the cost estimate submitted for the Administrator's evaluation, the Permittee shall make additional payments into the special revenue account to ensure that the sufficient funds are available to execute the required activities identified by W.S. § 35-11-320(c).

xiv. The Permittee shall record a notation on the deed of the facility property or any other document that is normally examined during the title search that will in perpetuity provide any potential purchaser of the property and shall file an affidavit in accordance with W.S. § 35-1-313(f)(vi)(G) that includes the information specified in WWQR Chapter 24 Section 24(e)(i) – (iii).

xv. The site closure report required by WWQR Chapter 24 Section 24 and any PISC data (including data and information used to establish the PISC time frame) shall be retained for ten (10) years following site closure.

xvi. The Permittee must deliver the records to the Administrator at the conclusion of the retention period.

TABLES

TABLE 1. JUNIPER PAD WELL LOCATIONS

Well Name	Latitude	Longitude	Total Depth
Juniper I-1	41.055944	-104.271028	9,315’
Juniper M-1	41.055982	-104.271968	8,630’*
Juniper-USDW-1-FH	41.055874	-104.272803	1,005’
Juniper-USDW-2-LN	41.055737	-104.272804	465’
Juniper-USDW-3-HP	41.055600	-104.272804	100’

Notes:
All Latitude and Longitude are using North American Datum 83
*Originally completed as a Stratigraphic Test Well under the WOGCC where drilling ended with a Total Depth of 9,850’. Corrective action completed to plugback the Stratigraphic Test Well and covert to a monitoring well with a Total Depth of 8,630’.

TABLE 2. NOTIFICATION AND REPORTING SUMMARY

TASK	FREQUENCY	DUE
Amended *PISC and Site Closure Plan*	The Permittee may amend the *PISC and Site Closure Plan* during the life of the project.	Within thirty (30) days of amending the plan.
Amended Plans or Demonstrations	Within one (1) year of an AoR reevaluation; following any significant changes to the facility, such as the addition of monitoring wells or newly permitted injection wells within the AoR; or when required by the Administrator.	Submitted within one (1) year of an AoR reevaluation or within Thirty (30) days of any significant changes to the facility or required by the Administrator.
Amend *Testing and Monitoring Plan*	Every five (5) years.	January 30th every five (5) years.
AoR Re-evaluation	Not to exceed two (2) years during the **operational life** of the facility or five (5) years **during the PISC period (until site closure)** as specified in the *AoR and CAP*, or when monitoring and operations conditions warrant.	January 30th every two (2) years during operational life. January 30th every five (5) years during the PISC period until site closure.
Compliance Schedules and Progress Reports	Compliance Schedules – Reports of compliance or noncompliance with, or any progress reports on, interim and final requirements contained in any compliance schedule of this permit.	No later than thirty (30) days following each interim date and the final date of compliance.
Financial Assurance Cost Estimate Update	Annual cost estimate update.	Within thirty (30) days of the anniversary date when the original financial assurance cost estimate was submitted.
	Whenever the owner or operator amends the *AoR and CAP*, the *injection well-plugging plan, the PISC and Site Closure Plan, the ERR Plan*, mitigation costs or reclamation costs.	Within sixty (60) days after notice of any amendment.
Financial Assurance Adjustment for Inflation	Annual inflation adjustment.	Within sixty (60) days prior to the anniversary date of the establishment of the financial instruments used.
Financial Assurance Update – *AoR or CAP* Modification	Revise the cost estimate after the Administrator has approved the request to modify the *AoR or CAP*.	Within sixty (60) days after notice of Administrator approval.
Financial Assurance Update – Any Increase in Financial Assurance Cost Estimate	Whenever the financial assurance cost estimate increases to an amount greater than the face amount of the current financial assurance, the Permittee shall either cause the face amount to be increased or an amount at least equal to the current financial assurance cost estimate and submit evidence of such increase to the Administrator, or the Permittee shall obtain other financial responsibility instruments to cover the increase.	Within sixty (60) days after the increase.
Financial Assurance – Notice of Cancellation	Upon notice of cancellation, the Permittee shall provide to the Director an alternate financial responsibility demonstration that meets the requirements of WWQR Chapter 24 Section 26(c) – (g).	Within sixty (60) days after notice of cancellation.
Financial Assurance – Bankruptcy	In the event of bankruptcy, the owner or operator shall notify the Director by certified mail of the commencement of a voluntary or involuntary proceeding under Title 11 (Bankruptcy), U.S Code, naming the owner or operator of the third-party provider of a financial responsibility instrument as debtor.	Within 10 days after the commencement of proceedings.
Oral Notification	If an automatic shutdown is triggered or a loss of mechanical integrity is discovered.	Within twenty-four (24) hours.
Oral Notification	Any monitoring data or other information indicates that any contaminant, including corrosion or precipitation of minerals, the injected CO_2 stream, displaced formation fluids, or associated pressure front may endanger a USDW or threaten human health, safety, or the environment.	Within twenty-four (24) hours.
Oral Notification	Any noncompliance with a permit condition or a requirement of WWQR Chapter 24 that may cause fluid migration into or between USDWs, and malfunction of the injection system that may cause fluid migration into or between USDWs or any excursion.	Within twenty-four (24) hours.
Schedule	Prior to pre-operational testing activities.	At least thirty (30) days prior to conducting the first test and submit any changes to the schedule thirty (30) days prior to the next scheduled test.
Written Notification	Transfer of Permits – Transfer of a permit is allowed only upon approval by the Director. The proposed permit transferee shall apply in writing as though that person were the original applicant of the permit, and the proposed permit transferee shall agree to be bound by all of the terms and conditions of the permit.	At least forty-five (45) days prior to transfer.

TASK	FREQUENCY	DUE
Written Notification	Discovery of an excursion.	Within thirty (30) days of discovering the excursion.
Written Notification	Prior to plugging a well.	At least sixty (60) days before plugging a well.
Written Notification	Any planned well workover; Any planned stimulation activities, other than stimulation for formation testing conducted under WWQR Chapter 24 Section 17; and Any other planned test of the injection well conducted by the Permittee.	At least thirty (30) days in advance of the activity.
Written Notification	Intent to close the site.	At least one hundred and twenty (120) days before filing a request for site closure.
Written Report – Annual	Annually.	January 30th annually.
Written Report – Annual Pressure Fall Off Test	Following Annual Pressure Fall off Test.	Report submitted within thirty (30) days of test completion or with the next quarterly monitoring reports, whichever comes first.
Written Report – Semi-annual	Thirty (30) days following the end of the period covered in the report.	Semiannual Reports are due on or before July 31st for the first reporting period and January 31st for the second reporting period.
Written Report – Quarterly Monitoring	Quarterly.	February 14 (4th quarter of the previous year). May 14 (1st Quarter). August 14 (2nd Quarter). November 14 (3rd Quarter).
Written Report – Quarterly Seismicity Record	All seismicity recorded by the seismic array above Moment Magnitude (M) 2.0 shall be recorded, with hypocenters resolved as accurately as possible, within a 10-mile radius of the most currently modeled and approved AoR.	February 14 (4th quarter of the previous year). May 14 (1st Quarter). August 14 (2nd Quarter). November 14 (3rd Quarter).
Written Report – Non-Compliance	Corresponding reporting period.	February 14 (4th quarter of the previous year). May 14 (1st Quarter). August 14 (2nd Quarter). November 14 (3rd Quarter).
Written Report – Plugging and Abandonment	Conclusion of plugging and abandonment activities.	Within sixty (60) days after completion of plugging and abandonment of a well.
Written Report –MIT	**Proposed Wells** – **Part I and Part II** at well completion. **Part II –** Annually per WQR Chapter 24 Section 19(c). **Part I –** after any well workover activities.	Report submitted within thirty (30) days of test completion or with the next quarterly monitoring reports, whichever comes first.
Written Report – Step-Rate Test	One-Time per well; the Step-Rate Test is to be conducted within one (1) year of permit authorization or at the time of well completion and prior to injection followed by a report of the test.	Within thirty (30) days of test completion.
Written Report – Final Construction Report	Based on construction completion of the injection or monitoring well(s). Includes As-Builts for all injection and monitoring well(s).	Within thirty (30) days after completion of any of the permitted injections or monitoring well(s) or with the next quarterly report, whichever is later.
Written Report – Site Closure	Following site closure activities.	Within ninety (90) days after completion of all closure operations.
Written Report	Any evidence that the injected CO_2 stream or associated pressure front may cause an endangerment to a USDW; Any noncompliance with a permit condition or malfunction of the injection system, which may cause fluid migration into or between USDWs; Any triggering of a shut-off system, either down-hole or at the surface; Ay release of CO_2 to the atmosphere or biosphere indicated by the surface air or soil gas monitoring or other monitoring technologies required by WWQR Chapter 24 Section 20(b)(ix); and Any failure to maintain mechanical integrity.	Within twenty-four (24) hours of the identified event.

TASK	FREQUENCY	DUE
Written Report	Any monitoring data or other information indicate that any contaminant, including corrosion or precipitation of minerals, the injected CO_2 stream, displaced formation fluids, or associated pressure front may endanger a USDW or threaten human health, safety, or the environment.	Within five (5) days of discovering the condition.
Written Report	Any noncompliance with a permit condition or a requirement of WWQR Chapter 24 that may cause fluid migration into or between USDWs, and malfunction of the injection system that may cause fluid migration into or between USDWs or any excursion.	Within five (5) days of discovering the condition.
Written Report	As needed after any failure of equipment or operational procedures that resulted in a violation of a permit condition and resulted in remedial well work.	Within thirty (30) days of the completion of any remedial work.
Written Report	Following any aborted or curtailed operation.	Within thirty (30) days of complete termination of the discharge or associated activities.
Written Report	Periodic test of mechanical integrity; Any other test of the injection well conducted by the Permittee if required by the Administrator; and any well workover.	Within thirty (30) days of test completion or with the next quarterly monitoring reports, whichever comes first.

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TABLE 3. FINANCIAL ASSURANCE COMPONENTS AND COST ESTIMATES

Financial Responsibility Element	Cost Estimate	Financial Assurance Required/When Funded	Financial Assurance Instrument
A. Corrective Action on other wells in the area of review that require corrective action under WWQR Chapter 24, Section 13	$256,000	Corrective action operations have been conducted on this well following the procedures outlined in Section 3.B of this permit. A plugback report describing this corrective action is included in Attachment B-1 of this permit. As corrective action has been completed for the well identified, financial assurance is not required to be submitted by the Permittee.	
B. Injection Well Plugging and Abandonment that meets the requirements of WWQR Chapter 24, Section 23.	$611,328	Yes, Prior to well Permit to Construct Issuance	*WWQR Chapter 24, Section 26(c):* (i) Irrevocable Trust Funds with government-backed securities, or (ii) Surety Bonds, or (iii) Irrevocable Letter of Credit, or (iv) Cash, or (v) Federally Insured Certificates of Deposit.
C. Testing and monitoring that meets the requirements of WWQR Chapter 24, Section 20	$6,522,035 (for 25 years)	No	Although not required, the Permittee must demonstrate that testing and monitoring activities are fully funded during the operational period.
D. PISC and Site Closure that meets the requirements of WWQR Chapter 24, Section 24	$10,665,677	Yes, Prior to ATI	*WWQR Chapter 24, Section 26(c):* (i) Irrevocable Trust Funds with government-backed securities, or (ii) Surety Bonds, or (iii) Irrevocable Letter of Credit, or (iv) Cash, or (v) Federally Insured Certificates of Deposit.
E. PISC and Site Closure – Monitor Well Plugging	$534,528	Yes, Prior to Permit to Construct	
F. ERR	$9,601,587	Yes, Prior to ATI	

Notes:

Per WWQR Chapter 24 Section 26(b)(viii), the Permittee shall submit updated financial assurance cost estimates annually. The amounts shown in these Tables are as of June 20, 2025 and are subject to change based on the annual financial assurance updates.

TABLE 4. MAXIMUM INJECTION RATES, ANNULUS PRESSURES, AND LIMITING SURFACE INJECTION PRESSURES

Parameter	Juniper I-1
Maximum Injection Rate (million standard cubic feet per day (mmscf/d))	77.5
Maximum Injection Rate tonnes per day (t/d)	4,110
Maximum Annulus Pressure (pounds per square inch gage (psig))	3,000
Minimum Annulus Pressure (psig)	2,250
Estimated Fracture Gradient, F (pounds per square inch per foot (psi/ft))	0.59
Fracture Pressure, $P_f = F \cdot D_p$	5,384
Depth to Top of Formation, D_p (ft-bgs)	9,124
Temperature at Mid-Point of Perforations (degrees Fahrenheit (°F))	250
Density of Injectate, ρ_j (grams per cubic centimeter (g/cm^3))	0.692 – 0.853
Injectate Fluid Gradient (psi/ft) $$grad_j = \rho_j \cdot 12\frac{in}{ft} \cdot 16.387\frac{cm^3}{in^3}/453.592\ \frac{g}{lb}$$	0.30 – 0.37
Hydrostatic Pressure (psi) $P_h = D_p \cdot grad_j$	2,738 – 3,376
Tubing Length, T_L (ft)	9,058
Tubing Inside Diameter, d (inches (in))	3.958
Tubing Friction Loss Factor, T (psi/1000 ft)	147.8
Average Injection rate, q (mmscf/d)	74
Pressure Loss due to Tubing Friction (psi/ft) $P_d = (4.52q^{1.85})/(\mathbf{c}^{1.85}d^{4.8655})$	0.1478
Total Pressure Loss from Tubing Friction (pounds per square inch(psi)) $P_L = P_d \cdot T_L$	1,339
Calculated $SIP = P_f - P_h + P_L$ (psig)	3,347*
Calculated $LSIP = 0.9 \cdot SIP$ (psig)	3,012*
Actual SIP	**2,150***

Notes:

* Calculated SIP and LSIP values included as verification. Actual SIP based on ANSI 900 rating limit of piping and flanges.

c Hazen-Williams design coefficient for lined stainless-steel piping, 145. This value is considered conservative, and the Permittee may propose an alternate coefficient value for use.

LSIP – Limiting Surface Injection Pressure

SIP – Surface Injection Pressure

TABLE 5. PERMIT ACTION FOR SEISMICITY

<table>
<tr><th colspan="3">Seismic monitoring system, for seismic events > Magnitude (M)2.0 with an epicenter within a 10-mile radius of the injection well</th></tr>
<tr><th>Operating State</th><th>Threshold Condition[1,2]</th><th>Response Action[3]</th></tr>
<tr><td>Green</td><td>Seismic events less than or equal to M2.0</td><td>1. Continue normal operation within permitted levels.</td></tr>
<tr><td>Yellow</td><td>Five (5) or more seismic events within a 30-day period having a magnitude greater than M2.1 but less than or equal to M2.7</td><td>1. Continue normal operation within permitted levels.
2. Within 24 hours of the incident, notify the WQD Administrator of the operating status of the well.</td></tr>
<tr><td>Orange</td><td>Seismic event greater than M2.7 and local observation or felt report</td><td>1. Continue normal operation within permitted levels.
2. Within 24 hours of the incident, notify the WQD Administrator of the operating status of the well.
3. Review seismic and operational data.
4. Report findings to the WQD Administrator and issue corrective actions.</td></tr>
<tr><td>Magenta</td><td>Seismic event greater than M3.4 and local observation or report</td><td>1. Initiate rate reduction plan.
2. Vent CO_2 from surface facilities.
3. Within 24 hours of the incident, notify the WQD Administrator of the operating status of the well.
4. Limit access to wellhead to authorized personnel only.
5. Communicate with facility personnel and local authorities to initiate evacuation plans, as necessary.
6. Monitor well pressure, temperature, and annulus pressure to verify well status and determine the cause and extent of any failure; identify and implement appropriate remedial actions (in consultation with the WQD Administrator).
7. Determine if leaks to ground water or surface water occurred.
8. If USDW contamination is detected:
a. Notify the WQD Administrator within 24 hours of the determination.
9. Review seismic and operational data.
10. Report findings to the WQD Administrator and issue corrective actions.</td></tr>
<tr><td rowspan="2">Red</td><td>Seismic event greater than M4.0, and local observation or report, and local report and confirmation of damage[4]</td><td rowspan="2">1. Initiate shutdown plan.
2. Vent CO_2 from surface facilities.
3. Within 24 hours of the incident, notify the WQD Administrator of the operating status of the well.
4. Limit access to wellhead to authorized personnel only.
5. Communicate with facility personnel and local authorities to initiate evacuation plans, as necessary.
6. Monitor well pressure, temperature, and annulus pressure to verify well status and determine the cause and extent of any failure; identify and implement appropriate remedial actions (in consultation with the WQD Administrator).
7. Determine if leaks to ground water or surface water occurred.
8. If USDW contamination is detected:
a. Notify the WQD Administrator within 24 hours of the determination.
9. Review seismic and operational data.
10. Report findings to the WQD Administrator and issue corrective actions.</td></tr>
<tr><td>Seismic event >M4.0</td></tr>
</table>

[1] Specified magnitudes refer to magnitudes determined by local Tallgrass High Plains seismic array or USGS seismic monitoring stations or reported by the USGS National Earthquake Information Center using the national seismic network.
[2] "Felt report" and "local observation and report" refer to events confirmed by local reports of felt ground motion or reported on the USGS "Did You Feel It?" reporting system.
[3] Reporting findings to the UIC Program Director and issuing corrective action will occur within 21 calendar days (3 weeks) of change in operating state.
[4] The onset of damage is defined as cosmetic damage to structures, such as bricks dislodged from chimneys and parapet walls, broken windows, and fallen objects from walls, shelves, and cabinets.

TABLE 6. INJECTATE ANALYSIS

Schedule	Parameter Analyzed	Composition	Composition	Method
Quarterly	CO_2	ppmv	mol%	Gas Chromatography
	Ethane	ppmv	mol%	Gas Chromatography
	Propane	ppmv	mol%	Gas Chromatography
	n-Butane	ppmv	mol%	Gas Chromatography
	Hydrogen	ppmv	mol%	Gas Chromatography
	Nitrogen	ppmv	mol%	Gas Chromatography
	Methane	ppmv	mol%	Gas Chromatography
	Oxygen	ppmv	mol%	Gas Chromatography
	Water	ppmv	mol%	Gas Chromatography
	Temperature	Degrees Celsius (°C)	-	2250 B

Note:
ppmv – Parts Per Million Per Volume
mol% - Mole percent is the percentage that the moles of a particle component are of the total moles that are in a mixture.

TABLE 7. MONITORING FREQUENCY

Monitoring Parameter	Frequency	Measurement Method
Injection rate (mmscf/d)	Continuous	digital recorder
Daily Injection Volume (tonnes)	Daily	digital totalizer
Total Cumulative Volume (tonnes)	Continuous	digital totalizer
Well head injection pressure (psig)	Continuous	digital recorder
Annular pressure (psig)	Continuous	digital recorder
Injection fluid temperature (°F)	Continuous	digital recorder
Injectate Analysis (**See Table 6**)	Quarterly	Injectate Grab Sample
Groundwater Sample Above Upper Confining Zone **(See Table 8)**	Quarterly	Monitor Well Sample
Annulus Fluid Volume Added (gallons)	When added	Measurement
Corrosion Monitoring of Well Materials	Quarterly	Method in Testing and Monitoring Plan

TABLE 8. MONITOR WELL ANALYSIS

Schedule	Parameter Analyzed	Units	USEPA Method	Standard Method
Quarterly	CO_2	ppmv	3C	GC, modified ASTM 1945D
	pH	s.u.	150.1 or 150.2	4500-H+B
	Conductivity	µmhos/cm	120.1	2510 B
	Alkalinity	mg/L	310.2	2320 B
	TDS	mg/L	160.1	2540 C

Notes:
µmhos/cm - Micromhos per centimeter
s.u. – standard unit

TABLE 9. RECORD RETENTION SCHEDULE

RECORD	RETENTION PERIOD
Calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation, copies of all reports required by this permit, and records of all data used to complete the application for the permit.	For a period of at least three (3) years from the date of the sample, measurement, report, or application. This period may be extended by request of the Administrator at any time;
The nature and composition of all injected fluids.	Until ten (10) years after the completion of any plugging and abandonment procedures under WWQR Chapter 24 Section 23.
All modeling inputs and data used to support AoR re-evaluations under WWQR Chapter 24 Section 13.	Retained for ten (10) years.
Well plugging report required by WWQR Chapter 24 Section 23, the site closure report required by Section 24, and any PISC data (including data and information used to establish the PISC time frame).	Retained for ten (10) years following site closure.
All data used to complete permit applications.	Retained for the life of the geologic sequestration project and for ten (10) years following site closure.
All other monitoring records required by a permit.	Retained for a period of ten (10) years following site closure.
The Permittee shall maintain in its records a current map of the access route(s) to the facility and contact information for the owners or agents of all properties that must be crossed to access the facility. The Permittee shall ensure that the documentation, map, and contact information are current at all times. The Permittee shall provide the documentation, map, and contact information to WDEQ personnel upon request.	On closure of the facility, the Permittee shall maintain such records for a period of three (3) years.

ATTACHMENTS

These attachments include but are not limited to, permit conditions and plans concerning operating procedures, monitoring, and reporting, in compliance with the WEQA, W.S. §§ 35-11-101 through 1104, specifically 301(a)(i) through 301 (a)(iv), Laws 1973, Ch. 250, Section 1), (W.S. § 31-11-313, Laws 2008, Ch. 30, Section 1), and WWQR, Chapters 24 and 29. The Permittee must comply with these conditions and adhere to these plans as they are approved by the Administrator by their incorporation into this permit.

ATTACHMENT A: UIC PERMIT NO. 2022-235v1.0

Attachment A is the issued September 11, 2024 Permit to Construct for the Juniper I-1 (2022-235v1.0) which contains proposed plans concerning operating procedures, monitoring, and reporting, in compliance with the WEQA, W.S. §§ 35-11-101 through 1104, specifically 301(a)(i) through 301 (a)(iv), Laws 1973, Ch. 250, Section 1), (W.S. § 31-11-313, Laws 2008, Ch. 30, Section 1), and WWQR, Chapters 24 and 29. The Permittee must comply with the conditions and adhere to the proposed plans as they are approved by the Administrator by their incorporation into the permit. The proposed plans become final upon issuance of an ATI and are incorporated into the permit as permit conditions.

The issued permit is not included as an attachment due to size of document, please see issued permit on the WDEQ website at https://deq.wyoming.gov/water-quality/groundwater/uic/class-vi/ located under:

Applicant: Tallgrass
Received: March 29, 2023
Status: Issued – September 11, 2024
File Name: 2024-0911_UIC_2022-235_WYS-021-00149_Tallgrass-High-Plains-Carbon-Storage_Juniper_I-1_Final-Permit-and-Attachments_Public

ATTACHMENT B: FINAL PLANS

These attachments include but are not limited to, permit conditions and plans concerning operating procedures, monitoring, and reporting, in compliance with the WEQA, W.S. §§ 35-11-101 through 1104, specifically 301(a)(i) through 301 (a)(iv), Laws 1973, Ch. 250, Section 1), (W.S. § 31-11-313, Laws 2008, Ch. 30, Section 1), and WWQR, Chapters 24 and 29. The Permittee must comply with these conditions and adhere to these plans as they are considered the final approved plans by the Administrator by their incorporation into this permit.

ATTACHMENT B-1: AREA OF REVIEW AND CORRECTIVE ACTION PLAN

Response to Specific Comments

Specific Comment 1

SC-1 WDEQ Comment:
The Geologic Report and Authorization to Inject Application state that "The Area of Review (AoR) provided in the Juniper I-1 permit submittal was confirmed based upon the results received from the characterization program." The Authorization to Inject and associated reports do not include an AoR model that has been run with updated data collected from the site characterization. While the collected data may fall within the original ranges presented in the permit application, the precise collected data shall be used to generate and provide WDEQ with an updated AoR model, all related figures, and affected information.

SC-1 Response:
As a sensitivity case, the Juniper I-1 model was run with site-specific data to validate that the permitted Area of Review (AoR) is within range of expected results once injection begins. There is no update to model methodology discussed in Appendix C of the approved permit application, in which the AoR is defined the by the CO_2 plume, not the pressure front, discussed further in SC-2 Response of this report. Figure 1 depicts the results of the model using site-specific data and demonstrates that the AoR obtained using site-specific data (green outline) is smaller relative to the permitted AoR using initial model assumptions (blue outline). Furthermore, the stabilized plume from the sensitivity case remains within the landowner notification boundary as shown in Figure 1. The sensitivity run incorporates the modeling parameters as described in the Juniper I-1 Authorization to Inject Geologic Report (Table 1). The sensitivity run rate assumptions are as permitted—1.5 million metric tons per year (MMT/yr) over 5 years, for a total volume of 7 MMT.

High Plains is not requesting a change to the AoR as the model is within the permitted AoR boundaries and landowner notification boundaries.

Table 1. Modeling Parameters for the Juniper Permit Model and the Updated Sensitivity Model that Incorporates Site-Specific Data

Model Parameter	Unit of Measurement	Juniper Permit Model (Blue Boundary, Figure 1)	Sensitivity Model (Green Boundary, Figure 1)
Lyons Temperature	°F	200	245
Lyons Pressure Gradient	psi/ft	0.3	0.344
Lyons Salinity	kppm	150	230
Frac Gradient	psi/ft	0.47	0.59
Lyons Porosity	%	18.5	16

Parameters that changed between the two iterations are listed in the table.

Specific Comment 2

SC-2 WDEQ Comment:
The High Plains Response to Comment SC-31 in the permit to construct application dated June 5, 2023 states that High Plains will update the model after drilling Juniper I-1 with site-specific data. The model referenced in the permit to construct response to comments is the initial model and has not been updated with site specific data. Please update the model and associated map showing maximum vertical and lateral extent of the plume and/or pressure front.

SC-2 Response:
As discussed in SC-1, the sensitivity case using site-specific data results in a smaller plume boundary (green outline Figure 1), which falls within the AoR as submitted with the Juniper I-1 permit. High Plains has demonstrated that the Juniper M-1 subsurface conditions are representative of the Juniper I-1 location, as explained in the Juniper I-1 Authorization to Inject Geological Report. The two wells are approximately 250 feet apart and exhibit similar downhole properties. Because the properties between the two wells are so similar, updating the model simulation using Juniper I-1 data results in an identical model.

There is no update to the AoR methodology in which the CO_2 plume defines the AoR, discussed in Section 5 of the Additional Juniper I-1 Permit Updates and Proposed Changes portion of the Response to Comments Issued November 6, 2023, of the approved permit. Site-specific data validated continued use of this method, discussed in Section 1 of the Authorization to Inject Geological Report. The simulation sensitivity with site-specific data is discussed in SC-1 Response of this report. The maximum vertical and lateral extent of the plume using site-specific data is depicted in Figure 2.

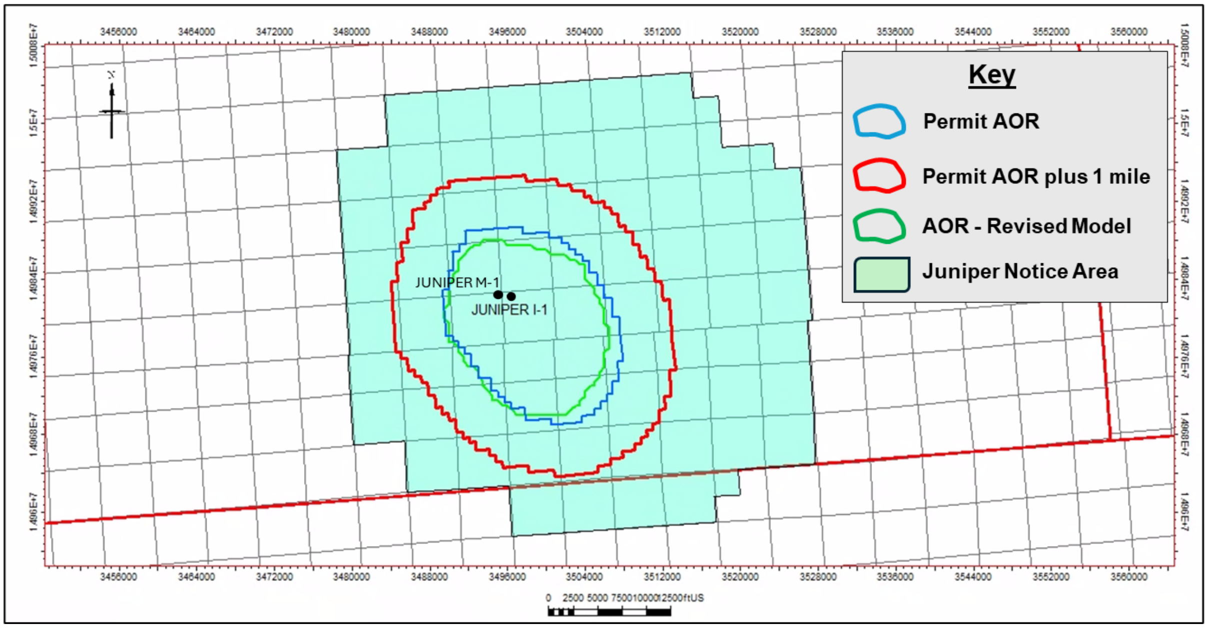

Figure 1. **Map showing the updated Juniper I-1 AoR (green outline) compared to the original permit model AoR (blue outline).**

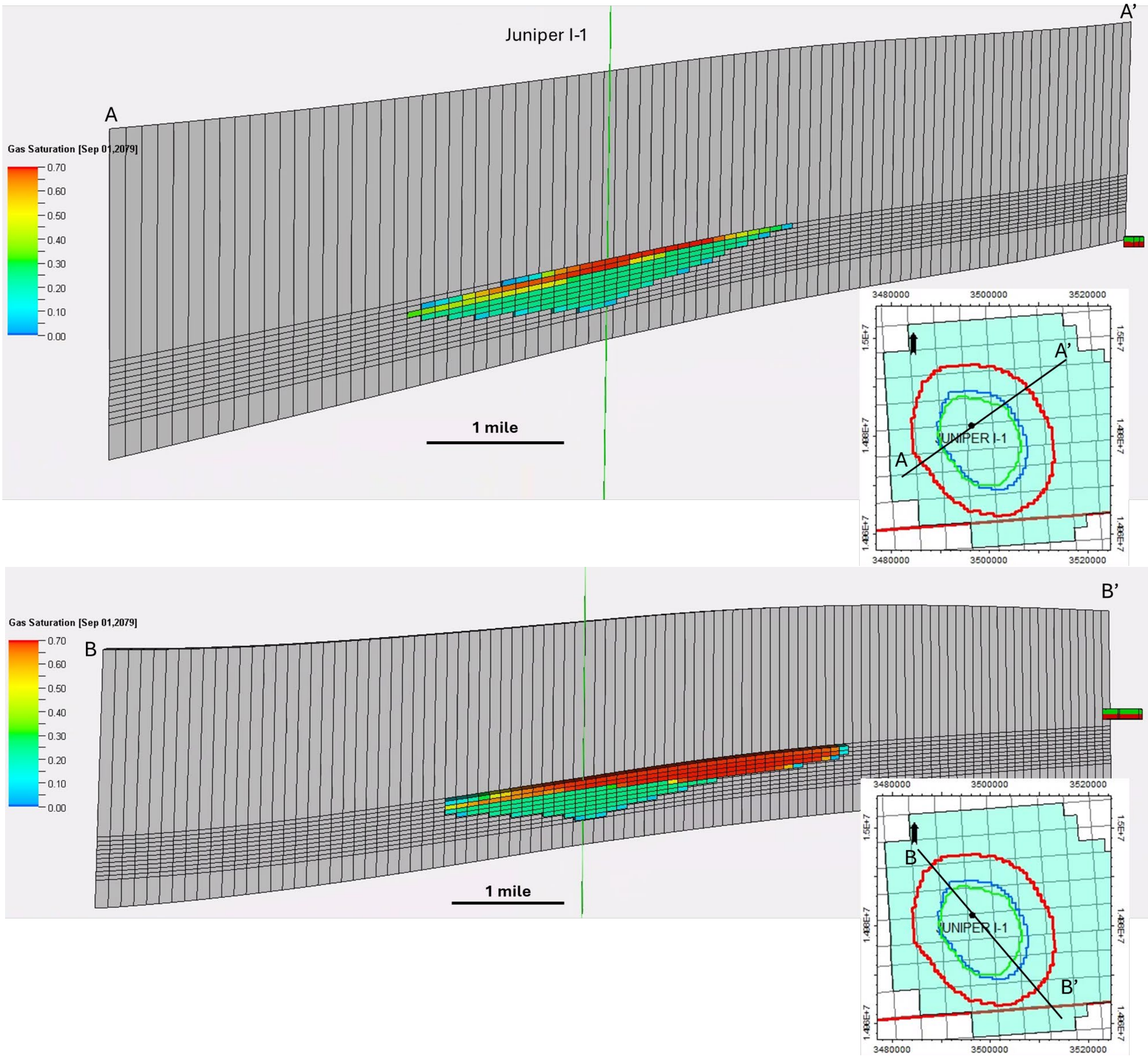

Figure 2. Cross sections depicting the vertical extent of the Juniper I-1 plume across the minimum lateral extent (upper image) and the maximum lateral extent (lower image).

06 May 2025

VIA E-MAIL AND WDEQ PORTAL

Wyoming Department of Environmental Quality
c/o Tyler Harris
200 West 17th Street
Cheyenne, Wyoming 82002
Tyler.Harris@wyo.gov;
cc: Lily.Barkau@wyo.gov ; hunter.hubbard@wyo.gov

Submitted electronically: WDEQ Water Quality Division Document Uploads (smartsheet.com)
Permit: 2022-235

Dear Mr. Harris:

Tallgrass High Plains Carbon Storage, LLC. is submitting the as-performed corrective action procedure. The attachment to this letter is the following:

Attachment 1: As-Plugged Juniper M-1 Plug-Back Procedure

High Plains will be providing additional correspondence detailing perforations, fluid sampler installation, and gauge installation to be reviewed pending approval of the Juniper M-1 plugging.

Kind Regards,

Katy Larson

Katy Larson
Geoscience Compliance Manager
Tallgrass Energy Partners, LP
cc: matt.hess@tallgrass.com; jessica.gregg@tallgrass.com; pete.feutz@tallgrass.com; michael.hilmes@tallgrass.com

TALLGRASS
Leading Energy Solutions

ACRONYMS AND ABBREVIATIONS

Note: All terms are written as used in the text.

API	American Petroleum Institute
BBLS	barrels
BHA	bottom hole assembly
BOP	blowout preventer
CIBP	cast iron bridge plug
CICR	cast iron cement retainer
FO	fiber optic
FT	feet
KB	kelly bushing
LD	lay down
MIRU	move in and rig up
MIT	mechanical integrity
ND	nipple down
NU	nipple up
P&T	pressure and temperature
P&ID	piping and instrumentation diagram
POOH	pull out of hole
PSI	pounds per square inch
PU	pull up
RBP	removable bridge plug
RD	rig down
RIH	run in hole

RU	rig up
SB	SIT-BO log
TBG	tubing
TD	total depth
TEC	tubing encased conductor
TIH	trip in hole
TOOH	trip out of hole
WH	wellhead
WL	wireline
WS	work string

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The following tables contain the Juniper M-1 wellbore data that corresponds to the objectives and procedure detailed in Section 1. The as-plugged wellbore diagram is illustrated in Figure 1.

Well Information (referenced from KB in feet)			
Well Name	**Injection Zone Formation Name(s)**	**Well Total Depth**	**Injection Zone Depths**
Juniper M-1	Lyons Formation	9,850 ft	9,127 – 9,194 ft*

*Depths are approximate

Casing Information (referenced below ground surface in feet)					
Casing Type	**Casing o.d., in**	**Weight, lb/ft**	**Grade**	**Connection**	**Bottom Depth, ft**
Surface	9-5/8	40	J55	BTC	1551
Intermediate	N/A	N/A	N/A	N/A	N/A
Production	5-1/2	20	L-80HC & 25CR-125	BTC	9824
Tubing	N/A	N/A	N/A	N/A	N/A

Geologic Tops	
Formation	**Formation Top, ft**
Fox Hills Aquifer	982
Hygiene Aquifer	1224
Sundance	8569
Lyons	9127
Amazon	9480

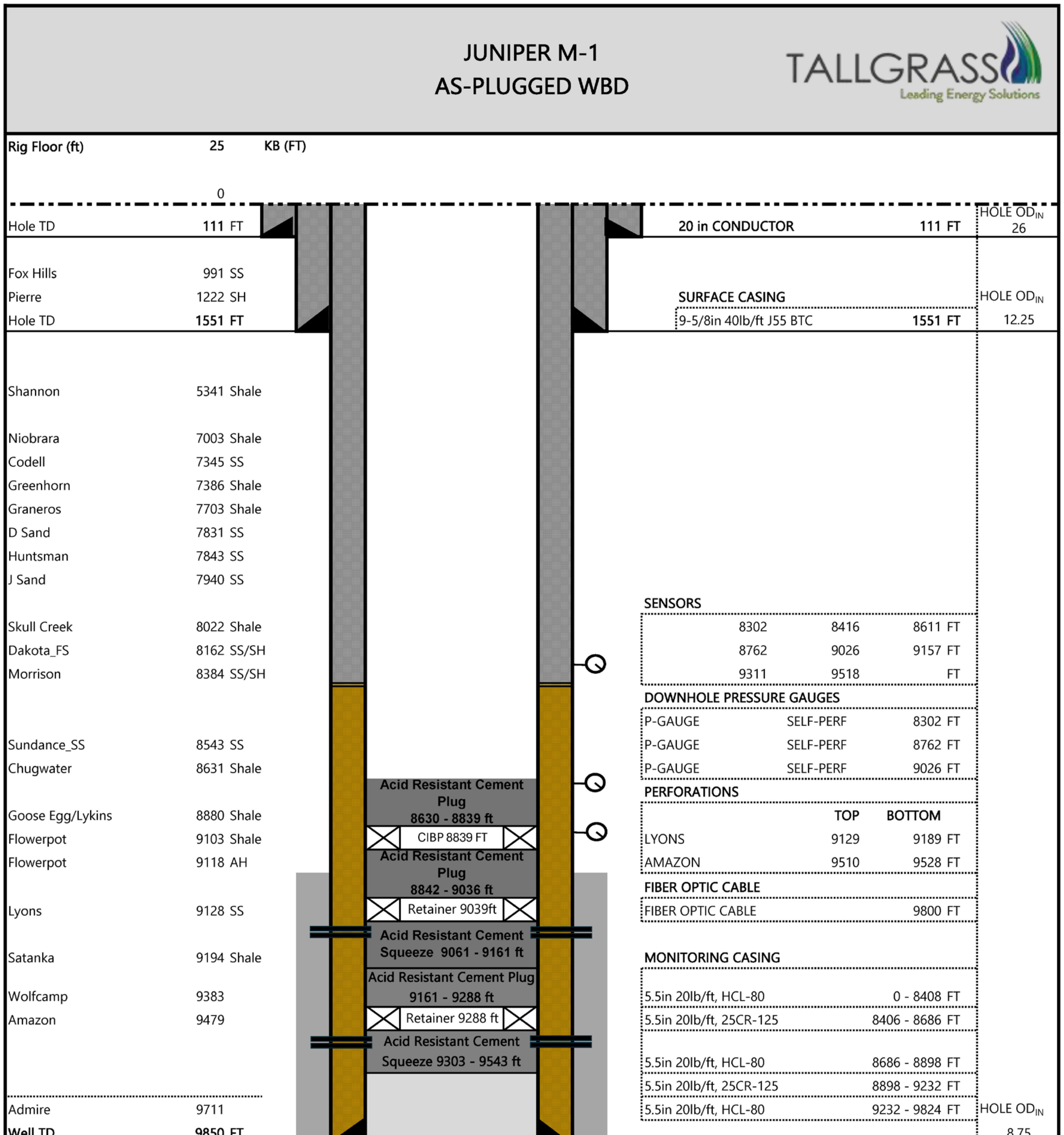
Plugged Back Perforations	
Formation	**Depths, ft**
Lyons	9129 - 9189
Amazon	9510 - 9528

Attachment 1: Juniper M-1 Plug-Back (First Workover – Completed from February 27 to April 3, 2025)

The Juniper M-1 plug back procedure from the first workover is as follows. The corresponding wellbore diagram is illustrated in Figure 1. The red text highlights changes from the proposed procedure. The changes reflect actual depths and added detail and do not materially modify the proposed procedure.

1.1 Juniper M-1 Plug-Back Procedure

1) Prior to MIRU, ensure deadmen are certified and pull tested. Refer to wellsite P&ID to locate deadmen. Inspect pad for any damages. Record and report monitor casing and surface casing pressures.
2) Mobilize to location. Spot in Rig, pipe wrangler, work tanks, rig pump, and work string.
3) RU rig, hook up to deadmen, RU 2" hardline between tanks, rig and pump: 100 ft apart.
4) Flow check well, ensure well static for 15 minutes. ND WH, test 7-1/16" BOP per API standards
5) NU 7-1/6" BOP. Tally 2-7/8" PH6 work string.
6) RU WL. RIH and retrieve KLX RBP at 9050'. RD WL.
7) MU 4-3/4" tricone bit, (6) 3-1/2" drill collars. TIH BHA and 2-7/8" L80 work string and tag CIBP at 9385 ft.
8) Mill out CIBP at 9400 ft. Tag TD at 9528 ft. TOOH and SB tbg, and LD BHA.
9) RIH w/wireline & gyro to Lyons or Amazon formations to locate fiber optics & TEC line orientation clamps. This is required for perforating the Sundance for installation of a sampling system at a later date, after the Amazon and Lyons P&A.
10) Rig up wireline. Ran gauge ring junk basket past 9460 ft to ensure perfs are open. Tagged fill at 9492' ft Rig Down Wireline.
11) Clean out wellbore to 9543 ft.
12) Rig up cementers. Mix and spot 14 sacks acid resistant cement at 9543 ft. Pull up hole above top of cement and squeeze cement into perforations. Cement interval from 9543 ft to 9303 ft.
13) Rig up wireline. Set 5-1/2" CICR at 9288 ft.
14) Rig up cementers. Mix and spot 18 sacks acid resistant cement from 9288 ft to 9161 ft. Shut down for day.
15) Tag top of cement at 9161 ft. Mix and pump 7 sacks acid resistant cement at 9161 ft. Pull up hole above top of cement and squeeze cement into perforations. Cement interval from 9161' to 9061 ft.
16) RU WL. RIH 5-1/2" CICR and set at 9039 ft. Pull out of hole.
17) TIH and spot acid resistant cement from 9036 ft - 8842 ft into perfs.
18) Pull out of hole above top of cement and wash clean. Pull out of hole.
19) RU WL. RIH 5-1/2" CIBP and set at 8839 ft. Pull out of hole.
20) Pressure test CIBP to 2,500 psi for 30 minutes. Record MIT data
21) TIH WS open ended and tag CIBP at 8839 ft.
22) Mix and pump acid resistant cement cap plug from 8839 ft to 8630 ft. Circulate clean at 8630 ft. Trip out of hole.
23) RD floor, ND 7-1/16" BOP, NU WH with gauges.
24) RD rig and ancillary equipment
25) Move out/demobilize



CASING SECTION	DRILL HOLE INTERVAL$_{FT}$	DRILL HOLE LENGTH$_{FT}$	DRILL HOLE ID$_{IN}$	OD$_{IN}$	ID$_{IN}$	WT$_{LB/FT}$	WALL TH.$_{IN}$	DRIFT ID$_{IN}$	GRADE	CONNECTION	CONNECTION OD$_{IN}$
CONDUCTOR	0 - 111	0	26	20	19.124	94.0	0.438				
SURFACE	0 - 1551	1551	12.25	9.625	8.835	40	0.395	8.679	J55	BTC	10.625
MONITOR	1551 - 9850	8299	8.75	5.5	4.778	20	0.361	4.653	HCL-80	LTC	6.100
	INJECTION SECTION (CR CSC SPECS)			5.5	4.778	20	0.361	4.653	25CR-125	VamTop	6.071

Figure 1: Juniper M-1 As-Plugged Wellbore Diagram. Figure is not drawn to scale.

3 AREA OF REVIEW

3.1 Area of Review Delineation

3.1.1 Written Description

This section satisfies WYDEQ Chapter 24 **§13**, which requires an AOR delineation for a Class VI carbon sequestration well application. Any location, as determined by the model, with a gas saturation value greater than 3% is determined to be occupied by the pore space plume. Injecting large amounts of supercritical fluid into a previously stable reservoir may result in an increase in reservoir pressure. This pressure increase may be large enough to push the formation matrix fluids up into a USDW, also known as the critical pressure. The plume boundary was determined from computational modeling, and the critical pressure was calculated using a set of equations and parameters suited for southern Wyoming geology. The pore occupancy plume is discussed in further detail in *Section 3.4.1*, and the pressure front in *Section 3.4.4.* The results of the AOR simulation show that the proposed Juniper I-1 well location is appropriate for carbon storage with minimal surrounding geologic or man-made conduits for CO_2 leakage.

The CO_2 plume growth after injection is depicted in Figure 46. The modeled AOR drifts to the south-southeast due to the influence of the offset SWDs and structural dip of the formation. Over time the plume will continue growing in this direction until it stabilizes, as the figure shows. The maximum extent of the plume used to delineate the AOR is the combination of the extents at the end of injection for Juniper I-1, the end of all potential offset injection wells, and the extent of the CO_2 after the stabilization of the plume.

Experts from across multiple disciplines conducted studies on reservoir characterization and, based on all available data acquired, these studies indicate that the Lyons formation has sufficient storage capabilities for the planned injection for Juniper I-1. The confining zones, the Goose Egg and Chugwater formations, are quality seals as discussed in *Section 2.4.2*.

3.1.2 Supporting Maps

Included in this subsection are maps and figures that support the delineation of the AOR. Other information that assisted in this investigation included EWS Hub location, pipelines, proposed injection and monitoring wells, CO_2 occupancy and pressure plume boundaries, faults, land disturbances, and all existing wells within the AOR and an adjacent 1-mile buffer.

As discussed in *Appendix C*, the extent of the pressure front at the critical pressure threshold is smaller than the CO_2 plume extent, therefore the AOR is determined by the CO_2 plume extent.

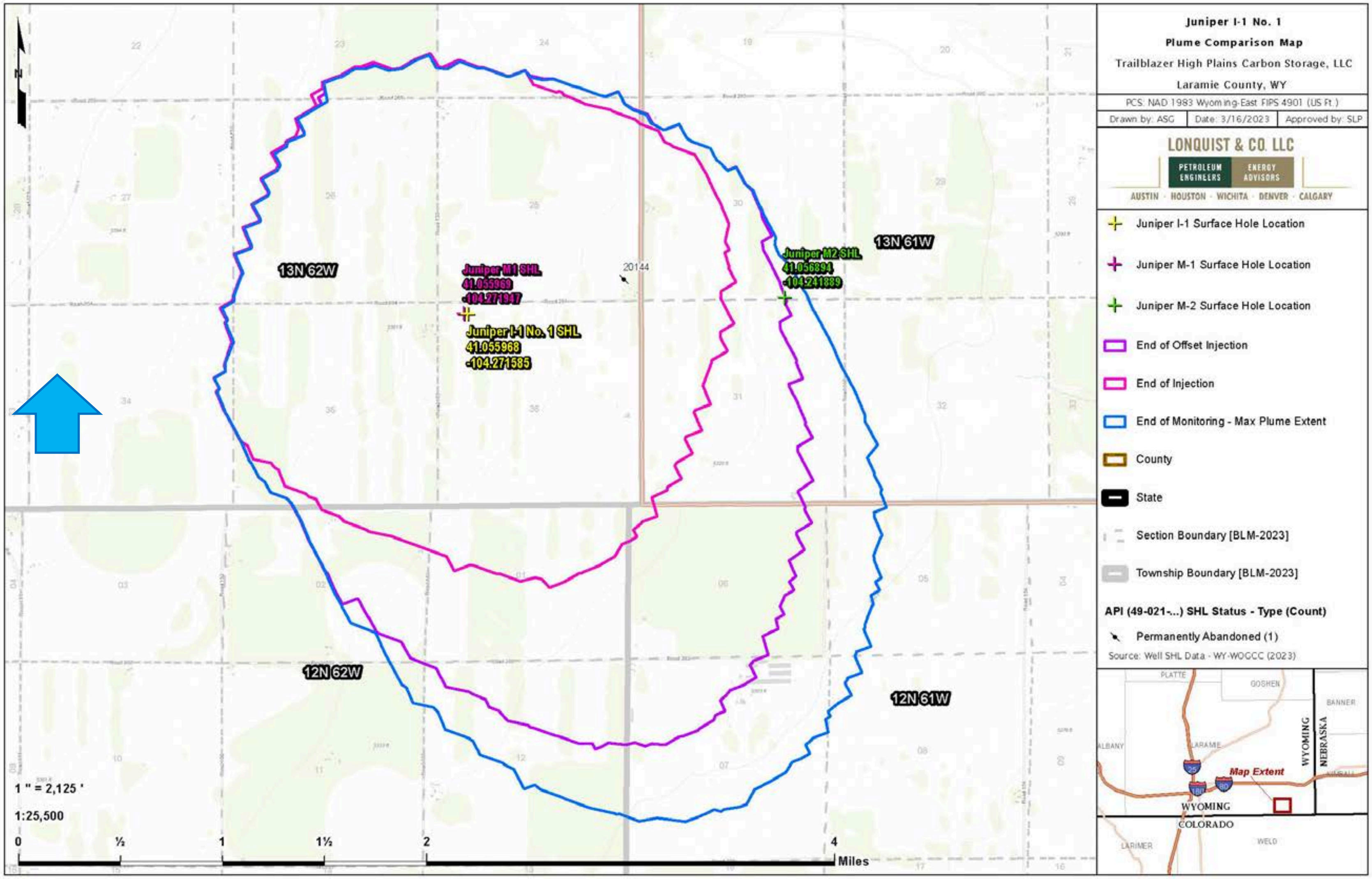


Figure 46 – CO_2 Plume Extent at End of Injection, Offset Injection, and Monitoring

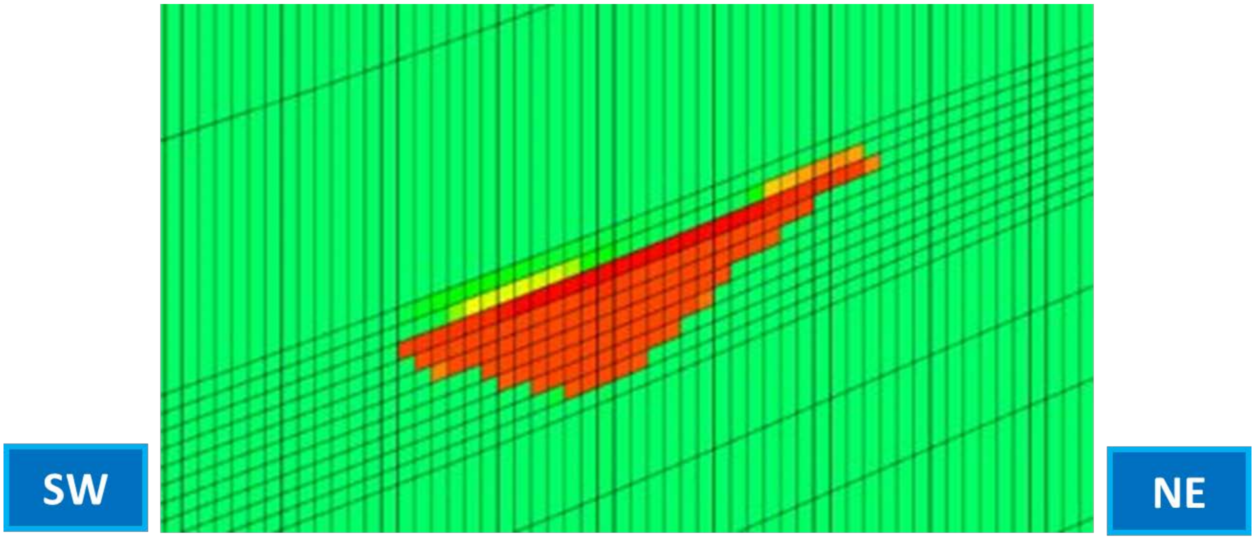


Figure 47 – SW-NE Cross Section of Gas Saturation at End of Monitoring

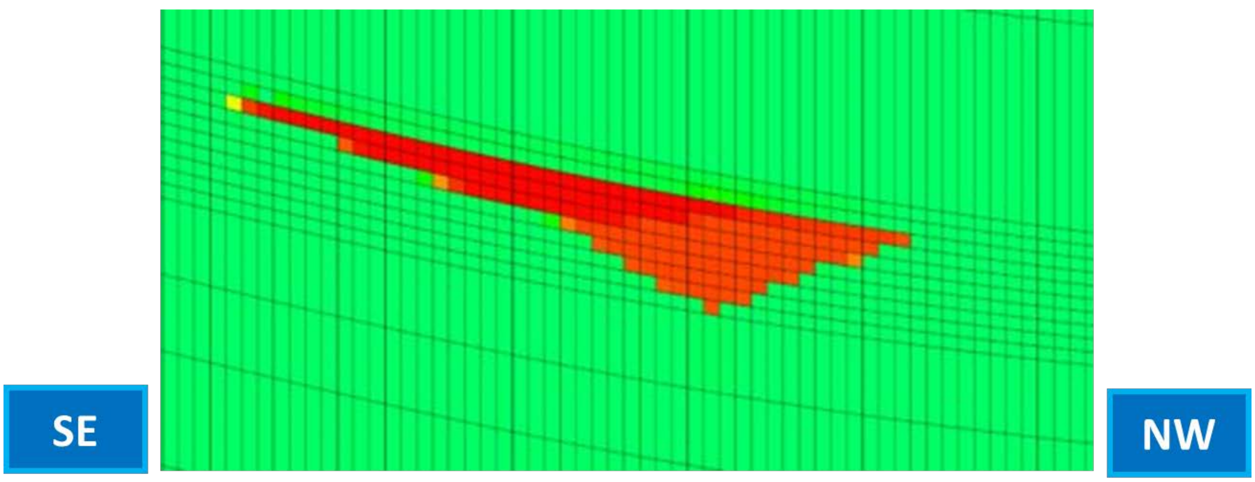


Figure 48 – SE-NW Cross Section of Gas Saturation at End of Monitoring

3.1.3 Existing Environmental Permits

Table 31 identifies environmental permits that High Plains will obtain during the development of the EWS Hub.

Table 31 – Existing Environmental Permits

Permit Type			
Resource Conservation and Recovery Act (RCRA) – Hazardous Waste Management	Permit No.:	N/A	☐
UIC – Underground Injection of Fluids	Permit No.: TBD	N/A	☐
National Pollutant Discharge Elimination System (NPDES) – Discharge of Surface Water	Permit No.:	N/A	☐
Prevention of Significant Deterioration – Air Emissions from Proposed Sources	Permit No.: TBD	N/A	☐
Nonattainment Program Under the Clean Air Act	Permit No.: TBD	N/A	☐
National Emissions Standards for Hazardous Air Pollutants Pre-Construction Approval Under the Clean Air Act	Permit No.: TBD	N/A	☐
Dredge and Fill Permitting Program Under Section 404 of the Clean Water Act	Permit No.:	N/A	☐
Other (specify)	Permit No.:	N/A	☐

2.1.1. Other Permits

Table 32 identifies additional permits that High Plains will obtain during the development of the EWS Hub.

Table 32 – Other Permits

	Permit No.:	N/A	☐
	Permit No.:	N/A	☐
	Permit No.:	N/A	☐
	Permit No.:	N/A	☐
	Permit No.:	N/A	☐

3.1.4 Surface and Subsurface Features in AOR

Table 33 identifies the surface and subsurface features reviewed in the AOR.

Table 33 – Investigated and Identified Surface and Subsurface Features

Surface and Subsurface Features	Investigated and Identified	Investigated But Not Found in AOR
Producing (Active Wells)		X
Abandoned Wells		X
Plugged Wells or Dry Holes	1 Identified	
Deep Stratigraphic Boreholes		X
Subsurface Cleanup Sites		X
Surface Bodies of Water		X
Other Pertinent Surface Features (including structures intended for human occupancy)		X
Springs		X
Water Wells	86	
Mines (surface and subsurface)		X
Quarries		X
Subsurface Structures (e.g., coal mines)		X
Location of Proposed Wells	2 Monitoring Wells	
Location of Proposed Cathodic Protection Boreholes		X
Any Existing Aboveground Facilities		X
Roads	X	
State Boundary Lines	X	
Tribal Boundary Lines		X
Known or Suspected Faults		X
Other Pertinent Surface Features		X
All Water Quality Management Plan Areas, Wellhead Protection Areas, and Source Water Protection Areas.		X

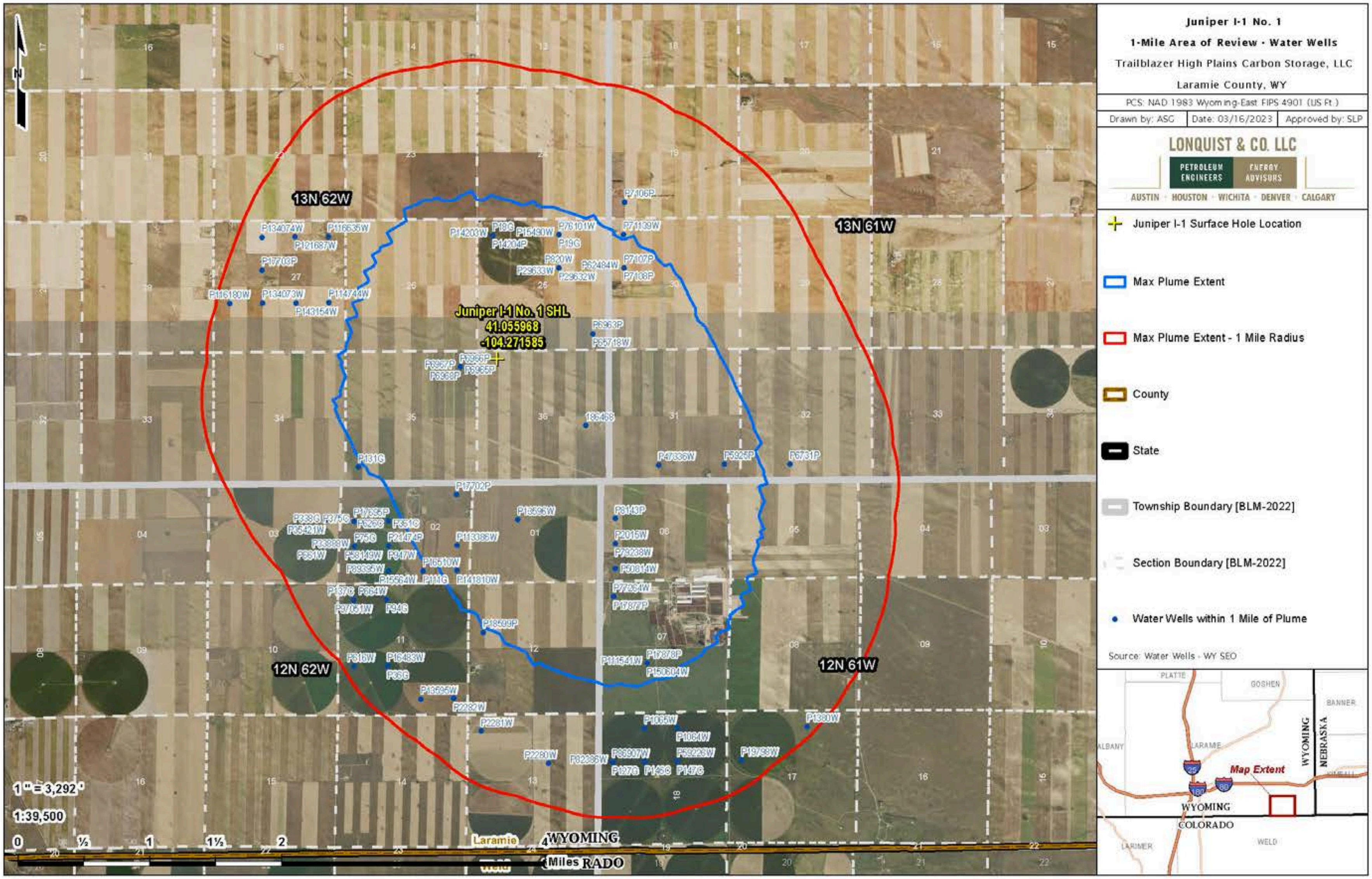


Figure 49 – Map of Water Wells in the Area of Review

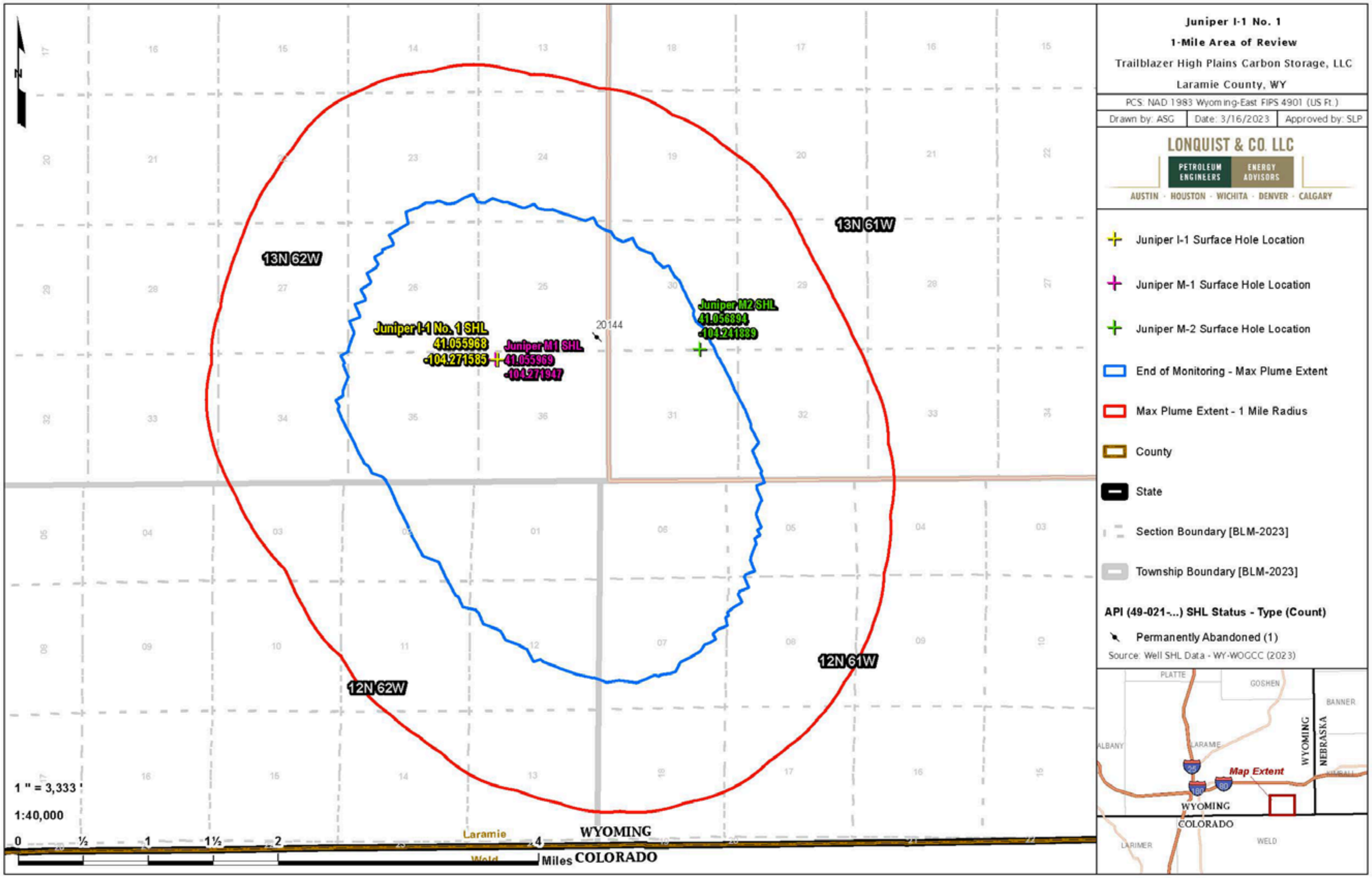


Figure 50 – Map of Oil and Gas Wells in the Area of Review

An investigation was conducted to evaluate all wellbores drilled within the determined AOR. In total, 87 wellbores were found: one was a plugged-and-abandoned oil-and-gas well; the other 86 were water wells (all of which are listed in *Appendix C*). None of the wells penetrate the injection zone or confining layer.

Table 34 includes the one oil-and-gas well identified within the AOR. Wells reviewed include injection wells, producing wells, abandoned wells, plugged wells, dry holes, and deep stratigraphic boreholes. These wells do not penetrate the injection zone or confining layer.

Table 34 – Area of Review Well Information

Well Name	Location	Operator	Well Status	Depth
Champlin 325 Amoco A1	41.058303, -104.256846	BP America Prod. Co.	Plugged and Abandoned	7,990 ft

3.2 Protection of USDWs

3.2.1 Introduction of USDW Protection

Evaluation of publicly available data and regional studies of southeastern Wyoming resulted in the identification of the Fox Hills formation as the lowermost USDW for the EWS Hub. The Chugwater formation and underlying Goose Egg formation act as the primary overlying confining zone for the Lyons formation. Shales and tight carbonates present between the upper confining zone and Fox Hills formation were identified as aquitards by the WSGS and will provide additional protection of all designated USDWs. Figure 3 (*Section 2.1*) in the site characterization depicts primary and secondary zones of confinement relative to the stratigraphic column, while Table 7 (*Section 2.4.1*) briefly describes additional confining zones with approximate formation tops and thicknesses at the Juniper M-1 test well location.

3.2.2 Geology of USDW Formations

The DJ Basin contains 14 potential aquifers identified in the 2013 WWDC Platte River Basin Water Plan Update (Taucher et al. 2013). General lithologic descriptions of potential hydrogeologic units are provided in *Section 2.2.3*, along with supporting information to determine proper USDW designations. Following the review of potential major aquifers, minor aquifers, marginal aquifers, and aquitards identified in the WWDC report, it was determined that the following hydrogeologic units should be designated as USDWs in the region:

- Quaternary alluvial and terrace deposits
- "High Plains Regional Aquifer System" or "Tertiary Aquifer System"
    - Ogallala, Arikaree, and White River formations
- Lance and Fox Hills formations

A 2021 USGS groundwater study of southeastern Laramie County collected groundwater quality samples from three monitoring wells (BR-1, LN-1, and FH-1) and two production wells (FH-2 and FH-3) (Bartos et al. 2021). The resulting TDS from the analysis conducted on the samples is shown in Table 35, along with producing aquifer, well name, and sample collection date. The values fall below 500 milligrams per liter (mg/L), classifying the groundwater samples as fresh by the EPA and Wyoming Class I domestic water standards (Bartos et al. 2021). Figure 33 (*Section 2.4.1.7*) identifies USGS monitoring wells relative to the proposed Juniper I-1 injector modeled plume, and illustrates that the BR-1, LN-1, and FH-1 wells are located approximately 1 mile east of Juniper I-1. Interpreted USDW designations of potential hydrogeologic units from the review are summarized in the stratigraphic column in Figure 51. Additional discussions and data regarding designated USDW formations can be found in *Section 2.2.3*.

Table 35 – TDS Values from USGS Monitoring Wells in Southeastern Wyoming (Bartos et al. 2021)

Aquifer	**White River**	**Lance**	**Fox Hills**	**Fox Hills**	**Fox Hills**
Well	BR-1	LN-1	FH-1	FH-2	FH-3
Sample Date	11/13/2013	12/17/2013	11/14/2013	12/3/2014	09/23/2015
TDS (mg/L)	373	286	384	532	411

Era	Period	Epoch	Formation	Designation	Approx. Depth	Comment
Cenozoic	Quaternary	Holocene & Pleistocene	Alluvium and Terrace Deposits	USDW	0'	may be present
	Tertiary	Pliocene			-	absent due to erosion or nondeposition
		Miocene	Ogallala	USDW	100'	regional aquifer
			Arikaree	USDW	160'	regional aquifer
		Oligocene	White River	USDW	210'	regional aquifer
		Eocene			-	absent due to erosion or nondeposition
		Paleocene			-	absent due to erosion or nondeposition
Mesozoic	Cretaceous	Upper Cretaceous	Lance	USDW	550'	regional aquifer
			Fox Hills	USDW	912'	regional aquifer
			Pierre	Aquitard	1,202'	confining unit
			Niobrara	Aquitard	6,980'	confining unit
			Codell	Exempt	7,328'	oil and gas resevoir
			Carlile	Aquitard	not determined	confining unit
			Greenhorn	Aquitard	7,381'	confining unit
			Graneros/Belle Fourche	Aquitard	7,690'	confining unit
			Mowry/Huntsman	Aquitard	7,845'	confining unit
		Lower Cretaceous	Muddy/J Sand	Exempt	7,928'	oil and gas resevoir
			Skull Creek/Thermopolis	Aquitard	8,002'	confining unit
			Inyan Kara/Dakota/Lakota/Cloverly	Exempt	8,153'	tight sand
	Jurassic	Upper Jurassic	Morrison		8,352'	minor aquifer not present, only confining unit
		Middle Jurassic	Sundance		8,518'	may not be present, too deep to be economic
	Triassic	Upper Triassic	Chugwater	Aquitard	8,610'	confining unit
		Lower Triassic	Goose Egg	Aquitard	8,844'	confining unit
Paleozoic	Permian	Upper Permian	Lyons		9,119'	saline aquifer, too deep to be economic
		Lower Permian	Satanka	Aquitard	9,187'	confining unit
	Pennsylvanian	Pennsylvanian	Casper/Hartville		9,352'	not present, too deep to be economic
	Mississippian	Lower Mississippian	Guernsey		not determined	not present, too deep to be economic
	Devonian	Upper Devonian	Fremont Canyon		not determined	not present, too deep to be economic
Precambrian			undifferentiated igneous/metamorphic rocks	Aquitard	not determined	basal confining unit

Figure 51 – Designation of Potential Hydrogeologic Units; Laramie County, Wyoming, DJ Basin. The shading indicates USDW in blue, exempt intervals in red, aquitards in dark gray, and uneconomic intervals in tan.

3.2.3 Hydrology of USDW Formations

Freshwater aquifers in the EWS Hub Juniper I-1 AOR are restricted to shallow formations that range from Quaternary to upper Cretaceous in age. These include unconsolidated Quaternary surface deposits and aquifers of the Ogallala, Arikaree, White River, Lance, and Fox Hills formations. The schematic cross section depicted in Figure 52 illustrates the stratigraphic relationship of the freshwater-bearing formations near the EWS Hub. Figures 53 and 54 indicate that the Juniper I-1 injection well and Juniper M-1 monitoring wells are likely to encounter Quaternary deposits at the surface.

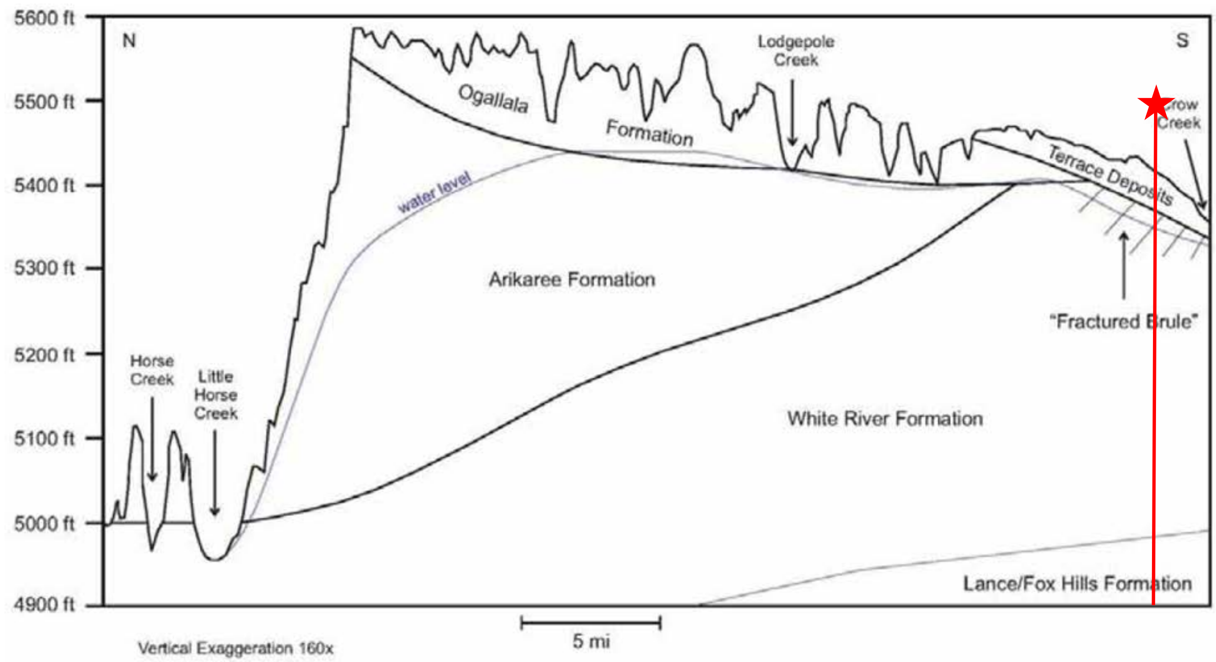


Figure 52 – North/South Schematic Cross Section Located in Laramie County, Wyoming (Brendecke and Hinckley 2014). The red star and line represent the approximate location of Juniper I-1.

Figure 53 displays an estimated saturated thickness map of the combined Quaternary, Ogalla, Arikaree, and White River aquifers—commonly referred to as the High Plains aquifer. The map suggests that the saturated thickness of the High Plains aquifer ranges from unsaturated to almost 900 ft thick in Laramie County and will have an approximate thickness of 320 ft thick near the EWS Hub location. Figure 54 contains an estimated saturated thickness map of the combined Quaternary, Ogalla, and Arikaree aquifers (same as Figure 53, only without the underlying White River formation) in Laramie County. The saturated thickness in Figure 54 varies from 500 ft thick to areas where Ogallala and/or Arikaree formations are absent from the geologic section. The map indicates that these formations are thin or potentially unsaturated within the extents of the Juniper I-1 modeled plume, and most of the saturated thickness within the High Plains aquifer of southeastern Laramie County is comprised of the White River aquifer.

Figure 56 depicts a mapped potentiometric surface of the High Plains aquifer system in southeastern Wyoming. The potentiometric surface strikes north-south and generally dips to the west around the EWS Hub. The groundwater flow direction is estimated to move towards the east within the High Plains aquifer and is visually represented in Figure 56 with large blue arrows. A potentiometric surface map of the Lance and Fox Hills formations was not identified in publicly available literature.

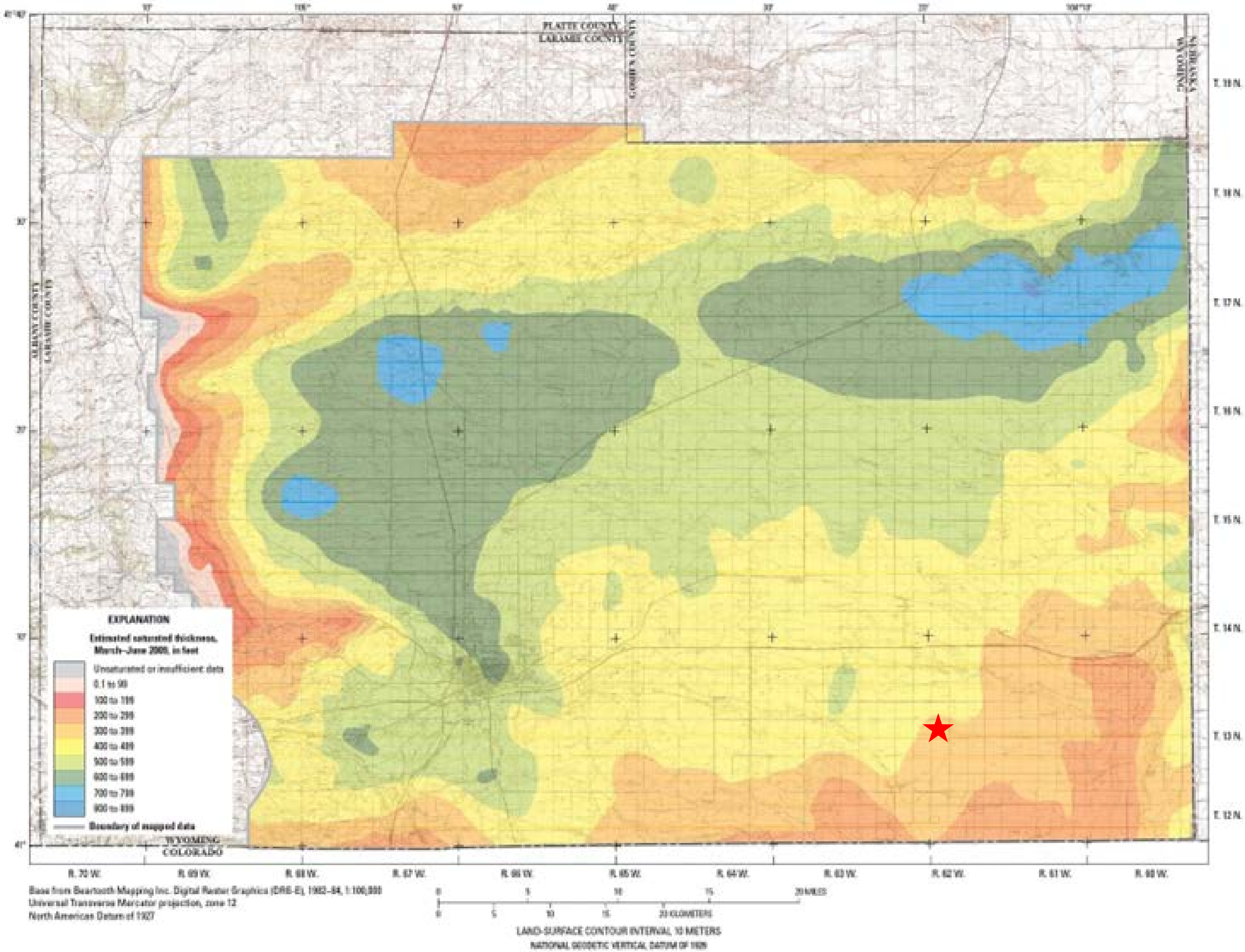


Figure 53 – Estimated Saturated Thickness of Combined Quaternary, Ogalla, Arikaree, and White River Aquifers in Laramie County, Wyoming (Bartos et al. 2021). The red star represents the approximate location of Juniper I-1.

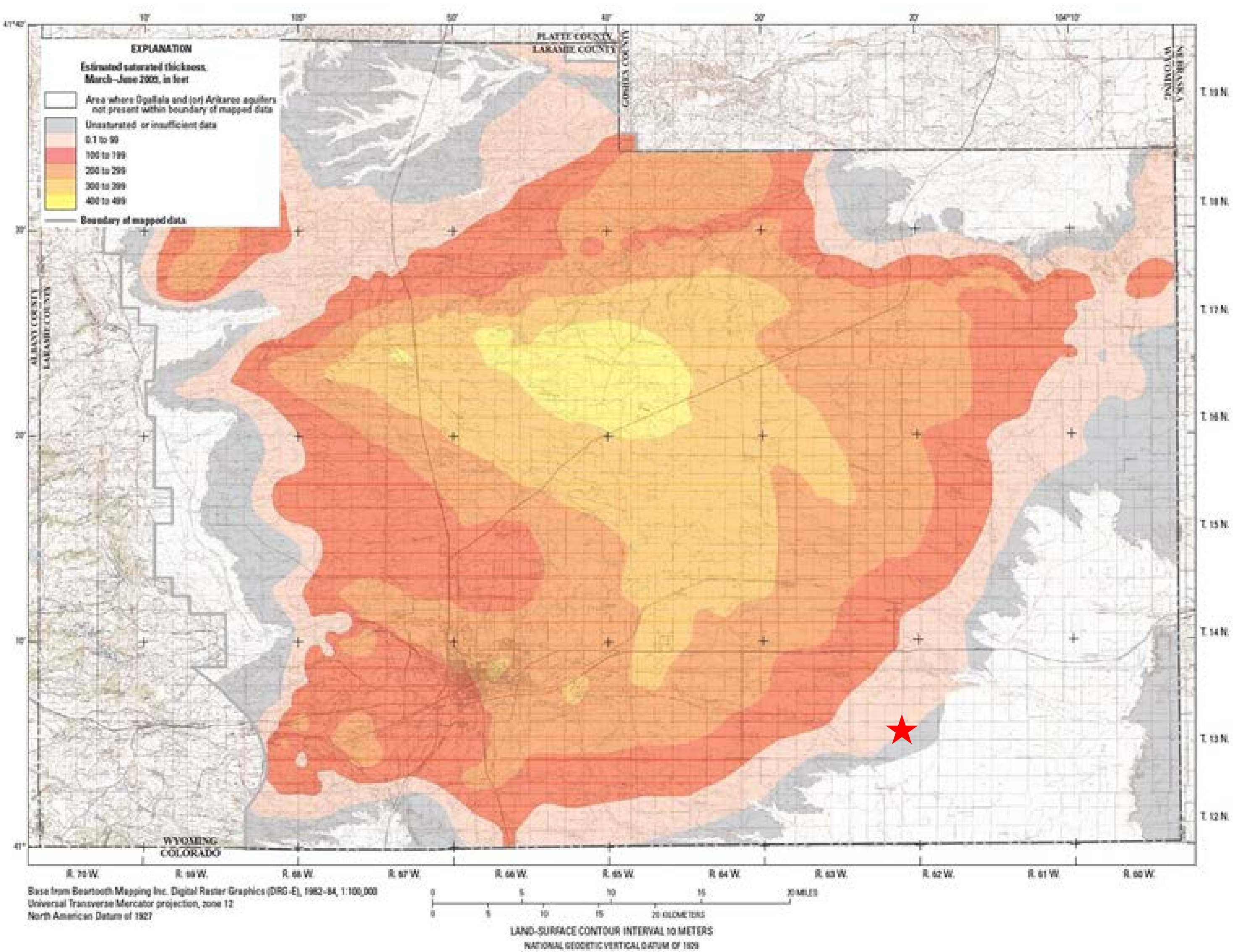


Figure 54 – Estimated Saturated Thickness of Combined Quaternary, Ogalla, and Arikaree Aquifers in Laramie County, Wyoming (Bartos et al. 2021). The red star represents the approximate location of Juniper I-1.

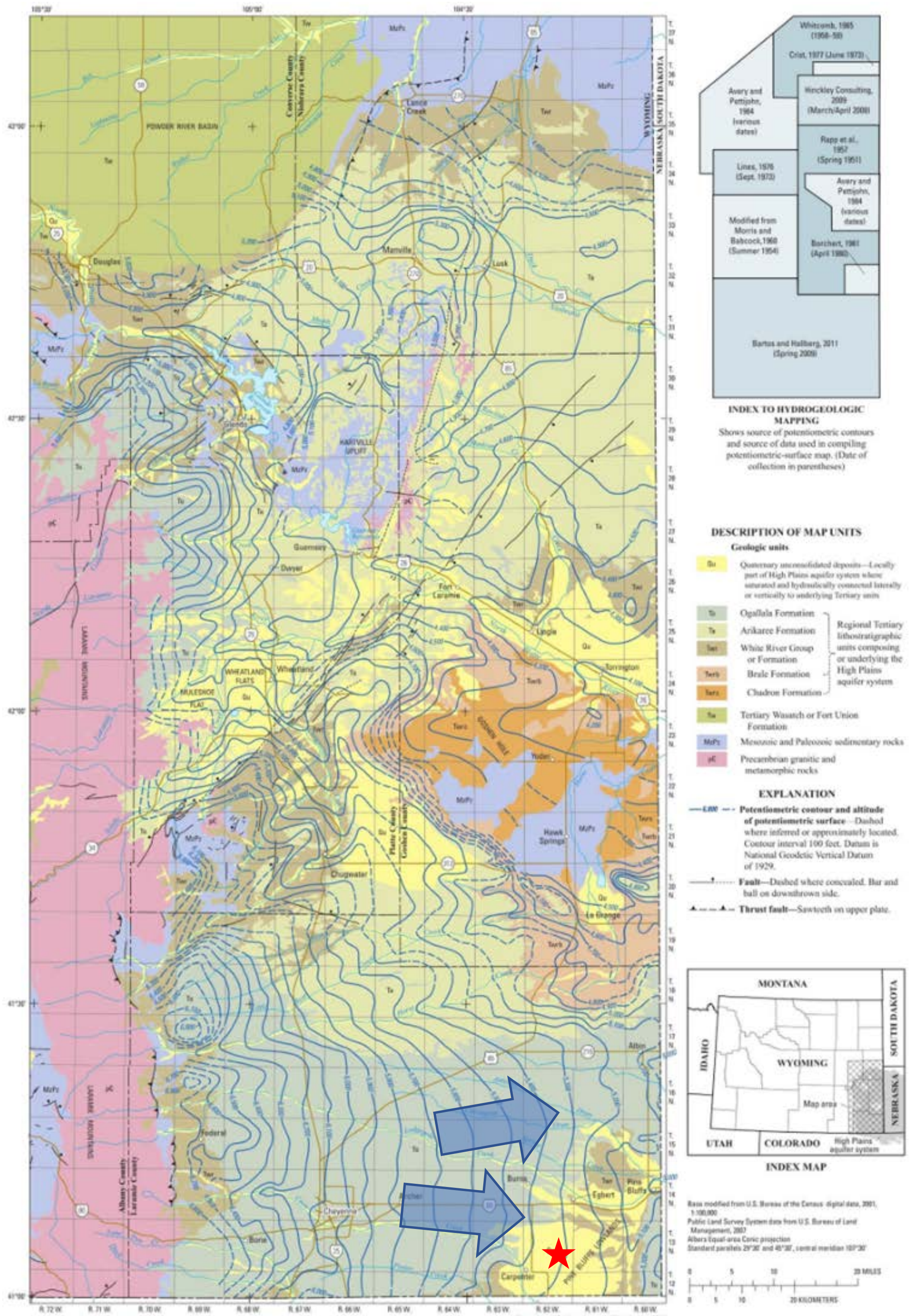


Figure 55 – Generalized Potentiometric-surface Map of the High Plains Aquifer System in Southeastern Wyoming (modified from Taucher et al. 2013). The red star and line represent the approximate location of Juniper I-1. The blue arrows indicate an estimate of the groundwater flow direction.

The Lance and Fox Hills aquifers underlie the White River formation of the High Plains aquifer system near the EWS Hub. The USGS cross section shown in Figure 56 is constructed with open-hole well logs located near Juniper I-1. The cross section accurately portrays the stratigraphic relationships between the Lance aquifer, Fox Hills aquifer, and Pierre shale within the Project Area. The Fox Hills is interpreted herein to contain the deepest freshwater aquifer and is therefore designated as the lowermost USDW designation for the EWS Hub.

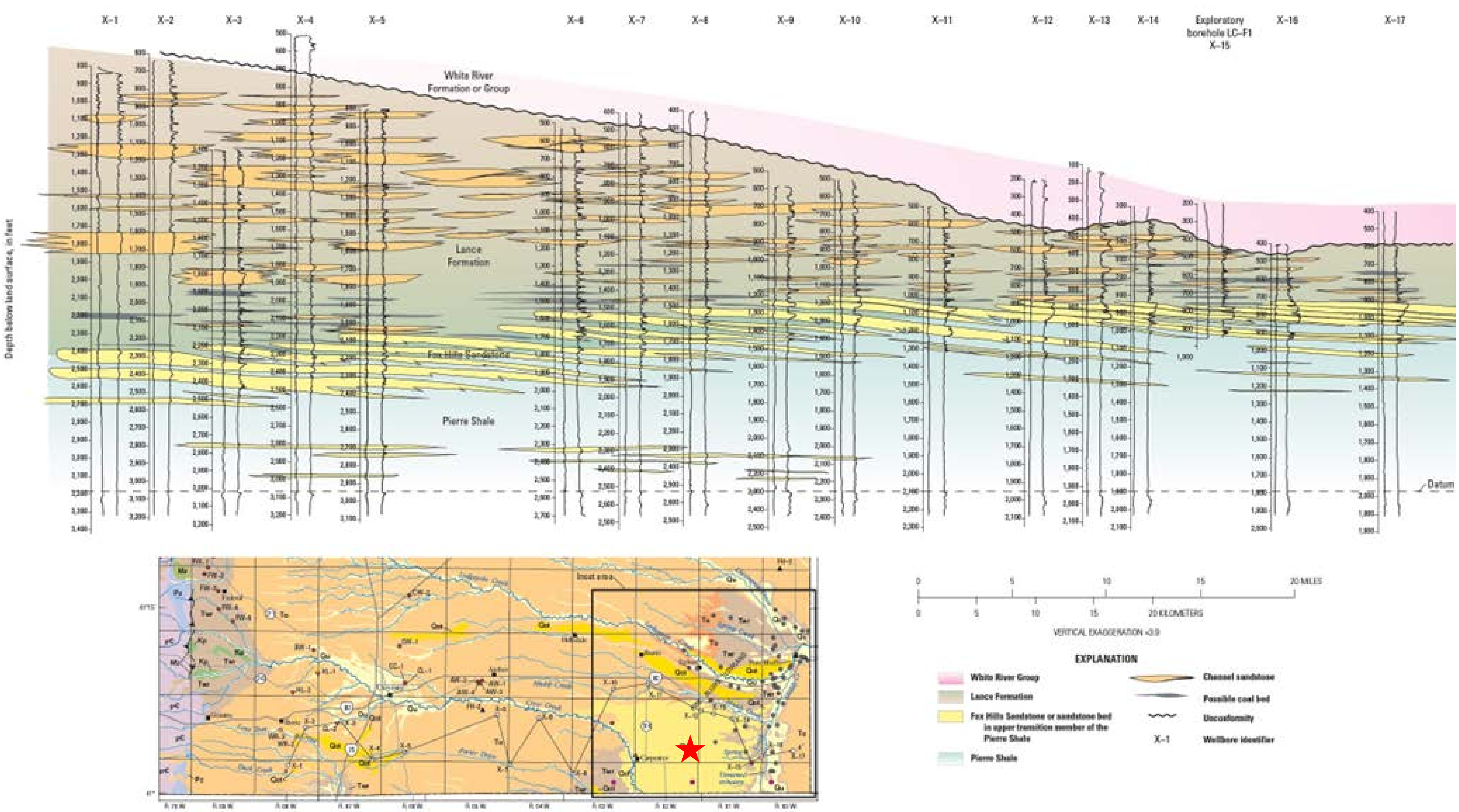


Figure 56 – Subsurface Occurrence of Fox Hills in Relation to the Lance Formation and Upper Transition to Pierre Shale in Laramie County, Wyoming, DJ Basin (Bartos et al. 2021). The red star and line represent the approximate location of Juniper I-1.

3.2.4 Protection of USDWs

As discussed in detail in *Section 2.4.2.5*, the Lyons formation comprises the injection interval for the proposed Juniper I-1, and in 2022 MICP analysis was retroactively performed on a Lyons sandstone core sample taken in 1953 from an undisclosed depth in the Fritz No. 1 well (API# 49-021-05033). The analysis determined that the sandstone contains 23% porosity and 500 mD permeability (Table 8, *Section 2.4.1.1*). Petrophysical analysis indicated that the Goose Egg—the formation providing 275 ft as the immediate upper confinement of the Lyons injection interval—has an average gross porosity of 2% and an average gross permeability of 0.00001 mD (Table 18, *Section 2.4.2*). Therefore, the Goose formation contains the physical properties typically required to reduce vertical transmission of fluids and constrain CO_2 from migrating out of the injection reservoir. Furthermore, petrophysical analysis of the Chugwater—the upper confining Triassic formation that overlays the Goose Egg—determined an average gross porosity of 4% and an average permeability of 0.00001 mD (Table 18, *Section 2.4.2*). Thus, the Chugwater is a secondary seal should the Goose Egg have a leakage pathway.

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. Blakey's paleogeographic map in Figure 57 displays peak transgression of the Western Interior Seaway that occurred during the late Cretaceous. The long-standing marine environment resulted in deposition of more than 4,000 ft of regionally extensive Cretaceous shale, siliceous shale, and marls between the lowermost designated USDW (Fox Hills) and primary upper confining zone. The schematic cross section displayed in Figure 58 is oriented across the EWS Hub and provides a visual representation of total Cretaceous sediment accumulation deposited between the upper confining zone and lowermost designated USDW. The thick shaly Cretaceous section contains physical properties required to provide additional protection of designated USDWs. A description of additional confinement intervals is provided in Table 36.

The Goose Egg and Chugwater formations total more than 500 ft thick and contain high concentrations of shale, silt, salt, or anhydrite in the section that were subsequently overlain by more than 4,000 ft of shale, sandy shale, and marl. These lithologies are known for their profound sealing characteristics and represent the upper confinement zone and additional confinement intervals of the Lyons injection complex. Proposed confining intervals are thick, tight, continuous across modeled plume extents, and contain physical properties necessary to restrict fluid migration. The 2D seismic evaluation referenced in *Section 2.3.4* did not identify any transmissive faults within the plume boundary or pressure front of the proposed Juniper I-1 injection well. Therefore, the geologic section near the EWS Hub is interpreted to provide adequate isolation of designated USDW formations from modeled CO_2 injection into the Lyons formation.

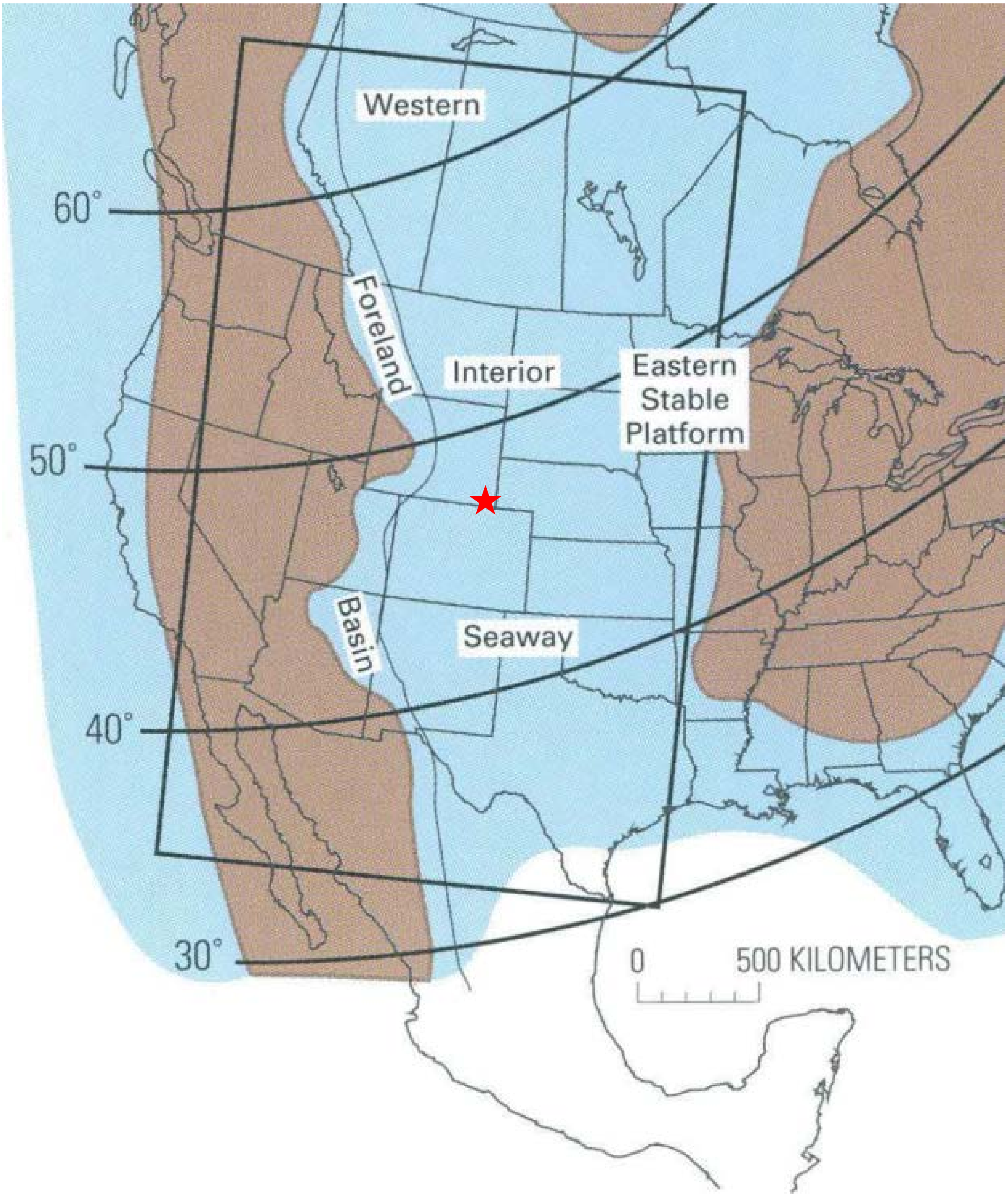


Figure 57 – Paleogeographic Map of the Western Interior Seaway During Peak Transgression, Late Turonian (Blakey 2014). The red star is the approximate location of the EWS Hub.

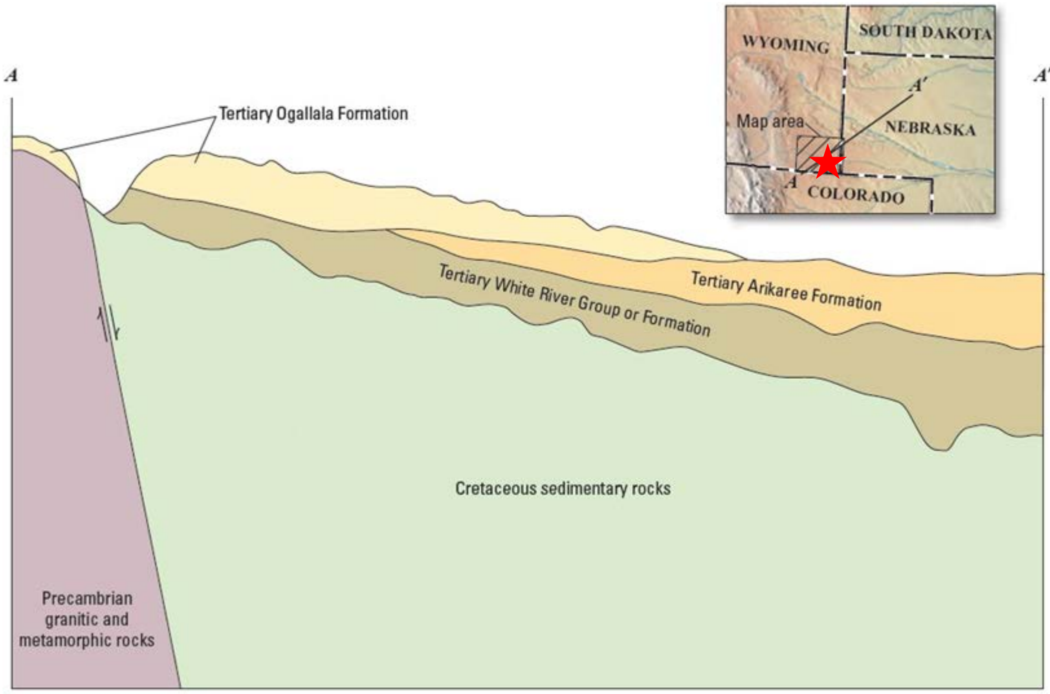


Figure 58 – USDW Southwest to Northeast Schematic Cross Section with Locator Map (Bartos and Hallberg 2011). The red star is the approximate location of Juniper I-1.

Table 36 – Description of Zones of Confinement Above the Immediate Upper Confining Zone

Name of Formation	Lithology	Formation Top Depth (ft)	Thickness (ft)	Depth Below Base Lowest Identified USDW (ft)
Pierre	shale	1,202	3,070	0
Niobrara/Carlile	calcareous shale	6,980	312	5,778
Greenhorn	shale	7,381	309	6,179
Graneros/Belle Fourche	shale	7,690	155	6,488
Mowry/Huntsman	siliceous shale	7,845	83	6,643
Skull Creek/Thermopolis	shale	8,002	151	6,800

Local USDW cross sections (Figures 60 and 61) and a locator map (Figure 59) have been included to convey High Plains's geologic interpretation of designated USDW formations near the EWS

Hub. The cross sections display the geologic section from several hundred feet below the lowest designated USDW to ground level. USDW cross sections are oriented north-south and west-east to present any lateral changes or stratigraphic variability. The geologic section demonstrates consistent structural behavior with the underlying Pierre shale present—well beyond the limits of the EWS Hub. The locator map (Figure 59) depicts the location of USDW cross-sectional lines, the Juniper I-1 injection well, the Juniper M-1 monitor well, and the plume extents of Juniper I-1. Additional discussions and data regarding designated USDW formations reside in *Sections 2.2.1* through *2.2.3*, and the preceding AOR sections.

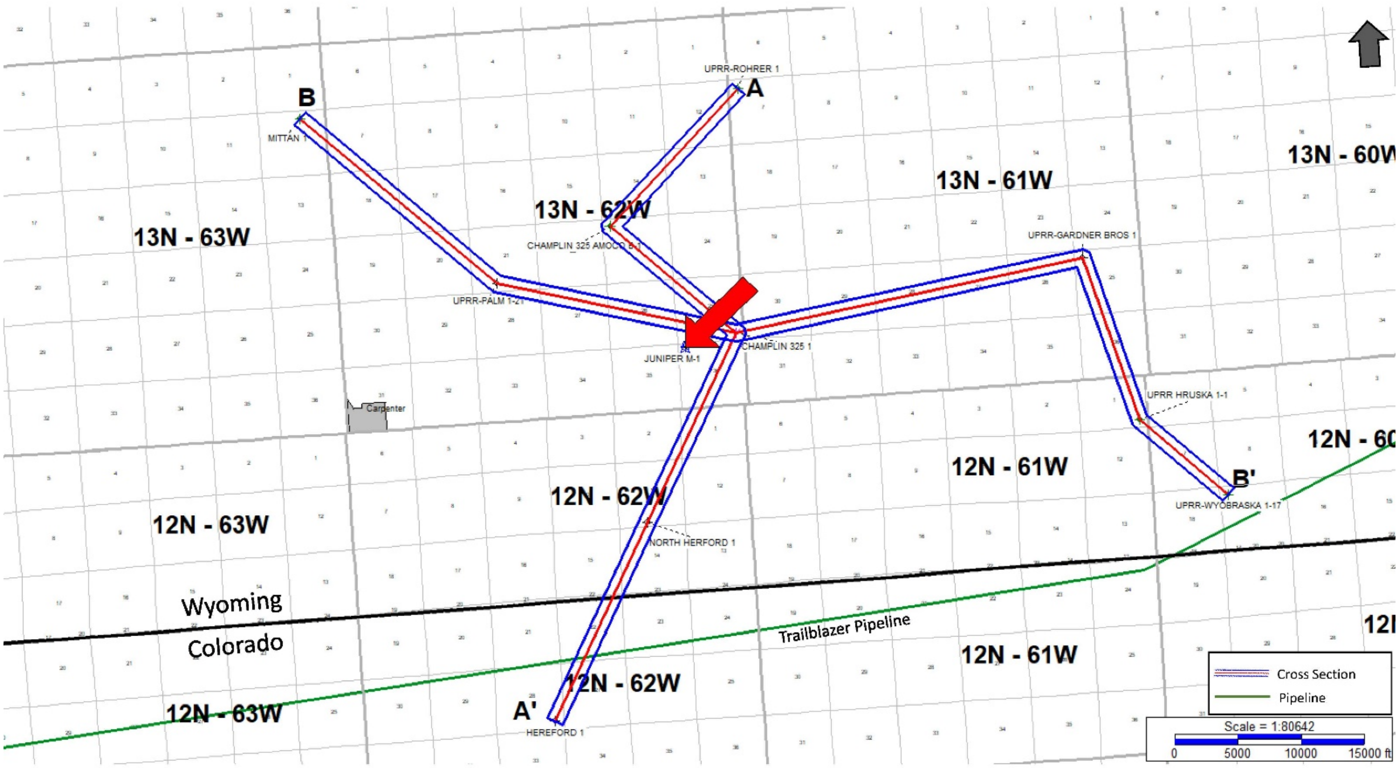


Figure 59 - USDW Cross-Section Locator Map. The red arrow indicates the approximate location of Juniper I-1, the dark gray arrow indicates north, and the dashed green line depicts modeled plume extents of the Juniper I-1 injector.

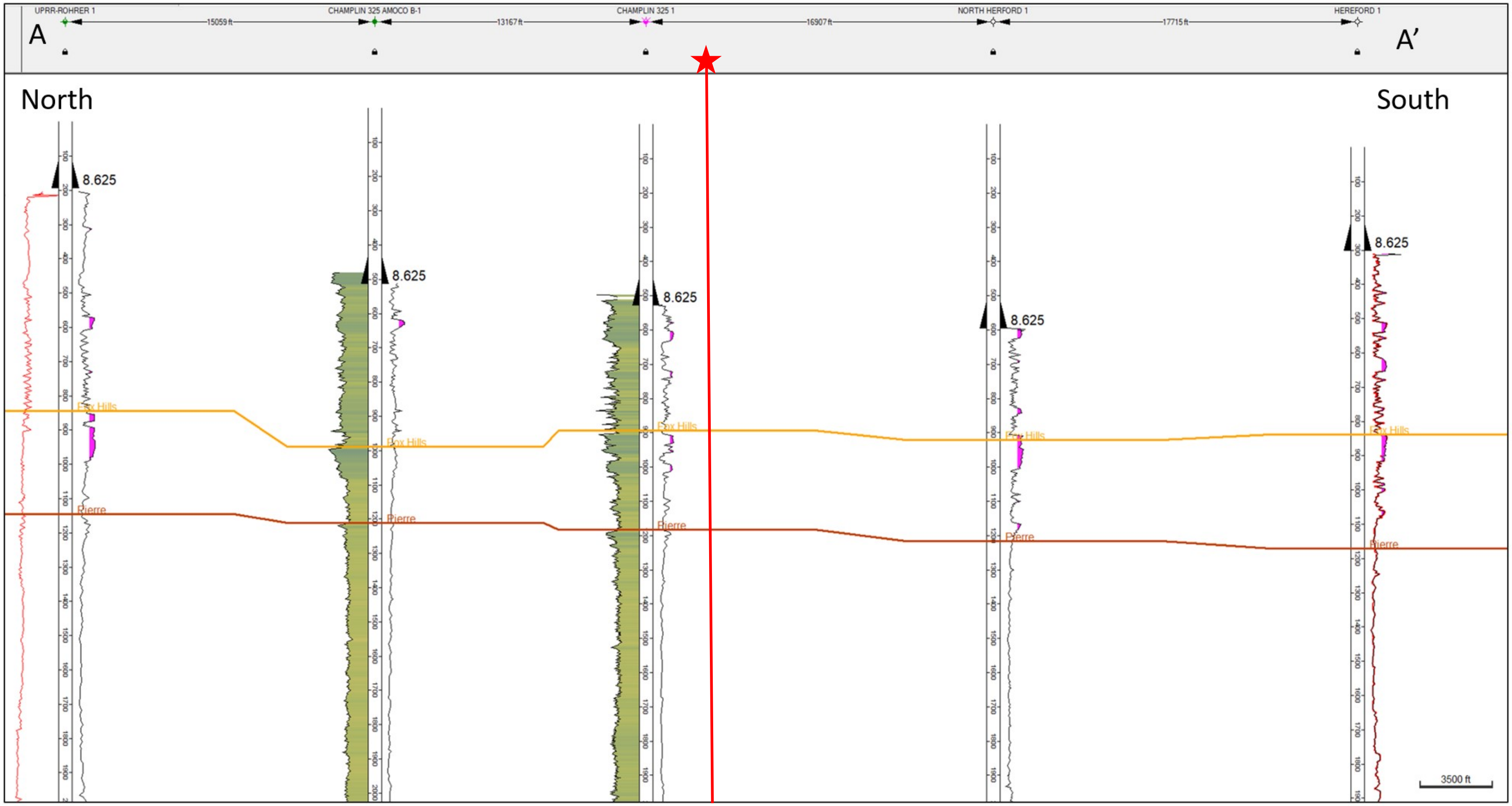


Figure 60 – USDW North-South Cross Section A-A'. The red star and line represent the approximate location of the Juniper I-1.

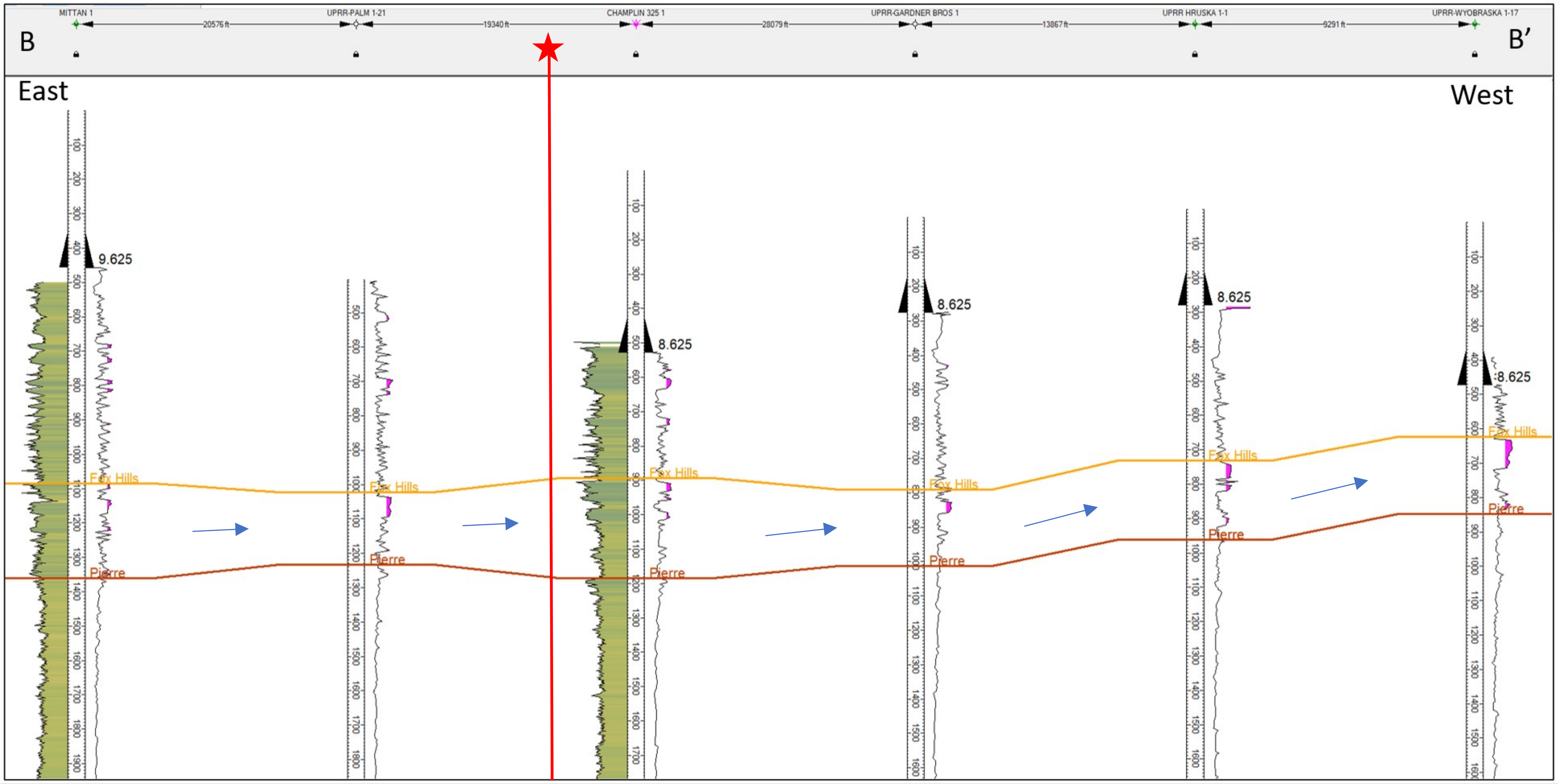


Figure 61 – USDW East-West Cross Section B-B'. The red star and line represent the approximate location of Juniper I-1. Blue arrows indicate an estimate of the groundwater flow direction.

3.3 Corrective Action Evaluation

No existing wellbores within the AOR penetrate the upper confining interval, therefore no corrective action is needed. The Juniper M-1 and M-2 monitoring wells will be designed and constructed to ensure protection from corrosion and prevent migration of fluids to the USDW.

3.4 Plume Model

3.4.1 Plume Model Overview

The data utilized in the creation of the geologic model to accurately represent the reservoir includes well logs, 2D seismic data, and publicly available literature. This data was incorporated into the geologic model using Schlumberger's Petrel™ software. Well logs and 2D seismic data were used to create a geologic model of the Lyons sandstone (injection zone), Chugwater formation (upper seal), and Satanka formation (lower seal). The geologic model is a geocellular model comprising a 500 ft by 500 ft grid of horizontal cell dimensions encompassing an area of 40 by 70 square miles. A sensitivity study was conducted to see the effects of a reduced grid cell size, which led to a negligible impact on the CO_2 plume. This sensitivity is further discussed in *Appendix C*. Reservoir rock properties were distributed in the Lyons formation using simple kriging methodology.

The geologic model was then used as an input into the Computer Modelling Group's (CMG) GEM 2022.10 (GEM) simulator—one of the most accurate and technically sound reservoir-simulation software packages for conventional, unconventional, and secondary recovery. GEM utilizes equation-of-state (EOS) algorithms along with advanced computational methods to evaluate compositional, chemical, and geochemical processes and characteristics, to produce highly accurate and reliable simulation models for carbon sequestration. Numerical simulations were conducted to accurately forecast supercritical CO_2 movement, pressure buildup due to CO_2 injection, and output wellbore model variables.

3.4.2 Geologic Model Development

Four key data activities were completed to characterize the injection zones and sealing formations: (1) data gathering, (2) data analysis, (3) static reservoir modeling, and (4) property distribution. Well logs were used as control points to identify geologic structure and formation tops. Two-dimensional seismic data was tied in with well tops to further determine the geologic structure. Petrophysical analysis was performed on well logs to interpret rock properties such as porosity and permeability. The rock properties were distributed and upscaled across the model domain.

No site-specific data has been gathered at this time. High Plains is drilling a stratigraphic test well, the Juniper M-1, to gather core, fluid samples, and well logs. Three-dimensional seismic data will be acquired to provide a higher resolution baseline of the reservoir and increase the overall accuracy of the geologic model.

Log analysis of 45 wells was performed to determine reservoir rock properties. These wells act as control points in the model to distribute porosity and permeability values. Property distribution consisted of applying the kriging algorithm from upscaled porosity logs guided by variograms for each zone. Figure 62 highlights the porosity distribution implemented into the model using simple kriging methodology.

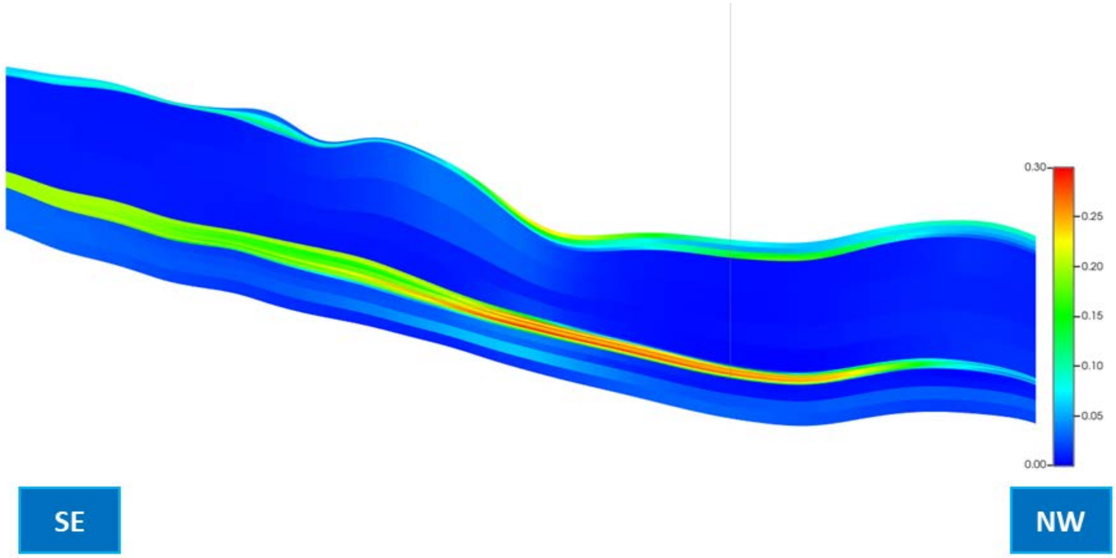


Figure 62 – Porosity Distribution in Geologic Model

Permeability was then distributed along corresponding porosity values and correlated to porosity to create a best-fit equation of the line. A permeability-porosity cross-plot was generated to apply permeability values across the model. This equation was input into the GEM software to distribute permeability values as seen in Figure 63. A more detailed discussion is provided in *Appendix C*.

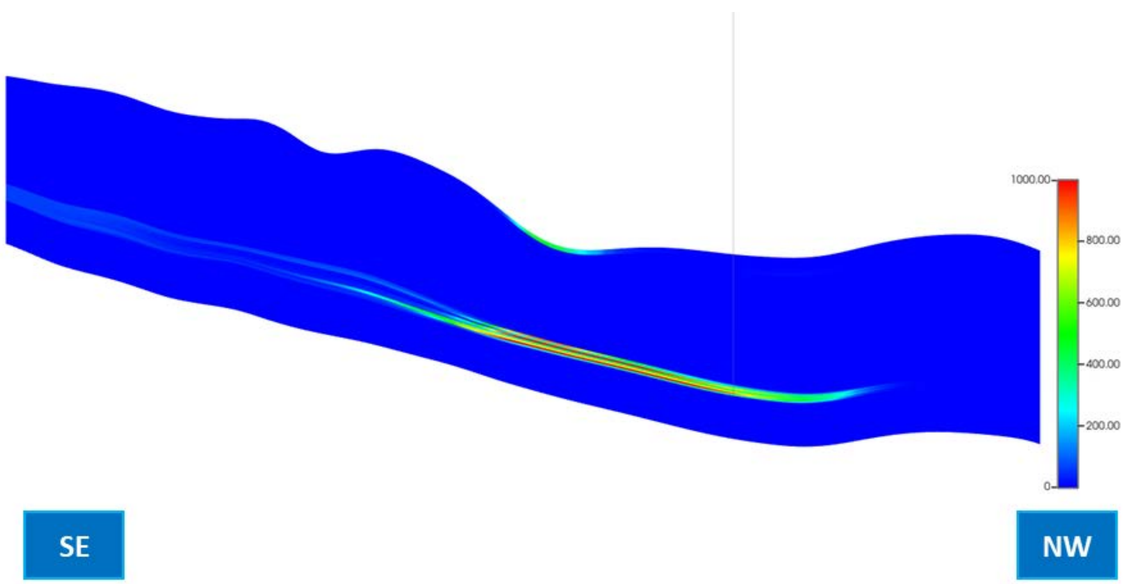


Figure 63 – Permeability Distribution in Geologic Model

3.4.3 Computational Model

The static geologic model was used as an input for the dynamic simulation model. A regional model was built to simulate the effect of offset SWD wells and CO_2 injection wells. The model comprises 22 layers and approximately 14 million grid blocks. The Lyons layers were upscaled from 2 ft to 7 ft in the compositional model. Fifteen CO_2 injectors and eight SWDs were included in the model to simulate the effect of any interference. Each CO_2 well injected supercritical phase CO_2 into the target formation. Historical SWD injection was also incorporated. Figure 64 provides a 3D representation of the whole model.

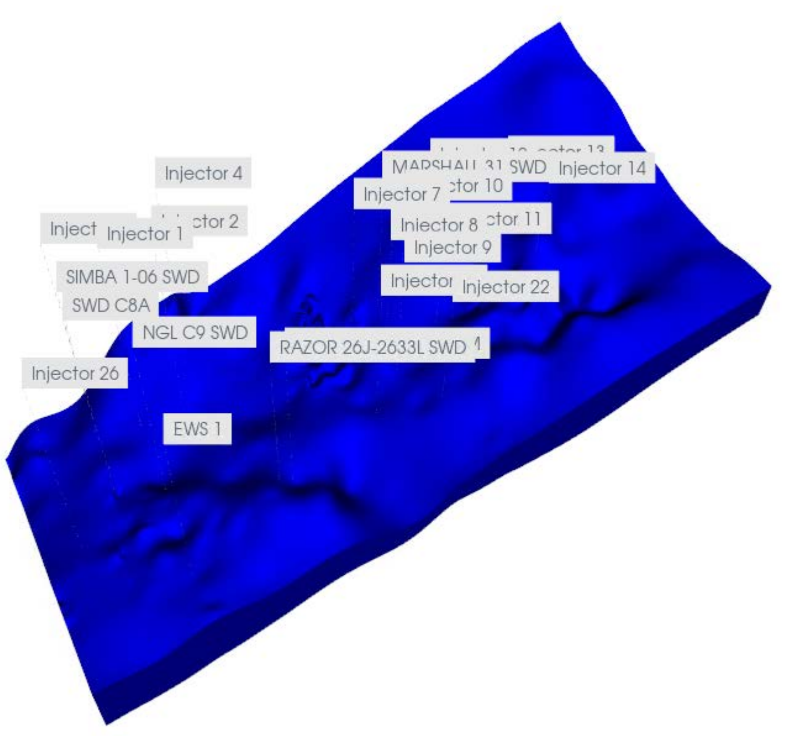


Figure 64 – 3D Representation of Regional Model

Reservoir pressure, temperature, residual gas saturation, and brine salinity were used to initialize the model. Injected CO_2 would remain in a supercritical state due to the initial pressures and temperatures in the model. Table 37 summarizes the property values at initial conditions of the reservoir (discussed in more detail in *Appendix C*, *Section C.2.3*). A pseudo-infinite acting reservoir was created using volume modifiers along the boundary. The well-log interpretation is that the reservoir pinches out to the northwest and southeast—hence, the opposing edges of the model were created to be open boundaries, to simulate a connected reservoir that extends for 70 miles from the model edge. A wellbore model is also included and discussed further in *Appendix C*.

Table 37 – Initial Assumptions Summary

Assumption	Value
Average Reservoir Permeability (mD)	141
Average Reservoir Porosity (%)	22
Net Thickness (ft)	40 – 55
Pore Gradient (psi/ft)	0.30
Frac Gradient (psi/ft)	0.47
Temperature Gradient (°F/100')	1.34
Surface Temperature (°F)	75
CO_2 Phase	Supercritical
Salinity (ppm)	150,000

The CO_2 will be injected in a supercritical state, where it will remain as such in the reservoir. There are numerous advantages to storing CO_2 under supercritical conditions. In this state, its density is significantly higher, allowing for more mass of molecules to be stored in the same space. CO_2 also retains a low viscosity, which lowers the pressure required to store it. Based on the pressure and temperature assumptions shown in Table 37 (and discussed further in *Appendix C*, *Section C.2.3*), CO_2 will continue to remain a supercritical fluid throughout the life of the project. Figure 65 provides a three-phase diagram of CO_2, highlighting the initial conditions to create a supercritical fluid.

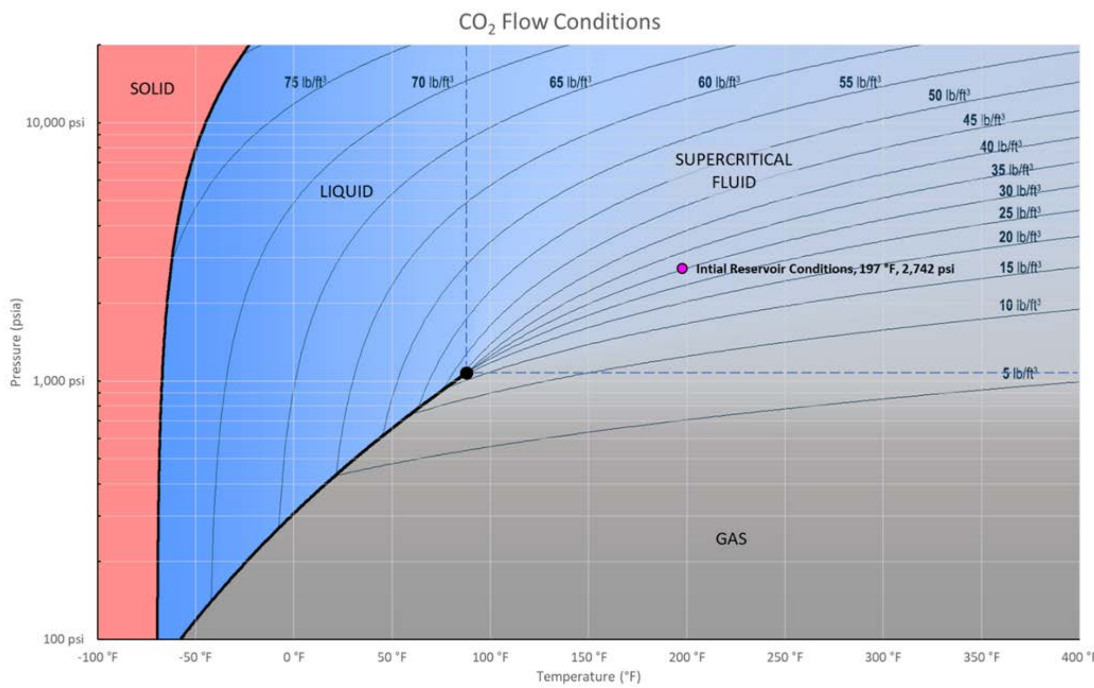


Figure 65 – CO_2 Phase Diagram

Hysteresis effects were considered in the compositional model even though, during its construction, site-specific data was unavailable. To help identify values for the missing data, a public literature review was instead conducted. Specifically, relative permeability was derived from such a review. The modeled pressure and temperature conditions keep the CO_2 in a supercritical phase; however, in academic papers relative permeability curves are discussed as being in the gas phase, to differentiate it from the water and oil phases. (A more detailed discussion of the model parameters is provided in *Appendix C*.) The literature review allowed for the generation of the relative permeability curves shown in Figure 66. Those curves and the maximum residual-gas saturation were hence used to simulate the hysteresis effects of supercritical CO_2 injection.

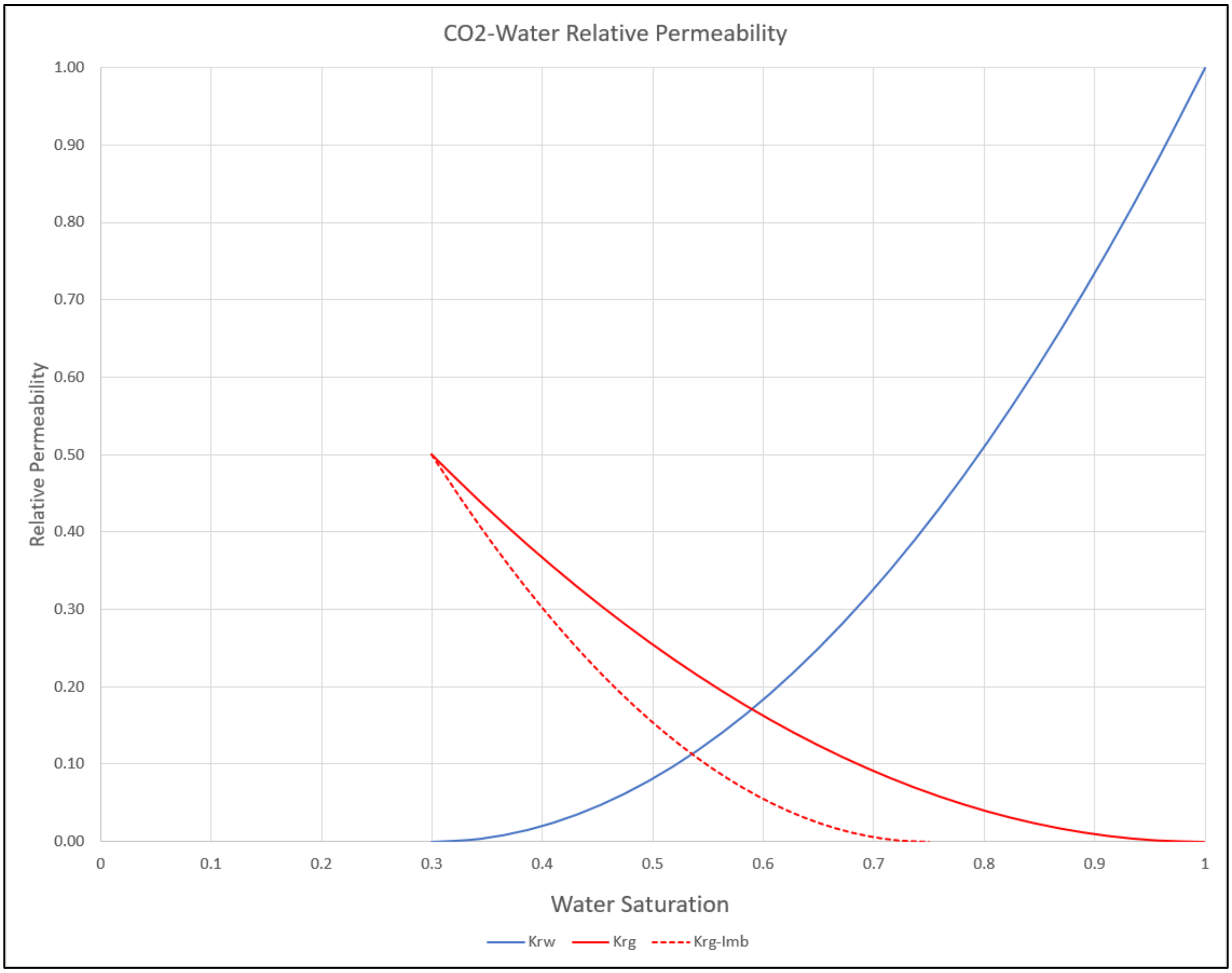


Figure 66 – Supercritical CO_2-Water Relative Permeability Curves (Sally Benson et al. 2015)

The model considers possible future injection operations in the area. The injector well, titled "Injector 1" in the simulator, delineates the AOR as displayed in Figure 67. The maximum extent of the plume, at stabilization, is captured approximately 50 years after injection. In total, approximately 55 years passed in the model from the time the injector came online. The plume encompasses approximately 5,601 acres of Wyoming land, with the greatest length of the plume extending from northwest to southeast for 21,595 ft (approximately 4 miles).

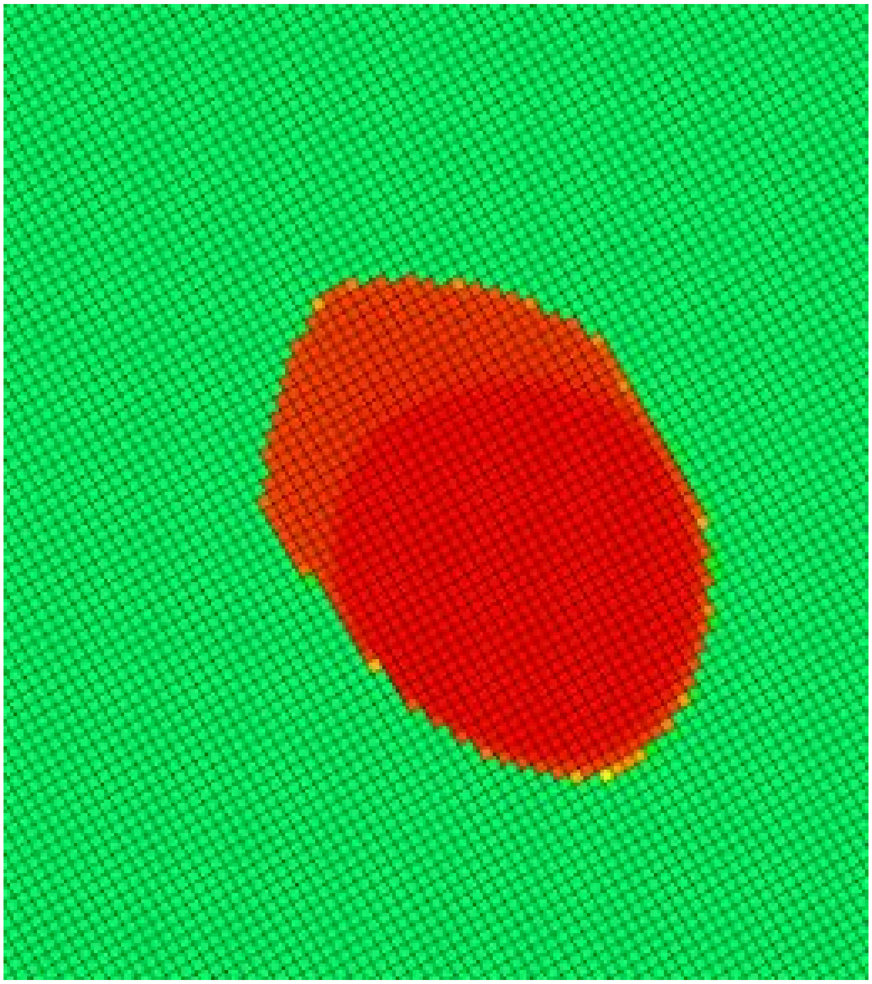


Figure 67 – Aerial View of Plume

Two methods were used to calculate the fracture gradient—Mohr's Coulomb and the isotropic method. The Mohr's Coulomb method resulted in a fracture gradient of 0.403 psi/ft, while the isotropic method resulted in a 0.533 psi/ft gradient. The average of these two methods, 0.47 psi/ft, was then implemented in the model. The synthetic shear isotropic value is believed to be the realistic fracture gradient, but the average was taken to provide a conservative estimate. Ninety percent of the gradient was then applied as the maximum allowable downhole injection pressure constraint. This approach and the discussion of it below are further discussed in *Appendix C*.

Injection pressure must not exceed 90% of the fracture gradient per WYDEQ Chapter 13 **§24.18(a)**, hence the use of that value as a constraint in the model to limit pressure buildup in the reservoir. Ninety percent of the fracture gradient value is henceforth referred to here as the *pressure constraint*. Applying a 10% safety factor to the averaged fracture gradient of 0.47 psi/ft results in a 0.42 psi/ft. The pressure constraint, which is based on the tubing setting depth, results in a 3,867-psi limit imposed on the injection—demonstrated in Equation 7.

(Eq. 7)
$$P_{Constraint} = 0.9 \times FG \times Depth_{tbg}$$

$$P_{Constraint} = 0.9 \times 0.47 \times 9{,}142$$
$$P_{Constraint} = 3{,}867\ psi$$

In the model, the well experienced a reduction in rate caused by the pressure constraint imposed on the well to prevent exceeding the fracture pressure. Once the bottomhole pressure (BHP) increased to the pressure constraint, the rate was reduced to prevent more pressure buildup. The BHP increased by 976 psi to a maximum of 3,718 psi during injection. Approximately 7 MMT of CO_2 was modeled as sequestered in the injection zone. Wellhead pressure (WHP) reached a maximum value of 1,593 psi during the life of the well. Table 38 provides a summary of injection operations, and a more detailed explanation is included in *Appendix C*.

Table 38 – Wellbore Model Outputs Summary

Wellbore Parameter	Value
Max Injection Rate (MT/yr)	1,500,000
Average Injection Rate (MT/yr)	1,500,000
Max BHP (psi)	3,718
Average BHP (psi)	3,596
Max Wellhead Pressure (WHP) (psi)	1,593
Average WHP (psi)	1,532

The average BHP and WHP are expected to be 3,596 and 1,532 psi, respectively. These pressures are the averaged values over the active life of the well, approximately a 5-year period. Table C-6 in *Appendix C* shows the average pressures for each year of active injection.

3.4.4 AOR Delineation

The AOR is delineated by the maximum extent of the CO_2 plume, critical pressure increase, or the maximum combination of the two. Since the reservoir was determined to be under-pressurized, EPA Method 1 was used to delineate the critical threshold pressure. This methodology calculates a 1,342-psi increase required to lift fluids out of the formation and into the USDW. The maximum pressure increase in the model was 976 psi and occurred at the wellbore itself. Since the critical pressure rise of 1,342 psi is greater than the maximum pressure buildup of 976 psi, the critical pressure will not be reached at any period during injection. This effectively means that there is no critical pressure front for Juniper I-1. The AOR was therefore delineated solely by the maximum CO_2 plume extent. A 1-mile buffer was added onto the AOR for the review area, as shown in Figure 68. The calculations for determining this critical pressure value are shown in *Appendix C.*

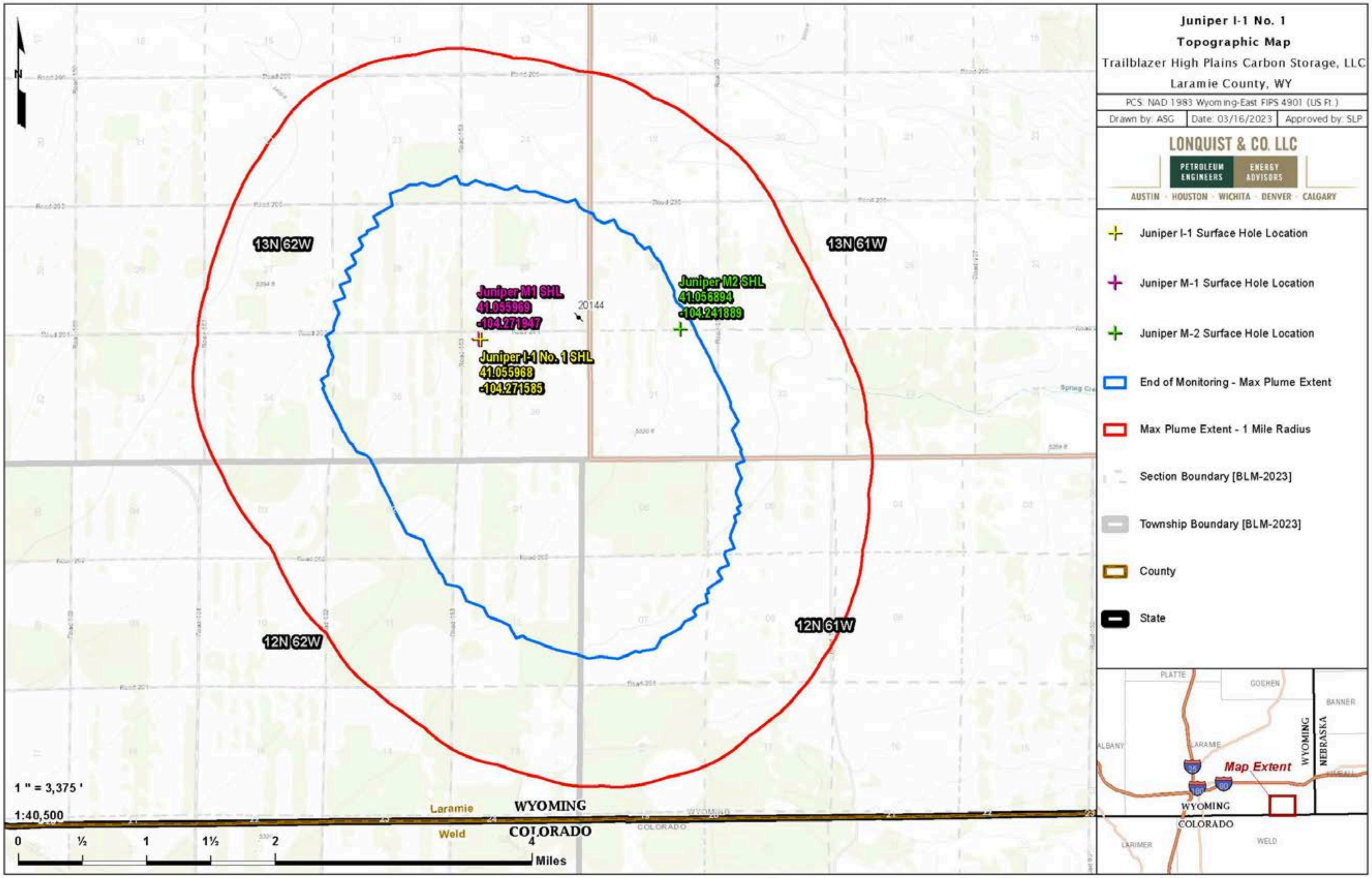


Figure 68 – Map of AOR Plus 1-mile Boundary.

3.5 Area of Review and Corrective Action Plan

The AOR is understood as the area where a CO_2 sequestration project could cause endangerment to a USDW. This area, as explained in *Section 3.4.4*, is determined from plume and pressure front modeling results and critical pressure calculations. There are possible cases where corrective action would be required to prevent endangerment from occurring.

The review of the proposed Juniper I-1 injector well AOR found no wells that require corrective action. The well listed in Table 34 is located within the bounds of the AOR but was not drilled deep enough to penetrate the entire upper confining layer, the Chugwater formation. There is currently no need for a corrective action plan. The proposed monitoring wells will be designed to resist corrosion and protect the USDW. The plume extent and reservoir pressures will be monitored constantly throughout the life of the project. If it is deemed necessary to include a corrective action plan, one will be crafted at that time.

3.6 Reevaluation of AOR and Corrective Action Plan

High Plains will regularly reevaluate the AOR and corrective action plan, per the requirements of WYDEQ Chapter 24 **§13(c)**, at least every two years during the operational life of the EWS Hub and every five years during the post-injection site care period (until site closure)—or when monitoring and operational conditions warrant. The AOR reevaluations will discuss the following:

- What changes to the monitoring and operational data occurred prior to the scheduled reevaluation date
- How the monitoring and operational data (e.g., injection rate and pressure) will be used to update the geologic model, the computational simulations to determine the AOR, and the corrective action plan
- How corrective action will be adjusted if there are changes in the AOR

The AOR will be reevaluated in the same manner as discussed in *Section 3.5*. Any new wells in the new AOR will be evaluated to determine if corrective action is required per the method described in *Section 3.5*; if necessary, corrective action will be performed in the same manner as described there. Either an amended AOR and corrective action plan will be submitted, or the data and modeling results that indicate no change to the AOR is needed.

3.7 References

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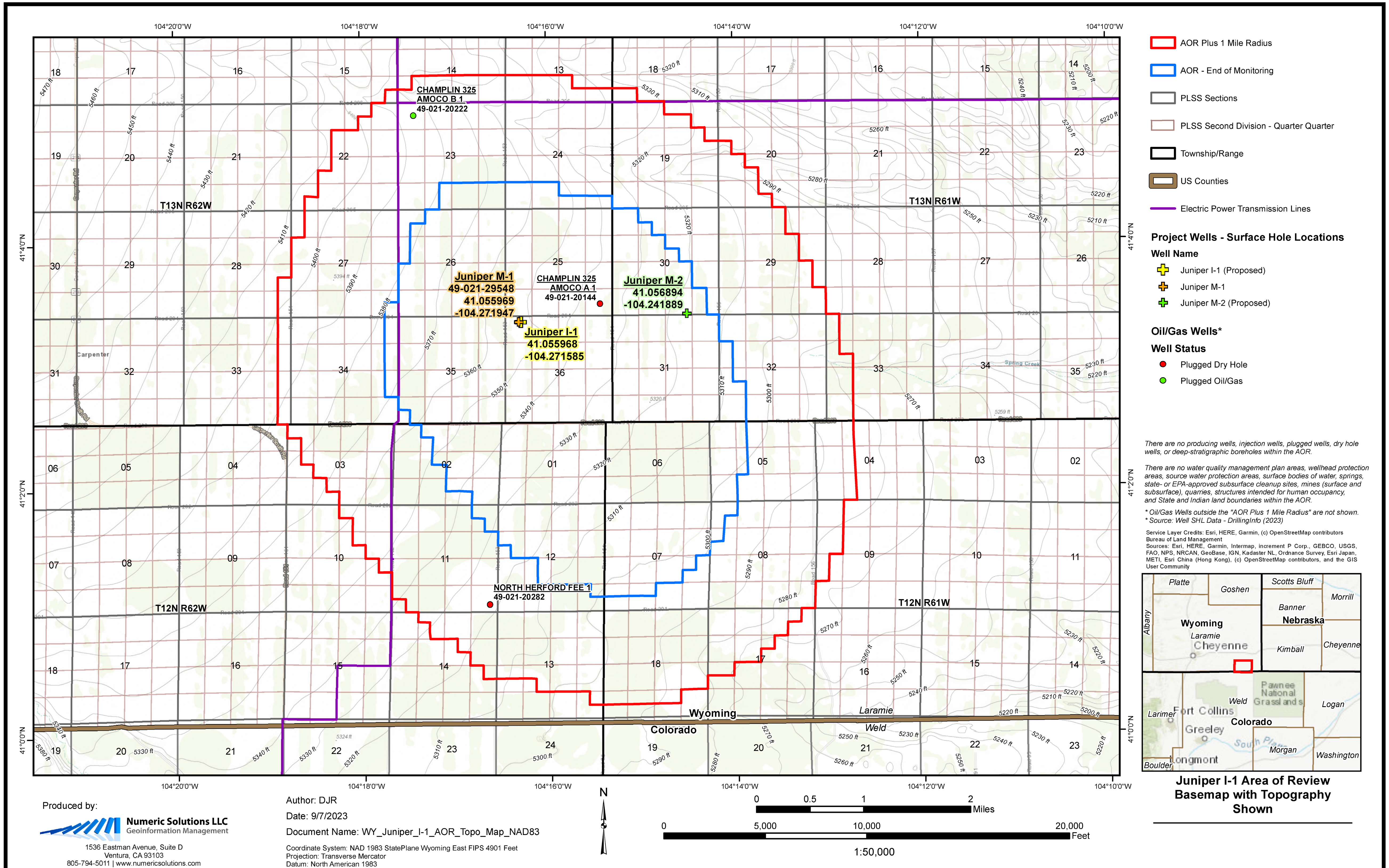

Figure 2—Topographic map of project site.

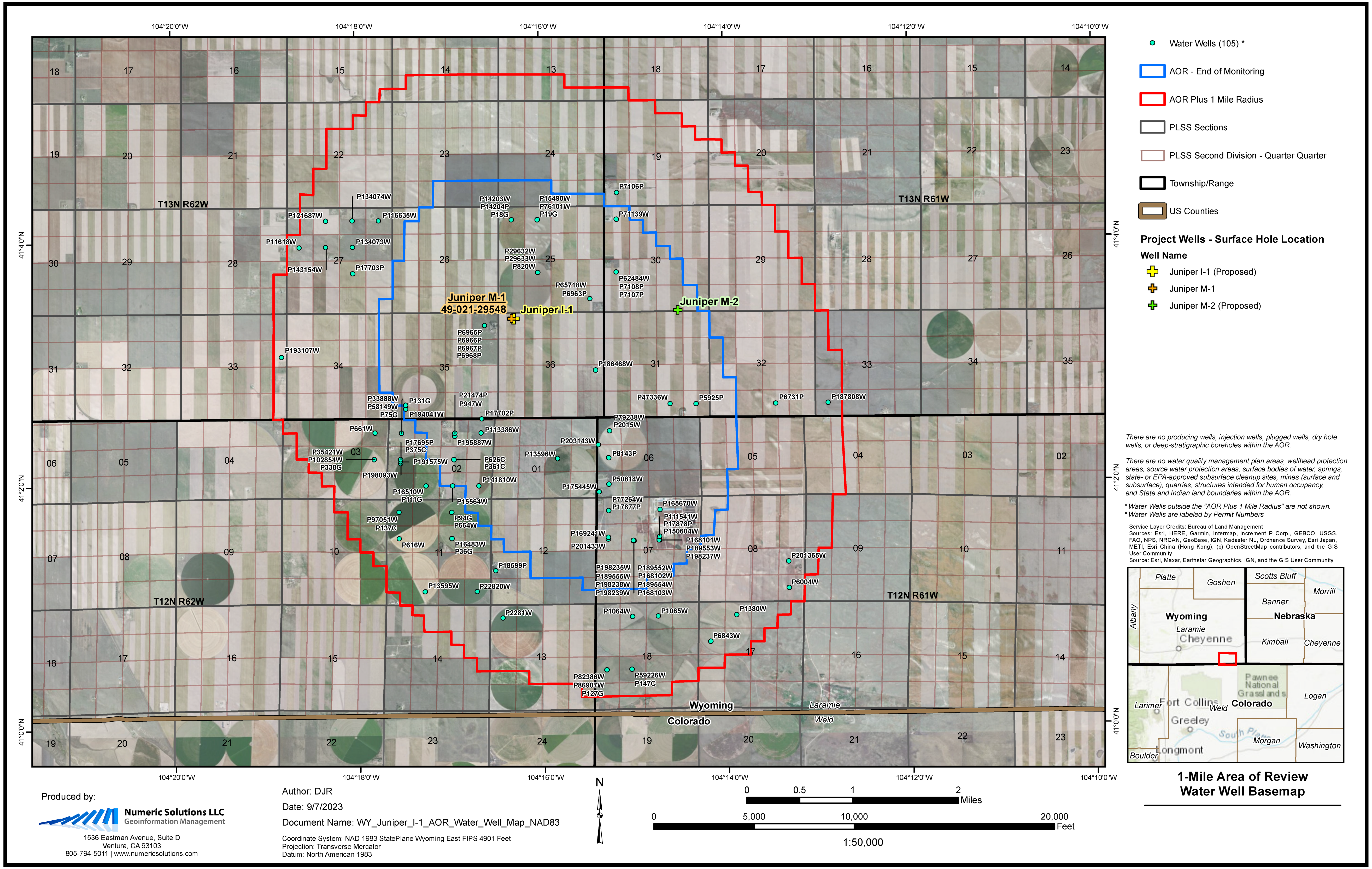

Figure 491—Water wells in the AOR plus a 1-mile buffer.

ATTACHMENT B-2: EMERGENCY AND REMEDIAL RESPONSE PLAN

4 SUPPORTING PERMIT PLANS

4.1 Emergency and Remedial Response Plan

4.1.1 Background

The following Emergency and Remedial Response Plan (ERRP) was prepared to meet the requirements of WYDEQ Chapter 24 **§25** to identify, prevent, and respond to an emergency event at the EWS Hub. The locations of the injection well and the monitoring wells are identified in Table 39. This plan incorporates the Testing and Monitoring plan described in *Section 4.3* to verify that the EWS Hub is operating as permitted and not endangering a USDW.

A list of possible emergency events has been generated and provided further below in Table 40 (*Section 4.1.3*). Table 41 (*Section 4.1.4*) includes the response actions to be taken, when an emergency event has been detected related to the movement of the injectate or formation fluids that may endanger a USDW—or threaten human health, safety, and/or the environment. This plan will remain in place during the construction, operation, closure, and post-closure periods. The procedures in this plan outline the response to coordinate among the emergency team response, local resources, surface owners, mineral claimants, mineral owners, lessees, owners of record with subsurface interests, and governmental authorities. The plan's objectives are to minimize the impact of the potential for loss of life and maximize the protection of the environment, the surrounding community, and company property.

High Plains is developing a site-specific Emergency Response Plan (ERP) for the EWS Hub, to detail further the procedures that will be followed during an emergency event. This ERP will be submitted to WYDEQ as confidential business information.

Table 39 – Well Name and Location Information

Well Name	Purpose	Qtr/Qtr	Sec	Town	Range	Longitude	Latitude
Juniper I-1	CO_2 Injection Well	NW/NW	36	13N	62W	41.0559685	-104.2715845
Juniper M-1	Stratigraphic Test / Monitoring Well	NW/NW	36	13N	62W	41.0559693	-104.2719471
Juniper M-2	Monitoring Well	SW/SE	30	13N	61W	41.0568935	-104.2418888

4.1.2 Local Resources and Infrastructure

The EWS Hub is in the southeast corner of Wyoming, approximately 14 miles southwest of Pine Bluffs. The Project Area and well locations were selected to minimize the potential impact on the surrounding landowners, farming areas, nearby communities, livestock, and wildlife. The infrastructure that an event could impact, including residences, farmland, oil and gas wells, water wells, roads, and pipelines, is shown in Figure 69. No tribal lands are located near the EWS Hub. The defined AOR includes 46 homes and farmsteads. Currently, the EWS Hub plans do not include large-structure construction, such as processing facilities, compression equipment, etc. To reduce environmental or safety impacts, assistance from local resources will be activated based on the type and severity of an event.

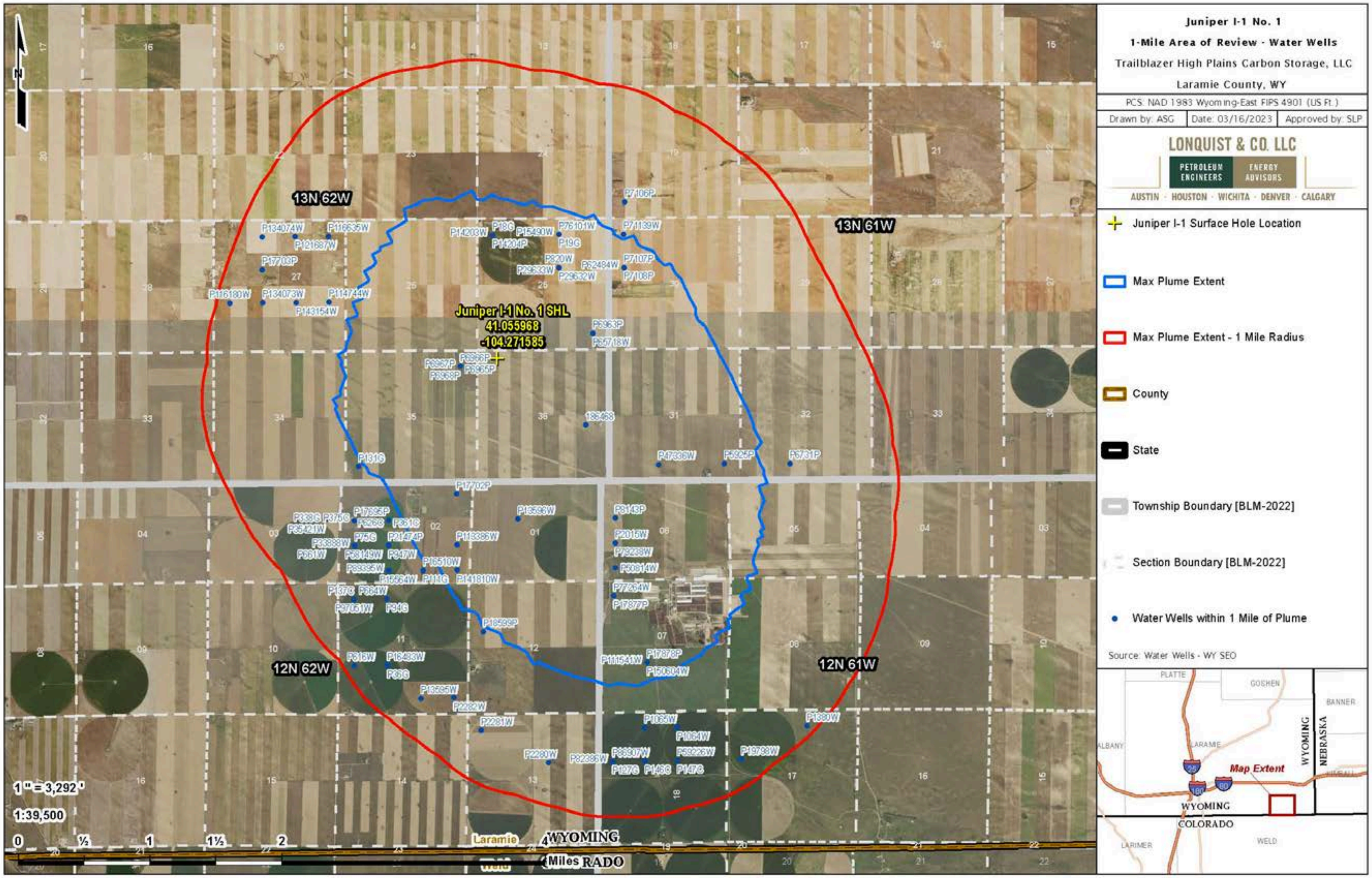

Figure 69 – Local Resources and Infrastructure

4.1.3 Identification of Potential Emergency Events

An *emergency event* occurs when an event endangers a USDW or threatens human health, safety, and/or the environment during the construction, operation, closure, and post-closure periods—due to the movement of the injectate, formation, or other fluids. Other events include the risk of accidental release of CO_2 into the atmosphere. Potential emergency events and the methods that will be used to identify such an event are included in Table 40.

Table 40 – Potential EWS Hub Emergency Events and Their Detection

Potential Emergency Events	Detection of Emergency Event
Well control event while drilling or completing the well with the loss of containments	• Sudden increase in drilling rate • Increase in flow rate at the surface • Changes in pump pressure • Reduction in drill pipe weight • Increase in gas, oil, or water-cut mud
Movement of brine between formations during drilling	• Indication of lost circulation
Presence of hydrogen sulfide (H_2S) while drilling or completing the well	• H_2S monitors located on the well site
Loss of mechanical integrity (flowlines, injection, monitoring wells, disposal well)	• Deviation of expected distributed temperature sensing (DTS) and distributed acoustic sensing (DAS) detects leaks in CO_2 flowline, injection well, and monitoring wells. • Wellhead pressure monitoring measurement exceeds maximum injection wellhead pressure. • Annular pressure monitoring exceeds expected pressure.
Loss of containment (LOC): vertical migration of CO_2/brines via injection wells, monitor wells, plugging and abandonment (P&A) wells, and undocumented wells	• Sampling and analysis indicate deviations of baseline values of groundwater wells, monitoring wells, and soil gas measurements. • Deviation of expected DTS/DAS measurements • CO_2 detectors at injection facilities indicate increased levels of CO_2 release.
LOC: lateral migration of CO_2 outside of defined AOR	• Sampling and analysis indicate deviations of baseline values of groundwater wells, monitoring wells, and soil gas measurements. • Indications of lateral migration on time-lapse 2D seismic survey
LOC: vertical migration due to failure in the confining zones, faults, and fractures	• Changes in downhole pressure and temperature, CO_2 measurements, and water chemistry analysis

External impact on flowlines, wells, and infrastructure	• Indication of CO_2 leak from detection systems in place
Monitoring equipment failure or malfunction	• Monitoring systems will alert site personnel if one or more portions of the system fail. Site personnel will also be reviewing data for anomalies.
Induced seismicity	• Seismic monitoring station
Seismic event	• Seismic monitoring station
Other natural disasters	• Tornados and severe storms, including lightning strikes, are additional risks that create the potential for the release of CO_2 due to injection well and EWS Hub damage, and that may disrupt surface and subsurface operations. • Monitoring systems will alert personnel to changes in operating parameters that may indicate the impact of such an event.

4.1.4 Emergency Response Actions

If monitoring data or information indicates that injection operations may pose a threat or endangerment to a USDW, human health, safety, and/or the environment, the procedures to be performed are to:

- Immediately cease all injections;
- Take all steps reasonably necessary to identify and characterize any release;
- Verbally notify the WYDEQ Administrator within 24 hours of discovering the condition; and
- Provide a written report to the Administrator within five days of discovering the condition. The written report will contain the following:
  - A description of the noncompliance, malfunction, or excursion and its cause;
  - The period of noncompliance, including dates and times, and if the noncompliance has not been controlled, the anticipated time it is expected to continue; and
  - Steps taken or planned to reduce, eliminate, and prevent the event's reoccurrence.

If a noncompliance condition or requirement under WYDEQ Chapter 24—or any malfunction of the injection system—occurs that may cause fluid migration into or between USDWs, High Plains shall

- Orally notify the Administrator within 24 hours of discovery;
- Provide a written report to the Administrator within five days of discovery that contains the following:
  - A description of the noncompliance, malfunction, or excursion and its cause;

- The period of noncompliance, malfunction, or excursion, including exact dates and times; or if the noncompliance, malfunction, or excursion has not been controlled, the anticipated time it is expected to continue; and
- Steps taken or planned to reduce, eliminate, and prevent the reoccurrence of the noncompliance, malfunction, or excursion.

If an excursion is discovered, written notice will be provided to all surface owners, mineral claimants, mineral owners, lessees, and other owners of record of subsurface interests within 30 days of discovering the excursion, and High Plains will implement the ERRP approved by the Administrator.

Table 41 lists the actions needed to determine the cause of an event and planned emergency responses.

Table 41 – Actions Necessary to Determine Cause of Events and Appropriate Emergency Response

Emergency Action	Determine Cause and Emergency Response
Failure of the CO_2 flow line from the capture system to the injection wellhead	• The DAS/DTS system at the EWS Hub will trigger an alarm upon any detected release of CO_2 and will automatically shut in the flow line. • In the event of a significant release of CO_2, personnel will be evacuated until CO_2 monitors indicate the CO_2 has been sufficiently dispersed to safe levels. • The pipeline will be inspected to determine the cause of failure, and the damaged flowline will be repaired or replaced.
Well control event while drilling or completing the well with the loss of containments	• Initiate well control procedures, including closing blowout prevention equipment and/or using appropriate drilling fluids and flow restrictions. • Determine the cause of the event and remediate as necessary. • Contact the Administrator within 24 hours of the emergency event.
Integrity failure of injection or monitoring well	• Pressures and temperatures in the injection well and monitoring wells will be monitored for indication of integrity failure and determination of the cause and extent of the failure. • If wellhead pressure exceeds the maximum allowed surface pressure or the annulus pressure indicates a loss of integrity, the well will automatically be shut in. • Notify the Administrator within 24 hours of an event that triggers an automatic shutdown. • Once the cause of failure is identified, determine the extent of any surface and subsurface impacts, and perform remediation as needed in coordination with the Administrator.

	• Notify the Administrator when injection can be expected to resume.
Failure of injection well monitoring equipment	• Pressure and temperature gauges will be continuously monitored, and the well's Supervisory Control and Data Acquisition (SCADA) system will alert personnel of any monitoring equipment failure. • Notify the Administrator within 24 hours of an event. • Once the cause of failure is identified, repair or replace the equipment in coordination with the Administrator. Remediate any contamination resulting from the event.
Leakage of CO_2 from the storage reservoir	• Analysis of data from the monitoring wells plus the proposed groundwater and soil monitoring systems, per the Testing and Monitoring Plan, will indicate the release of CO_2 out of the injection interval. • If measurements indicate the risk of CO_2 leakage, injection operations will cease until the root cause is identified. • If the indicator parameters are identified, High Plains will develop a work plan to implement additional monitoring stations, as needed, and develop a remediation plan in coordination with the Administrator. • If samples from the USDW indicate parameters outside of drinking water standards, High Plains will arrange for an alternate potable water supply until the USDW is remediated. • If CO_2 is released to the surface in excess of predetermined parameters, an evacuation plan will be initiated.
Induced seismic event	• Identify the location, depth, and magnitude of the event. • If a seismic event occurs within the AOR of the injection well, of a magnitude greater than 3.0, review the pressure and volume injection history to determine if there is a correlation with the injection activities. Confirm that the well has maintained mechanical integrity and whether a loss of CO_2 containment has occurred. • Remediate as necessary in coordination with the Administrator.
Natural disaster	• Preparations will be made as appropriate before the forecasted event, when possible. This would include the shutdown of the EWS Hub if necessary. • Well pressures and temperatures will be continuously monitored to detect any release of CO_2 caused by a natural disaster event. • If inspections or monitoring measurements indicate damage to the injection system, injection operations will cease immediately.

	• Remediate as necessary in coordination with the Administrator.

4.1.5 Response Personnel/Equipment and Training

High Plains will use an Incident Command System (ICS) response structure (Figure 70) when an emergency event has been detected. This structure identifies the individuals designated as team members and indicates the responsibilities required, detailed further below.

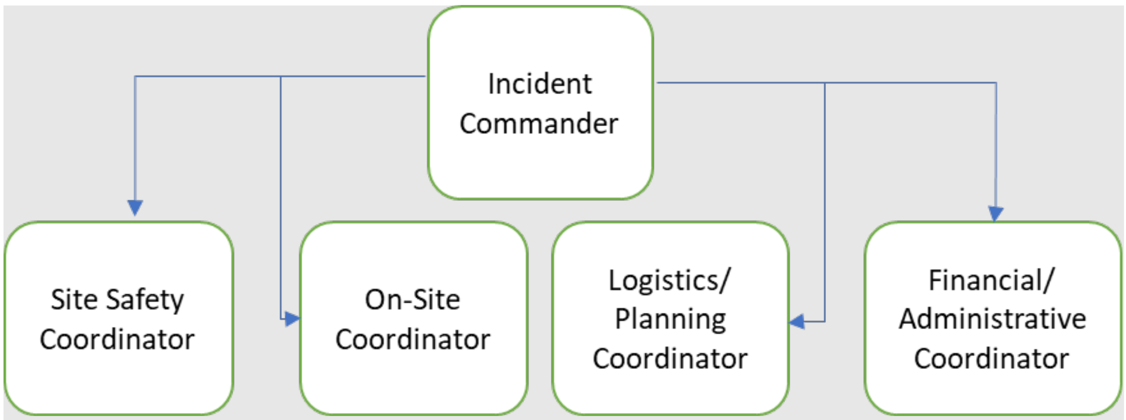

Figure 70 – Incident Command System Response Structure.

The **Incident Commander** is responsible for managing the emergency event and will coordinate emergency response activities. The commander must be fully briefed and have a written delegation of authority. Initially, assigning tactical resources and overseeing operations will be under the commander's direct supervision.

The Incident Commander is responsible for ensuring incident safety, providing information services to internal and external stakeholders, and establishing and maintaining liaison with other agencies participating in the incident. These responsibilities include the following:

- Meet with the operations chief for a briefing on the situation and current activities of on-site personnel.
- Work on-scene with state and federal officials in a support and advisory role.
- Prepare for post-emergency operations to make repairs and return the EWS Hub to service.
- Conduct containment and cleanup operations to minimize personnel and community exposure.
- Communicate with the media.

The **Site Safety Coordinator** ensures site, public, and employee safety; establishes the site safety plan; coordinates the environmental response; maintains contact with the area/region Environmental, Health and Safety (EHS) Project Manager and other EHS personnel as required;

and maintains contact with local, state, and federal emergency response organizations or other agencies as necessary.

The **On-Site Coordinator** handles on-site activities.

The **Logistics/Planning Coordinator** obtains the necessary response equipment, materials, contractors, other company personnel, etc.

The **Financial/Administration Coordinator** arranges for humanitarian assistance, lodging, meals, etc., and manages purchase orders, contracts, etc.

Equipment

The type and severity of an emergency event will determine the equipment needed for the event response. Most event responses, such as stopping injections, well shut-in, etc., will not require special equipment. High Plains will provide any special equipment that might be needed.

Training

All EWS Hub personnel will undergo Hazardous Waste Operations and Emergency Response (HAZWOPER) training per Occupational Safety and Health Administration (OSHA) regulations. Training will cover the contents of the EWS Hub ERP, roles and responsibilities of the Emergency Response Team (i.e., ICS), and employee roles and responsibilities during emergency events, alarms, evacuation procedures, and drills.

High Plains will coordinate with local and county personnel to discuss the ERP and coordinate response actions, including annual drills.

4.1.6 Emergency Communications Plan

Before initiating injection operations, High Plains will provide a written summary of this ERRP to the landowners adjacent to the EWS Hub. This summary will include information about the nature of the CO_2 injection operations, an operator emergency-contact list, potential risks, and responses. Additionally, High Plains will maintain an emergency contact list throughout the project life. If an emergency event occurs, the Site Safety Coordinator will ensure that the correct personnel are contacted. High Plains's designated personnel will handle all communication with the public.

The EWS Hub will rely on pre-designated radio frequencies and telecommunications numbers to manage communications effectively.

4.1.7 Emergency and Remedial Response Plan Review and Updates

This ERRP will be reviewed and updated in accordance with the schedule below:

- Every two years during injection operations and every five years post-injection, in coordination with the AOR review
- Following any significant changes to the EWS Hub, such as adding injection or monitoring wells
- As required by the Administrator

ATTACHMENT B-3: FINANCIAL ASSURANCE DEMONSTRATION PLAN

March 29, 2023 Application	Estimated Total Cost
Submitted as CBI; later rescinded. Not complete - waiting on development by Financial Assurance company	NA

September 8, 2023 Response to Comments				
Activity		Estimated Total Cost		
Corrective Action on Wells in the AOR			**$**	**250,000.00**
Plugging of Injection Well				
Workover Rig	$	100,000.00		
Rental Tools	$	15,000.00		
Mud/Brine	$	10,000.00		
Frac Tanks	$	8,500.00		
Wireline	$	30,500.00		
Final Mechanical Integrity Test and Casing Logs	$	75,000.00		
Cement	$	105,000.00		
Bridge Plugs/Packers	$	75,000.00		
Casing Crew	$	15,000.00		
Miscellaneous	$	58,000.00		
		Total	**$**	**492,000.00**
Post-Injection Site Care and Facility Closure (50 years)				
2D Time-lapse Seismic Surveys (every 5 years)	$	1,970,000.00		
Groundwater and Soil Monitoring	$	1,000,000.00		
Operations and Maintenance of Monitoring Wells	$	5,400,000.00		
Subtotal:	**$**	**8,370,000.00**		
Site Closure				
Monitor Well Plugging (2 wells)	$	984,000.00		
Surface Facilities Closure	$	600,000.00		
Subtotal:	**$**	**1,584,000.00**		
		Total	**$**	**9,954,000.00**
Emergency and Remedial Response (including endangerment to USDWs)				
Comes from Tab TG Risk Matrix Values, cell K53				
		Total	**$**	**7,733,000.00**
		Total	**$**	**18,429,000.00**

January 31, 2024 Draft Financial Assurance Demonstration				
Activity		Estimated Total Cost		
Corrective Action on Wells in the AOR				
Juniper M-1 Plugback				
		Total	**$**	**250,000.00**
Testing and Monitoring (Injection Period)				
2D Time-lapse Seismic Survey (1/5th of $2,808,000)	$	561,600.00		
Groundwater and soil monitoring	$	820,000.00		
Testing and Monitoring logs/testing	$	2,799,996.00		
		Total	**$**	**4,181,596.00**
Plugging of Juniper I-1				
Workover Rig	$	100,000.00		
Rental Tools	$	15,000.00		
Mud/Brine	$	10,000.00		
Frac Tanks	$	8,500.00		
Wireline	$	30,500.00		
Final Mechanical Integrity Test and Casing Logs	$	75,000.00		
Cement	$	105,000.00		
Bridge Plugs/Packers	$	75,000.00		
Casing Crew	$	15,000.00		
Miscellaneous	$	58,000.00		
		Total	**$**	**597,000.00**
Post-Injection Site Care and Facility Closure				
Post-Injection Site-Care (50 years)				
2D Time-lapse Seismic Survey (1/5th of $2,808,000)	$	561,600.00		
Groundwater soil monitoring	$	1,025,000.00		
Operations and maintenance of monitoring wells	$	2,160,000.00		
Subtotal	**$**	**3,746,600.00**		
Site Closure				
Juniper M-1 Plugging				
Workover Rig	$	100,000.00		
Rental Tools	$	15,000.00		
Mud/Brine	$	10,000.00		
Frac Tanks	$	8,500.00		
Wireline	$	30,500.00		
Final Mechanical Integrity Test and Casing Logs	$	75,000.00		
Cement	$	210,000.00		
Casing Crew	$	15,000.00		
Miscellaneous	$	58,000.00		
Surface Facility Closure	$	600,000.00		
Subtotal	**$**	**1,122,000.00**		
		Total	**$**	**4,868,600.00**
Emergency and Remedial Response (including endangerment to USDWs)				
Average	$	1,125,916.00		
Standard Deviation	$	1,096,628.00		
5th Percentile	$	-		
50th Percentile	$	935,290.00		
95th Percentile	$	3,228,341.00		
99th Percentile	$	4,473,010.00		
Minimum	$	-		
Maximum	$	9,376,550.00		
		Coverage 5 well Total (maximum)	**$**	**9,376,550.00**
		Juniper I-1 (adjusted maximum)	**$**	**852,414.00**
For Juniper	**Total**		**$**	**10,749,610.00**

February 22, 2024 Draft Financial Assurance Demonstration				
Activity		Estimated Total Cost		
Corrective Action on Wells in the AOR				
Juniper M-1 Plugback				
		Total	**$**	**250,000.00**
Testing and Monitoring (Injection Period)				
2D Time-lapse Seismic Survey (1/5th of $2,808,000)	$	561,600.00		
Groundwater and soil monitoring	$	1,025,000.00		
Testing and Monitoring logs/testing	$	3,500,000.00		
		Total	**$**	**5,086,600.00**
Plugging of Juniper I-1				
Workover Rig	$	100,000.00		
Rental Tools	$	15,000.00		
Mud/Brine	$	10,000.00		
Frac Tanks	$	8,500.00		
Wireline	$	30,500.00		
Final Mechanical Integrity Test and Casing Logs	$	75,000.00		
Cement	$	105,000.00		
Bridge Plugs/Packers	$	75,000.00		
Casing Crew	$	15,000.00		
Miscellaneous	$	58,000.00		
		Total	**$**	**597,000.00**
Post-Injection Site Care and Facility Closure				
Post-Injection Site-Care (50 years)				
2D Time-lapse Seismic Survey (1/5th of $2,808,000)	$	561,600.00		
Groundwater soil monitoring	$	512,500.00		
Operations and maintenance of monitoring wells	$	2,160,000.00		
Subtotal	**$**	**3,234,100.00**		
Site Closure				
Juniper M-1 Plugging				
Workover Rig	$	100,000.00		
Rental Tools	$	15,000.00		
Mud/Brine	$	10,000.00		
Frac Tanks	$	8,500.00		
Wireline	$	30,500.00		
Final Mechanical Integrity Test and Casing Logs	$	75,000.00		
Cement	$	210,000.00		
Casing Crew	$	15,000.00		
Miscellaneous	$	58,000.00		
Surface Facility Closure	$	600,000.00		
Subtotal	**$**	**1,122,000.00**		
		Total	**$**	**4,356,100.00**
Emergency and Remedial Response (including endangerment to USDWs)				
Average	$	1,125,916.00		
Standard Deviation	$	1,096,628.00		
5th Percentile	$	-		
50th Percentile	$	935,290.00		
95th Percentile	$	3,228,341.00		
99th Percentile	$	4,473,010.00		
Minimum	$	-		
Maximum	$	9,376,550.00		
		Total	**$**	**15,000,000.00**
For Juniper	**Total**		**$**	**25,289,700.00**

February 29, 2024 Financial Assurance Demonstration				
Activity		Estimated Total Cost		
Corrective Action on Wells in the AOR				
Juniper M-1 Plugback				
		Total	**$**	**250,000.00**
Testing and Monitoring (Injection Period)				
Soil Gas Sampling Method				
Locations for Sampling		1		
Time (hours)		4		
Labor ($125/hour)	$	1,000.00		
Tedlar Bags ($15/bag)	$	75.00		
Lab Analysis	$	1,000.00		
Report Generation	$	1,000.00		
Equipment	Purchased prior to injection			
Total/Occurrence	**$**	**2,575.00**		
Groundwater Monitoring				
Locations for Sampling		1		
Total Groudnwater Wells		3		
Labor (purging and testing)	$	10,000.00		
Lab Analysis	$	5,000.00		
Truck Usage	$	2,000.00		
Per Diem	$	1,000.00		
Report Generation	$	10,000.00		
Contingency	$	20,000.00		
Total/Occurrence	**$**	**48,000.00**		
Annual Air Monitoring				
Labor Field Coordination	$	1,000.00		
Locations for Sampling		1		
Labor (monthly inspections)	$	1,548.00		
Truck Usage (mob/demob)	$	1,400.00		
Per diem (mob/demob)	$	2,400.00		
Labor (Atmospheric Monitoring)	$	1,585.00		
Vehicle rental	$	1,440.00		
per diem	$	2,400.00		
Field Equipment and supplies	$	19,008.00		
data management	$	2,400.00		
SQL Server License/Month	$	3,960.00		
cloud Storage and Server	$	1,901.00		
Report Generation	$	2,110.00		
Total/Annum	**$**	**41,153.00**		
Annual Injector Well Testing and Monitoring Program				
Annular Pressure Test	$	5,000.00		
DTS Fiber Optic Log	$	30,000.00		
Mob/Demob Wireline	$	5,000.00		
Per Diem	$	5,200.00		
Pulsed Neutron Log	$	25,000.00		
Mob/Demob Cased Hole	$	5,000.00		
Miscellaneous	$	4,750.00		
Juniper I-1 Subtotal/Occurrence	**$**	**79,950.00**		
5-Year Testing and Monitoring Program				
Annular Pressure Test	$	5,000.00		
Temp Log, Static and Dynamic	$	8,000.00		
Pressure Fall Off Test	$	30,000.00		
DTS Fiber Optic Log	$	30,000.00		
Mob/Demob Wireline	$	5,000.00		
Per Diem	$	12,750.00		
Multiple Arm Caliper	$	25,000.00		
Electro-magnetic Tools	$	25,000.00		
Pulsed Neutron Log	$	25,000.00		
Pulling Tubing and Running Tubing	$	9,000.00		
Additional Rig Costs (Mob/Demob)	$	8,000.00		
Unit Charge Wireline/Rig	$	36,500.00		
Mob/Demob Cased Hole	$	5,000.00		
Juniper I-1 Subtotal/Occurrence	**$**	**214,500.00**		
Injection Period Testing and Monitoring (25 Years)				
2D Time-lapse Seismic Survey (1/5th of $2,808,000)			$	561,600.00
Soil Gas Monitoring			$	128,750.00
Groundwater monitoring			$	2,400,000.00
Air Monitoring			$	1,028,825.00
Testing and Monitoring logs/testing			$	2,250,000.00
		Total	**$**	**6,369,175.00**

Plugging of Juniper I-1					
Workover Rig	$	100,000.00			
Rental Tools	$	15,000.00			
Mud/Brine	$	10,000.00			
Frac Tanks	$	8,500.00			
Wireline	$	30,500.00			
Final Mechanical Integrity Test and Casing Logs	$	75,000.00			
Cement	$	105,000.00			
Bridge Plugs/Packers	$	75,000.00			
Casing Crew	$	15,000.00			
Miscellaneous	$	58,000.00			
			Total	**$**	**597,000.00**
Post-Injection Site Care (50 years) and Facility Closure					
Monitoring					
2D Time-lapse Seismic Survey (1/5th of $2,808,000)	$	561,600.00			
Soil Gas Monitoring	$	128,750.00			
Groundwater soil monitoring	$	2,400,000.00			
Air Monitoring	$	2,057,650.00			
Testing and monitoring logs	$	2,464,500.00			
Subtotal	**$**	**7,612,500.00**			
Operations and Maintenance of Monitoring Wells					
Subtotal	**$**	**2,160,000.00**			
Juniper M-1 Plugging					
Workover Rig	$	100,000.00			
Rental Tools	$	15,000.00			
Mud/Brine	$	10,000.00			
Frac Tanks	$	8,500.00			
Wireline	$	30,500.00			
Final Mechanical Integrity Test and Casing Logs	$	75,000.00			
Cement	$	210,000.00			
Casing Crew	$	15,000.00			
Miscellaneous	$	58,000.00			
Subtotal ($/well)	**$**	**522,000.00**			
Surface Facility Closure					
Annual Labor Costs	$	30,000.00			
Annual Ops Cost (utilities, equipment, etc.)	$	10,000.00			
Annual Miscellaneous & Contingency	$	3,200.00			
Surface Remediation	$	120,000.00			
Road Remediation	$	120,000.00			
Surface Equipment Removal	$	120,000.00			
Pipelein Flushing and Abandonment in Place	$	120,000.00			
Additional Miscellaneous & Contingency	$	120,000.00			
Subtotal ($/well)	**$**	**643,200.00**			
			Total	**$**	**10,937,700.00**
Emergency and Remedial Response (including endangerment to USDWs)					
Average	$	1,125,916.00			
Standard Deviation	$	1,096,628.00			
5th Percentile	$	-			
50th Percentile	$	935,290.00			
95th Percentile	$	3,228,341.00			
99th Percentile	$	4,473,010.00			
Minimum	$	-			
Maximum	$	9,376,550.00			
			Total	**$**	**9,376,550.00**
	Total			**$**	**27,530,425.00**

February 13, 2025 Annual Update to the Financial Assurance Cost Estimate

Activity		Estimated Total Cost
Corrective Action on Wells in the AOR - Juniper M-1 Plugback		
Total	**$**	**256,000.00**
Testing and Monitoring (Injection Period)		
Total	**$**	**6,522,035.00**
Plugging of Juniper I-1		
Total	**$**	**611,328.00**
Post-Injection Site Care (50 years) and Facility Closure		
Total	**$**	**10,665,677.00**
Juniper M-1 Plugging		
Total	**$**	**534,528.00**
Emergency and Remedial Response (including endangerment to USDWs)		
Total	**$**	**9,601,587.00**

In 2024 the GDP price deflator was 2.4% (The GDP price deflator for 2024 is 125.230 and the GDP price deflator for 2023 is 122.273. The percentage change is (new-old)/old x 100.)	**Total**	**$ 28,191,155.00**
The GDP price deflator for 2024	125.23	
The GDP price deflator for 2023	122.273	
	0.024183589	
%	2.418358918	

Updated Financial Assurance Demonstration Plan for Juniper I-1

February 29, 2024

1.0 Financial Assurance Demonstration Plan

This Financial Assurance Demonstration Plan (FADP) was developed to meet the requirements of WYDEQ Chapter 24 **§26**. High Plains will maintain financial responsibility for all applicable phases of this project, including:

- Permitting/characterization;
- Testing and monitoring (pursuant to Chapter 24 **§20**);
- Operations, including injection and well-plugging (pursuant to Chapter 24 **§18** and **§23**);
- Post-injection site care; and
- Emergency and remedial response (pursuant to Chapter 24 **§25**).

The estimation of required coverage is provided for Juniper. The emergency and remedial response costs and the 2D seismic survey costs for the injection period and the post injection and site closure period were evaluated first as a total for the five injection wells and five monitoring wells listed in Table 1, and then assessed for the Juniper Project. The FADP and the associated instruments of coverage for emergency remedial response will be updated at a later time to include the Spirea injection and Spirea monitoring wells.

Table 1—Well names and location information for the wells included in the emergency and remedial response financial assurance cost estimation and total seismic cost estimation.

Project Wells	
Proposed Injection Wells	**Proposed Deep Monitoring Wells**
Juniper I-1	**Juniper M-1**
Azalea I-1	Azalea M-1
Cypress I-1	Cypress M-1
Barberry I-1	Barberry M-1
Old Barberry I-1	Old Barberry M-1

All costs included in this financial assurance cost estimate are third party costs. These costs will be updated annually to account for inflation costs and project-related changes.

1.1 Cost Estimation

A financial assurance cost estimate, based on current dollars, provided in Table 2. Cost estimates for third party monitoring are provided in Tables 3-8.

Table 2 has been estimated for the following:

- Performing corrective action for all wells in the AoR that require it (as identified and approved by the Administrator)
- Plugging the injection well
- Post-injection site care (including plume stabilization, monitoring, measurement, verification, corrective action, and other actions needed, to ensure that USDWs are

not endangered from the time of well-plugging until site closure is certified by the Administrator and above ground-reclamation is completed) and site closure

- Testing and monitoring activities throughout the injection period
- Emergency and remedial response

Table 2—Summary of financial assurance cost estimations.

Activity Estimated Total Cost	
Corrective Action on Wells in the AOR	$250,000
Testing and Monitoring (25 year Injection Period)	$6,369,175
Plugging of Juniper I-1	$597,000
Post-Injection Site Care and Facility Closure	$10,937,700
Emergency and Remedial Response (including endangerment to USDWs)	$2,790,640
Total	**$20,944,515**

Table 3—Third Party Cost Estimate for Soil Gas Sampling

Soil Gas Sampling Method	
Locations for Sampling	1
Time (Hours)	4
Labor ($125/hr)	$1000
Tedlar Bags ($15/bag)	$75
Lab Analysis	$1000
Report Generation	$1000
Equipment	Purchased Prior to Injection
Total/ Occurrence	**$2,575**

Table 4—Third Party Cost Estimate for Ground Water Sampling

Ground Water Monitoring	
Locations for Sampling	1
Total Ground Water Wells	3
Labor (purging and testing)	$10,000
Lab Analysis	$5,000
Truck Usage	$2,000
Per Diem	$1,000
Report Generation	$10,000
Contingency	$20,000
Total/ Occurrence	**$48,000**

Table 5—Third Party Cost Estimate for Vegetation Survey and Continuous Air Monitoring

Annual Air Monitoring	
Labor Field Coordination	$1,000
Locations for Sampling	1
Labor (Monthly Inspections)	$1,548
Truck Usage (Mob/Demob)	$1,400
Per Diem (Mob/Demob)	$2,400
Labor (Atmospheric Monitoring)	$1,585
Vehicle Rental	$1,440

Per Diem	$2,400
Field Equipment and Supplies	$19,008
Data Management	$2,400
SQL Server License/ Month	$3,960
Cloud Storage and Server	$1,901
Report Generation	$2,110
Total/ Annum	**$41,153**

Table 6—Third Party Cost Estimate for Seismic Monitoring Program.

2D Seismic Monitoring	
Miles Over 5 Well Scenario	72
Cost/ Mile	$39,000
Seismic Total 5 Well Scenario	$2,800,000
Juniper I-1 Subtotal	**$561,000**

Table 7—Third Party Cost Estimate for Annual Well Testing and Monitoring Program.

Annual Injector Well Testing and Monitoring Program	
Annular Pressure Test	$5,000
DTS Fiber Optic Log	$30,000
Mob/ Demob Wireline	$5,000
Per Diem	$5,200
Pulsed Neutron Log	$25,000
Mob/Demob Cased Hole	$5,000
Miscellaneous	$4,750
Juniper I-1 Subtotal/ Occurrence	**$79,950**

Table 8—Third Party Cost Estimate for Annual Well Testing and Monitoring Program.

5 Year Testing and Monitoring Program	
Annular Pressure Test	$5,000
Temp Log, Static and Dynamic	$8,000
Pressure Fall Off Test	$30,000
DTS Fiber Optic Log	$30,000
Mob/ Demob Wireline	$5,000
Per Diem	$12,750
Multiple Arm Caliper	$25,000
Electro-magnetic Tools	$25,000
Pulsed Neutron Log	$25,000
Pulling Tubing and Running Tubing	$9,000
Additional Rig Costs (Mob/ Demob)	$8,000
Unit Charge Wireline/ Rig	$36,500
Mob/ Demob Cased Hole	$5,000
Juniper I-1 Subtotal/ Occurrence	**$214,500**

1.1.1 Corrective Action

One well within the AoR requires corrective action. The remediation costs included in Table 9 are for the activities in the proposed remediation plan for the Juniper M-1. No other corrective action remediations are anticipated for the AoR.

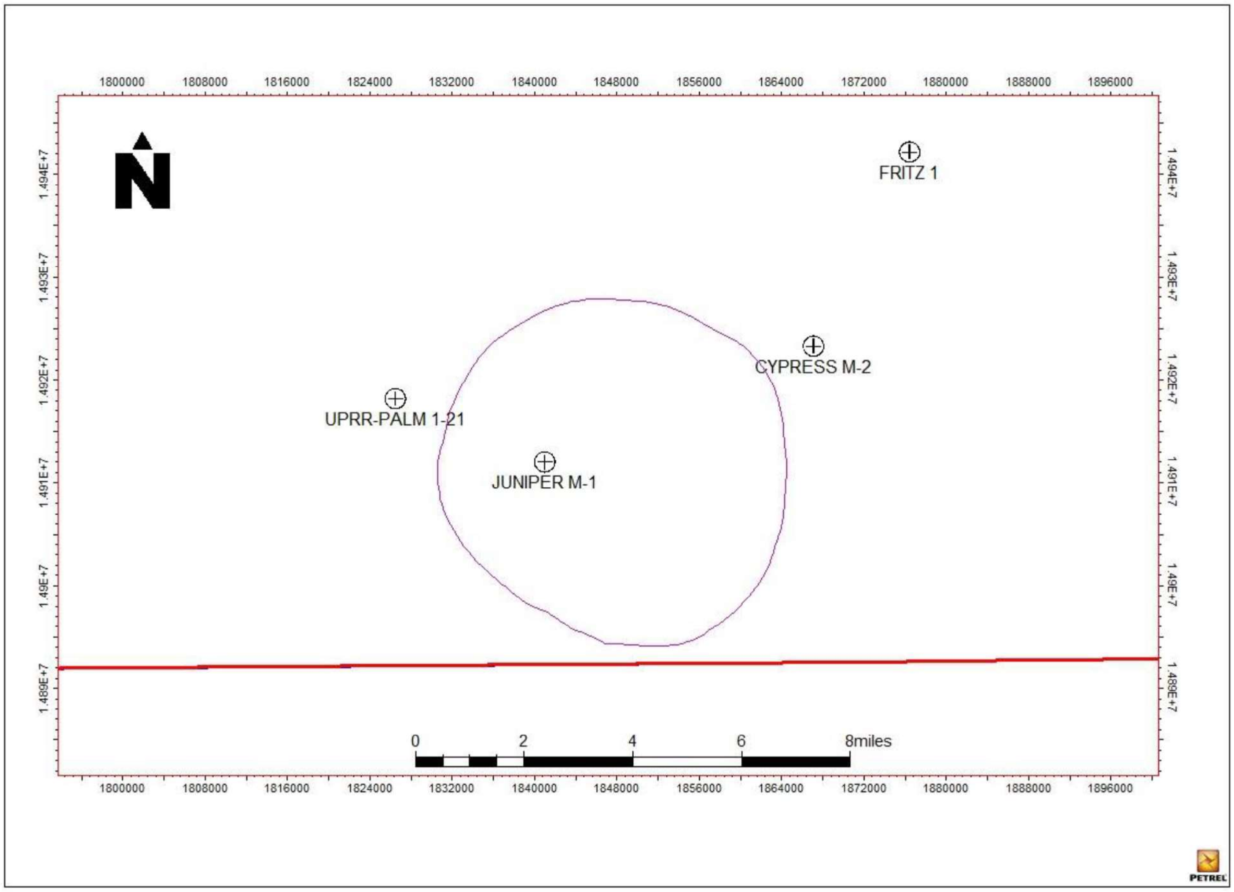

Figure 1. Map demonstrating that the Juniper M-1 is the only penetration (of the top seal or deeper) within the Juniper I-1 plume.

Table 9—Financial assurance cost estimations for corrective action within the AoR.

Corrective Action Cost Estimate	
Juniper M-1 Plugback	$250,000
Total	**$250,000**

1.1.2 Testing and Monitoring during the Injection Period

The cost estimates for the testing and monitoring for the project are included in Table 10 . These costs are inclusive of the activities occurring during the modeled injection period of the Juniper I-1 outlined in the Testing and Monitoring Plan. The cost for the 2D seismic is estimated to be

$561,600; one fifth of the total estimated seismic cost of $2,808,000 for a 2D seismic survey covering the total modeled plume area for the wells listed in Table 1.

Table 10 — Financial assurance cost estimations for Testing and Monitoring

Injection Period Testing and Monitoring (25 years)	
2D Time-lapse Seismic Survey (1/5th of $2,808,000)	$561,600
Soil Gas Monitoring	$128,750
Groundwater Monitoring	$2,400,000
Air Monitoring	$1,028,825
Testing and Monitoring Logs	$2,250,000
Total	**$6,369,175**

1.1.3 Injection Well Plugging

The cost estimate for the plugging of the Juniper I-1 is $597,000. The costs for this estimate are broken down in Table 11. A detailed plugging procedure is included in *Section 4.5 Plugging Plan* in the Juniper I-1 permit with updates included in the Second Response to Comments.

Table 11—Financial assurance cost estimations for injection well plugging.

Juniper I-1 P&A Cost Estimate		
Workover Rig	$	100,000
Rental Tools	$	15,000
Mud/Brine	$	10,000
Frac Tanks	$	8,500
Wireline	$	30,500
Final Mechanical Integrity Test and Casing Logs	$	75,000
Cement	$	210,000
Bridge Plugs/Packers	$	75,000
Casing Crew	$	15,000
Miscellaneous	$	58,000
Total ($/well)	**$**	**597,000**

1.1.4 PISC and Site Closure

The PISC and site closure cost estimates shown in Table 12 and include costs for the post injection period related to the monitoring described in *Section 4.6 Post Injection Site Care and Facility Closure Plan* of the original Juniper I-1 permit with updates in the Second Response to Comments. The site closure costs include plugging the Juniper M-1 for an estimated $522,000 as described in Table 13, and surface facility closure costs for an estimated $600,000 as described in Table 14. The cost for the 2D seismic was estimated to be $561,600, one fifth of the total estimated seismic cost of $2,808,000 for a 2D seismic survey covering the total modeled plume area for the wells listed in Table 1.

Table 12—Financial assurance cost estimations for PISC and site closure.

Post-Injection Site-Care (50 years) and Facility Closure	
Monitoring	
2D Time-lapse Seismic Survey (1/5th of $2,808,000)	$561,600
Soil Gas Monitoring	$128,750
Ground Water Monitoring	$2,400,000
Air Monitoring	$2,057,650
Testing and Monitoring Logs	$2,464,500
Subtotal	**$7,612,500**
Operations and Maintenance of Monitoring Wells	
Subtotal	**$2,160,000**
Juniper M-1 Plugging	
Juniper M-1 Plugging Subtoal	**$522,000**
Surface Facilities Closure	
Subtotal	**$643,200**
PISC and Facility Closure Total	
Total	**$10,937,700**

Table 13—Financial assurance cost estimations for monitoring well plugging.

Juniper M-1 P&A Cost Estimate		
Workover Rig	$	100,000
Rental Tools	$	15,000
Mud/Brine	$	10,000
Frac Tanks	$	8,500
Wireline	$	30,500
Final Mechanical Integrity Test and Casing Logs	$	75,000
Cement	$	210,000
Casing Crew	$	15,000
Miscellaneous	$	58,000
Subtotal ($/well)	**$**	**522,000**

Table 14—Post-Injection Site Care Ops and Closure.

Post Injection Site-Care- Ops and Closure	
Annual Labor Costs	$30,000
Annual Ops Costs (utilities, equipment, etc.)	$10,000
Annual Miscellaneous & Contingency	$3,200
Surface Remediation	$120,000
Road Remediation	$120,000
Surface Equipment Removal	$120,000
Pipeline Flushing and Abandonment in Place	$120,000
Additional Miscellaneous & Contingency	$120,000
Subtotal ($/well)	**$ 643,200**

1.1.5 Emergency and Remedial Response

The Emergency Remedial Response (ERR) Financial Assurance Costs estimation was performed by Industrial Economics, Inc. (IEc) and the summary of the Monte Carlo outputs, including the total maximum per occurrence ERR cost estimate is provided in Table 15. The maximum per occurrence cost estimate across 50,000 trials was $9,376,550. The estimate was calculated per the requirements of Chapter 24 §25. IEc believes this estimate to be reasonable and appropriately conservative for emergency and remedial response involving event-based occurrences in the project location. The basis for the IEc cost estimates is discussed in greater detail in the report included in Exhibit 1 in the Response to Comments Attachments.

Table 15—Financial assurance cost statistical outcomes for emergency and remedial response.

Emergency and Remedial Response Cost Estimation	
Average	$1,125,916
Standard Deviation	$1,096,628
5th Percentile	$0

50th Percentile	$935,290
95th Percentile	$3,228,341
99th Percentile	$4,473,010
Minimum	$0
Maximum	$9,376,550
Total (per occurrence maximum)	**$9,376,550**

1.2 Financial Assurance Instruments

The financial assurance instruments will be submitted during the application phase of the project and on the required forms.

1.2.1 Instrument Funding

The costs outlined in the Cost Estimation section above have been broken into the anticipated phases of funding in Tables 16 and 17.

Table 16- Financial Assurance Components and Costs – Pre-injection and year 1 of Injection

Financial Responsibility Element	**Cost Estimate**	**When Funded**
A. Corrective Action:	$250,000	Prior to well construction
B. Injection Well Plugging	$597,000	Prior to well construction
C. PISC and Site Closure – Monitor Well	$522,000	Prior to well construction
D. PISC and Site Closure – Site Remediation	$643,200	Prior to well construction
E. PISC Testing & Monitoring	$7,612,500	Prior to well construction
Total Cost Prior to Well Construction:		**$9,624,500**
F. Emergency and Remedial Response	$2,790,640	Prior to Authorization to Inject
Total Cost Prior to Authorization to Inject:		**$2,790,640**
G. Operation and Maintenance During Testing and Monitoring – Injection Period	$254,767	After one (1) year of injection
One (1) Year After Injections Begin:		**$254,767**

Table 17- Financial Assurance Components and Costs – year 2 through 25 of injection period

Financial Responsibility Element	**Cost Estimate**	**When Funded**
Financial Responsibility Element - years 2-25	Cost Estimate	When Funded
Operation and Maintenance During Testing and Monitoring – Injection Period		Within thirty (30) days of the anniversary date of submittal of original financial assurance listed on Row G of Table 9.
Total Cost for year 2-20 of Injection:		**$6,114,408**

1.2.2 Public Liability Insurance

High Plains will obtain and maintain public liability insurance for the Juniper I-1 and associated facilities to meet the requirements of Wyoming Statutes **§35-11-313(f)(ii)(O)** and WYDEQ Chapter 24 **§26(l)(i)(B)**. Such policy will identify each facility by name, address, and EPA Identification Number as well as identify the amounts and types of coverage for each facility. The policy will be arranged by Marsh USA LLC, a subsidiary of Marsh McLennan, and provided by Ascot. A CCS Support Letter is provided in Exhibit 2 in the Response to Comments Attachments. The specimen policy and certificate of insurance from Ascot are provided in Exhibit 3 in the Response to Comments Attachments.

1.2.3 Surety Bond

Berkley Surety has confirmed that High Plains will be able to obtain a surety bond for the coverage of the remaining financial assurance items, per the letter provided in Exhibit 4 in the Response to Comments Attachments. High Plains is still determining what form of financial assurance will be used to cover the ERR but will have that secured prior to the authorization to inject.

APPENDIX A—FINANCIAL DEMONSTRATION PLAN

Exhibit 1—Cost Estimates for Emergency and Remedial Response Section and Event-Based Risk Activities

Exhibit 2—Pollution Support Letter – Marsh

Exhibit 3—Specimen Policy and Certificate

Exhibit 4—Surety Bond Letter - Berkley Surety

29 February 2024

Tallgrass Energy Eastern Wyoming Sequestration Hub Project

Written Financial Assurance Cost Estimates in Support of:

Section 26(b)(i)(E) Emergency and Remedial Response

Section 26(b)(ii)(A)-(G) Event-Based Risk Activities

(Risks 1 through 7 of the Risk Activity Table in Appendix A of Chapter 24)

Prepared for:

Tallgrass Energy

Eastern Wyoming Sequestration (EWS) Hub Project

Prepared by:

Industrial Economics, Inc.

1.0 INTRODUCTION

This report provides written Financial Assurance Cost Estimates for the Eastern Wyoming Sequestration Hub located in Laramie, Wyoming which will comprise five Class VI injection wells (hereinafter, EWS Hub Project).[1] The estimates conform to the regulatory requirements promulgated at Wyoming Water Quality Rules (WWQR) Chapter 24: Section 26(b)(i)(E) Emergency and Remedial Response, and Section 26(b)(ii)(A)-(G) Event-Based Risk Activities (Risks 1 through 7 of the Risk Activity Table in Appendix A of Chapter 24).[2] These estimates are intended to inform the face amount of financial assurance(s) necessary to satisfy emergency and remedial response actions, and the stated event-based risk activities summarized in Appendix A of Chapter 24.[3,4] For the avoidance of doubt, this document does **not** include costs associated with corrective action, well plugging and abandonment, post-injection site care or site closure (including removal of above-ground facilities and site reclamation) in the estimation of ERR response costs. All such costs are addressed elsewhere in the Tallgrass Class VI permit application.

Estimating financial assurance cost estimates for possible emergency and remedial responses, as well as actions to address the event-based risk activities contemplated in Appendix A of Chapter 24 necessitates understanding of the interactions between the carbon capture and underground storage (CCUS) stream, the geophysical environment in which it will be stored, and nearby populations. The long-term nature of such projects, the low (but not zero) probability of a release event occurring that may require emergency and remedial response, variability in potential incident conditions at the site, the size of the potentially impacted population, and likely exposure pathways (among other factors) inform the following emergency and remedial response cost estimates.

As described in more detail below, we combine readily available information with the results of Monte Carlo analysis tailored to project-specific risks and uncertainties to generate reasonable upper bound estimates of financial assurance costs related to emergency and remedial response and WWQR event-based risk activities.

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[1] The EWS Hub Project comprises the following five injection wells: Juniper I-1, Azalea I-1, Cypress I-1, Barberry I-1 and Old Barberry I-1 at latitude/longitudes (NAD83): 41.055976, -104.272853; 41.101266, -104.334272; 41.086491, -104.214625; 41.135708, -104.251332; and 41.200677, -104.144977 (respectively). The resulting estimates of ERR coverages relate to risk-based event activities arising within the project AOR, and have not been scaled to individual injection wells.

[2] Per WWQR Chapter 24, Section 26(b)(iii) and Appendix A, Risk Activity Table, cost estimation for "Major Risk" 1 through 7, as listed in Appendix A of WWQR, can be found in the following sections of this report: Section 7.5 (Risk 1 Mineral Rights Infringement), Sections 7.1 and 7.2 (Risk 2 Water Quality Contamination), Sections 7.3 and 7.4 (Risk 3 Single Large Volume CO2 Release to Surface and Risk 4 Low Level CO2 Release to Surface), Section 7.7 (Risk 5 Storage Rights Infringement), Section 7.6 (Risk 6 Modified Surface Topography Resulting in Property/Infrastructure Damage), and Sections 7.1 and 7.2 (Risk 7 Entrained Contaminant (Non-CO2) Releases). As we understand from the project developer, Risk 8 (Accidents/Unplanned Events (Typical Insurable Events) is addressed through the company's general liability insurance coverages, and therefore are not separately quantified in this report for purposes of ERR cost estimation.

[3] Per WWQR Chapter 24, Section 26(b), financial assurance cost estimates (including those that address emergency and remedial response) must be updated annually, or within 60 days of receiving notice that the Administrator has determined that a demonstration of financial assurance is not adequate. Consistent with Section 25(a)(i) and (a)(ii) requirements, ERR cost estimates also will need to be reevaluated after any updates to the emergency and remedial response plan.

[4] In general, because "accidents and unplanned events" are typical insurable events that are covered through the company's general liability coverages, they are not addressed further in this analysis. Financial assurance cost estimates for well capping and permitted abandonment, and removal of above-ground facilities and site reclamation are addressed elsewhere in the Tallgrass submission, and therefore are not addressed further in this analysis.

Importantly, model results will vary with factors that would be expected to impact project risk, such as: the purity of the sequestration stream and degree to which any co-contaminants might result in additional emergency response challenges; the duration of injection and post-injection site care activities; the number of wells present in the Area of Review (AOR) that extend below USDWs and the proportion that penetrate caprock; population density and the type/extent of private water well use; the presence and size of community/municipal water systems; and the use and length of new pipelines to transport captured CO2 to injection well locations. In our view, the following analyses and resulting cost estimates provide a reasonable, conservative, and objective basis for determining the face amount of financial assurance instrument(s) necessary to support a Class VI permit consistent with Wyoming regulation.

The cost estimation method applied to the EWS Hub Project is based on the peer-reviewed approach pioneered by Industrial Economics, Incorporated ("IEc"); this approach has been used to inform estimation of emergency and remedial response costs in previously approved Class VI permits.[5] IEc tailored the valuation parameters of its Carbon Capture and Storage stochastic Monte Carlo model ("CCSvt model") to reflect site-specific factors associated with the EWS Hub Project. Specifically, the model's input parameters reflect the geologic location and specific chemical composition of the project's CCUS stream, as well as site-specific conditions that exist within the established area of review. The analysis adopts several conservative input assumptions and incorporates probabilistic calculations that allow for multiple release incidents through operation and post-injection site care. Cost estimates are based upon generally accepted actions to address the types of events identified in WWQR Chapter 24 Section 26(b)(ii) and the Risk Activity Matrix identified in Section 26(b)(iii) and supported by WWQR Chapter 24 Appendix A.

Based on a model run of 50,000 Monte Carlo trials **we estimate an upper-bound financial assurance cost estimate to satisfy emergency and remedial response and WWQR event-based risk activities of $9.4 million in current 2023 dollars.** This upper-bound cost estimate reflects the single Monte Carlo trial with the greatest financial assurance costs out of the 50,000 trials run. We believe this estimate to be reasonable and appropriately conservative. In the sections that follow, we discuss the basis for our cost estimates in greater detail.

2.0 WWQR CHAPTER 24 SECTION 26: FINANCIAL ASSURANCE COST REQUIREMENTS

The Wyoming regulations promulgated under Chapter 24 Section 26 require demonstration of financial responsibility, and specifically that owners or operators of Class VI wells establish, demonstrate, and maintain financial responsibility for emergency and remedial response pursuant to Section 25 of the Chapter. In deriving the financial assurance cost estimate, owners and operators of Class VI wells must consider the Risk Activity Matrix in Appendix A of Chapter 24, which includes the following array of event-based risk activities:

A. Contamination of underground sources of water including, drinking water supplies;
B. Mineral rights infringement;

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[5] This approach informed the ERR coverage estimates for the Class VI permits in North Dakota, including for example, Dakota Gasification Company (Case No. 29450), Red Trail Energy, LLC (Case No. 28848) and Blue Flint Sequester Company, LLC (Case No.: 29888). See Trabucchi, C., Donlan, M., Sprit, V., Friedman, S. and Esposito, R., 2014, 'Application of a Risk-Based Probabilistic Model (CCSvt Model) to Value Potential Risks Arising from Carbon Capture and Storage', Energy Procedia 63 (2014) 7608-7618, https://www.sciencedirect.com/science/article/pii/S1876610214026101. See also Trabucchi, C., Donlan, M. and Wade, S., 2010 'A Multi-Disciplinary Framework to Monetize Financial Consequences Arising from CCS Projects and Motivate Effective Financial Responsibility', International Journal of Greenhouse Gas Control 4 (2010) 388-395, https://www.sciencedirect.com/science/article/abs/pii/S1750583609001108. See also Trabucchi, C., Donlan, M., Huguenin, M, Konopka, M., Bolthrunis, S., 2012, Valuation of Potential Risks Arising from a Model, Commercial-Scale CCS Project Site: Prepared for GCCSI and the CCS Valuation Sponsor Group, June 1, 2012, https://www.globalccsinstitute.com/archive/hub/publications/40831/iec2012valuationofpotentialrisks.pdf.

C. Single large-volume release of carbon dioxide that impacts human health and safety or that causes ecological damage;
D. Low-level leakage of carbon dioxide to the surface that impacts human health and safety or that causes ecological damage;
E. Storage rights infringement;
F. Property and infrastructure damage, including changes to surface topography and structures;
G. Entrained contaminant releases of contaminants other than carbon dioxide;
H. Accidents and unplanned events;
I. Well capping and permitted abandonment; and
J. Removal of above-ground facilities and site reclamation.

This report focuses on financial assurance cost estimation for Section 26(b)(i)(E) Emergency and Remedial Response, and Section 26(b)(ii)(A)-(G) Event-Based Risk Activities – Risks 1 through 7 of the Risk Activity Table in Appendix A of Chapter 24, (hereinafter WWQR event-based risk activities). As previously noted, because "accidents and unplanned events" are typical insurable events separately covered through the company's general liability coverages, they are not addressed further in this section. The exception are accidents and unplanned events that may endanger an underground source of drinking water, or threaten human health, safety, or the environment. In addition, financial assurance cost estimates for well capping and permitted abandonment (I), and removal of above-ground facilities and site reclamation (J) are addressed elsewhere in the Tallgrass submission, and therefore are not addressed further in this report.

3.0 MONTE CARLO APPROACH TO FINANCIAL ASSURANCE COST ESTIMATION

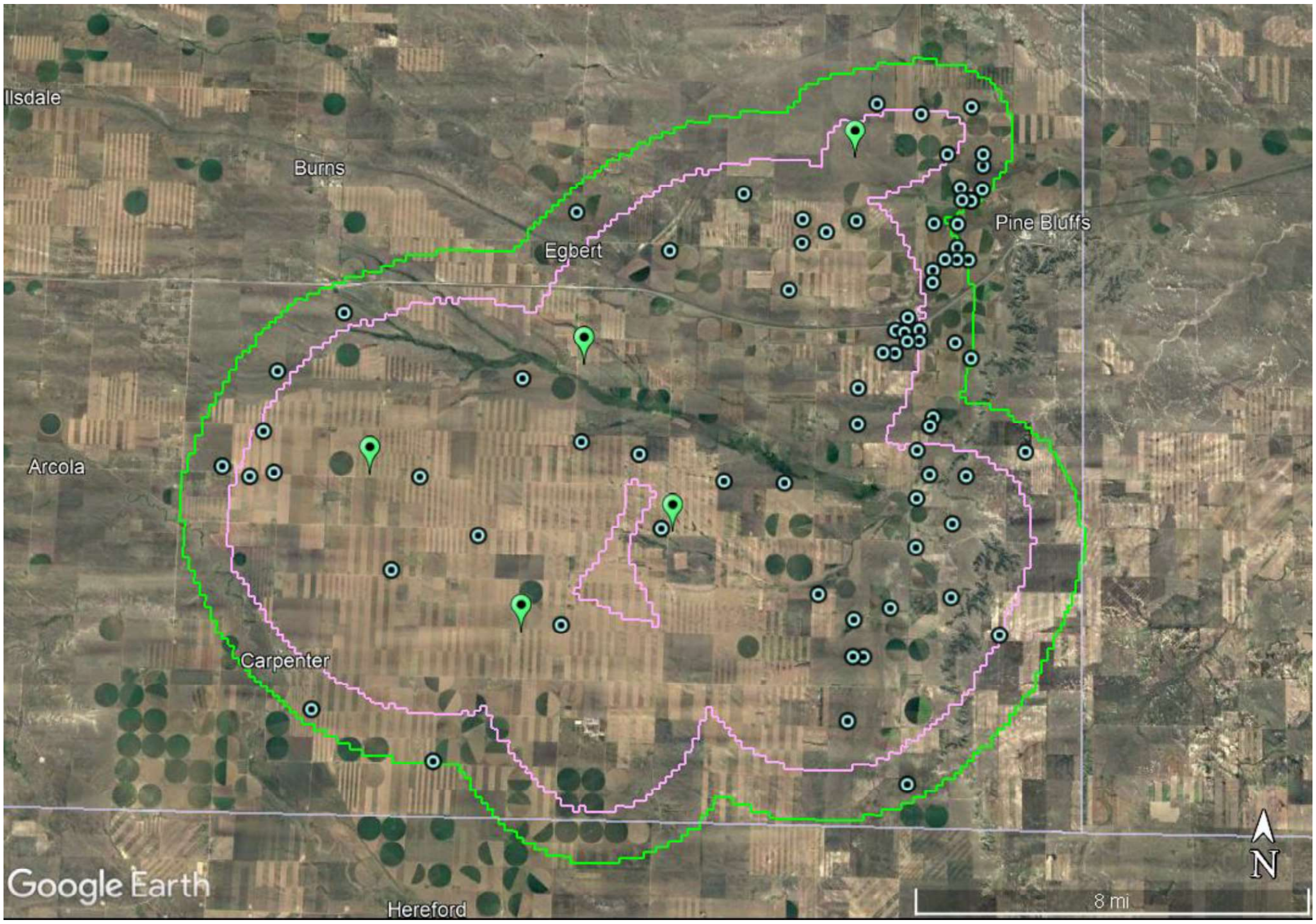
We estimate the cost of emergency and remedial response actions and WWQR event-based risk activities by tailoring the valuation parameters underpinning the CCSvt model to reflect site-specific factors associated with the EWS Hub Project. The CCSvt model published in the peer-reviewed technical literature leverages Monte Carlo (i.e., risk-based, probabilistic) modeling and site-specific scenario analysis (Trabucchi et al., 2014). In our view, Monte Carlo analysis is particularly well suited to the evaluation of potential costs arising from low probability events over long periods of time. As described in Trabucchi et. al (2014), key parameters which inform the CCSvt model inputs include identification of release event types and probabilities, the duration of injection and post-injection/site closure (PISC) activities, and cost distributions for anticipated response actions if ERR incidents or WWQR event-based risk activities occur.

This approach is explicitly consistent with WWQR Chapter 24 Section 26 (b)(iv) requirements, which state: "*the financial assurance cost estimate shall be based upon a multi-disciplinary analytical framework such as Monte Carlo or other commonly accepted stochastic modeling tools*." The section goes on to state that: "*cost curves shall combine risk probabilities, event outcomes, and damages assessment to calculate expected losses under a series of events;*" and, "*for all cases of potential damages, the probability distributions should be identified for 50 percent, 95 percent, and 99 percent probabilities of occurrence.*" The analyses underpinning this report conform to these requirements.

4.0 AREA OF REVIEW

Consistent with WWQR Chapter 24 Section 26(b)(7), the information and analyses underpinning the estimation of financial assurance costs reflect the AOR for the EWS Hub Project, as shown in Exhibit 1 (delineated by the green line). Exhibit 1 also reflects the maximum extent of the CO2 plume, critical pressure increase, or the maximum combination of the two (shown by the purple line) and incorporates a one mile buffer (delineated by the green line). For context, Exhibit 1 also shows the location of the five injection wells (green tear drops) that comprise the EWS Hub Project, as well as adjacent oil and gas wells (blue circles).

Exhibit 1. Area of Review



5.0 DURATION OF INJECTION AND POST-INJECTION SITE CARE (PISC) ACTIVITIES

The financial assurance cost estimates reflect: (1) a 30-year CO2 injection period, (2) a 50-year PISC period, and (3) the possibility of having to address risk-based event activities that potentially could occur during the operational and PISC project phases, necessitating emergency and remedial response action.[6] Consistent with these assumptions, the Monte Carlo calculations incorporate an overall project timeline of 80 years (i.e., 30 years of injection, plus 50 years of PISC). Financial assurance cost estimates are provided for the entirety of the project timeline, as well as by project phase.

6.0 RISK EVENT TYPES AND PROBABILITIES

6.1 Leakage through Wells, Caprock, and Faults

Exhibit 2 identifies the risk event types and probabilities used to estimate emergency and remedial response costs arising from well leaks and leakage through caprock, existing faults and induced faults. We base annual release probabilities on the Final Risk Assessment Report for the FutureGen Project Environmental Impact Statement, revised April 2007.[7] These data reflect extensive, federally-funded analysis, are publicly available, and informed the U.S. Department of Energy's development of an Analog Site Database regarding the release of CO2 from existing injection sites and natural releases.[8] The Analog Site Database includes information from

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[6] Information provided by the project sponsor indicates that the injection periods for the individual injection wells will vary, but none will exceed 30 years.

[7] See https://www.energy.gov/sites/prod/files/EIS-0394-DEIS-RiskAssessmentReport-2007.pdf, p. 6-15, Table 6-11.

[8] Ibid, pg 5-1.

four existing CCUS sites, 16 natural CO2 sites in sedimentary rock formations, and 17 sites in VHM (volcanic, hydrothermal, and metamorphic) areas. These sites have been identified in several natural analog investigations for CCUS. In addition to leakage from reservoirs via natural pathways, the FutureGen efforts considered leakage information from myriad CCUS risk assessments and developed a well failure-release event database, which reflects applied experience from the natural gas storage industry, the oil and gas industry, and wells at natural CO2 reservoirs.

In our view, absent event data arising from recently permitted CCUS projects in North America, the FutureGen databases offer an objective, reasonable basis for determining annual probabilities.[9] Although carbon dioxide enhanced oil recovery (CO2 EOR) is a technique used to recover oil from mature fields that may no longer be productive through traditional recovery methods, to our knowledge, there are no systematic studies of real world frequencies of CO2-related emergency and remedial response events that could be used to augment the FutureGen analyses.[10]

Estimates of potential consequences for the EWS Hub Project are informed by the annual probability point estimates resulting from the FutureGen efforts. In some cases, FutureGen provides a range of probabilities – in such circumstances, we conservatively use the highest probability in the range. Exhibit 2 reflects the release probabilities for eight types of event-based risk activities.[11] For well-related events, the identified probabilities reflect the risk of release for a single well.

As previously noted, five injection wells are planned for the EWS Hub Project (see Exhibit 1). As noted elsewhere in the permit application, Tallgrass has determined that there are three 'deep' (i.e., deep enough to penetrate the injection zone) oil & gas wells in the AOR. However, for purposes of the Monte Carlo calculation, we conservatively assume the presence of two undocumented 'deep' oil & gas wells in the AOR. We believe that doing so provides a buffer against the possibility that records may be incomplete, and construction or natural landscape features may obscure old well locations.[12]

The project sponsor has identified 81 'shallow' (i.e., not deep enough to penetrate the injection zone) oil & gas wells in the AOR. Our Monte Carlo calculations conservatively assume the presence of eight additional undocumented shallow wells.[13] We add these wells for the same reasons discussed above – a buffer against the possibility of incomplete records – resulting in a total of 89 shallow oil & gas wells for purposes of estimating consequences arising from WWQR event-based risk activities. Finally, we include the five anticipated above-

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[9] Notably, since development of the FutureGen analysis, the Arthur Daniels Midland (ADM) site in Decatur, IL was granted a Class VI permit by EPA to inject CO2 into the subsurface environment for purposes of permanent carbon capture and storage. Publicly available information suggests that, over the last decade, ADM has safely and permanently stored more than 3.5 million metric tons of CO2 at its commercial CCS site in Decatur, IL. See: https://www.adm.com/en-us/standalone-pages/adm-and-carbon-capture-and-storage/. To our knowledge, none of the more recently permitted CCS projects in North America are operational and actively injecting CO2 for permanent subsurface storage. Further, off-shore analogs such as Sleipner, do not appear to offer corresponding storage characteristics and attendant risk profiles that are akin to the system contemplated by the EWS Hub Project. In our view, relying on such analogs do not offer a necessarily more reasonable basis for determining annual probabilities than the FutureGen databases.

[10] See for example Porse, Sean, Sarah Wade and Susan Hovorka "Can we Treat CO2 Well Blowouts like Routine Plumbing Problems? A Study of the Incidence, Impact and Perception of Loss of Well Control" Energy Procedia 63 (2104) 7149 – 7161, which notes that "There are no standard formats for reporting loss of control events at the Federal or state level; consequently, many states have varying levels of accessibility for reporting ranging from relatively organized to completely unavailable. With such a wide degree of reporting standards, it was difficult to gather the desired data" (pg. 7154).

[11] Specified risk events could occur for a variety of reasons, including but not limited to mechanical failure, industrial activities unrelated to CCUS, incomplete/inaccurate subsurface characterization, natural or induced seismicity, other natural subsurface processes. Every WWQR event-based risk activity that occurs in the Monte Carlo analysis, whatever its underlying cause, is assumed to require an emergency and remedial response action.

[12] This adjustment for unknown wells is based on professional judgement, informed by the fact that Tallgrass has identified approximately 84 oil & gas wells in the AOR, three of which extend to depths sufficient to penetrate the injection zone.

[13] This adjustment for unknown wells is based on professional judgement, reflecting a 10% increase relative to the number of known wells.

zone monitoring wells planned for the project in the 'shallow well' category, yielding a total shallow well count of 94.

The FutureGen efforts do not provide release probability estimates for 'shallow' wells, as defined and identified for purposes of the Monte Carlo calculation. As such, we assume that shallow wells that do not penetrate the caprock have a release probability equal to twice the highest probability for caprock or fault release events. This assumption reflects the fact that CO2 or brine would need to escape through the caprock or fault before reaching the shallow well, at which point the well may yield a more direct pathway to a USDW. We believe this approach is reasonable and conservative.

Because in-zone monitoring wells necessarily penetrate caprock and confining layers and extend to the surface, they represent potential conduits for CO2 injectate and/or formation brines. For completeness, the Monte Carlo model used to monetize consequences necessitating emergency and remedial response actions can incorporate deep CO2 monitoring wells for purposes of ERR cost estimation. To do so, we conservatively assign an annual release probability to in-zone monitoring wells equal to that used for CO2 injection wells. This approach is likely to realize a conservative output given that monitoring wells are not subject to the same type or extent of use as injection wells. Importantly however, as we understand, no in-zone monitoring wells are anticipated for the EWS Hub Project. As such, although the capability to evaluate and model the consequences of this potential risk conduit exists, we have not done so because such wells are not anticipated by the project sponsor.

Exhibit 2. Probabilities for Well, Caprock and Fault Leakage Events

Risk Event Type	Annual Probability	Number of Wells
Deep Oil & Gas Well Leak	0.1% per well[a]	5
CO2 Injection Well Leak	0.001% per well[b]	5
Deep CO2 Monitoring Well Leak	0.001% per well[c]	0
Rapid Leakage Through Caprock	0.00000002%[d]	n/a
Slow Leakage Through Caprock	0.004%[e]	n/a
Release Through Existing Faults	0.000002%[f]	n/a
Release Through Induced Faults	0.000002%[g]	n/a
Leakage Through Caprock/Faults then Shallow Well	0.008%[h]	94

Source for risk events and annual probabilities: Final Risk Assessment Report for the FutureGen Project Environmental Impact Statement, revised April 2007, available online at: https://www.energy.gov/sites/prod/files/EIS-0394-DEIS-RiskAssessmentReport-2007.pdf, p. 6-15, Table 6-11.

Additional Notes:

a) Highest probability within FutureGen range for undocumented deep wells developed from the FutureGen analog database.
b) Highest probability within FutureGen range for CO2 injection wells developed from the FutureGen analog database.
c) Conservatively assumed to be equal to CO2 injection well leak probability.
d) Equal to FutureGen probability for rapid leakage through caprock developed from the FutureGen analog database.
e) Equal to FutureGen probability for slow leakage through caprock developed from the FutureGen analog database.
f) Equal to FutureGen probability for release through existing faults developed from the FutureGen analog database.
g) Equal to FutureGen probability for release through induced faults developed from the FutureGen analog database.
h) Conservatively assumed to be twice as likely as the highest caprock/fault probability.

6.2 Pipeline Releases

The Monte Carlo calculations underpinning this cost estimation exercise include potential costs associated with the new, 'feeder' CO2 pipeline(s) that will connect the existing Trailblazer pipeline to the EWS Hub Project

CO_2 injection wells. [14]The annual pipeline release probability used in the model is based on U.S. Department of Energy Pipeline and Hazardous Materials Safety Administration (PHMSA) data for CO_2 pipeline release incidents. PHMSA has compiled pipeline incident data since 2002. In 2020, there were approximately 5,100 miles of CO_2-carrying pipeline in the U.S., up from about 3,400 miles in 2004. There were 103 CO_2 pipeline accidents recorded from 2002 through 2021. Those figures result in an annual release probability of 0.12% per pipeline mile. It is our understanding that approximately 34 miles of new CO_2 pipeline currently are anticipated for the EWS Hub Project. The added feeder pipeline is to allow for transport of the CCUS stream from the existing Trailblazer pipeline to each injection well location. A reasonably conservative 4.08% annual pipeline release probability is used in this analysis.[15]

6.3 Induced Seismicity

We have been unable to identify any record of induced seismic events in the EWS Hub Project area. The project sponsor conducted an evaluation of seismic activity for Laramie County, which indicates that the project is in an area of low seismic activity. Exhibit 3 shows that the project (represented by the red star) is located in the 2% probability of exceedance in 50 years (grey zone) with a range from 5% to almost 14% peak ground acceleration in southeastern and northwestern Laramie County, respectively. As described in more detail in Section 7.6 of this document, this level of peak ground acceleration (5% to 14%) is the minimum scale of seismic event anticipated to cause measurable damage to surface infrastructure.

Induced seismicity of sufficient magnitude to potentially damage infrastructure most commonly occurs in areas with a history of extensive deep injection of fluids from nearby oil and gas operations.[16] As described throughout this document, the project AOR has a limited history of oil and gas development. Regardless, for financial assurance cost estimation purposes, we conservatively assume a probability and magnitude of induced seismic events equal to that for 'natural' seismic events. A 2% probability of exceedance in 50 years translates to an annual exceedance probability of 0.04%.[17]

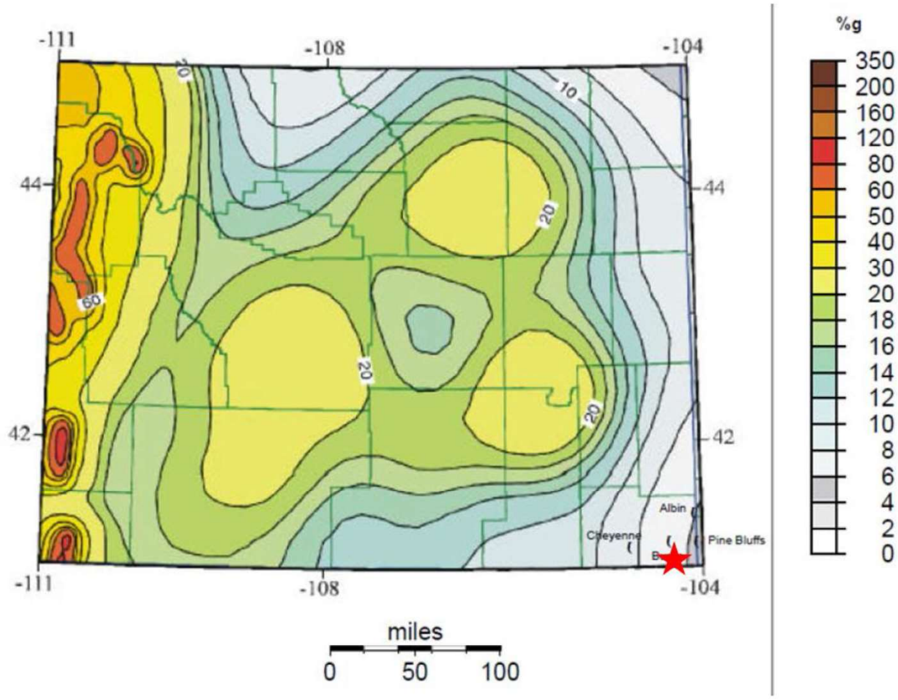
[14] Potential release events associated with the existing Trailblazer pipeline are subject to regulatory, permitting, and financial assurance coverage requirements separate and distinct from this Class VI permit application. As such, risk events associated with the main Trailblazer pipeline are excluded from further analysis in this report.

[15] 4.08% EWS Hub Project pipeline annual release probability = 0.12% release probability per CO_2 pipeline mile * approximately 34 miles of new pipeline.

[16] See, for example, Rubinstein, Justin and Alireza Babaie Mahani. Myths and Facts on Wastewater Injection, Hydraulic Fracturing, Enhanced Oil Recovery and Induced Seismicity. Seismological Research Letters. July 2015.

[17] 0.04% annual seismic probability = 2% seismic probability over 50 years / 50 years.

Exhibit 3. USGS 2,500-year Probabilistic Acceleration Map of Wyoming*



*Map contours represent a 2% probability of exceedance in 50 years.

6.4 Pore Space Trespass

As described elsewhere in the Tallgrass Class VI permit application materials, the project sponsor has made substantial progress obtaining pore space rights. Through the pore space unitization process, the sponsor anticipates that it will have acquired pore space rights for all subsurface areas in which injected CO2 from the five injection wells is expected to reside.

Based on extensive subsurface data collection, site characterization, and plume modeling efforts, the sponsor believes it is unlikely that stored CO2 will migrate to other subsurface locations. The actual movement of CO2 in the subsurface environment will be calibrated with modeled predictions on a regular and systematic basis, and therefore it is likely that any potential trespass issue would be identified prior to occurrence and the amount and/or location of ongoing CO2 injection potentially adjusted to reduce or eliminate the trespass concern. Nevertheless, for purposes of deriving a financial assurance cost estimate, we conservatively assume a 10 percent chance that trespass occurs at some point during injection and/or PISC periods, and that such trespass will necessitate a response action. Specifically, the project sponsor's site characterization efforts indicate a substantially low likelihood of trespass. To ensure that the likelihood of trespass remains low, the sponsor anticipates closely monitoring the storage plumes as injection occurs; and, to the extent necessary, will adjust injection volumes and/or rates of injection if any risk of trespass emerges. Finally, after injection ends, current site characterization analyses suggest that pressure gradients will quickly dissipate, limiting the potential for plume movement and trespass during the PISC period. Regardless, for the avoidance of doubt, and in the interest of deriving a conservative estimate for purposes of ERR financial assurance coverages, we apply a 10% likelihood of trespass occurrence based on professional judgment.

7.0 COST DISTRIBUTIONS APPLIED TO EVENT-BASED RISK ACTIVITIES NECESSITATING EMERGENCY AND REMEDIAL RESPONSE ACTION

Previously peer-reviewed, published applications of the CCSvt model relied on 10,000 Monte Carlo trials. In the interest of reasonable conservatism, and for purposes of demonstrating financial responsibility in support of the Class VI permitting process, this analysis relies on 50,000 Monte Carlo trials. In our view, the reliance on 50,000 Monte Carlo trials offers an additional measure of conservatism and certainty. If a release from a WWQR event-based risk activity occurs during a Monte Carlo trial, the model randomly chooses a cost amount from the indicated cost distributions.

7.1 Well Repair Cost Distribution

Injection Well, Deep Monitoring Well, and Non-Project Deep Well repair cost distribution is as follows:

- Minimum: $5,000
- 10th percentile: $25,000
- Median: $62,000
- 90th percentile: $140,000
- Maximum: $1,700,000
- Burr Distribution[18]

Shallow Well repair cost distribution is as follows:

- Minimum: $5,000
- 10th percentile: $8,100
- Median: $56,000
- 90th percentile: $170,000
- Maximum: $500,000
- Exponential Distribution

We apply the above cost distributions to all well release incidents that occur in the Monte Carlo trials to stop leaks and prevent reoccurrence. For the EWS Hub Project analysis, we conservatively assume that addressing a well-related release of CO2 would involve plugging and surface reclamation.[19] As a proxy for such costs, we rely on information and analysis provided in Raimi et al (2021).[20] This peer-reviewed, publicly available analysis provides cost estimates for plugging and surface reclamation of oil and gas wells, based on data from five states (Montana, New Mexico, Kansas, Texas and Pennsylvania).[21]

For 'deep' wells (extending more than 4,000 feet below the surface), we use a Burr distribution in which the 10th percentile, median, and 90th percentile costs align with those found for high cost (and generally deepest) wells in Raimi et al., (2021). We conservatively set the minimum cost to $5,000, notwithstanding the fact that costs below this amount were observed in the data set. We set the maximum cost to $1.7 million, consistent

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[18] The Burr distribution is commonly used to fit non-normally distributed data characterized by a right-skewed distribution (i.e., most values are clustered around the left tail of the distribution while the right tail of the distribution is longer).

[19] Plugging and surface reclamation are the most likely response measures to address a release from any inactive wells in the AOR. If an active CO2 injection well, monitoring well or industrial well was the source of a release, we assume that funds described in this section would be used to support well repair.

[20] Raimi, Daniel, A. Krupnik, J-S Shah, A. Thompson. "Decommissioning Orphaned and Abandoned Oil and Gas Wells: New Estimate and Cost Drivers. Environ. Sci. Technol. 2021, 55, 10224-10230.

[21] To our knowledge, there is no systematic, detailed information repository on well repair costs specific to Wyoming. In the absence of such data, we rely on the entire Raimi et al., data set so as to ensure robust, conservative cost estimation. We explored available cost data associated with orphan wells plugged by the Wyoming Oil and Gas Conservation Commission orphan well program; these Wyoming-specific data reveal cost curves that are substantially lower than the cost distribution curve obtained when using the entire Raimi et al., data set. In the interest of conservatism, we elect to rely on the full Raimi et al., data set. See also: https://drive.google.com/file/d/19dlfOmzhCvjTxLcdWXOoHdg39x24EOqf/view.

with the highest cost for well plugging and surface reclamation costs observed in the Raimi data set. For shallow wells (extending up to 4,000 feet below the surface) we assume an exponential distribution based on Raimi et al., (2021) data for all wells, but with a maximum cost of $500,000 (which reflects the highest cost for wells with depths up to approximately 4,000 feet.)

We believe that these estimates reasonably characterize the distribution of potential shallow and deep well repair costs in the event well-related release events were to occur at the EWS Hub Project site.

7.2 Cost Distribution for USDW Non-Endangerment

- Minimum: $50,000
- Maximum: $1,423,500
- Uniform distribution

We apply the above cost distribution to all incidents that involve a well, caprock or fault release that occurs in a Monte Carlo trial. This distribution reflects several different response components, including the characteristic use of USDWs in the AOR for the EWS Hub Project Site and the professional judgement of experts versed in federal and state response action to groundwater contamination incidents. We describe the underlying basis for this cost distribution below.

For groundwater that is intended for domestic use, Wyoming state groundwater regulations incorporate federal groundwater quality standards established by EPA.[22] The National Primary Drinking Water Regulations (NPDWRs) developed by EPA establish mandatory water quality standards for drinking water contaminants. These standards are referred to as "maximum contaminant levels" (MCLs), which are intended to protect the public against consumption of drinking water contaminants that present a risk to human health. An MCL is the maximum allowable amount of a contaminant in drinking water delivered to the consumer.

National Secondary Drinking Water Regulations (NSDWRs) set non-mandatory water quality standards for 15 contaminants. These standards (referred to as "secondary MCLs or SMCLs") are offered as guidelines to assist public water systems in managing their drinking water for aesthetic considerations, such as taste, color and odor. These contaminants are not considered to present a risk to human health at the SMCL.[23]

Consistent with these mandates, we evaluate potential consequences arising from release incidents or WWQR event-based risk activities at the project site, which could result in an exceedance of one or more MCLs in a USDW. We do so because, however unlikely, it is possible that such incidents could result in the need for an emergency and remedial response action. Our evaluation of potential consequences begins with the composition of the CCUS stream and the potential pathways for harm to USDWs.

- Composition of the CCUS Stream. Tallgrass anticipates that the CO2 injectate will meet the minimum pipeline specifications identified in Exhibit 4; and, the sponsor intends to operate the EWS Hub Project in compliance with WWQR water quality standards.[24] However, for some constituents, the pipeline specification limits in Exhibit 1 do not provide enough information to assess the potential for an MCL exceedance. For example, 'hydrocarbons' may contain various polycyclic aromatic hydrocarbons (PAHs), for which there are established MCLs. Therefore, it is possible that such contaminants could impair groundwater uses designated by the state. To address these uncertainties, as well as the possibility for trace amounts of contaminants other than those identified in Exhibit 1, the cost distributions (discussed in later sections of this document) assume use of reverse osmosis (RO)

[22] See WWQR Chapter 8, Section 4(d)(v)(A).
[23] See https://www.epa.gov/sdwa/secondary-drinking-water-standards-guidance-nuisance-chemicals.
[24] WWQR Chapter 8 cites to Federal regulatory standards (see Chapter 8 Section 4(d)(v)). Further, the Chapter also states that any release to underground water must not impair designated use(s) for particular aquifers.

treatment units for residences potentially affected by a release event. RO treatment units are highly effective at removing a wide variety of contaminants, including PAHs.[25]

- Potential Pathways for Endangerment of USDWs. In addition to 'direct' impacts resulting from a release of constituents present in the CCUS stream into a USDW, 'indirect' impacts could arise if released CO2 reduces the USDW's pH sufficiently to increase the leaching of heavy metals from aquifer minerals at concentrations that exceed an MCL. It also is possible that increases in subsurface pressure arising from injection activities could result in USDW impacts due to resulting movement of underground brines. This analysis incorporates emergency and remedial response actions to address potential MCL exceedances that could arise in these scenarios. We anticipate that these actions also would address any aesthetic impacts (e.g., taste, color, odor, etc.) that could be associated with potential exceedance of secondary MCLs (e.g., for pH, TDS, chlorides, etc.).[26]

Exhibit 1 provides context regarding land use within the EWS Hub Project site AOR. As illustrated in the image, land use in the approximately 210 square mile AOR is highly rural, with a low density of scattered residences and a substantial amount of agriculture and ranching/livestock activity. There are neither municipal water systems, nor population centers within the AOR. Data provided by the project sponsor indicate that there are approximately 841 water wells distributed throughout the AOR (approximately 394 for domestic use, 390 for livestock watering (some dual-purpose domestic/livestock), 267 for irrigation, and three for 'industrial'purposes). The maximum water well depth is 3,511 feet, all others are at depths less than 1,000 feet, approximately 796 wells are depths less than 500 feet. The deepest domestic well is 735 feet.

Exhibit 4. EWS Hub Project CO2 Pipeline Specifications

Constituent	Limit
CO_2	>96 mol%
CO	< 0.4 mol%
H_2	< 0.5 mol%
H_2S	< 20 ppm
Total Sulfur	<35 ppm
Total NO_x	<10 ppm
O_2	< 10 ppm (w)
H_2O	< 150 ppm
Hydrocarbons	<4 mol %
Glycol	0.3 gallons/MMCF
Maximum dew point at 400 psig	30°F
Non condensable gases	<3% mol%

Based on the aforementioned site context, we estimate a maximum per-incident cost range tailored to the EWS Hub Project site as follows:

[25] For example, as noted on EPA's website "RO and NF [nanofiltration] are useful for the removal a wide range of contaminants. RO can remove contaminants including many inorganics, dissolved solids, radionuclides and synthetic organic chemicals. RO can also be used for removing salts from brackish water or sea water." https://www.epa.gov/sdwa/overview-drinking-water-treatment-technologies#RO

[26] Information provided by the project sponsor confirms that there are no USDWs (i.e., <10,000 mg/l total dissolved solids) below the storage zone, and therefore no threat of USDW endangerment from releases that might occur (however unlikely) through the bottom seal. Further, were any releases to occur at the EWS Hub site that could impact mineral rights, human health, ecological health, storage rights or property and infrastructure, such releases would need to penetrate and migrate through the upper confining layer of the storage zone and not through the bottom seal.

- A maximum of $75,000[27] to drill new water monitoring wells, to facilitate data collection to evaluate the spatial extent, existence, and/or significance of a potential release-related plume for existing water users,[28] plus;
- A maximum of $13,000[29] for quarterly sampling and analysis for standard field measurements and heavy metals at an estimated $200 per sample,[30] including collection and analysis, for up to two years and 8 residences,[31] plus;
- A maximum of $3,500[32] for residential replacement water for one year for up to 8 residences,[33] plus;
- A maximum of $20,000[34] for purchase and installation of residential reverse osmosis (RO) units at up to 8 residences,[35] plus;
- A maximum of $12,000[36] for RO replacement filters, including servicing of such units at $300 per unit per year for up to five years at 8 residences,[37] plus;
- A maximum of $400,000 for irrigation support,[38] plus;

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[27] $75,000 = 4 wells * 750 foot depth * $25 drilling cost per foot.
[28] At an estimated drilling cost of $25 per foot (see https://homeguide.com/costs/well-drilling-cost#cost, which estimates a cost of $15-$25 per foot for drilling a water well), this cost allowance would allow, for example, drilling of four new wells at a 500-foot depth.
[29] $13,000 (rounded) = 8 residences * 8 quarterly samples * $200 per sample.
[30] See for example information from laboratory vendor Chemtech international at https://chemtech-us.com/articles/cost-of-well-water-testing-in-2021/#:~:text=It%20costs%20%24165%20at%20the,%24279%20at%20the%20full%20price, which states "the Essential Water Test is a standard test that screens the general water chemistry, the hardness and alkalinity of the water, toxic and heavy metals, nitrates and nitrites, coliform and E.coli bacteria, and silica. It costs $165 at the full price." We round up to $200 to account for potential sample collection costs.
[31] If there is a release incident, a common response measure would be to periodically test water wells within the potential impact area to determine if any residences are at risk of exposure to contaminants at levels above an MCL. If no impacts are found within two years of an incident, we anticipate that continued testing would no longer be necessary. Alternatively, if household treatment needs arose, we anticipate that treatment solutions would be implemented within two years of the incident. As a result, testing of residential wells should be unnecessary after two years.
[32] $3,500 (rounded) = 8 residences * $35 per month for 25 gallons * 12 months.
[33] If residential water well testing identifies contaminant levels of concern, replacement water for drinking and cooking would be provided for affected residents. Commercial companies offer water delivery service at approximately $35 per month for 25 gallons, a typical consumption level for a family of 3-4 (see for example pricing and family water quantity recommendations from water vendor Culligan at https://www.culligan.com/bottled-delivery/select). This pricing estimate is conservative, as it is likely that bottled water could be provided in bulk at costs lower than those charged by residential delivery services. We also note that replacement water typically is a temporary measure; in this case, if contamination issues persist for longer than one year, we anticipate that the replacement water program would end and be replaced by installation of residential reverse osmosis units to provide clean water, which is a more expensive, but more appropriate solution for longer term contamination issues.
[34] $20,000 = 8 residences * $2,500 per RO unit.
[35] While some residential RO units (and other types of residential treatment technologies) can cost several hundreds of dollars, for this analysis, we assume installation of the much more expensive Kinetico K5 Drinking Water Station RO unit, which is an RO model currently designated for use in response to a severe, long-term groundwater contamination incident in North Carolina, affecting thousands of residences (see https://edocs.deq.nc.gov/WasteManagement/DocView.aspx?id=1636579&dbid=0&repo=WasteManagement). Pricing information from Consumer Reports indicates that $2,500 is a reasonable cost estimate for this unit.
[36] $12,000 = 8 residences * $300 per RO unit per year * 5 years.
[37] Annual RO unit maintenance costs will vary depending on water use, contaminant levels and other factors. Based on warranty information, replacement filter prices and professional judgement, $300 per year per unit is a reasonable approximation of annual maintenance costs. For reasons described throughout this document, we anticipate that release incidents that occur should be resolvable within months or a few years. Out of an abundance of caution, for purposes of cost estimation, we assume maintenance of RO units for five years after installation to allow for natural dilution/dissipation of any residual CO_2/low pH/brine plume, supplemented by active remediation, if needed.
[38] Information provided by the project sponsor indicates that there are approximately 267 irrigation wells within the approximately 210 square mile AOR. While difficult to forecast specific irrigation needs in response to a potential release event due to seasonal timing, weather, specific crop requirements, and other factors, $400,000 provides a significant incident-specific sum that could be used for a variety of potential response activities, including but not limited to: funding new irrigation system connections to existing, unaffected wells; digging new wells in areas away from potential release impacts and connecting them to irrigation systems; farm-specific treatment solutions; and temporary replacement water (trucked water can cost about $30-$65 per 1,000 gallons).

- A maximum of $400,000 for ranch/livestock support,[39] plus:
- A maximum of $500,000 for additional response and remedial actions.[40]

Summing the maximum dollar amount for each of these components results in a total maximum per-release cost of $1,423,500, in 2023 dollars.

The maximum per-release cost reflects a cost distribution for USDW non-endangerment that is tailored to the site specific circumstances of the EWS Hub Project site. We rely on a minimum cost of $50,000 for the cost distribution, reflecting the potential for small releases insufficient to cause measurable adverse impacts, or for releases that cause minor impacts, which are easily addressed at minimal cost. For estimation purposes, we assume a uniform probability distribution in the Monte Carlo trials. That is, every incident that occurs in a trial is randomly assigned a cost from the cost distribution discussed above; and every cost within that range has an equal chance of being assigned. We offer additional context for our approach below.

Evaluation of the EWS Hub Project site suggests that the most likely pathway for a potential release that could impact a USDW in the project's AOR is migration through a well of some kind. Such releases are associated with a very specific release location; and, tend to offer a better opportunity to identify and mitigate impacts than often is available at groundwater contamination sites caused by spatially dispersed, slow infiltration of contaminants from the surface.

As previously noted, the composition of the EWS Hub Project site's CCUS stream has a very low potential for introducing co-constituents that could directly contaminate a USDW and cause an exceedance of a health-based MCL. Rather, potential impacts from a release more likely would occur indirectly by: 1) lowering groundwater pH, which, in turn, could lead to increased dissolution of metals present in the aquifer matrix (if present in sufficient quantities); or 2) injection-related increases in subsurface pressure that results in the vertical migration of underground brines into a USDW.

Importantly, there are natural factors that are likely to limit the impact of any released CO_2 on pH at the EWS Hub Project site. Specifically, carbonate will act to buffer pH from changes due to CO_2 – with a carbonate concentration of even 1% by weight, pH changes are unlikely to be meaningful. Although carbonate aquifer matrix measurements in or near the AOR were not available, information provided by the project sponsor

[39] Information provided by the project sponsor indicates that there are approximately 390 water wells within the approximately 210 square mile AOR identified as serving 'stock watering' purposes (although many also co-list 'domestic' water provision). $400,000 is a substantial sum that could, for example, allow for drilling one or more new wells in areas away from potential release impacts and connecting them to existing water delivery systems; facilitating more complex treatment solutions; enabling dilution with other unimpacted water sources; or providing temporary bulk replacement water (trucked water typically can cost about $30-$65 per 1,000 gallons). While water needs for livestock will depend on the season, type and age and other livestock characteristics, as an approximation we note that beef cattle can require 4-20 gallons of water per day, per head (see https://www.ag.ndsu.edu/publications/livestock/livestock-water-requirements). As additional context, if livestock required 10 gallons per day per head, and replacement water could be obtained for $65 per 1,000 gallons, that implies an annual replacement water cost on the order of roughly $250 per head per year.

[40] As part of the emergency and remedial response to a release incident involving a WWQR event-based risk activity, additional actions might be needed to protect USDWs, including limiting plume movement, accelerating dilution of CO2 concentrations or brine, extracting CO2 or brine-related contamination through air stripping or other technologies, buffering pH or constructing reactive barriers to limit CO2 impacts, reducing subsurface pressure by halting CO2 and/or other subsurface injection activities in relevant areas, and/or otherwise undertaking actions to speed the return of an impacted USDW to baseline conditions. This cost estimate reflects several factors: as discussed elsewhere in this document, CO2 releases or pressure-related brine movement through faulty wells is the most likely release pathway and can be relatively straightforward to stop through well repair/plugging; the aquifer matrix is likely to have meaningful buffering capacity that limit pH changes; resultant/residual plumes of groundwater with substantially reduced pH are not likely to be large or long-lived; dilution/natural attenuation can reduce CO2 and/or brine levels without intervention; CO2 is relatively inexpensive to remove from groundwater; low pH also is relatively inexpensive to address; subsurface pressure fronts can dissipate relatively quickly after the cessation of injection activities if lateral plume movement in the injection zone is not confined; "thief" zones between the injection formation and USDW can absorb CO2 or brine flux; density differences due to temperature and salinity can limit the vertical migration of displaced brine; and rural land use patterns and the low density of water wells in the AOI limit the potential for plume impacts on water users.

indicates that the primary injection zone is in the Lyons formation, which in some locations includes carbonates. There is one groundwater alkalinity[41] measurement in the vicinity of the AOR and it exceeds 200 mg/L, which suggests some potential for buffering capacity.

For USDW endangerment to occur from a CO2 release event that lowers aquifer pH, there also needs to be a sufficient reservoir of metals in the aquifer matrix to be leached into USDWs to result in health-based MCL exceedances. According to the project sponsor, concentrations of metals in the aquifer matrix in the AOI are not known.

With respect to potential pressure-induced brine migration into a USDW, halting or modifying injection activity until corrective action is taken (e.g., plugging/repairing a deep well that allowed brine to migrate to a USDW) can reduce subsurface pressure and limit the spatial extent/duration of potential impact. After injection is complete at the site the pressure front will dissipate over time, which also can limit the potential for USDW endangerment during the PISC period. Articles from the peer-reviewed technical literature identify additional factors that can limit potential impacts from brine migration. For example, Nicot et al., (2009) note that "owing simply to density differences due to temperature and salinity subsurface variations, a wellbore with a continuous open pathway between the injection formation and the bottom of the USDW will not necessarily lead to [brine] contamination of the USDW when CO2 is injected."[42] Nicot et al., also note that Minkoff et al., (2007) and Chang et al., (2008) showed that "thief" zone(s) between the USDW and injection formation "can attenuate significantly well bore pressure and absorb a significant fraction of the material flux."[43]

These factors support the reasonable assumption that, if a plume occurred in a USDW as a result of a release incident, that plume likely would be relatively modest in size. For example, analyses in relevant published literature generally describe radial CO_2 plume distances on the order of hundreds of meters or less.[44] Nevertheless, to estimate potential residential and irrigation impacts from a release incident associated with the EWS Hub Project Site, we conservatively assume that an impact plume could extend up to one mile from the release point and potentially endanger the aquifers currently used by local residents.

Specifically, an impact plume with a radius on the order of one mile from its center would affect an area roughly 3.14 square miles in size.[45] With respect to the potential number of residences that might be affected if a release event of that size were to occur in the EWS Hub Project site's AOR, our evaluation assumes impacts to a maximum of 8 households. As previously noted, satellite imagery (see Exhibit 1) shows that most of the AOR is highly rural, with a low density of scattered residences and a substantial amount of agriculture and ranching/livestock activity. As previously noted the AOR is approximately 210 square miles in size and includes approximately 394 domestic water wells, which implies an average density of about 1.9 domestic wells per square mile or about 6.0 domestic wells within a hypothetical release incident impact radius of 3.14

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[41] Alkalinity is a different measure of the capacity of water (or any solution) to neutralize or "buffer" acids.
[42] See Nicot, Jean-Philippe, Curtis M. Oldenburg, Steven L. Bryant and Susan D. Hovorka "Pressure perturbations from geologic carbon sequestration: Area of-review boundaries and borehole leakage driving forces" in Energy Procedia 1 (2009) 47-54.
[43] As cited in Nicot et al., (2009): S. E Minkoff,. S. L. Bryant, J.-P. Nicot, and C. M. Oldenburg, Modeling leakage of CO2 along a fault for risk assessment (abs.), in Sixth Annual Conference on Carbon Capture & Sequestration: Expediting deployment of industrial scale systems: Can it be done? How? Concerns to be addressed, May 7–10, Pittsburgh, Abstract #053, (2007) and K.W Chang, S. E. Minkoff and S. L. Bryant, Modeling Leakage through Faults of CO2 Stored in an Aquifer, SPE 115929, presented at 2008 SPE Annual Technical Conference and Exhibition held in Denver, Colorado, USA, 21–24 September 2008.
[44] See for example Elizabeth Keating, D. Bacon, S. Carroll, K. Mansoor, Y. Sun, L Zheng, D. Harp and Z. Dai. Applicability of aquifer impact models to support decisions at CO2 sequestration sites. International Journal of Greenhouse Gas Control 52 (2016) 319-330. and Nicholas Huerta, D. Bacon, C. Carman and C. Brown. NRAP Toolkit Screening for CarbonSAFE Illinois – Macon County. Illinois State Geological Survey Prairie Research Institute and Pacific Northwest National Laboratory. Report prepared for US DOE 00029381. 2020.
[45] 3.14 square miles = $\pi * (1 \text{ mile radius})^2 = 3.14 * 1$ square mile.

square miles.[46] Overall, publicly available information suggests an average residential density within the AOR that is well below the 8 residences per 3.14 square miles conservatively used in this analysis.

7.3 Cost Distribution for Endangerment to Human Health from Acute or Chronic Surface Release of CO2 Injectate

- Minimum: $0
- Median: $100,000
- 75th Percentile: 200,000
- Maximum: $900,000
- Bimodal distribution

We apply the above cost distribution to all incidents that involve a well, caprock, fault or pipeline release that occurs in a Monte Carlo trial.

There is a non-zero possibility that WWQR event-based risk activities may result in release incidents. Such incidents can create acute or chronic exposures to nearby residents necessitating emergency and remedial response. The maximum end of the cost distribution is based on the CO2 pipeline incident that occurred in Satartia, Mississippi in 2020.[47] It is generally accepted that this incident resulted in the most significant CO2-related public health impact to date.[48]

The Satartia MS incident resulted in 45 hospitalizations. National Institute of Health (NIH) data suggests a 12-month treatment cost for 'unintentional suffocation or poisoning' at approximately $10,000 per person.[49] We believe that this estimate is reasonably conservative, and set it as the upper-bound (maximum) of the cost distribution. Importantly, the Satartia MS impacts occurred, in part, because a CO2 pipeline was located close to a small town. To our knowledge, there are no comparable towns or population centers in the AOR associated with the EWS Hub Project site.

In addition to treatment costs, we assume an additional $10,000 per person to address potential lost income and/or pain and suffering associated with a release incident that adversely impacts human health. Median per capita income for Wyoming residents is approximately $40,000.[50] We conservatively assume an average of one month's lost income for individuals affected by a pipeline release (i.e., slightly more than $3,000 per person). We assign approximately $7,000 per-person (to arrive at the $10,000 included in the cost distribution)

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[46] 7.5 wells (rounded) = (48 water wells / 20 square mile AOI) * 3.14 square mile hypothetical contamination impact area with a radius of 1 mile from its center.

[47] US Department of Transportation, Pipeline and Hazardous Materials Safety Administration, Office of Pipeline Safety Accident Investigation Division. Failure Investigation Report – Denbury Golf Coast Pipelines, LLC – Pipeline Rupture/Natural Force Damage. May 26, 2022. On February 22, 2020, Denbury's 24-inch Delhi Pipeline ruptured, releasing liquid CO2 that immediately began to vaporize at atmospheric conditions. The site of the rupture was approximately one mile southeast of Satartia, Mississippi. Denbury reported that the rupture released an estimated total of 31,405 barrels of CO2. Local authorities evacuated approximately 200 people near the rupture, including the entire town of Satartia (around 50 residents), and three homes across the Yazoo River. Forty-five people sought medical attention at local hospitals, including individuals who were caught in the vapor cloud while driving a vehicle. One individual was admitted to the hospital for reasons unrelated to the pipeline failure. There were no fatalities.

[48] To our knowledge, there are no documented 'real world' CO2 release events arising from land-based injection wells that resulted in documented human health impacts. In the absence of such data, we conservatively rely on a pipeline incident as a proxy for the types of surficial CO2 release events relevant to the CCS context. We do so because the types of impacts that might arise from a pipeline rupture are not dissimilar to those that might arise from an acute or chronic surface release of CO2 injectate from a CCS operation. We believe this approach to be both reasonable and conservative. To date, the most significant 'real world' CO2-related impact event in the United States that resulted in acute / chronic CO2-related impacts is the February 2020 Satartia, MS pipeline release. In our view, in the absence of other data specific to Wyoming, this release event offers a conservative proxy for estimating a cost distribution for endangerment to human health arising from an acute or chronic surface release of CO2 injectate.

[49] Peterson, Cora, Likang Xu and Curtis Florence. Average medical cost of fatal and non-fatal injuries by type in the USA. Inj Prev. 2021 February ; 27(1): 24–33. doi:10.1136/injuryprev-2019-043544. To our knowledge, there are no documented, publicly available and comparable Wyoming-specific treatment cost information. In the absence of such data, we rely on national cost estimate data as a reasonably proxy.

[50] https://www.census.gov/quickfacts/WY.

to address potential pain and suffering.[51] Given the likelihood that the potential impacts associated with CO2-related morbidity are likely to be relatively short-term, we believe $7,000 (about twice estimated lost income, and comparable to treatment costs) is reasonably conservative for purposes of deriving a financial assurance cost estimate.

Based on the information described above, we use a maximum cost estimate of $900,000.[52] We also include a minimum value of $0 in the cost distribution, because acute and chronic surface releases of CO2 injectate may have no human health impact. For example, in many circumstances, atmospheric dilution quickly reduces CO2 concentrations below relevant human health thresholds; there is diminished likelihood that, in this rural AOR with no population centers, people will be close enough to surface release locations to receive meaningful exposure; the injectate composition contributes to reduced risk (e.g., no hydrogen sulfide); and implementation of the emergency response plan will help avoid impacts.

Readily available data indicate that public health impacts due to the transport and industrial use of CO2 are rare. A recent evaluation of PHMSA data identified 113 CO2 pipeline incidents that occurred between 1994 and 2021; to our knowledge, the Satartia, MS release is the only one that resulted in public health impacts.[53] Importantly, we have been unable to find documentation of any public health impacts arising from CO2 used in enhanced oil recovery operations or other industrial activities.

In light of this research we use a bimodal cost distribution to conservatively assume that 10% of subsurface or pipeline release events result in some level of human health impact. As a result, 90% of subsurface or pipeline release events are assigned $0 cost, because there no human health impacts expected to occur. For the remaining 10% of events, we assume a minimum cost of $20,000 (consistent with harm to one person) and a maximum cost of $900,000 (consistent with the Satartia, MS pipeline incident).

Further, we assume a median cost of $100,000 and a 75th percentile cost of $200,000, approximately consistent with impacts to five to ten people, respectively. In our view, this cost distribution reasonably reflects the potentially exposed population, if an incident were to occur near a residence or small gathering in this highly rural area. Finally, we apply a Burr distribution to the cost range – while higher cost incidents potentially could occur, the AOR characteristics of the EWS Hub Project suggest that impacts to small numbers of people are substantially more likely than impacts to larger numbers of people.

7.4 Cost Distribution for Ecological and Response/Infrastructure Costs from Acute or Chronic Surface Release of CO2 Injectate

- Minimum: $5,000
- Maximum: $450,000
- Burr distribution

We apply the above cost distribution to all incidents that involve a well, caprock, fault or pipeline release incident that occur in a Monte Carlo trial.

This distribution is based on release-related cost information reported to the U.S. Department of Energy Pipeline and Hazardous Materials Safety Administration (PHMSA) for the 103 CO2 pipeline release incidents recorded from 2002 through 2021. We believe that PHMSA offers the most reasonably conservative data for estimating costs associated with ecological response, and property and infrastructure damage, including changes to surface topography and structures, arising from acute or chronic surface releases of CO2 injectate.

[51] Pain and suffering amounts (if awarded) are difficult to forecast and depend largely on legal jurisdiction, case-specific circumstances, and other factors impossible to predict with any degree of certainty.
[52] $900,000 = 45 people impacted * ($10,000 per person treatment cost + $10,000 per person lost income/pain & suffering)
[53] Vitali, Matteo, C. Zuliani, F Corvaro, B Marchetti and F Tallone. Statistical Analysis of Incidents on Onshore CO2 Pipelines Based on PHMSA Database. Journal of Loss Prevention in the Process Industries 77 (2022) 104799.

Specifically, the Monte Carlo simulation includes PHMSA-identified costs arising from emergency response, environmental remediation and non-operator property damage due to release incidents. We do not include private-party costs, including, for example, the value of product lost or operator property damage, as these categories do not inform emergency and remedial response actions responsive to estimating financial assurance cost estimates for WWQR event-based risk activities.

Although PHMSA data indicate that most incidents resulted in relevant costs *less than* $5,000 per incident, we conservatively assign $5,000 as the cost distribution minimum. This cost estimate is intended to reflect minor incidents with minimal response-related activities.

We use $450,000 as the cost distribution maximum, which reflects the single incident with the highest cost in the PHMSA data (adjusted for inflation); that is, the 2020 Sartartia, MS pipeline release. The total cost for this WWQR event-based risk activity is $431,361, which results from the afore-mentioned cost categories. We apply a Burr distribution to reflect the fact that pipeline release costs are skewed towards the lower end of the distribution – although higher costs can occur, they do so much less frequently than lower costs.

7.5 Cost Distribution for Mineral Rights Infringement

- Minimum: $0
- Maximum: $35,000
- Bimodal distribution

We apply the above cost distribution to all incidents involving well, caprock or fault releases that occur in a Monte Carlo trial.

Data on Wyoming mineral rights are available from the state's Office of State Lands and Investments. We downloaded geospatial layers for active oil and gas and mineral rights and cross-referenced them with the AOR shapefile for the EWS Hub Project. This cross-reference revealed 17 active oil and gas leases in the AOR issued between December 2018 and August 2023; and, a total of 7,478 acres with no active mineral leases. The active oil and gas leases cover approximately six percent of the roughly 210 square mile AOR.

Few of the 'active' oil and gas leases in the AOR appear to be producing oil or gas. Information provided by the project sponsor indicates that there are approximately 84 oil and gas wells in the AOR, but only two wells are identified as active, and the vast majority (at least 75) of these oil and gas wells are identified as plugged and abandoned.

Further, we note that only three of the 84 wells are deep enough to extend into the planned CO2 storage interval. In our view, it is reasonable to expect that most mineral activity would continue at depths shallower than the subsurface confining layers above the CO2 storage plume. Conceptually, however, it is possible that a subsurface release event could temporarily interfere with mineral extraction operations that were planned or underway in subsurface areas adjacent to the release.

To reflect these site-specific circumstances, we use a bimodal cost distribution. If a subsurface release event occurs in a Monte Carlo trial, we assign a 94% chance of $0 cost, reflecting an event that occurs somewhere in the 94% of the AOR without an active mineral lease. We also assign a 6% chance of a cost between $5,000 and $35,000 (the total cost of all currently actively leases in the AOR). This cost distribution reflects the possibility that the project sponsor may need to "refund" the equivalent of a lease payment to affected mineral rights holders in response to potentially interfering with the holder's ability to exercise their lease rights.[54]

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[54] Losses and attendant cost estimates for environmental and/or ecological event-based risks are addressed in other sections of this report. Other types of losses from a WWQR risk-based event activity involving mineral rights infringement (e.g. lost profits, business interruption) are not quantifiable at this time, given that there is limited active mineral operation activity in the AOR. Quantifying any such potential losses are too speculative to result in a reasonable or meaningful cost estimate. Per the regulations, the financial

It is our understanding that Wyoming mineral leases typically reflect a five-year term, require a lease payment, and a royalty based on mineral production. The Wyoming Office of State Lands and Investments data indicate that active lease payments in the AOR for current leases (i.e., issued between December 2018 and August 2023) total $32,138 (which we conservatively round to $35,000 for purposes of this analysis).

Royalty payments data are not readily available, but likely are negligible given the small volume of actual production in the AOR. For this portion of the bimodal distribution, we assume all costs between $5,000 and $35,000 to be equally likely (i.e., a uniform distribution).

Finally, it is possible that active mineral operations could experience other types of losses from a WWQR risk-based event activity (e.g. lost profits, business interruption). At this time, given that there is such limited active mineral operation activity in the AOR, quantifying any such potential losses would be too speculative to result in a reasonable cost estimate.

Per WWQR Chapter 24, Section 26(b), financial assurance cost estimates (including those that address emergency and remedial response associated with WWQR risk-based event activities like mineral rights infringement) must be updated annually, or within 60 days of receiving notice that the Administrator has determined that a demonstration of financial assurance is no longer adequate. Consistent with Section 25(a)(i) and (a)(ii) requirements, financial assurance cost estimates also will need to be reevaluated after any updates to the emergency and remedial response plan. Consistent with these regulatory requirements, to the extent actual mineral extraction activity in the AOR increases during the life of the EWS Hub Project, the financial assurance cost estimates will be reevaluated.

7.6 Cost Distribution for Property and Infrastructure Damage Arising from Induced Seismicity

- Minimum: $0
- Median: $275,000
- 75th Percentile: $1,000,000
- Maximum: $2,750,000
- Burr distribution

We apply the above cost distribution to all induced seismic events that occur in a Monte Carlo trial.

To develop this cost distribution, we develop a dataset of all parcels that intersect with the AOR by combining: 1) Wyoming Department of Revenue statewide property assessment and valuation data; 2) the shapefile of the EWS Hub Project AOR; and 3) a separately-accessed shapefile of all parcels in Laramie County. This data analysis yielded 905 individual parcels, as of tax year 2023.

The property value data for these parcels are summarized in Exhibit 5, including the value of land and any improvements made to the land (generally, structures). Exhibit 6 summarizes the same data set, but excludes land values.

In our view, an induced seismic event of the magnitude relevant to the EWS Hub Project (discussed further below) could adversely impact structures, but is not likely to result in adverse impact to the land, itself. We estimate there is approximately $110 million property infrastructure within the AOR that potentially could be adversely impacted by an induced seismic event.

As previously indicated, the project sponsor's seismicity evaluation found a 2% probability of exceedance in 50 years for seismic events ranging from 5% to almost 14% peak ground acceleration (in southeastern and northwestern Laramie County, respectively). For purposes of deriving a financial assurance cost estimate for

assurance cost estimates will be reevaluated annually, at which time estimates of losses (if any) will be refined to reflect actual increases in mineral extraction activity in the AOR.

emergency and remedial response related to this WWQR risk-based event activity, we converted peak ground acceleration numbers into a measure of possible monetary damage.

Exhibit 7 summarizes information from the United States Geological Survey (USGS) that relates peak ground acceleration to Modified Mercalli Intensity (MMI), a commonly referenced measure of earthquake intensity. The maximum peak ground acceleration of 14% estimated for the AOR corresponds to MMI category VI (which includes seismic events with peak ground accelerations between 9.2% and 18%).

The USGS also provides summary information describing the type of damage associated with different MMI categories (see Exhibit 8). As show in Exhibit 8, MMI Category VI events are associated with events "felt be all, many frightened, some heavy furniture moved, a few instances of fallen plaster. Damage slight." Relying on these representations, we assume a maximum repair cost equal to 2.5% of total structure value.

Exhibit 5. Summary of Property Values for Parcels in the AOR

Parcel Type	Count	Total Acreage	Average Acreage	Total Value ($)
Agricultural	463	131,746	285	$127,109,758
Commercial	13	39	3	$970,372
Commercial – Vacant Land	4	61	15	$84,813
Industrial	5	206	41	$1,856,290
Industrial – Vacant Land	8	315	39	$315,149
Residential	255	6,241	24	$59,719,027
Residential – Vacant Land	117	5,344	46	$6,043,123
Exempt, w/ data	13	660	51	$374,191
Exempt, w/o data	*24*	*7,331*	*305*	--
N/A (no data available)	*3*	--	--	--
Total Parcels with Data	**878**	**144,612**	**165**	**$196,472,723**

Notes: From Laramie County, Wyoming geospatial data (https://maps.laramiecounty.com/arcgis/rest/services/features/CountyBaseMapFeatures/MapServer/2). Fields relied upon: "accttype" for parcel type; "netacres" for acreage; and "totalcostv" for value.

Exhibit 6. Summary of Parcel Structure Values in the AOR

Parcel Type	Count	No. w/ Improvements	Total Impr. Value
Agricultural	463	177	$56,815,755
Commercial	13	13	$801,435
Commercial – Vacant Land	4	0	--
Industrial	5	5	$1,398,907
Industrial – Vacant Land	8	0	--
Residential	255	249	$50,660,131
Residential – Vacant Land	117	0	--
Exempt, w/ data	13	0	--
Exempt, w/o data	*24*	*0*	--
N/A (no data available)	*3*	*0*	--
Total Parcels with Data	**878**	**444**	**$109,676,228**

Notes: From Laramie County, Wyoming geospatial data (https://maps.laramiecounty.com/arcgis/rest/services/features/CountyBaseMapFeatures/MapServer/2). Fields relied upon: "accttype" for parcel type; "netacres" for acreage; "totalimpsv" for improvement value; and "totalcostv" for total (land plus improvement) value.

We believe this estimate is reasonably conservative and likely would be sufficient to address potential damage on the order of "a few instances of fallen plaster." To derive the maximum value for this cost distribution, we assume all structures in the AOR are impacted by a seismic event and require the maximum level of repair (i.e., 2.5% of total structure value). This assumption results in a cost distribution maximum of $2.75 million.[55] We use a minimum cost distribution value of $0, because induced seismic events can occur at low intensities with no attendant damage. We also assume a median distribution value of $275,000, consistent with an event that impacts approximately 10% of the 210 square mile AOR. Experience in areas with relatively high incidences of induced seismicity (e.g., Oklahoma) suggest that the spatial extent of impact is substantially more likely to be on the order of 20 square miles than 200 square miles.[56] For similar reasons, we assume a 75th percentile estimate of $1,000,000 and use a Burr distribution for this cost range.

Exhibit 7. Modified Mercalli Intensity Relative to Peak Ground Acceleration, Perceived Shaking and Potential Damage*

Modified Mercalli Intensity	Acceleration (%g) (PGA)	Perceived Shaking	Potential Damage
I	<0.17	Not felt	None
II	0.17 – 1.4	Weak	None
III	0.17 – 1.4	Weak	None
IV	1.4 – 3.9	Light	None
V	3.9 – 9.2	Moderate	Very Light
VI	9.2 – 18	Strong	Light
VII	18 – 34	Very Strong	Moderate
VIII	34 – 65	Severe	Moderate to Heavy
IX	65 – 124	Violent	Heavy
X	>124	Extreme	Very Heavy
XI	>124	Extreme	Very Heavy
XII	>124	Extreme	Very Heavy

*See, for example, https://d9-wret.s3.us-west-2.amazonaws.com/assets/palladium/production/s3fs-public/atoms/files/EQ101.pdf.

Exhibit 8. Damage Potential Associated with Different MMI Category Events*

[55] $2.75 million = $110 million total value of structures in the AOR * 2.5% maximum repair cost.

[56] See, for example, Celebi, Mehmet et al. EERI Earthquake Reconnaisance Team Report: M5.0 Cushing Oklahoma USA Earthquake on November 7, 2016. Technical Report February 2017 and Halkia, Georgia and L.G. Ludwig. Household Earthquake Preparedness in Oklahoma: A Mixed Methods Study of Selected Municipalities. International Journal of Disaster Risk Reduction 73 (2022) 102872.

Intensity	Shaking	Description/Damage
I	Not felt	Not felt except by a very few under especially favorable conditions.
II	Weak	Felt only by a few persons at rest,especially on upper floors of buildings.
III	Weak	Felt quite noticeably by persons indoors, especially on upper floors of buildings. Many people do not recognize it as an earthquake. Standing motor cars may rock slightly. Vibrations similar to the passing of a truck. Duration estimated.
IV	Light	Felt indoors by many, outdoors by few during the day. At night, some awakened. Dishes, windows, doors disturbed; walls make cracking sound. Sensation like heavy truck striking building. Standing motor cars rocked noticeably.
V	Moderate	Felt by nearly everyone; many awakened. Some dishes, windows broken. Unstable objects overturned. Pendulum clocks may stop.
VI	Strong	Felt by all, many frightened. Some heavy furniture moved; a few instances of fallen plaster. Damage slight.
VII	Very strong	Damage negligible in buildings of good design and construction; slight to moderate in well-built ordinary structures; considerable damage in poorly built or badly designed structures; some chimneys broken.
VIII	Severe	Damage slight in specially designed structures; considerable damage in ordinary substantial buildings with partial collapse. Damage great in poorly built structures. Fall of chimneys, factory stacks, columns, monuments, walls. Heavy furniture overturned.
IX	Violent	Damage considerable in specially designed structures; well-designed frame structures thrown out of plumb. Damage great in substantial buildings, with partial collapse. Buildings shifted off foundations.
X	Extreme	Some well-built wooden structures destroyed; most masonry and frame structures destroyed with foundations. Rails bent.

*See, for example, https://www.usgs.gov/programs/earthquake-hazards/modified-mercalli-intensity-scale

Although analyses completed by the project sponsor suggest a potential peak ground acceleration of 14% for northwest Laramie County, the AOR is in the southeastern portion of the county; and, in fact, the AOR is associated with a lower peak ground acceleration of 5%. This intensity level is associated with MMI Category V, which, in turn, is associated with lower levels of damage ("felt by nearly everyone, many awakened, some dishes, windows broken, unstable objects overturned, pendulum clocks may stop").

Although higher costs (i.e., MMI category VI risk-based event across the entire AOR) could result, we believe they are substantially less likely to occur than lower cost events. Further, as previously noted, the project AOR has limited oil and gas development and lacks the extensive history of deep injection of fluids from nearby oil and gas operations that typically accompany areas experiencing significant induced seismicity.

7.7 Cost Distribution for Pore Space Trespass

- Minimum: $5,000
- Maximum: $2,000,000
- Uniform distribution

We apply this cost distribution above to all pore space trespass incidents that occur in a Monte Carlo trial.

As we understand, prior to initial CO2 injection, the project sponsor will have secured all necessary pore space, consistent with processes identified in the State of Wyoming regulations for unitization of geologic sequestration sites (WY § Stat 35-11-315 (2022)). Information provided by the project sponsor indicates that after initial CO2 injection, rights holders will share a lease payment expected to be approximately $1 per ton of CO2, divided among rights holders in proportion to their ownership (i.e., an owner contributing 1% of the area used for storage will receive 1% of the per-ton storage payments).[57]

Presently, the project sponsor forecasts storage of approximately 125.4 million tons of CO2 at the EWS Hub Project site, resulting in total nominal per-ton payments for pore space storage rights of $125.4 million.[58] For

[57] Some rights holders also will receive pre-injection payments, but such payments are not relevant to trespass cost estimation (which can only occur after injection begins).
[58] This total value is consistent with the project sponsor's representation of $1 per-ton of CO2 stored, divided among rights holders in proportion to ownership.

purposes of deriving a financial assurance cost estimate, we assume that the per-ton payments will be made annually over the 30-year injection period, based on injected volumes evinced in the prior year.[59]

Per WWQR Chapter 24: Section 26(b)(i), financial assurance cost estimates must be in current dollars. We determine the present (current) value of the stream of nominal ($1 per ton) pore space payments, based on the operational life of each of the five injection wells that comprise the EWS Hub Project. We do so, using the present value method.[60] The calculations underpinning the present values summarized in Exhibit 9 are based on: 1) anticipated injection rates, as provided by the project sponsor; 2) the staggered schedule for when each of the five injection wells in the EWS Hub Project AOR are anticipated to begin injection, 3) the length of time each individual well is anticipated to remain operational; and 4) annual discount rates aligned to future expected inflation rates[61] published by the Board of Governors of the U.S. Federal Reserve System as a measure of the rate at which prices are likely to change over the life of each injection well. As shown in Exhibit 9, factoring for the above assumptions, pore space rights payments total approximately $90 million (2023$).

Exhibit 9. Pore Space Rights Payments Discounting Calculations

Well	Injection Start Date	Injection End Date	Total Injection Days	Total MMT	Present Value (2023$)
Cypress	1/1/2025	12/26/2048	8,760	29,000,000	$21,298,431
Azalea	1/1/2025	1/1/2055	10,957	45,000,000	$31,030,091
Juniper	1/1/2025	1/1/2045	7,305	11,400,000	$8,753,331
Barberry	1/1/2025	1/1/2055	10,957	38,000,000	$26,203,188
Old Barb	1/1/2025	5/4/2026	488	2,000,000	$1,887,901
			Total (5 Wells)	**125,400,000**	**$89,172,942**

Importantly, if pore space trespass were to occur, it is possible that no additional payments would be required. As we understand from the project sponsor, the payment amount initially negotiated with pore space rights holders and identified in a unitization agreement (anticipated to be $1 per ton) would remain unchanged, the total payment simply would be divided among a (larger) number of storage acres.

For purposes of financial assurance cost estimation, however, we conservatively assume that is not the case. Rather, we assume that an additional, supplemental payment would be required to pore space rights holders who were not part of the original unitization agreement, and who, subsequent to CO2 injection, experience trespass.

From a timing perspective, trespass is highly unlikely to occur during the early years of injection – in our view, trespass risk increases as the total volume of injection increases and more time is provided for the CO2 plume to move through the subsurface environment. For these reasons, and for purpose of financial assurance cost estimation, we make the reasonable, simplifying assumption that should any trespass occur it is likely to occur during the last 10 years of the project's 30 year injection period. At that time, should trespass occur, 'trespassed' pore space rights holders would be entitled to receive a per-acre payment comparable to that

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[59] The project sponsor has represented that such payments may be done quarterly instead of annually. The difference in the time value of money between quarterly and annually is de minimis.

[60] The present value method is used in corporate finance to determine today's value of a stream of future cash flows or payments. Present value analysis is based on the expectation that funds invested, today, can grow over time to match the expected need and timing for funds in the future. This concept is referred to as the Time Value of Money; that is, money available today is worth more than the same amount in the future, because of its potential to earn a return on investment.

[61] See Federal Reserve Bank of Cleveland, "Inflation Expectations" data series: "Expected Inflation and Real and Inflation Risk Premia" at https://www.clevelandfed.org/our-research/indicators-and-data/inflation-expectations.aspx (Nov. 2023).

received by pore space rights holders who were subject to the initial unitization agreement and who received payments during the operational life of the well.[62]

Based on injection volume and the timing information provided by the project sponsor for each of the five injection wells in the AOR, pore space rights payments during the last 10 years of the project's injection period are expected to total approximately $17.5 million (2023$). We assume these payments would be allocated over an average area of 85,000 acres, which implies a total pore space rights payment price of approximately $200/acre over the ten year 'trespass' period.[63] If, instead, the storage plume extended (and thereby trespassed) into an additional 9,500 acres (about 10% of the maximum anticipated plume size), that would result in a total maximum trespass payment of approximately $2,000,000.[64]

Based on the information and approach described above, we use $2,000,000 as the maximum for our potential trespass cost distribution. This estimate is conservative – as previously noted, the actual movement of CO2 in the subsurface environment will be calibrated with modeled predictions on a regular and systematic basis, and therefore it is likely that any potential trespass issue would be identified prior to occurrence and the amount and/or location of ongoing CO2 injection potentially adjusted to reduce or eliminate the trespass concern. In addition, if trespass occurs it is possible that no additional payments would be required (i.e., the storage rights per-injected-ton payment amount would remain unchanged, but divided among a (larger) number of storage acres). To the extent potential trespass begins later than assumed in our calculations, the present value (2023$) of storage rights payments would decrease.

Finally, for purposes of Monte Carlo analysis, we assume a minimum trespass payment of $5,000, which allows for the reasonable possibility of trespass across very small acreages. We apply a uniform distribution to the cost range, which results in an equal chance for selection of every cost within the range.

8.0 MONTE CARLO ANALYSIS RESULTS

Based on a model run of 50,000 Monte Carlo trials **we estimate an upper-bound financial assurance cost estimate to satisfy emergency and remedial response and WWQR event-based risk activities of $9.4 million in current 2023 dollars.** This upper-bound cost estimate reflects the single Monte Carlo trial with the greatest financial assurance costs out of the 50,000 trials run (see Exhibit 10). We believe this estimate to be reasonable and appropriately conservative.

[62] We focus on the injection period for these calculations, because pore space rights payments are expected to be made as CO2 is injected. Based on information provided by the project sponsor, no additional storage rights payments are expected during site closure or post-injection site care (PISC).
[63] $200 ($2023) per acre (rounded) = $17.5 million ($2023) pore space rights payments over last ten years of injection / 85,000 acres. The 85,000 acre estimate assumes that during the last ten years of injection, the storage plume size would range between 75,000 acres and its maximum anticipated extent of approximately 95,000 acres.
[64] $2,000,000 (rounded) = $200 per acre * 9,500 acres trespassed

Exhibit 10. ERR and Event-Based Risk Activity Financial Assurance Cost Estimation Results (2023$)

Summary Statistic	Cost	# of Events Occurring
Average	$1,125,916	2.37
Standard Deviation	$1,096,628	1.53
5th Percentile	$0	0
50th Percentile	$935,290	2
95th Percentile	$3,228,341	5
99th Percentile	$4,473,010	7
Minimum	$0	0
Maximum	$9,376,550	12

Consistent with WWQR Chapter 24: Section 26(b)(iv) requirements, the Monte Carlo-based financial assurance cost estimates: incorporate cost curves shall combine risk probabilities, event outcomes, and damages assessment to calculate expected losses under a series of events; provide estimates of 50th, 95th, 99th percentile probabilities of occurrence; are calculated by project phase; are based on cost estimates that reflect third party-performance of response actions; and account for the entire EWS Hub Project AOR.

Exhibit 11 provides a summary of results by event and cost type. Across all 50,000 Monte Carlo trials, leakage through caprock/faults then shallow wells accounted for the largest fraction of estimated costs (approximately 48.2%) followed by deep oil & gas well leak (31.5%), pipeline release (8.8%), pore space trespass (8.8%), induced seismicity (2.2%), CO2 injection well leak (0.32%) and slow leakage through caprock (0.21%). The types of costs addressed in these estimates include: well repair; USDW non-endangerment; release-related human health, ecological and infrastructure impacts; mineral rights infringement; pore space storage trespass; and, induced seismicity-related infrastructure damage.

Exhibit 11. Cost Estimate Breakdown by Event and Cost Category Types

Event	Associated Cost Categories	Percent of Total Costs Across All Trials
Leakage Through Caprock/Faults then Shallow Well	Well repair (as applicable), USDW non-endangerment, release-related human health, ecological and infrastructure impacts, mineral rights infringement	48.2%
Deep Oil & Gas Well Leak		31.5%
CO2 Injection Well Leak		0.32%
Slow Leakage Through Caprock		0.2%
Rapid Leakage Through Caprock		0%
Release Through Existing Faults		0%
Release Through Induced Faults		0%
Pipeline Release	Release-related human health, ecological and infrastructure impacts	8.8%
Pore Space Trespass	Pore space storage rights payment	8.8%
Induced Seismicity	Seismicity-related infrastructure damage	2.2%

Matthew Kern
Senior Vice President

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+1 312 627 6181
www.marsh.com
matthew.kern@marsh.com

Via Email

February 29, 2024

Wyoming Department of Environmental Quality
200 West 17th St.
Cheyenne, Wyoming 82002

Re: Insurer Support – **Eastern Wyoming Sequestration Hub, Laramie County, WY**

To whom it may concern:

It is our pleasure to provide **Tallgrass High Plains Carbon Storage, LLC** insurance coverages to address project risks and meet their financial assurance responsibilities under the United States Environmental Protection Agency's Class VI Underground Injection Control regulations for the **Tallgrass High Plains Carbon Storage, LLC's Juniper I-1 Well Located in Laramie County** ("Project") as detailed below:

- Class VI Application 2023-039
- Facility ID No.: WYS-021-00153
- Facility Name: Juniper I-1
- Facility Address: 5313 Road 204, Carpenter, Wyoming 82054

This letter amends and supersedes the Insurer Support Letter prepared on November 27, 2023 for the Project. Marsh USA LLC, a subsidiary of Marsh McLennan, will approach carriers with AM Best ratings of A- or higher, and with size categories of VII or greater to secure bindable quotes for pollution insurance coverage. As a good faith measure of its commitment to the Class VI project, Tallgrass is providing a specimen policy with endorsements and a certificate. We will request quotes for policies conforming to these specimens of $15MM (each incident) / $45MM (aggregate), as required by the Wyoming rule.

After receipt and satisfactory review of all the required underwriting data, Marsh USA LLC expects to bind the program and incept a Pollution Legal Liability insurance policy, with all applicable financial assurance endorsements attached, and the required certificate. Placing a Pollution Legal Liability policy requires an underwriting review to protect the carrier's exposure, as well as ensure that the programs they put in place (1) will comply with the Class VI Underground Injection Control regulations, and (2) protect human health and the environment - a goal enthusiastically shared by all parties involved in the Project. Marsh USA LLC. and its carrier trading partners are committed to supporting the carbon capture & storage industry, and will work **Tallgrass High Plains Carbon Storage, LLC** to support the project with effective risk transfer and financial assurance. The Pollution Legal Liability will meet the requirements of the W.S. §35-11-313(f)(ii)(O) and Section 26(l)(i)(B).

Please do not hesitate to contact us with questions. We look forward to working with you.

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Sincerely,

Matthew Kern
Senior Vice President
Marsh Environmental Practice

cc: Mark Webster

Effective Date of Endorsement:
Insured Name:

THIS ENDORSEMENT CHANGES THE POLICY. PLEASE READ IT CAREFULLY.

CLAIM AND NOTICE REPORTING

This endorsement modifies insurance provided under the following:
PRIME POLLUTION LIABILITY COVERAGE FORM
PRIME PUMPER POLLUTION LIABILITY COVERAGE FORM
PRIME PLUS GENERAL LIABLITY AND POLLUTION LIABILITY COVERAGE FORM
PRIME CONTRACTORS POLLUTION LIABILITY COVERAGE FORM
EXCESS LIABILITY COVERAGE FORM

Subject to the claims and notice reporting provisions within the policy, claim and notice reports may be given in writing via:

POSTAL SERVICE to:
ASCOT Insurance Company
55 W. 46th Street, 26th Floor
New York, NY 10036

E-MAIL to:
Environmentalclaims@ascotgroup.com

or

By phone:
24 Hour Claims Reporting: 1-833-454-3023
24 Hour Emergency Response: 1-833-ER-ASCOT

PRIME PUMPER POLLUTION LIABILITY

(Pollution for Upstream, Midstream, Production, Exploration and Refining)

COVERAGE FORM

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PRIME PUMPER POLLUTION LIABILITY

(Pollution for Upstream, Midstream, Production, Exploration and Refining)

COVERAGE FORM

Various provisions in this policy restrict coverage. Please read the entire policy carefully to determine rights, duties and what is and is not covered.

SECTION I – COVERAGES, **Coverage A – Covered Location Pollution Liability** of this policy provide claims-made coverage.

Throughout this policy the words "you" and "your" refer to the Named Insured shown in the Declarations, and any other person or organization qualifying as a Named Insured under this policy. The words "we", "us" and "our" refer to the Company providing this insurance.

The word "insured" means any person or organization qualifying as such under **SECTION II – WHO IS AN INSURED**.

Defined terms, other than headings, appear in bold face type. Refer to **SECTION V - DEFINITIONS**.

SECTION I – COVERAGES

Coverage A – Covered Location Pollution Liability

1. Insuring Agreement

a. We will pay those sums that the insured becomes legally obligated to pay as damages because of **bodily injury**, **property damage** or **environmental damage** to which this insurance applies caused by or resulting from a **pollution event** on, at, under or migrating from a **covered location**. We will have the right and the duty to defend the insured against any **suit** seeking those damages. However, we will have no duty to defend the insured against any **suit** seeking damages for **bodily injury**, **property damage** or **environmental damage** to which this insurance does not apply. We may, at our discretion, investigate any **pollution event** and settle any **claim** or **suit** that may result. But:

(1) The amount we will pay for damages is limited as described in **Section III – LIMITS OF INSURANCE AND DEDUCTIBLE**; and

(2) Our right and duty to defend ends when we have used up the applicable limit of insurance in the payment of judgments, settlements, **clean-up costs** under **Coverage A** or costs under **Coverage C**.

No other obligation or liability to pay sums or perform acts or services is covered unless explicitly provided for under **SECTION I – SUPPLEMENTARY PAYMENTS**.

b. This insurance applies to **bodily injury**, **property damage** or **environmental damage** only if:

(1) The **bodily injury**, **property damage** or **environmental damage** is caused by or resulting from a **pollution event** that takes place in the **coverage territory**; and

(2) The **bodily injury**, **property damage** or **environmental damage** is caused by or resulting from a **pollution event** that occurs before the end of the **policy period**; and

(3) The insured first discovers the **pollution event** during the **policy period**. Discovery of a **pollution event** happens when a **responsible insured (i)** first becomes aware of the **pollution event**, **(ii)** reports the **pollution event** to us in writing during the **policy period** or any extended reporting period we provide under **SECTION IV – CONDITIONS**, Condition **9. Extended Reporting Period**, and **(iii)** promptly reports the **pollution event** to the appropriate governmental authority as required by **environmental law**; or

(4) A **claim** for damages because of **bodily injury**, **property damage** or **environmental damage** is first made against the insured and reported to us in writing during the **policy period** or any extended reporting period we provide under **SECTION IV – CONDITIONS**, Condition **9. Extended Reporting**

Period. A **claim** received by the insured during the **policy period** and reported to us within 30 days after the end of the **policy period** will be considered to have been reported within the **policy period**.

c. If a **claim** is first made against an insured and reported to us during the **policy period**, and additional **claims** arising from the same, related or continuous **pollution event** are made against an insured and reported to us during the **policy period** or during the policy period of a subsequent policy issued by us to you providing coverage substantially the same as that provided by **Coverage A – Covered Location Pollution Liability** for **claims** first made against an insured and reported to us during the **policy period**, then all such **claims** shall be:

(1) Deemed to be one **claim**;

(2) Deemed to have been first made and reported during this **policy period** on the date the first of such **claims** was made and reported; and

(3) Subject to the Coverage A – Covered Location Pollution Liability Limit stated in the Declarations.

Coverage under this **Coverage A – Covered Location Pollution Liability** for such **claims** shall not apply, however, unless at the time such subsequent **claims** are first made and reported, you have maintained with us coverage substantially the same as this **Coverage A – Covered Location Pollution Liability** on a continuous, uninterrupted basis since the first such **claim** was made against an insured.

d. Damages because of **bodily injury** include damages claimed by any person or organization for care, loss of services or death resulting at any time from the **bodily injury**.

2. Exclusions

In addition to exclusions found in **SECTION I – COMMON EXCLUSIONS**, this insurance does not apply to:

a. Damage to Mode of Transportation

Property damage to any **mode of transportation** utilized during **transportation**. This exclusion does not apply to **claims** made by third-party carriers for such **property damage** arising from the insured's negligence.

b. Change in Use

Clean-up costs required by **environmental law** due to a change in zoning or permitted use of any **covered location** during the **policy period**.

However, this exclusion does not apply to a **non-owned location** or a **divested location**.

c. Construction Activities

Environmental damage caused by or resulting from **pollutants** or a **pollution event** discovered during **construction activities** at a **covered location**.

d. Intrusive Investigation

Environmental damage caused by or resulting from a **pollution event** discovered during **intrusive investigation** at a **covered location** during the **policy period**.

However, this exclusion does not apply to a **non-owned location**.

e. Landfill or Impoundment

Costs, charges and expenses, incurred to investigate, remove, dispose of, abate, contain, treat, neutralize, monitor or test contaminated soil or other media in a landfill cell or an impoundment.

However, this exclusion does not apply to a **non-owned location**.

f. Prior Known Pollution Event

Bodily injury, **property damage** or **environmental damage** caused by or resulting from a **pollution event** or a **recognized environmental condition** known to a **responsible insured** prior to **(i)** the effective date of the **policy period** or **(ii)** the effective date of an Endorsement to this policy adding a **covered location**.

This exclusion does not apply if:

(1) The **pollution event** known to a **responsible insured** did not meet reporting requirements under **environmental law**;

(2) A No Further Action (NFA) or equivalent decision has been documented in writing in accordance with **environmental law** as respects the **pollution event** or **recognized environmental condition** giving rise to the **bodily injury**, **property damage** or **environmental damage**;

(3) We have been notified in writing of such **pollution event** giving rise to the **bodily injury**, **property damage** or **environmental damage** during the policy period of a policy previously issued by us to you; or

(4) The **pollution event** or **recognized environmental condition** giving rise to the **bodily injury**, **property damage** or **environmental damage** is specifically referenced, or identified on a Prior Known Pollution Event Exclusion Amendment Endorsement attached to this policy.

Coverage B - Miscellaneous Pollution Liability

1. Insuring Agreement

a. We will pay those sums that the insured becomes legally obligated to pay as damages, to which this insurance applies, because of:

(1) Bodily injury, **property damage** or **environmental damage** caused by or resulting from a **pollution event** arising out of **your work** scheduled to this policy by Endorsement;

(2) Bodily injury, **property damage** or **environmental damage** caused by or resulting from a **pollution event** during **transportation**; or

(3) Bodily injury, **property damage** or **environmental damage** caused by or resulting from a **time-element pollution event** on, at, under or migrating from a **newly acquired location**.

b. We will have the right and duty to defend the insured against any **suit** seeking those damages. However, we will have no duty to defend the insured against any **suit** seeking damages to which this insurance does not apply. We may, at our discretion, investigate any **pollution event** and settle any **claim** or **suit** that may result. But:

(1) The amount we will pay for damages is limited as described in **SECTION III - LIMITS OF INSURANCE AND DEDUCTIBLE**; and

(2) Our right and duty to defend ends when we have used up the applicable limits of insurance in the payment of judgments, settlements, **clean-up costs** under **Coverage A** or costs under **Coverage C**.

No other obligation or liability to pay sums or perform acts or services is covered unless explicitly provided for under **SECTION I – SUPPLEMENTARY PAYMENTS**.

c. This insurance applies to **bodily injury**, **property damage** or **environmental damage** only if:

(1) The **bodily injury**, **property damage** or **environmental damage** is caused by or resulting from a **pollution event** that takes place in the **coverage territory**;

(2) The **bodily injury**, **property damage** or **environmental damage** caused by or resulting from a **pollution event** arising out of **your work** occurs during the **policy period**; and

(3) Prior to the **policy period**, no **responsible insured** knew that the **bodily injury**, **property damage** or **environmental damage** caused by or resulting from a **pollution event** arising out of **your work** had occurred, in whole or in part. If any **responsible insured** knew, prior to the **policy period**, that the **bodily injury**, **property damage** or **environmental damage** occurred, then any continuation, change or resumption of such **bodily injury**, **property damage** or **environmental damage** during or after the **policy period** will be deemed to have been known prior to the **policy period**. However, this does not apply to any continuation, change or resumption of **environmental damage** arising out of **your work** performed after the effective date of the **policy period**;

(4) The **bodily injury**, **property damage** or **environmental damage** caused by or resulting from a **pollution event** during **transportation** occurs before the end of the **policy period**; and

(5) No **claim** for such **bodily injury**, **property damage** or **environmental damage** caused by or resulting from a **pollution event** during **transportation** was made against the insured prior to the effective date of the **policy period**;

(6) The **bodily injury**, **property damage** or **environmental damage** caused by or resulting from a **time-element pollution event** on, at under or migrating from a **newly acquired location** occurs during the **policy period**.

d. **Bodily injury**, **property damage** or **environmental damage** will be deemed to have been known to have occurred at the earliest time when any **responsible insured**:

(1) Reports all, or any part, of the **bodily injury, property damage** or **environmental damage** to us or any other insurer;

(2) Receives a **claim** or **suit** for damages because of the **bodily injury**, **property damage** or **environmental damage**; or

(3) Becomes aware by any other means that **bodily injury**, **property damage** or **environmental damage** has occurred or has begun to occur.

e. The following applies to progressive or indivisible **bodily injury**, **property damage** or **environmental damage**, including any continuation, change or resumption of such **bodily injury**, **property damage** or **environmental damage**, which takes place over a period of days, weeks, months or longer caused by continuous or repeated exposure to the same, related or continuous **pollution event**:

(1) Such **bodily injury**, **property damage** or **environmental damage** shall be deemed to have taken place only on the date of first exposure to such **pollution event**; or

(2) Such **bodily injury**, **property damage** or **environmental damage** shall be deemed to have taken place during the policy period of the first policy issued by us to you providing coverage substantially the same as that provided by **Coverage B – Miscellaneous Pollution Liability** of this policy for **bodily injury**, **property damage** or **environmental damage** that takes place during the **policy period** but only if:

(a) The date of first exposure cannot be determined or is before the effective date of the first policy issued by us to you providing coverage substantially the same as that provided by **Coverage B – Miscellaneous Pollution Liability** of this policy for **bodily injury**, **property damage** or **environmental damage** that takes place during the **policy period**; and

(b) Such **bodily injury**, **property damage** or **environmental damage** continues, in fact, to occur during this **policy period**.

f. If the same, related or continuous **pollution event** results in **bodily injury**, **property damage** or **environmental damage** that takes place during the policy periods of different policies issued by us to you providing coverage substantially the same as that provided by **Coverage B – Miscellaneous Pollution Liability** of this policy for **bodily injury**, **property damage** or **environmental damage** that takes place during the **policy period**:

(1) All such **bodily injury**, **property damage** and **environmental damage** shall be deemed to have taken place only during the first policy period of such policies in which any of the **bodily injury**, **property damage** or **environmental damage** took place; and

(2) All damages arising from all such **bodily injury**, **property damage** or **environmental damage** shall be deemed to have arisen from one **pollution event** and shall be subject to the Coverage B – Miscellaneous Pollution Liability Limit applicable to the policy for such first policy period.

g. Damages because of **bodily injury** include damages claimed by any person or organization for care, loss of services or death resulting at any time from the **bodily injury**.

2. Exclusions

In addition to exclusions found in **SECTION I – COMMON EXCLUSIONS**, this insurance does not apply to:

a. Covered Location Transportation

Environmental damage caused by or resulting from a **pollution event** during **transportation** within the boundaries of a **covered location**.

b. Damage to Mode of Transportation

Property damage to any **mode of transportation** utilized during **transportation**. This exclusion does not apply to **claims** made by third-party carriers for such **property damage** arising from the insured's negligence.

c. Damage to Your Work

Property damage or **environmental damage** to that particular part of any property on which you are performing **your work** if the **property damage** or **environmental damage** arises out of **your work**.

This exclusion does not apply if the damaged work or the work out of which the damage arises was performed on your behalf by a subcontractor.

d. Disposal Site

Bodily injury, **property damage** or **environmental damage** caused by or resulting from a **pollution event** on, at, under or migrating from any transfer, storage, disposal, landfill, treatment or consolidation **location** beyond the boundary of a job site where **your work** is performed.

Coverage C - Emergency and Crisis Management Costs

1. Insuring Agreement

a. We will pay **emergency costs** incurred by or on behalf of the insured in response to an imminent or substantial threat to human health or the environment caused by or resulting from a **pollution event**:

(1) Arising out of **your work**;

(2) During **transportation**; or

(3) On, at, under or migrating from a **covered location** or a **newly acquired location**.

b. But only if:

(1) The **pollution event** first commenced during the **policy period**;

(2) The **pollution event** takes place in the **coverage territory**;

(3) The **emergency costs**, except for **crisis management costs**, are incurred within ten business days of commencement of the **pollution event**; or

(4) The **crisis management costs** are incurred within six months of commencement of the **pollution event**; and

(5) The **pollution event** and related **emergency costs** are reported to us in writing within 30 business days of commencement of the **pollution event**.

c. We will pay these costs regardless of fault. But the amount we will pay is limited as described in **SECTION III - LIMITS OF INSURANCE AND DEDUCTIBLE**.

No other obligation or liability to pay sums or perform acts or services is covered unless explicitly provided for under **SECTION I – SUPPLEMENTARY PAYMENTS**.

2. Exclusions

In addition to exclusions found in **SECTION I – COMMON EXCLUSIONS** and **Coverage A – Covered Location Pollution Liability**, this insurance does not apply to:

a. Divested Location

Emergency costs incurred as a result of a **pollution event** on, at, under or migrating from a **divested location**.

b. Non-Owned Location

Emergency costs incurred as a result of a **pollution event** on, at, under or migrating from a **non-owned location**.

SECTION I – COMMON EXCLUSIONS

The insurance provided in **SECTION I** does not apply to:

1. Asbestos and Lead

Environmental damage caused by, resulting from, arising out of or related to, in whole or in part, the actual, alleged, threatened or suspected presence or existence of asbestos, asbestos containing materials, lead or lead containing materials in, on, or applied to any building or other structure.

However, this exclusion does not apply to **environmental damage** to land, any **mode of transportation**, the atmosphere, any watercourse or body of water including surface water or groundwater.

2. Closure Costs

Any cost, charges and expenses for closure, post closure, reclamation or plug and abandonment of well activities or obligations.

3. Contractual Liability

Bodily injury, **property damage** or **environmental damage** for which the insured is obligated to pay damages by reason of the assumption of liability in a contract or agreement. This exclusion does not apply to liability for damages:

a. That the insured would have in the absence of the contract or agreement; or

b. Assumed in a contract or agreement that is an **insured contract**, provided the **bodily injury**, **property damage** or **environmental damage** occurs subsequent to the execution of the contract or agreement. Solely for the purposes of liability assumed in an **insured contract**, reasonable attorneys' fees and necessary litigation expenses incurred by or for a party other than an insured are deemed to be damages because of **bodily injury**, **property damage** or **environmental damage**, provided:

(1) Liability to such party for, or for the cost of, that party's defense has also been assumed in the same **insured contract**; and

(2) Such attorneys' fees and litigation expenses are for defense of that party against a civil or alternative dispute resolution proceeding in which damages to which this insurance applies are alleged.

4. Drilling and Specialty Equipment

Property damage to drilling, work-over or servicing equipment.

5. Employer's Liability

Bodily injury to:

a. An **employee** of the insured arising out of and in the course of employment by the insured or performing duties related to the conduct of the insured's business; or

b. The spouse, child, parent, brother or sister of that **employee** as a consequence of Paragraph **a.** above.

This exclusion applies whether the insured may be liable as an employer or in any other capacity and to any obligation to share damages with or repay someone else who must pay damages because of the injury.

This exclusion does not apply to liability assumed by the insured under an **insured contract**.

6. **Expected or Intended Injury or Damage**

   Bodily injury, **property damage** or **environmental damage** expected or intended from the standpoint of the insured.

   However, this exclusion does not apply to **property damage** or **environmental damage** caused by or resulting from response to an imminent and substantial threat to human health or the environment.

7. **Noncompliance**

   Bodily injury, **property damage** or **environmental damage** caused by or resulting from a **responsible insured's** intentional disregard of, or deliberate, knowing, willful or dishonest noncompliance with any **environmental law**.

   However, this exclusion does not apply to **bodily injury**, **property damage** or **environmental damage** caused by or resulting from a **responsible insured's** knowing or willful noncompliance with any **environmental law** in response to an imminent and substantial threat to human health or the environment.

8. **Nuclear Material**

   Bodily injury, **property damage** or **environmental damage** caused by, resulting from, arising out of or related to, in whole or in part, the radioactive, toxic or explosive properties of **nuclear material** but only if the insured is:

   a. Required to maintain financial protection pursuant to the Atomic Energy Act of 1954;

   b. Entitled to indemnity from the United States of America or any agency thereof; or

   c. An insured under a nuclear energy liability policy issued by Nuclear Energy Liability Insurance Association, Mutual Atomic Energy Liability Underwriters, Nuclear Insurance Association of Canada or any of their successors, or would be an insured under any such policy but for its termination upon exhaustion of limits.

9. **Subsurface Storage of Natural Gas**

   Bodily injury, **property damage** or **environmental damage** that results from or is associated with the storage of natural gas in an underground storage facility including but not limited to depleted reservoirs in oil and gas fields, aquifers, salt caverns, salt domes, hard-rock caverns and mines.

10. **Underground Storage Tanks**

   Bodily injury, **property damage** or **environmental damage** caused by or resulting from a **pollution event** originating from or arising out of an **underground storage tank** which is: **(i)** known to a **responsible insured** as of the effective date of the **policy period**; **(ii)** known to a **responsible insured** as of the date of acquisition or initial occupancy of a **newly acquired location**; **(iii)** known to a **responsible insured** as of the date a **covered location** is added by Endorsement during the **policy period**; or **(iv)** installed during the **policy period**.

   This exclusion does not apply to an **underground storage tank** which has been:

   a. Closed, abandoned in place or removed in accordance with all applicable **environmental laws**; or

   b. Scheduled to this policy by Endorsement.

11. **Upgrades, Improvements or Installations**

   Any costs, charges or expenses for upgrade to, improvement of, or installation of any control of:

   a. Any personal property on a **covered location**; or

   b. Processes on, within or under a **covered location**.

   This exclusion applies even if such upgrade, improvement or installation is required by **environmental law**.

12. War

Bodily injury, **property damage** or **environmental damage**, however caused, arising, directly or indirectly, out of:

a. War, including undeclared or civil war;

b. Warlike action by a military force, including action in hindering or defending against an actual or expected attack, by any government, sovereign or other authority using military personnel or other agents; or

c. Insurrection, rebellion, revolution, usurped power, or action taken by governmental authority in hindering or defending against any of these.

13. Workers' Compensation and Similar Laws

Any obligation of the insured under a workers' compensation, disability benefits or unemployment compensation law or any similar law.

SECTION I – SUPPLEMENTARY PAYMENTS

1. We will pay, with respect to any **claim** we investigate or settle, any **suit** against an insured we defend, or any **emergency costs** incurred by or on behalf of any insured:

a. All expenses we incur that are directly allocated to a particular **claim** or **suit**.

b. All attorneys' fees or attorneys' expenses incurred by the insured in connection with **emergency costs**.

c. All reasonable expenses incurred by the insured at our request to assist us in the investigation or defense of the **claim** or **suit**, including actual loss of earnings up to $500 a day because of time off from work.

d. All court costs taxed against the insured in the **suit**. However, these payments do not include attorneys' fees or attorneys' expenses taxed against the insured.

e. Prejudgment interest awarded against the insured on that part of the judgment we pay. If we make an offer to pay the applicable limit of insurance, we will not pay any prejudgment interest based on that period of time after the offer.

f. All interest on the full amount of any judgment that accrues after entry of the judgment and before we have paid, offered to pay, or deposited in court the part of the judgment that is within the applicable limit of insurance.

These payments will not reduce the limits of insurance.

2. If we defend an insured against a **suit** and an indemnitee of the insured is also named as a party to the **suit**, we will defend that indemnitee if all of the following conditions are met:

a. The **suit** against the indemnitee seeks damages for which the insured has assumed the liability of the indemnitee in a contract or agreement that is an **insured contract**;

b. This insurance applies to such liability assumed by the insured;

c. The obligation to defend, or the cost of the defense of, that indemnitee, has also been assumed by the insured in the same **insured contract**;

d. The allegations in the **suit** and the information we know about the **pollution event** are such that no conflict appears to exist between the interests of the insured and the interests of the indemnitee;

e. The indemnitee and the insured ask us to conduct and control the defense of the indemnitee against such **suit** and agree that we can assign the same counsel to defend the insured and the indemnitee; and

f. The indemnitee:

(1) Agrees in writing to:

(a) Cooperate with us in the investigation, settlement or defense of the **suit**;

(b) Immediately send us copies of any demands, notices, summonses or legal papers received in connection with the **suit**;

(c) Notify any other insurer whose coverage is available to the indemnitee; and

(d) Cooperate with us with respect to coordinating other applicable insurance available to the indemnitee; and

(2) Provides us with written authorization to:

(a) Obtain records and other information related to the **suit**; and

(b) Conduct and control the defense of the indemnitee in such **suit**.

So long as the above conditions are met, attorneys' fees incurred by us in the defense of that indemnitee, necessary litigation expenses incurred by us and necessary litigation expenses incurred by the indemnitee at our request will be paid as **SECTION I – SUPPLEMENTARY PAYMENTS**. Notwithstanding the provisions of **SECTION I – COMMON EXCLUSIONS**, Exclusion **3. Contractual Liability**, Paragraph **b.**, such payments will not be deemed to be damages for **bodily injury**, **property damage** and **environmental damage** and will not reduce the limits of insurance.

Our obligation to defend an insured's indemnitee and to pay for attorneys' fees and necessary litigation expenses as **SECTION I – SUPPLEMENTARY PAYMENTS** ends when we have used up the applicable limit of insurance in the payment of judgments or settlements; or the conditions set forth above, or the terms of the agreement described in Paragraph **f.** above, are no longer met.

SECTION II – WHO IS AN INSURED

1. If you are designated in the Declarations as:

   a. An individual, you and your spouse are insureds, but only with respect to the conduct of a business of which you are the sole owner.

   b. A partnership or joint venture, you are an insured. Your members, your partners, and their spouses are also insureds, but only with respect to the conduct of your business.

   c. A limited liability company, you are an insured. Your members are also insureds, but only with respect to the conduct of your business. Your managers are insureds, but only with respect to their duties as your managers.

   d. An organization other than a partnership, joint venture or limited liability company, you are an insured. Your **executive officers** and directors are insureds, but only with respect to their duties as your officers or directors. Your stockholders are also insureds, but only with respect to their liability as stockholders.

   e. A trust, you are an insured. Your trustees are also insureds, but only with respect to their duties as trustees.

2. Any subsidiary, associated, affiliated, allied or limited liability company or corporation, including subsidiaries thereof, over which you maintain ownership or majority interest as of the effective date of the **policy period** qualify as a Named Insured.

3. Any organization you newly acquire or form, other than a partnership, joint venture or limited liability company, and over which you maintain ownership or majority interest, will qualify as a Named Insured if there is no other similar insurance available to that organization. However, coverage under this policy does not apply to **bodily injury**, **property damage** or **environmental damage** that occurred before you acquired or formed the organization.

4. Each of the following is also an insured:

   a. Your **volunteer workers** only while performing duties related to the conduct of your business, or your **employees**, other than either your **executive officers** (if you are an organization other than a partnership, joint venture or limited liability company) or your managers (if you are a limited liability company), but only for acts within the scope of their employment by you or while performing duties related to the conduct of your business. However, none of these **employees** or **volunteer workers** are insureds for:

(1) Bodily injury:

(a) To you, to your partners or members (if you are a partnership or joint venture) or to your members (if you are a limited liability company); or

(b) For which there is any obligation to share damages with or repay someone else who must pay damages because of the injury described in Paragraphs **(1)(a)** above.

(2) Property damage or **environmental damage** to property owned, occupied or used by, rented to, in the care, custody or control of, or over which physical control is being exercised for any purpose by you, any of your **employees**, **volunteer workers**, any partner or member (if you are a partnership or joint venture), or any member (if you are a limited liability company).

b. Any person (other than your **employee**), or any organization while acting as your real estate manager.

c. Any person or organization having proper temporary custody of your property if you die, but only with respect to liability arising out of the maintenance or use of that property and until your legal representative has been appointed.

d. Your legal representative if you die, but only with respect to duties as such. That representative will have all your rights and duties under this policy.

e. Any person(s) or organization(s) for whom you have agreed in writing in a contract, agreement or permit that such person(s) or organization(s) be added as an additional insured on your policy. Such person(s) or organization(s) is an additional insured only with respect to liability for **bodily injury**, **property damage** or **environmental damage** caused, in whole or in part, by:

(1) Your acts or omissions or the acts or omissions of those acting on your behalf in connection with a **covered location** or **newly acquired location**;

(2) Your work;

(3) Your ownership, maintenance, operation or use of a **covered location** or **newly acquired location**.

However, the insurance afforded to such additional insured only applies to the extent permitted by law and will not be broader than that which you are required by the contract, agreement or permit to provide for such additional insured.

f. Any owner, co-owner, party of joint venture, mining partner or limited liability company having a non-operating working interest in any oil or gas lease of which you are the operator, but only with respect to their liability for **bodily injury**, **property damage** or **environmental damage** arising out of such non-operating working interest.

g. Any person or organization that has a controlling interest in you, but only with respect to their liability for **bodily injury**, **property damage** or **environmental damage** arising out of their financial control of you.

SECTION III – LIMITS OF INSURANCE AND DEDUCTIBLE

1. The Limits of Insurance shown in the Declarations and the rules below fix the most we will pay regardless of the number of:

a. Insureds;

b. Claims made or **suits** brought;

c. Persons or organizations making **claims** or bringing **suits**; or

d. Pollution events.

2. The Policy Aggregate Limit is the most we will pay for the sum of all damages, **clean-up costs** and **emergency costs** under **Coverages A** through **C** inclusive.

3. Subject to Paragraph **2.** above, the Coverage A - Covered Location Pollution Liability Limit is the most we will pay for the sum of all damages and **clean-up costs** under **Coverage A - Covered Location Pollution Liability** because of all **bodily injury**, **property damage** and **environmental damage** caused by or resulting from the same, related or continuous **pollution event**.

4. Subject to Paragraph **2.** above, the Coverage B - Miscellaneous Pollution Liability Limit is the most we will pay for the sum of all damages under **Coverage B - Miscellaneous Pollution Liability** because of all **bodily injury, property damage** and **environmental damage** caused by or resulting from the same, related or continuous **pollution event**.

5. Subject to Paragraph **2.** Above, the Coverage C - Emergency and Crisis Management Costs Limit is the most we will pay under **Coverage C - Emergency and Crisis Management Costs** for the sum of all **emergency costs** incurred arising from the same, related or continuous **pollution event**.

6. The Limits of Insurance apply in excess of the Deductible amounts shown in the Declarations. The deductible amount applies as follows:

   a. As respects Coverage A - Covered Location Pollution Liability Limit, to the sum of all damages and **clean-up costs** and any payments made under **SECTION I – SUPPLEMENTARY PAYMENTS** because of **bodily injury**, **property damage** or **environmental damage** caused by or resulting from the same, related or continuous **pollution event**.

   b. As respects Coverage B - Miscellaneous Pollution Liability Limit, to the sum of all damages and any payments made under **SECTION I – SUPPLEMENTARY PAYMENTS** because of **bodily injury**, **property damage** or **environmental damage** caused by or resulting from the same, related or continuous **pollution event**.

   c. As respects Coverage C – Emergency and Crisis Management Costs Limit, to the sum of all **emergency costs** incurred and any payments made under **SECTION I – SUPPLEMENTARY PAYMENTS** arising from the same, related or continuous **pollution event**.

   However, if this insurance applies on an excess basis as described in **SECTION IV – CONDITIONS**, Condition **14. Other Insurance**, Paragraph **b. Excess Insurance**, the Deductible amounts shown in the Declarations will be eroded by any such valid and collectible other insurance.

   We may pay any part or the entire deductible amount to effect settlement of any **claim** or **suit** or to pay **clean-up costs** or **emergency costs** which may be covered under this policy and, upon notification of the action taken, you shall promptly reimburse us for such part of the deductible amount as has been paid by us.

   If the same or related **pollution event** results in coverage under more than one Coverage Part, only the highest deductible under any one Coverage Part will apply.

7. The Limits of Insurance apply to the entire **policy period**. If the **policy period** is extended after policy issuance for an additional period, the additional period will be deemed part of the last preceding period for the purposes of determining the Limits of Insurance.

SECTION IV – CONDITIONS

1. **Bankruptcy**

   Bankruptcy or insolvency of the insured or of the insured's estate will not relieve us of our obligations under this policy.

2. **Cancellation**

   a. The first Named Insured shown in the Declarations may cancel this policy by mailing or delivering to us advance written notice of cancellation.

b. We may cancel this policy by mailing or delivering to the first Named Insured written notice of cancellation at least:

  (1) Ten days before the effective date of cancellation if we cancel for nonpayment of premium; or

  (2) Ninety days before the effective date of cancellation if we cancel for any other reason.

c. We will mail or deliver our notice to the first Named Insured's last mailing address known to us.

d. Notice of cancellation will state the effective date of cancellation. The **policy period** will end on that date.

e. If this policy is cancelled, we will send the first Named Insured any premium refund due. If we cancel, the refund will be pro rata. If the first Named Insured cancels, the refund will be less than pro rata and will be subject to the minimum earned premium stated in the Declarations. The cancellation will be effective even if we have not made or offered a refund.

f. If notice is mailed, proof of mailing will be sufficient proof of notice.

3. Changes

This policy contains all the agreements between you and us concerning the insurance afforded. The first Named Insured shown in the Declarations is authorized to make changes in the terms of this policy with our consent. This policy's terms can be amended or waived only by endorsement issued by us and made a part of this policy.

4. Choice of Forum

In the event that the insured and we have any dispute concerning or relating to this policy, including its formation, coverage provided hereunder, or the meaning, interpretation or operation of any term, condition, definition or provision of this policy resulting in litigation, arbitration or other form of dispute resolution, the insured agrees with us that any such litigation, arbitration or other form of dispute resolution shall take place in the appropriate federal or state courts located in New York, New York.

5. Choice of Law

In the event that the insured and we have any dispute concerning or relating to this policy, including its formation, coverage provided hereunder, or the meaning, interpretation or operation of any term, condition, definition or provision of this policy resulting in litigation, arbitration or other form of dispute resolution, the insured agrees with us that the internal laws of the State of New York shall apply without giving effect to any conflicts or choice of law principles. The terms and conditions of this policy shall not be deemed to constitute a contract of adhesion and shall not be construed in favor of or against any party hereto by reason or authorship or otherwise.

6. Currency

All reimbursement shall be made in United States currency at the rate of exchange prevailing on the date of judgment if judgment is rendered, the date of settlement if settlement is agreed upon with our written consent or the date of payment of **clean-up costs** and **emergency costs**, whichever is applicable.

7. Duties in the Event of a Pollution Event, Claim or Suit

a. Without limiting the requirements of any insuring agreement in this policy, you must see to it that we are notified as soon as practicable of a **pollution event** which may result in a **claim** or is reasonably likely to involve this policy. To the extent possible, notice should include:

  (1) How, when and where the **pollution event** took place;

  (2) The names and addresses of any injured persons and witnesses; and

  (3) The nature and location of any injury or damage arising out of the **pollution event**.

b. If a **claim** is made or **suit** is brought against any insured, you must:

  (1) Immediately record the specifics of the **claim** or **suit** and the date received; and

  (2) Notify us as soon as practicable.

You must see to it that we receive written notice of the **claim** or **suit** as soon as practicable.

c. You and any other involved insured must:

(1) Immediately send us copies of any demands, notices, summonses or legal papers received in connection with the **claim** or **suit**;

(2) Immediately send us copies of contracts, certificates of insurance, environmental site assessments and any other documents deemed pertinent by us to the **claim** or **suit**;

(3) Authorize us to obtain records and other information;

(4) Cooperate with us in the investigation or settlement of the **claim** or defense against the **suit**; and

(5) Assist us, upon our request, in the enforcement of any right against any person or organization which may be liable to the insured because of injury or damage to which this insurance may also apply.

d. In the event **emergency costs** are incurred, you must provide, in writing, all available information relating to such **emergency costs** and the **pollution event** giving rise thereto to us within 30 days of commencement of the pollution event.

e. In the event of a **time-element pollution event**, you must provide, in writing, all available information relating to the **pollution event** giving rise thereto to us within 30 days of commencement of the **pollution event**.

f. No insured will, except at that insured's own cost, voluntarily make a payment, assume any obligation, or incur any expense, other than **emergency costs**, without our consent.

g. When any insured becomes legally obligated to pay **clean-up costs** to which this insurance applies, the insured must:

(1) Submit, for our approval, all proposed work plans prior to submittal to any regulatory agency.

(2) Submit, for our approval, all bids and contracts for **clean-up costs** prior to execution or issuance.

(3) Forward progress submittals regarding **clean-up costs** at reasonable intervals and always prior to submittal to any regulatory agency that is authorized to review and approve such submittals.

We shall have the right, but not the duty, to assume direct control of such **clean-up costs**. Any **clean-up costs** incurred by us shall be applied against the applicable Limit of Insurance and deductible.

h. If we are prohibited under applicable law from investigating, defending or settling any such **claim** or **suit,** the insured shall, under our supervision, arrange for such investigation and defense thereof as is reasonably necessary, and subject to our prior authorization, shall effect such settlement thereof.

8. Economic and Trade Sanctions

In accordance with laws and regulation of the United States concerning economic and trade sanctions administered and enforced by The Office of Foreign Assets Control (OFAC), this policy is void ab initio solely with respect to any term or condition of this policy that violates any laws or regulations of the United States concerning economic and trade sanctions.

9. Extended Reporting Period

This condition applies only as respects **Coverage A – Covered Location Pollution Liability**.

a. This condition applies only if:

(1) The policy is cancelled or non-renewed for any reason except non-payment of the premium; or

(2) We renew or replace this policy with **Coverage A – Covered Location Pollution Liability** that provides claims-made coverage for **bodily injury**, **property damage** or **environmental damage** and that has a Retroactive Date; and

(3) You do not purchase coverage to replace the coverage described in Paragraph **a.(2)** above.

b. Automatic Extended Reporting Period

You shall automatically have a period of 90 days following the effective date of such termination of coverage in which to provide written notice to us of **claims** first made and reported within the automatic extended reporting period.

A **claim** first made and reported within the automatic extended reporting period will be deemed to have been made on the last day of the **policy period**, provided that the **claim** is for damages or **clean-up costs** arising from a **pollution event** which commenced before the end of the **policy period** and is otherwise covered by this policy.

No part of the automatic extended reporting period shall apply if the optional extended reporting period is purchased.

c. Extended Reporting Period Option:

(1) A **claim** first made and reported within 48 months after the end of the **policy period** will be deemed to have been made on the last day of the **policy period**, provided that the **claim** is for damages or **clean-up costs** arising from a **pollution event** which commenced before the end of the **policy period** and is otherwise covered by this policy.

(2) The Extended Reporting Period Endorsement will not reinstate or increase the Limits of Insurance or extend the **policy period**.

d. We will issue the Endorsement indicating the Extended Reporting Period Option has been accepted if the first Named Insured shown in the Declarations:

(1) Makes a written request for it within 30 days after the end of the **policy period**; and

(2) Promptly pays the additional premium, which will not exceed 200% of the policy premium, when due.

The Extended Reporting Period Endorsement will not take effect unless the additional premium is paid when due. If that premium is paid when due, the Endorsement may not be cancelled. The additional premium will be fully earned when the Endorsement takes effect.

e. The Extended Reporting Period Endorsement will also amend **SECTION IV – CONDITIONS**, Condition **14. Other Insurance** so the insurance provided will be excess over any other valid and collectible insurance available to the insured, whether primary, excess, contingent or on any other basis, whose policy period begins or continues after the Endorsement takes effect.

10. First Named Insured Duties

The first Named Insured shown in the Declarations:

a. Is responsible for the payment of all premiums;

b. Will act on behalf of all other Named Insureds for giving and receiving of notice of cancellation;

c. Will be the payee for any return premiums that may become payable.

11. Independent Counsel

In the event the insured is entitled by law to select independent counsel to oversee our defense of a **claim** or **suit** at our expense, the attorney fees and all other litigation expenses we must pay to that counsel are limited to the rates we actually pay to counsel we retain in the ordinary course of business in the defense of similar **claims** or **suits** in the community where the **claim** or **suit** arose or is being defended.

Additionally, we may exercise the right to require that such counsel have certain minimum qualifications with respect to their competency including experience in defending **claims** or **suits** similar to the one pending against the insured and to require such counsel have a specific minimum amount of errors and omissions insurance coverage. As respects any such counsel, the insured agrees that counsel will timely respond to our request for information regarding the **claims** or **suit**.

Furthermore, the insured may at any time, by the insured's written consent, freely and fully waive these rights to select independent counsel.

12. Inspections and Surveys

a. We have the right but not the duty to make inspections and surveys at any time, report on the conditions we find and recommend changes.

b. We are not obligated to make any inspections, surveys, reports or recommendations and any such actions we do undertake relate only to insurability and the premiums to be charged. We do not make safety inspections. We do not undertake to perform the duty of any person or organization to provide for the health or safety of workers or the public. We do not warrant that conditions are safe, healthful or comply with laws, regulations, codes or standards.

This applies not only to us, but also to any rating, advisory, rate service or similar organization which makes insurance inspections, surveys, reports or recommendations.

13. Legal Action Against Us

No person or organization has a right under this policy:

a. To join us as a party or otherwise bring us into a **suit** asking for damages from an insured; or

b. To sue us on this policy unless all of its terms have been fully complied with.

A person or organization may sue us to recover on an agreed settlement or on a final judgment against an insured; but we will not be liable for damages that are not payable under the terms of this policy or that are in excess of the applicable limit of insurance. An agreed settlement means a settlement and release of liability signed by us, the insured and the claimant or the claimant's legal representative.

14. Other Insurance

If other valid and collectible insurance is available to the insured for a loss we cover under this policy, our obligations are limited as follows:

a. Primary Insurance

This insurance is primary except when Paragraph **b.** below applies. If this insurance is primary, our obligations are not affected unless any of the other insurance is also primary. Then, we will share with all that other insurance by the method described in Paragraph **c.** below. However, regardless of whether **b.** below applies, in the event that a written contract or agreement or permit requires this insurance to be primary for any person or organization you agreed to insure and such person or organization is an insured under this policy, we will not seek contributions from any such other insurance issued to such person or organization.

b. Excess Insurance

(1) This insurance is excess over:

(a) Any other insurance, whether primary, excess, contingent or on any other basis that covers your liability for **bodily injury**, **property damage** or **environmental damage** arising from a **pollution event**;

(b) Any other insurance, whether primary, excess, contingent or on any other basis, available to you covering liability for damages caused by or resulting from a **pollution event** during **transportation**;

(c) Any other insurance, whether primary, excess, contingent or on any other basis, available to you covering liability for damages at a **covered location**, for which you have been added as an additional insured; or

(d) Any project specific primary insurance available to you covering liability for damages arising out of **your work**, for which you are an insured.

(2) When this insurance is excess, we will have no duty to defend the insured against any **suit** if any other insurer has a duty to defend the insured against that **suit**. If no other insurer defends, we will undertake to do so, but we will be entitled to the insured's rights against all those other insurers.

(3) When this insurance is excess over other insurance, we will pay only our share of the amount of the loss, if any, that exceeds the sum of:

(a) The total amount that all such other insurance would pay for the loss in the absence of this insurance; and

(b) The total of all deductible and self-insured amounts under all that other insurance; and

(c) The Deductible amounts shown in the Declarations of this policy less the total amount pay in Paragraph **(a)** above.

(4) We will share the remaining loss, if any, with any other insurance that is not described in this Excess Insurance provision and was not bought specifically to apply in excess of the Limits of Insurance shown in the Declarations of this policy.

c. Method of Sharing

If other insurance is also primary, then we will share with all that other insurance by an equal share contribution method. Under this approach each insurer contributes equal amounts, excess of applicable deductible and self-insured amounts under all such insurance, until it has paid its applicable limit of insurance or none of the loss remains, whichever comes first.

15. Representations

By accepting this policy, you agree:

a. The statements in the Declarations are accurate and complete;

b. Those statements are based upon representations you made to us; and

c. We have issued this policy in reliance upon your representations.

16. Separation of Insureds

Except with respect to the Limits of Insurance and any rights or duties specifically assigned in this policy to the first Named Insured, this insurance applies:

a. As if each Named Insured were the only Named Insured; and

b. Separately to each insured against whom **claim** is made or **suit** is brought.

17. Service of Suit

It is hereby understood and agreed that we may be sued upon any cause of action arising under any insurance contract made by us or evidence of insurance issued or delivered by the broker, in the courts for the county(s) where the insurance provides coverage or in the courts of New York, New York where we maintain our home office.

It is further agreed that service of process in such suit may be made upon the Superintendent, Commissioner, Director of Insurance or other appropriate person at the state Department of Insurance, Secretary of State or other designee as provided for in specific state laws and/or regulations.

When service of process is made upon a statutory designee according to state law, such process should be provided via certified mail to us to the attention of our General Counsel.

It is further agreed that in any **suit** instituted against any insured under this policy or otherwise upon this policy, we will abide by the final decision of such court or of any appellate court in the event of an appeal.

18. Transfer of Rights of Recovery Against Others to Us

If the insured has rights to recover all or part of any payment we have made under this policy, those rights are transferred to us. The insured must do nothing after loss to impair them. At our request, the insured will bring **suit** or transfer those rights to us and help us enforce them. However, if the insured has waived rights of recovery against any person or organization, in writing, prior to a loss, we waive any right of recovery we may have under this policy against such person or organization.

19. Transfer of Your Rights and Duties Under This Policy

Your rights and duties under this policy may not be transferred until we consent by Endorsement to the policy, except in the case of death of an individual named insured.

If you die, your rights and duties will be transferred to your legal representative but only while acting within the scope of duties as your legal representative. Until your legal representative is appointed, anyone having proper temporary custody of your property will have your rights and duties but only with respect to that property.

20. When We Do Not Renew

If we decide not to renew, we will mail or deliver to the first Named Insured shown in the Declarations written notice of the nonrenewal not less than 90 days before the expiration date. If notice is mailed, proof of mailing will be sufficient proof of notice.

SECTION V – DEFINITIONS

1. **Auto** means:

   a. A land motor vehicle, trailer or semitrailer designed for travel on public roads, including any attached machinery or equipment; or

   b. Any other land vehicle that is subject to a compulsory or financial responsibility law where it is licensed or principally garaged.

2. **Bodily injury** means physical injury, sickness, disease, building-related illness, mental anguish, shock or emotional distress, sustained by a person, including death resulting from any of these at any time. **Bodily injury** shall also include medical monitoring costs.

3. **Claim** means a written or verbal demand, notice or assertion of a legal right alleging liability or responsibility on the part of the insured.

4. **Clean-up costs** means reasonable costs, charges and expenses, incurred to investigate, remove, dispose of, abate, contain, treat, neutralize, monitor or test contaminated soil, surface water, groundwater, air or other media but only:

   a. To the extent required by **environmental law**;

   b. As respects **mold matter**, to the extent recommended in writing by an indoor environmental professional that we deem acceptable;

   c. To the extent incurred by the government or any political subdivision within Definition **6.a**. **Coverage territory**; or

   d. To the extent incurred by parties other than you.

   Clean-up costs includes **restoration costs**.

5. **Construction activities** means interior demolition, remodeling or renovation or subsurface excavation at a refinery or terminal.

6. **Coverage territory** means:

   a. The United States of America (including its territories and possessions), Puerto Rico, Canada and the Gulf of Mexico; or

   b. All other parts of the world if the injury or damage is caused by or results from a **pollution event**:

      (1) On, at, under or migrating from a **non-owned location** or a scheduled **covered location** located in all other parts of the world;

      (2) Arising out of **your work**; or

      (3) During **transportation**.

However, we assume no responsibility for furnishing certificates or evidence of insurance or bonds and we will not be liable for any fine or penalty imposed on you for failing to comply with insurance laws.

7. **Covered location** means:

   a. Any **location** you own, occupy, lease pursuant to terms of an oil & gas mineral lease or access pursuant to an easement or license agreement as of the effective date of the **policy period**;

   b. Any **location** in which you have a non-operating working interest pursuant to a Joint Operating Agreement as of the inception of the **policy period**;

   c. A **non-owned location**;

   d. A **divested location**; and

   e. Any **location** added by Endorsement to this policy.

8. **Crisis management costs** means reasonable costs, charges and expenses incurred for services provided by a crisis management firm that we deem acceptable. However, **crisis management costs** do not include compensation, fees, benefits, overhead charges or expenses of the insured.

9. **Divested location** means any **location** you cease to own, occupy, lease pursuant to terms of an oil and gas lease, access pursuant to an easement or license agreement or have a non-operating working interest pursuant to a Joint Operating Agreement during the **policy period** or any policy period of a policy previously issued by us to you providing coverage substantially the same as that provided by **SECTION I – COVERAGES** of this policy.

10. **Emergency costs** means reasonable costs, charges and expenses incurred to investigate, remove, dispose of, abate, contain, treat, neutralize, monitor or test contaminated soil, surface water, groundwater, air or other media.

    Emergency costs include **crisis management costs**.

11. **Employee** includes a **leased worker** and a **temporary worker**.

12. **Environmental damage** means physical damage to land, any **mode of transportation**, structures on land or water, the atmosphere, any watercourse or body of water including surface water or groundwater, giving rise to **clean-up costs**.

    Environmental damage does not include **property damage**.

13. **Environmental law** means any federal, state, provincial, municipal or local laws, including, but not limited to, statutes, rules, ordinances, guidance documents, regulations and all amendments thereto, including state voluntary cleanup or risk based corrective action guidance, and governmental, judicial or administrative orders and directives that are applicable to a **pollution event.**

14. **Executive officer** means a person holding any of the officer positions created by your charter, constitution, by-laws or any other similar governing document.

15. **Insured contract** means:

    a. A Joint Operating Agreement;

    b. A contract for a lease of premises;

    c. A sidetrack agreement;

    d. Any easement or license agreement;

    e. An obligation, as required by ordinance, to indemnify a municipality, except in connection with work for a municipality;

    f. An elevator maintenance agreement;

    g. That part of any other contract or agreement pertaining to your business (including an indemnification of a municipality in connection with work performed for a municipality) under which you assume the tort liability of another party to pay for **bodily injury**, **property damage** or **environmental damage** to a third person or organization. Tort liability means a liability that would be imposed by law in the absence of any contract or agreement.

Paragraph **g.** does not include that part of any contract or agreement that indemnifies an architect, engineer or surveyor for injury or damage arising out of:

(1) Preparing, approving, or failing to prepare or approve, maps, shop drawings, opinions, reports, surveys, field orders, change orders or drawings and specifications; or

(2) Giving directions or instructions, or failing to give them, if that is the primary cause of the injury or damage.

16. Intrusive investigation means the collection of original samples of soil, surface water or groundwater to analyze for quantitative values of various contaminants, performed for one or more of the following reasons:

a. Contemplation of purchase or purchase by a person or entity other than you;

b. Change in capital structure or ownership requiring **intrusive investigation**;

c. Your noncompulsory desire to understand **environmental damage**;

d. State specific Property Transfer Act requirements.

17. Leased worker means a person leased to you by a labor leasing firm under an agreement between you and the labor leasing firm, to perform duties related to the conduct of your business. **Leased worker** does not include a **temporary worker**.

18. Location means:

a. Premises involving the same or connected lots;

b. Premises whose connection is interrupted only by a street, roadway, waterway or right-of-way of a railroad;

c. Real property contained within an easement.

Location includes pooled units.

19. Misdelivery means the delivery of any liquid product into a wrong receptacle or to a wrong address or the erroneous delivery of one liquid product for another.

20. Mode of transportation means an **auto**, railcar, rolling stock, train, watercraft or aircraft. **Mode of transportation** does not include pipelines.

21. Mold matter means mold, mildew and fungi, whether or not such **mold matter** is living.

22. Natural resource damage means physical injury to or destruction of, as well as the assessment of such injury or destruction, including the resulting loss of value of land, fish, wildlife, biota, air, water, groundwater, drinking water supplies, and other such resources belonging to, managed by, held in trust by, appertaining to, or otherwise controlled by the United States (including the resources of the fishery conservation zone established by the Magnuson-Stevens Fishery Conservation and Management Act (16 U.S.C. 1801 et seq.)), any state, local or provincial government, any foreign government, any Native American tribe, or, if such resources are subject to a trust restriction on alienation, any member of a Native American tribe.

23. Newly acquired location means any **location** that:

a. You begin ownership or occupancy of after the effective date of the **policy period**; or

b. You enter into a lease agreement pursuant to terms of an oil and gas mineral lease, an easement or license agreement or a non-operating working interest pursuant to a Joint Operating Agreement after the effective date of the **policy period**.

However, coverage does not apply to **bodily injury**, **property damage** or **environmental damage** that occurred before you began ownership or occupancy or entered into any agreements in **b.** above.

A **newly acquired location** does not include a **location** which is specifically scheduled as a **covered location**.

24. Non-owned location means any **location** performing operations or services on your behalf provided that the **location** is not, and never was, owned by, occupied by, loaned to, leased pursuant to terms of an oil and gas lease or accessed pursuant to an easement or license agreement by any insured. A **non-owned location** shall also include any job site location leased, rented, occupied or borrowed for use as a staging area to facilitate **your work**.

Non-owned location does not include:

a. Any **location** which any insured has or had a non-operating working interest pursuant to a Joint Operating Agreement.

b. Any **location** which is not licensed by the appropriate federal, state or local authority to perform storage, disposal, processing or treatment of waste from your operations or **your work** in compliance with **environmental law**.

c. Any **location** or any part thereof that has been listed or proposed to be listed on the Federal National Priorities list (NPL) or a state specific superfund site list prior to waste from your operations or **your work** being legally consigned for delivery or delivered for storage, disposal, processing or treatment at such **location**.

d. Any **location** of a purchaser or user of **your product**.

25. Nuclear material means source material, special nuclear material or byproduct material which have the meanings given them in the Atomic Energy Act of 1954 or in any law amendatory thereof.

26. Policy period means the period of time stated in the Declarations. However, if the policy is cancelled in accordance with **SECTION IV – CONDITIONS**, Condition **2. Cancellation**, the **policy period** ends on the effective date of such cancellation.

27. Pollutants means any solid, liquid, gaseous or thermal irritant, or contaminant, including smoke, soot, vapor, fumes, acids, alkalis, chemicals, hazardous substances, hazardous materials, or waste materials, including medical, infectious and pathological wastes. **Pollutants** includes electromagnetic fields, **mold matter** and legionella pneumophila.

28. Pollution event means:

a. The discharge, dispersal, release, escape, migration, or seepage of **pollutants** on, in, into, or upon land, any **mode of transportation**, structures on land or water, the atmosphere, any watercourse or body of water including surface water or groundwater; or

b. The presence of **mold matter**; or

c. **Misdelivery**.

Pollution event includes the illicit abandonment of **pollutants** at any **location** which is owned or occupied by you provided that such abandonment was committed by parties other than an insured and without the knowledge of a **responsible insured**.

Pollution event includes a **time-element pollution event**.

29. Property damage means:

a. Physical injury to or destruction of tangible property, including all resulting loss of use and diminished value of that property. All such loss of use and diminished value shall be deemed to occur at the time of the physical injury that caused it;

b. Loss of use and diminished value of tangible property that is not physically injured or destroyed. All such loss of use shall be deemed to occur at the time of the **occurrence** or **pollution event** that caused it; or

c. **Natural resource damage**.

Property damage does not include **environmental damage**.

For the purpose of this insurance, electronic data is not tangible property. As used in this definition, electronic data means information, facts or programs stored as or on, created or used on, or transmitted to or from computer software, including systems and applications software, hard or floppy disks, CDROMS, tapes, drives, cells, data processing devices or any other media which are used with electronically controlled equipment.

30. Recognized environmental condition means a recognized environmental condition (REC) identified in a Phase I Environmental Site Assessment identifying the presence or likely presence of a hazardous substance or petroleum product indicative of:

a. An existing **pollution event**;

b. A past **pollution event**; or

c. A material threat of a future **pollution event**.

31. Responsible insured means:

a. Your **executive officers**, directors, partners or members;

b. Your manager of a **covered location** or **newly acquired location**;

c. Your **employee** responsible for environmental affairs, health and safety affairs, control or compliance or any other **employee** authorized by you to give or receive notice of a **claim**.

32. Restoration costs means reasonable and necessary costs incurred by the insured, to repair, restore or replace damaged real or personal property damaged during work performed in the course of incurring **clean-up costs** in order to restore the property to the condition it was in prior to being damaged during such work. **Restoration costs** shall not exceed the lesser of actual cash value of such real or personal property or the cost of repairing, restoring or replacing the damaged property with other property of like kind and quality. An adjustment for depreciation and physical condition shall be made in determining actual cash value. If a repair or replacement results in better than like kind or quality, we will not pay for the amount of the betterment, except to the extent such betterments of the damaged property entail the use of materials which are environmentally preferable to those materials which comprised the damaged property. Such environmentally preferable material must be certified as such by an applicable independent certifying body, where such certification is available, or, in the absence of such certification, based on our judgment in our sole discretion.

33. Suit means a civil proceeding in which damages to which this insurance applies are alleged. **Suit** includes an arbitration proceeding in which such damages are claimed and to which the insured must submit or does submit with our consent or any other alternative dispute resolution proceeding in which such damages are claimed and to which the insured submits with our consent.

34. Temporary worker means a person who is furnished to you to substitute for a permanent worker on leave or to meet seasonal or short-term workload conditions.

35. Time-element pollution event means a **pollution event** which:

a. First commences during the **policy period**;

b. Is first discovered by the insured within ten business days of commencement;

c. Is reported to us in writing within 30 business days of commencement; and

d. Does not originate or arise from an **underground storage tank**.

36. Transportation means the movement of goods, product, merchandise, supplies or waste in a **mode of transportation** by the insured or a third-party carrier from the time of movement from the point of origin until delivery to the final destination. **Transportation** includes the movement of goods, products, merchandise, supplies or waste into, onto or from a **mode of transportation**.

37. Underground storage tank means any tank, including any piping and appurtenances connected to the tank, located on or under a **covered location** or a **newly acquired location**, that has at least 10% of its combined volume underground. **Underground storage tank** does not include:

a. Septic tanks, sump pumps, or oil/water separators;

b. A tank that is enclosed within a basement or cellar, if the tank is upon or above the surface of the floor; or

c. Storm-water or wastewater collection systems.

38. **Volunteer worker** means a person who is not your **employee**, and who donates his or her work and acts at the direction of and within the scope of duties determined by you, and is not paid a fee, salary or other compensation by you or anyone else for their work performed for you.

39. **Your product**:

a. Means:

(1) Any goods or products, other than real property, manufactured, sold, handled, distributed or disposed of by:

(a) You;

(b) Others trading under your name; or

(c) A person or organization whose business or assets you have acquired; and

(2) Containers (other than vehicles), materials, parts or equipment furnished in connection with such goods or products.

b. Includes:

(1) Warranties or representations made at any time with respect to the fitness, quality, durability, performance or use of **your product**; and

(2) The providing of or failure to provide warnings or instructions.

40. **Your work** means work or operations performed by you or on your behalf scheduled by Endorsement to this policy.

Effective Date of Endorsement:
Insured Name:

THIS ENDORSEMENT CHANGES THE POLICY. PLEASE READ IT CAREFULLY.

CONSTRUCTION ACTIVITIES EXCLUSION DELETION

This endorsement modifies insurance provided under the following:
PRIME PUMPER POLLUTION LIABILITY COVERAGE

It is hereby agreed that the policy to which this Endorsement is attached is amended as follows:

SECTION I – COVERAGES, **Coverage A – Covered Location Pollution Liability**, Paragraph **2. Exclusions**, Exclusion **c. Construction Activities** is deleted in its entirety.

ALL OTHER TERMS, CONDITIONS AND EXCLUSIONS OF THIS POLICY REMAIN UNCHANGED.

Effective Date of Endorsement:
Insured Name:

THIS ENDORSEMENT CHANGES THE POLICY. PLEASE READ IT CAREFULLY.

DESIGNATED COVERED LOCATION LIMITATION

This endorsement modifies insurance provided under the following:
PRIME PUMPER POLLUTION LIABILITY COVERAGE FORM

It is hereby agreed that the policy to which this Endorsement is attached is amended as follows:

A. **SECTION V – DEFINITIONS**, Definition **7. Covered location** is deleted and replaced with the following:

7. **Covered location** means the **location(s)** designated in the Schedule below and any **non-owned location** utilized by a **covered location** for the disposal of your waste generated and transported solely from that **covered location**.

B. **SECTION I – COVERAGES**, **Coverage B – Miscellaneous Pollution Liability**, Paragraph **1. Insuring Agreement**, Subparagraph **a.** is deleted and replaced with the following:

a. We will pay those sums that the insured becomes legally obligated to pay as damages, to which this insurance applies, because of:

(1) **Bodily injury**, **property damage** or **environmental damage** caused by or resulting from a **pollution event** arising out of **your work** scheduled to this policy by Endorsement; or

(2) **Bodily injury**, **property damage** or **environmental damage** caused by or resulting from a **pollution event** during **transportation** to or from a **covered location**.

C. **SECTION I – COVERAGES**, **Coverage C – Emergency and Crisis Management Costs**, Paragraph **1. Insuring Agreement**, Subparagraph **a.** is deleted and replaced with the following:

a. We will pay **emergency costs** incurred by or on behalf of the insured in response to an imminent or substantial threat to human health or the environment caused by or resulting from a **pollution event**:

(1) Arising out of **your work**;

(2) During **transportation** to or from a **covered location**; or

(3) On, at, under or migrating from a **covered location**.

SCHEDULE OF DESIGNATED COVERED LOCATION(S):

WELL DESCRIPTION

WELL DESCRIPTION

ALL OTHER TERMS, CONDITIONS AND EXCLUSIONS OF THIS POLICY REMAIN UNCHANGED.

Effective Date of Endorsement:
Insured Name:

THIS ENDORSEMENT CHANGES THE POLICY. PLEASE READ IT CAREFULLY.

SUBSURFACE STORAGE OF NATURAL GAS EXCLUSION DELETION

This endorsement modifies insurance provided under the following:
PRIME PUMPER POLLUTION LIABILITY FORM

It is hereby agreed that the policy to which this Endorsement is attached is amended as follows:

SECTION I – COMMON EXCLUSIONS, Exclusion **9. Subsurface Storage of Natural Gas** is deleted in its entirety.

ALL OTHER TERMS, CONDITIONS AND EXCLUSIONS OF THIS POLICY REMAIN UNCHANGED.

Effective Date of Endorsement:
Insured Name:

THIS ENDORSEMENT CHANGES THE POLICY. PLEASE READ IT CAREFULLY.

FINANCIAL RESPONSIBILITY –
UNDERGROUND INJECTION CONTROL PROGRAM – CLASS VI

This endorsement modifies insurance provided under the following:
PRIME PUMPER POLLUTION LIABILITY COVERAGE FORM

It is hereby agreed that the policy to which this Endorsement is attached is amended as follows:

Solely as respects the **covered location(s)** identified in the Schedule of this Endorsement and the insured's obligation to demonstrate financial responsibility under the United States Environmental Protection Agency, Chapter I – Environmental Protection Agency, Subchapter D – Water Programs, Part 146 – Underground Injection Control Program: Criteria and Standards, Subpart H – Criteria and Standards Applicable to Class VI Wells, Section 40 CFR § 146.85, it is hereby agreed:

SCHEDULE:

Covered Location: Facility Name and Mailing Address	Covered Location:	Permit Number:

LIMITS of INSURANCE:

Financial Responsibility Each Event Limit	TBD
Financial Responsibility Aggregate Limit	TBD

A. SECTION III – LIMITS OF INSURANCE AND DEDUCTIBLE is amended to include the following:

The Financial Responsibility Each Event Limit shown in the Schedule of this Endorsement is the most we will pay for the sum of all damages and **clean-up costs** under **SECTION I – COVERAGES, Coverage A – Covered Location Pollution Liability** because of **bodily injury, property damage** or **environmental damage** caused by or resulting from the same, related or continuous **pollution event** at a **covered location** shown in the Schedule.

The Financial Responsibility Aggregate Limit shown in the Schedule of this Endorsement is the most we will pay for the sum of all damages and **clean-up costs** under **SECTION I – COVERAGES, Covered Location Pollution Liability**, **Coverage A – Covered Location Pollution Liability**.

B. SECTION IV – CONDITIONS is amended to include the following:

We agree to furnish the Regional Administrator of the USEPA a signed duplicate original of the policy and all endorsements when requested.

C. **SECTION IV – CONDITIONS**, Condition **3. Cancellation** is deleted in its entirety and replaced with the following:

2. Cancellation

a. We may cancel this policy only for nonpayment of premium. In such event, we will mail or deliver to the first Named Insured and the Regional Administrator of the USEPA, by certified mail, written notice of cancellation at least 120 days before the effective date of cancellation.

b. We will mail or deliver our notice to the first Named Insured's last mailing address known to us.

c. Notice of cancellation will state the effective date of cancellation. The **policy period** will end on that date.

ALL OTHER TERMS, CONDITIONS AND EXCLUSIONS OF THIS POLICY REMAIN UNCHANGED.

Effective Date of Endorsement:
Insured Name:

THIS ENDORSEMENT CHANGES THE POLICY. PLEASE READ IT CAREFULLY.

PRIOR KNOWN POLLUTION EVENT EXCLUSION AMENDMENT

This endorsement modifies insurance provided under the following:
PRIME PUMPER POLLUTION LIABILITY COVERAGE FORM

It is hereby agreed that the policy to which this Endorsement is attached is amended as follows:

SECTION I – COVERAGES, **Coverage A – Covered Location Pollution Liability**, Paragraph **2. Exclusions**, Exclusion **f. Prior Known Pollution Event** is deleted and replaced with the following:

f. Prior Known Pollution Event

Bodily injury, **property damage** or **environmental damage** caused by or resulting from a **pollution event** or a **recognized environmental condition** known to a **responsible insured** prior to **(i)** the effective date of the **policy period** **(ii)** the effective date of an Endorsement to this policy adding a **covered location** or **(iii)** the acquisition or initial occupancy date of a **newly acquired location**.

This exclusion does not apply if:

(1) The **pollution event** known to a **responsible insured** did not meet reporting requirements under **environmental law**. However, if no reporting requirements exist for such known **pollution event** then this exception does not apply;

(2) The presence of **mold matter** known to a **responsible insured** has been remediated to the extent recommended in writing by an indoor environmental professional that we deem acceptable;

(3) A No Further Action (NFA) or equivalent decision has been documented in writing in accordance with **environmental law** as respects the **pollution event** or **recognized environmental condition** giving rise to the **bodily injury**, **property damage** or **environmental damage**;

(4) We have been notified in writing of such **pollution event** giving rise to the **bodily injury**, **property damage** or **environmental damage** during the policy period of a policy previously issued by us to you; or

(5) The **pollution event** or **recognized environmental condition** giving rise to the **bodily injury**, **property damage** or **environmental damage** is identified in the Schedule below:

SCHEDULE:

None Scheduled

ALL OTHER TERMS, CONDITIONS AND EXCLUSIONS OF THIS POLICY REMAIN UNCHANGED.

CERTIFICATE OF INSURANCE

Name and Address of Insured: ____

Name and Address of Insurer: ____

Policy Amount: ____

Policy Number: ____

Effective Date: ____

Certification:

Ascot Specialty Insurance Company, the Insurer, as identified above, hereby certifies that it has issued liability insurance covering the following Injection Well(s):

Name	Address	Identification No.

Ascot Specialty Insurance Company, the Insurer, hereby certifies that it has issued to the Insured the policy of insurance identified above to provide financial assurance for emergency and remedial response for the injection wells identified above. The Insurer further warrants that such policy conforms in all respects with the requirements for the fulfillment of emergency and remedial response obligations as described by 40 CFR §146.94 as applicable and as such regulations were constituted on the date shown below. It is agreed that any provision of the policy inconsistent with such regulations is hereby amended to eliminate such inconsistency.

The Insurer may cancel the policy only for failure to pay the premium and by sending notice of cancellation by certified mail to the owner or operator and to the Director for the area in which the injection well is located. The EPA requires that cancellation not become final for 120 days beginning on the date of receipt of the notice of cancellation by the Director, as evidence by the return receipts.

Whenever requested by the Director, the Insurer agrees to furnish to the Director a duplicate original of the policy listed above, including all endorsements.

[Signature of an authorized representative of Insured]

[Name]

[Title], [Authorized Representative of Ascot Specialty Insurance Company]

[Address of Representative]

[Signature of Witness or Notary]

[Date]

January 31, 2024

Re: Tallgrass High Plains Carbon Storage, LLC- CCS Wyoming Project
Class VI Application 2023-039
Facility ID No. WYS-021-00153
Facility Name: Juniper I-1
Facility Address: 5313 Road 204, Carpenter, WY 82054

To Whom it May Concern:

It has been the privilege of Berkley Insurance Company ("Berkley Surety")[1] and/or its underwriting team to consider providing a surety bond for Tallgrass High Plains Carbon Storage, LLC for the CCS Wyoming Project referenced above. Berkley Insurance Company has supported Tallgrass High Plains Carbon Storage, LLC up to $20,000,000. At their request we will give favorable consideration to providing the required bonds.

Please note that the decision to issue surety bonds is a matter between Tallgrass High Plains Carbon Storage, LLC and Berkley Surety, and will be subject to our standard underwriting at the time of the final bond request, which will include but not be limited to the acceptability of the contract documents, bond forms and financing. We assume no liability to third parties or to you if for any reason we do not execute said bonds.

Berkley Surety is "Treasury Listed" by the U. S. Department of the Treasury with an underwriting limitation expressed therein of over $717,168,000. The A.M. Best Company has assigned Berkley Surety a rating of "A+". Berkley Surety is fully licensed and authorized to write bonds of this size and type in the State of Wyoming. If you have any questions or need any additional information, please do not hesitate to contact me.

Sincerely,
Berkley Insurance Company

Hillary D. Shepard
Attorney-in-Fact

ACORD® CERTIFICATE OF LIABILITY INSURANCE

DATE (MM/DD/YYYY): 06/27/2025

THIS CERTIFICATE IS ISSUED AS A MATTER OF INFORMATION ONLY AND CONFERS NO RIGHTS UPON THE CERTIFICATE HOLDER. THIS CERTIFICATE DOES NOT AFFIRMATIVELY OR NEGATIVELY AMEND, EXTEND OR ALTER THE COVERAGE AFFORDED BY THE POLICIES BELOW. THIS CERTIFICATE OF INSURANCE DOES NOT CONSTITUTE A CONTRACT BETWEEN THE ISSUING INSURER(S), AUTHORIZED REPRESENTATIVE OR PRODUCER, AND THE CERTIFICATE HOLDER.

IMPORTANT: If the certificate holder is an ADDITIONAL INSURED, the policy(ies) must have ADDITIONAL INSURED provisions or be endorsed. If SUBROGATION IS WAIVED, subject to the terms and conditions of the policy, certain policies may require an endorsement. A statement on this certificate does not confer rights to the certificate holder in lieu of such endorsement(s).

PRODUCER
Marsh USA LLC
2405 Grand Boulevard, #900
Kansas City, MO 64108

CN109534658---24-25

CONTACT NAME:
PHONE (A/C, No, Ext): **FAX (A/C, No):**
E-MAIL ADDRESS:

INSURER(S) AFFORDING COVERAGE	NAIC #
INSURER A : ASCOT SPECIALTY INSURANCE COMPANY	
INSURER B : N/A	N/A
INSURER C :	
INSURER D :	
INSURER E :	
INSURER F :	

INSURED
Tallgrass High Plains Carbon Storage LLC
11550 Ash St Ste 220
Leawood, KS 66211

COVERAGES

CERTIFICATE NUMBER: CHI-010887058-04 **REVISION NUMBER:** 18

THIS IS TO CERTIFY THAT THE POLICIES OF INSURANCE LISTED BELOW HAVE BEEN ISSUED TO THE INSURED NAMED ABOVE FOR THE POLICY PERIOD INDICATED. NOTWITHSTANDING ANY REQUIREMENT, TERM OR CONDITION OF ANY CONTRACT OR OTHER DOCUMENT WITH RESPECT TO WHICH THIS CERTIFICATE MAY BE ISSUED OR MAY PERTAIN, THE INSURANCE AFFORDED BY THE POLICIES DESCRIBED HEREIN IS SUBJECT TO ALL THE TERMS, EXCLUSIONS AND CONDITIONS OF SUCH POLICIES. LIMITS SHOWN MAY HAVE BEEN REDUCED BY PAID CLAIMS.

INSR LTR	TYPE OF INSURANCE	ADDL INSD	SUBR WVD	POLICY NUMBER	POLICY EFF (MM/DD/YYYY)	POLICY EXP (MM/DD/YYYY)	LIMITS	
	COMMERCIAL GENERAL LIABILITY CLAIMS-MADE / OCCUR GEN'L AGGREGATE LIMIT APPLIES PER: POLICY / PRO-JECT / LOC OTHER:						EACH OCCURRENCE DAMAGE TO RENTED PREMISES (Ea occurrence) MED EXP (Any one person) PERSONAL & ADV INJURY GENERAL AGGREGATE PRODUCTS - COMP/OP AGG	\$ \$ \$ \$ \$ \$ \$
	AUTOMOBILE LIABILITY ANY AUTO OWNED AUTOS ONLY / SCHEDULED AUTOS HIRED AUTOS ONLY / NON-OWNED AUTOS ONLY						COMBINED SINGLE LIMIT (Ea accident) BODILY INJURY (Per person) BODILY INJURY (Per accident) PROPERTY DAMAGE (Per accident)	\$ \$ \$ \$ \$
	UMBRELLA LIAB / OCCUR **EXCESS LIAB** / CLAIMS-MADE DED / RETENTION \$						EACH OCCURRENCE AGGREGATE	\$ \$ \$
	WORKERS COMPENSATION AND EMPLOYERS' LIABILITY Y / N ANYPROPRIETOR/PARTNER/EXECUTIVE OFFICER/MEMBER EXCLUDED? N **(Mandatory in NH)** If yes, describe under DESCRIPTION OF OPERATIONS below	N / A					PER STATUTE / OTH-ER E.L. EACH ACCIDENT E.L. DISEASE - EA EMPLOYEE E.L. DISEASE - POLICY LIMIT	 \$ \$ \$
A	Pollution Liability			ENXU2510001511-01 Deductible Value: N/A	01/23/2025	01/23/2028	Primary Limit: Aggregate limit:	\$5,000,000 \$20,000,000

DESCRIPTION OF OPERATIONS / LOCATIONS / VEHICLES (ACORD 101, Additional Remarks Schedule, may be attached if more space is required)

CERTIFICATE HOLDER

State of Wyoming c/o Wyoming DEQ
200 W. 17th Street, 4th Floor
Cheyenne, WY 82001

CANCELLATION

SHOULD ANY OF THE ABOVE DESCRIBED POLICIES BE CANCELLED BEFORE THE EXPIRATION DATE THEREOF, NOTICE WILL BE DELIVERED IN ACCORDANCE WITH THE POLICY PROVISIONS.

AUTHORIZED REPRESENTATIVE

Marsh USA LLC

AGENCY CUSTOMER ID: CN109534658

LOC #: Kansas City

ACORD®

ADDITIONAL REMARKS SCHEDULE

AGENCY	NAMED INSURED
Marsh USA LLC	Tallgrass High Plains Carbon Storage LLC 11550 Ash St Ste 220 Leawood, KS 66211
POLICY NUMBER	
CARRIER / NAIC CODE	EFFECTIVE DATE:

ADDITIONAL REMARKS

THIS ADDITIONAL REMARKS FORM IS A SCHEDULE TO ACORD FORM,

FORM NUMBER: 25 FORM TITLE: Certificate of Liability Insurance

CERTIFICATE OF LIABILITY INSURANCE

DATE (MM/DD/YYYY): 06/27/2025

THIS CERTIFICATE IS ISSUED AS A MATTER OF INFORMATION ONLY AND CONFERS NO RIGHTS UPON THE CERTIFICATE HOLDER. THIS CERTIFICATE DOES NOT AFFIRMATIVELY OR NEGATIVELY AMEND, EXTEND OR ALTER THE COVERAGE AFFORDED BY THE POLICIES BELOW. THIS CERTIFICATE OF INSURANCE DOES NOT CONSTITUTE A CONTRACT BETWEEN THE ISSUING INSURER(S), AUTHORIZED REPRESENTATIVE OR PRODUCER, AND THE CERTIFICATE HOLDER.

IMPORTANT: If the certificate holder is an ADDITIONAL INSURED, the policy(ies) must have ADDITIONAL INSURED provisions or be endorsed. If SUBROGATION IS WAIVED, subject to the terms and conditions of the policy, certain policies may require an endorsement. A statement on this certificate does not confer rights to the certificate holder in lieu of such endorsement(s).

PRODUCER
Marsh USA LLC
2405 Grand Boulevard, #900
Kansas City, MO 64108

CN109534658---24-25

CONTACT NAME:
PHONE (A/C, No, Ext): **FAX (A/C, No):**
E-MAIL ADDRESS:

INSURER(S) AFFORDING COVERAGE	NAIC #
INSURER A : MOSAIC AMERICAS INSURANCE SERVICES LLC	
INSURER B : N/A	N/A
INSURER C :	
INSURER D :	
INSURER E :	
INSURER F :	

INSURED
Tallgrass High Plains Carbon Storage LLC
11550 Ash St Ste 220
Leawood, KS 66211

COVERAGES **CERTIFICATE NUMBER:** CHI-010887058-04 **REVISION NUMBER:** 18

THIS IS TO CERTIFY THAT THE POLICIES OF INSURANCE LISTED BELOW HAVE BEEN ISSUED TO THE INSURED NAMED ABOVE FOR THE POLICY PERIOD INDICATED. NOTWITHSTANDING ANY REQUIREMENT, TERM OR CONDITION OF ANY CONTRACT OR OTHER DOCUMENT WITH RESPECT TO WHICH THIS CERTIFICATE MAY BE ISSUED OR MAY PERTAIN, THE INSURANCE AFFORDED BY THE POLICIES DESCRIBED HEREIN IS SUBJECT TO ALL THE TERMS, EXCLUSIONS AND CONDITIONS OF SUCH POLICIES. LIMITS SHOWN MAY HAVE BEEN REDUCED BY PAID CLAIMS.

INSR LTR	TYPE OF INSURANCE	ADDL INSD	SUBR WVD	POLICY NUMBER	POLICY EFF (MM/DD/YYYY)	POLICY EXP (MM/DD/YYYY)	LIMITS	
	COMMERCIAL GENERAL LIABILITY CLAIMS-MADE / OCCUR GEN'L AGGREGATE LIMIT APPLIES PER: POLICY / PRO-JECT / LOC OTHER:						EACH OCCURRENCE	$
							DAMAGE TO RENTED PREMISES (Ea occurrence)	$
							MED EXP (Any one person)	$
							PERSONAL & ADV INJURY	$
							GENERAL AGGREGATE	$
							PRODUCTS - COMP/OP AGG	$
								$
	AUTOMOBILE LIABILITY ANY AUTO OWNED AUTOS ONLY / SCHEDULED AUTOS HIRED AUTOS ONLY / NON-OWNED AUTOS ONLY						COMBINED SINGLE LIMIT (Ea accident)	$
							BODILY INJURY (Per person)	$
							BODILY INJURY (Per accident)	$
							PROPERTY DAMAGE (Per accident)	$
								$
	UMBRELLA LIAB / OCCUR EXCESS LIAB / CLAIMS-MADE DED / RETENTION $						EACH OCCURRENCE	$
							AGGREGATE	$
								$
	WORKERS COMPENSATION AND EMPLOYERS' LIABILITY Y/N ANYPROPRIETOR/PARTNER/EXECUTIVE OFFICER/MEMBER EXCLUDED? N (Mandatory in NH) If yes, describe under DESCRIPTION OF OPERATIONS below	N/A					PER STATUTE / OTH-ER	
							E.L. EACH ACCIDENT	$
							E.L. DISEASE - EA EMPLOYEE	$
							E.L. DISEASE - POLICY LIMIT	$
A	Pollution Liability			PEN5061625AA Deductible Value: $250,000	01/23/2025	01/23/2028	Primary Limit: Aggregate limit:	$10,000,000 $25,000,000

DESCRIPTION OF OPERATIONS / LOCATIONS / VEHICLES (ACORD 101, Additional Remarks Schedule, may be attached if more space is required)

CERTIFICATE HOLDER

State of Wyoming c/o Wyoming DEQ
200 W. 17th Street, 4th Floor
Cheyenne, WY 82001

CANCELLATION

SHOULD ANY OF THE ABOVE DESCRIBED POLICIES BE CANCELLED BEFORE THE EXPIRATION DATE THEREOF, NOTICE WILL BE DELIVERED IN ACCORDANCE WITH THE POLICY PROVISIONS.

AUTHORIZED REPRESENTATIVE

Marsh USA LLC

ADDITIONAL REMARKS SCHEDULE

AGENCY		NAMED INSURED
Marsh USA LLC		Tallgrass High Plains Carbon Storage LLC 11550 Ash St Ste 220 Leawood, KS 66211
POLICY NUMBER		
CARRIER	NAIC CODE	EFFECTIVE DATE:

ADDITIONAL REMARKS

THIS ADDITIONAL REMARKS FORM IS A SCHEDULE TO ACORD FORM,
FORM NUMBER: 25 FORM TITLE: Certificate of Liability Insurance

1st Excess
Policy Paper: Ascot Specialty Insurance Company
Policy number: ENXU2510001511-01
Effective Date: 01/23/2025
Expiration Date: 01/23/2028
Limit: $5,000,000 Each Event
$20,000,000 Aggregate

24 June 2025

Wyoming Department of Environmental Quality
c/o Tyler Harris
200 West 17th Street
Cheyenne, Wyoming 82002
Tyler.Harris@wyo.gov;
cc: Lily.Barkau@wyo.gov ; hunter.hubbard@wyo.gov; jennifer.zygmunt@wyo.gov

Permit: 2022-235

Dear Mr. Harris:

Tallgrass High Plains Carbon Storage, LLC (High Plains) is submitting the renewed Control of Well Policy as requested by the Wyoming Department of Environmental Quality during the meeting on June 23, 2025. This document has been uploaded to the WDEQ Water Quality Division Document Uploads Page.

Kind Regards,

Jessica Gregg

Director Geoscience Compliance
Tallgrass Energy Partners, LP
cc: pete.feutz@tallgrass.com; michael.hilmes@tallgrass.com; katy.larson@tallgrass.com; craig.spreadbury@tallgrass.com; joey.mahmoud@tallgrass.com;

CERTIFICATE OF LIABILITY INSURANCE

6/21/2025

DATE (MM/DD/YYYY) 6/23/2025

THIS CERTIFICATE IS ISSUED AS A MATTER OF INFORMATION ONLY AND CONFERS NO RIGHTS UPON THE CERTIFICATE HOLDER. THIS CERTIFICATE DOES NOT AFFIRMATIVELY OR NEGATIVELY AMEND, EXTEND OR ALTER THE COVERAGE AFFORDED BY THE POLICIES BELOW. THIS CERTIFICATE OF INSURANCE DOES NOT CONSTITUTE A CONTRACT BETWEEN THE ISSUING INSURER(S), AUTHORIZED REPRESENTATIVE OR PRODUCER, AND THE CERTIFICATE HOLDER.

IMPORTANT: If the certificate holder is an ADDITIONAL INSURED, the policy(ies) must have ADDITIONAL INSURED provisions or be endorsed. If SUBROGATION IS WAIVED, subject to the terms and conditions of the policy, certain policies may require an endorsement. A statement on this certificate does not confer rights to the certificate holder in lieu of such endorsement(s).

PRODUCER Lockton Companies, LLC DBA as Lockton Insurance Brokers, LLC in CA CA license #0F15767 3657 Briarpark Dr., Ste. 700 Houston TX 77042 (866) 260-3538	CONTACT NAME: PHONE (A/C, No, Ext): FAX (A/C, No): E-MAIL ADDRESS:
INSURED 1558357 Tallgrass Energy, LP 370 Van Gordon St Lakewood CO 80228	

INSURER(S) AFFORDING COVERAGE	NAIC #
INSURER A : Underwriters at Lloyds London	15642
INSURER B :	
INSURER C :	
INSURER D :	
INSURER E :	
INSURER F :	

COVERAGES CERTIFICATE NUMBER: 22030389 REVISION NUMBER: XXXXXXX

THIS IS TO CERTIFY THAT THE POLICIES OF INSURANCE LISTED BELOW HAVE BEEN ISSUED TO THE INSURED NAMED ABOVE FOR THE POLICY PERIOD INDICATED. NOTWITHSTANDING ANY REQUIREMENT, TERM OR CONDITION OF ANY CONTRACT OR OTHER DOCUMENT WITH RESPECT TO WHICH THIS CERTIFICATE MAY BE ISSUED OR MAY PERTAIN, THE INSURANCE AFFORDED BY THE POLICIES DESCRIBED HEREIN IS SUBJECT TO ALL THE TERMS, EXCLUSIONS AND CONDITIONS OF SUCH POLICIES. LIMITS SHOWN MAY HAVE BEEN REDUCED BY PAID CLAIMS.

INSR LTR	TYPE OF INSURANCE	ADDL INSD	SUBR WVD	POLICY NUMBER	POLICY EFF (MM/DD/YYYY)	POLICY EXP (MM/DD/YYYY)	LIMITS	
	COMMERCIAL GENERAL LIABILITY CLAIMS-MADE / OCCUR GEN'L AGGREGATE LIMIT APPLIES PER: POLICY / PRO-JECT / LOC OTHER:			NOT APPLICABLE			EACH OCCURRENCE	$ XXXXXXX
							DAMAGE TO RENTED PREMISES (Ea occurrence)	$ XXXXXXX
							MED EXP (Any one person)	$ XXXXXXX
							PERSONAL & ADV INJURY	$ XXXXXXX
							GENERAL AGGREGATE	$ XXXXXXX
							PRODUCTS - COMP/OP AGG	$ XXXXXXX
								$
	AUTOMOBILE LIABILITY ANY AUTO OWNED AUTOS ONLY / SCHEDULED AUTOS HIRED AUTOS ONLY / NON-OWNED AUTOS ONLY			NOT APPLICABLE			COMBINED SINGLE LIMIT (Ea accident)	$ XXXXXXX
							BODILY INJURY (Per person)	$ XXXXXXX
							BODILY INJURY (Per accident)	$ XXXXXXX
							PROPERTY DAMAGE (Per accident)	$ XXXXXXX
								$ XXXXXXX
	UMBRELLA LIAB / OCCUR EXCESS LIAB / CLAIMS-MADE DED / RETENTION $			NOT APPLICABLE			EACH OCCURRENCE	$ XXXXXXX
							AGGREGATE	$ XXXXXXX
								$ XXXXXXX
	WORKERS COMPENSATION AND EMPLOYERS' LIABILITY Y / N ANY PROPRIETOR/PARTNER/EXECUTIVE OFFICER/MEMBER EXCLUDED? (Mandatory in NH) If yes, describe under DESCRIPTION OF OPERATIONS below	N / A		NOT APPLICABLE			PER STATUTE / OTH-ER	
							E.L. EACH ACCIDENT	$ XXXXXXX
							E.L. DISEASE - EA EMPLOYEE	$ XXXXXXX
							E.L. DISEASE - POLICY LIMIT	$ XXXXXXX
A	Control of Well	N	N	TR25610891	6/21/2025	6/21/2026	See Attachment	

DESCRIPTION OF OPERATIONS / LOCATIONS / VEHICLES (ACORD 101, Additional Remarks Schedule, may be attached if more space is required)

REF: Juniper well is scheduled.

CERTIFICATE HOLDER

22030389
Wyoming Department of Environmental Quality
200 W. 17th St. 2nd Floor
Cheyenne WY 82002

CANCELLATION See Attachment

SHOULD ANY OF THE ABOVE DESCRIBED POLICIES BE CANCELLED BEFORE THE EXPIRATION DATE THEREOF, NOTICE WILL BE DELIVERED IN ACCORDANCE WITH THE POLICY PROVISIONS.

AUTHORIZED REPRESENTATIVE

Type of Policy:	**Operator's Extra Expense/Control of Well**
Insurer(s):	Underwriters at Lloyd's of London
Policy Term:	6/21/2025 - 6/21/2026
Policy No.:	TR25610891
Limits:	**Control of Well, Redrill/Extra Expense, Seepage and Pollution and Contamination**
	$15,000,000 (100%) any one occurrence, drilling/workover/re-entry wells 0-7,500' TVD
	$40,000,000 (100%) any one occurrence, drilling/workover/re-entry wells deeper than 7,500' TVD
	$5,000,000 (100%) any one occurrence, all other wells
	Care, Custody and Control/Removal of Debris
	$10,000,000 (100%) any one occurrence

Rachel White
Tallgrass High Plains Carbon Storage LLC
11550 Ash Street
Suite 220
Leawood, KS 66211

RE: Bond Increase Approval: WQD UIC Permit 2022-235, Facility WYS-021-00149
Endurance Assurance Corporation Bond No. EACX4044408

Dear Ms. White:

The Wyoming Department of Environmental Quality does hereby accept bond no. EACX4044408 in the amount of $611,328.00 and a copy has been enclosed for your records. Please see the details of the bond acceptance below.

Bond Action	Bonder	Bond No.	Bond Type	Previous Bond Amount	Change	Current Bond Amount
				A	B	C=A+B
Acceptance	Endurance Assurance Corporation	EACX4044408	Surety	$597,000.00	$14,328.00	$611,328.00
None	Endurance Assurance Corporation	EACX4044409	Surety	$534,528.00	$0.00	$534,528.00
None	Axis Insurance Company	DUA003747	Surety	$10,665,677.00	$0.00	$10,665,677.00
None	Tallgrass High Plains Carbon Storage LLC	250604456678	Wire Transfer	$9,601,587.00	$0.00	$9,601,587.00
Total				**$21,398,792.00**	**$14,328.00**	**$21,413,120.00**

Should you have any questions regarding your bond, please contact the Bond Analyst at (307-777-3767) or frances.tormey@wyo.gov. Be sure to reference your permit/facility number in all voicemails and emails.

Sincerely,

Todd Parfitt
Director
Department of Environmental Quality

Date: 6-23-25

cc: Lily Barkau, Natural Resource Program Manager, WDEQ/WQD

Department of Environmental Quality

To protect, conserve and enhance the quality of Wyoming's environment for the benefit of current and future generations.

DEQ

Mark Gordon, Governor

Todd Parfitt, Director

Rachel White
Tallgrass High Plains Carbon Storage LLC
11550 Ash Street
Suite 220
Leawood, KS 66211

RE: Bond Increase Approval: WQD UIC Permit 2022-235, Facility WYS-021-00149
Tallgrass High Plains Carbon Storage LLC Wire Transfer No. 250604456678
Axis Insurance Company Bond No. DUA003747

Dear Ms. White:

The Wyoming Department of Environmental Quality does hereby accept bond no. 250604456678 in the amount of $9,601,587.00 and bond no. DUA003747 in the amount of $10,665,677.00. A copy of each has been enclosed for your records. Please see the details of the bond acceptances below.

Bond Action	Bonder	Bond No.	Bond Type	Previous Bond Amount	Change	Current Bond Amount
				A	B	C=A+B
Acceptance	Tallgrass High Plains Carbon Storage LLC	250604456678	Wire Transfer		$9,601,587.00	$9,601,587.00
Acceptance	Axis Insurance Company	DUA003747	Surety		$10,665,677.00	$10,665,677.00
None	Endurance Assurance Corporation	EACX4044409	Surety	$534,528.00	$0.00	$534,528.00
None	Endurance Assurance Corporation	EACX4044408	Surety	$597,000.00	$0.00	$597,000.00
Total				**$1,131,528.00**	**$20,267,264.00**	**$21,398,792.00**

Should you have any questions regarding your bond, please contact the Bond Analyst at (307-777-3767) or frances.tormey@wyo.gov. Be sure to reference your permit/facility number in all voicemails and emails.

Sincerely,

Kimberly Wachman for

Todd Parfitt
Director
Department of Environmental Quality

Date: 10-20-25

cc: WQD UIC – Lily Barkau

Department of Environmental Quality

To protect, conserve and enhance the quality of Wyoming's environment for the benefit of current and future generations.

DEQ

Mark Gordon, Governor

Todd Parfitt, Director

June 20, 2025

Tallgrass High Plains Carbon Storage, LLC
ATTN: Craig Spreadbury
370 Van Gordon St.
Lakewood, CO 80228

Sent Via Email: Craig.Spreadbury@Tallgrass.com

RE: Tallgrass High Plains Carbon Storage, LLC, Juniper I-1
2025 Financial Assurance Cost Estimate Update
UIC Permit to Construct 2022-235, Facility ID No. WYS-021-00149
Laramie County, Wyoming

Dear Mr. Spreadbury:

The Wyoming Department of Environmental Quality Water Quality Division (WDEQ/WQD), Underground Injection Control (UIC) Program has reviewed the Financial Assurance Cost Estimate Update (Cost Estimate) completed by Tallgrass High Plains, LLC, dated May 19, 2025 and subsequent review for Emergency and Remedial Response, completed June 11, 2025 for the Juniper I-1 UIC Class VI well.

Based on WDEQ/WQD's review of the Cost Estimate and the Emergency and Remedial Response, the following cost estimate amounts are approved:

1. Corrective Action on other wells in the area of review that require corrective action under Wyoming Water Quality Rule (WWQR) Chapter 24, Section 13: $256,000.
2. Injection Well Plugging and Abandonment that meets the requirements of WWQR Chapter 24, Section 23: $611,328.
3. Testing and monitoring that meets the requirements of WWQR Chapter 24, Section 20: $6,522,035.
4. PISC and Site Closure that meets the requirements of WWQR Chapter 24, Section 24: $10,665,677.
5. PISC and Site Closure – Monitor Well Plugging: $534,528.
6. Emergency and Remedial Response: $9,601,587.

Total: $28,191,155.00

The WDEQ currently holds three surety bonds (DUAO03747, EACX4044408 and EACX4044409) and a cash bond (250604456678) for a total of $21,398,792.00 for Facility ID No. WYS-021-00149. Per UIC Class VI Permit No. 2022-235, which authorized well construction, financial assurance for corrective action on other wells in the Area of Review and testing and monitoring are not required under the permit. WDEQ/WQD received a corrective action plan for the Juniper M-1 as part of the Authorization to Inject Request. As WDEQ has not received documentation that corrective action activities have been completed, financial assurance for corrective action on other wells in the Area of Review is required at this time. In regard to testing and monitoring, although financial assurance is not required, Tallgrass High Plains Carbon Storage, LLC shall demonstrate that testing and monitoring during the operational period of 25 years will be fully funded. Therefore, an increase in the amount of **$270,328.00 (including $256,000.00 for corrective action)** must be submitted prior to the issuance of the Authorization to Inject. Financial assurance instruments are identified in WWQR, Chapter 24, Section 26.

Public liability insurance is also required in accordance with WWQR Chapter 24, Section 26(l) and shall include coverage for the major risks identified in Appendix A of Chapter 24. Minimum coverage of at least $15 million per occurrence with an annual aggregate of at least $45 million, exclusive of legal defense costs, is required.

In accordance with WWQR, Chapter 24, Section 26(f)(i), No Class VI permit shall be issued until and unless the Director has considered and approved the financial responsibility demonstration for all phases of the geologic sequestration project. The owner or operator may demonstrate financial responsibility by using one (1) or multiple qualifying financial instruments subject to the requirements outlined in WWQR Chapter 24, Section 26(g)(i) through (iii).

Pursuant to UIC Class VI permit requirements and WWQR Chapter 24 Section 26, please submit your financial assurance to the Bonding Team, Department of Environmental Quality, 200 W. 17th Street, Cheyenne, WY 82002. Please note any increase of financial assurance instruments should be submitted on the required WDEQ form(s) available through the Bonding Team or at https://deq.wyoming.gov/admininstration/bonding/ under the 'Water Quality Division' tab located towards the top of the page. As a note, review and approval of financial assurance instruments or the public liability insurance may take up to sixty days to review and approve.

If you have any questions regarding bonding or public liability insurance, please contact Frances Tormey, Bond Analyst at (307) 777- 3767. If you have any questions regarding this letter or feel that a meeting is necessary, please do not hesitate to contact me at (307) 777-7072 or lily.barkau@wyo.gov.

Sincerely,

Lily R. Barkau

Lily R. Barkau, P.G.
Groundwater Section Manager
Water Quality Division
Wyoming Department of Environmental Quality

cc: Jennifer Zygmunt, Administrator, WDEQ/WQD
Kimber Wichmann, Administrator, WDEQ-Administration
Tyler Harris, P.G., Hunter Hubbard, P.G., WDEQ/WQD
Frances Tormey, WDEQ/Bonding
Jessica Gregg, Director, Geoscience Compliance, Tallgrass Energy (jessica.gregg@tallgrass.com)
Katy Larson, Geoscience Compliance Manager, Tallgrass Energy (katy.larson@tallgrass.com)
file

Rachel White
Tallgrass High Plains Carbon Storage LLC
11550 Ash Street
Suite 220
Leawood, KS 66211

RE: Bond Increase Approval: WQD UIC Permit 2022-235, Facility WYS-021-00149
Endurance Assurance Corporation Bond No. EACX4044409

Dear Ms. White:

The Wyoming Department of Environmental Quality does hereby accept bond no. EACX4044409 in the amount of $534,528.00 and a copy has been enclosed for your records. Please see the details of the bond acceptance below;

Bond Action	Bonder	Bond No.	Bond Type	Previous Bond Amount	Change	Current Bond Amount
				A	B	C=A+B
Acceptance	Endurance Assurance Corporation	EACX4044409	Surety	$522,000.00	$12,528.00	$534,528.00
None	Endurance Assurance Corporation	EACX4044408	Surety	$597,000.00	$0.00	$597,000.00
Total				**$1,119,000.00**	**$12,528.00**	**$1,131,528.00**

Should you have any questions regarding your bond, please contact the Bond Analyst at (307-777-3767) or frances.tormey@wyo.gov. Be sure to reference your permit/facility number in all voicemails and emails.

Sincerely,

Tomlu Wichman 7-7

Date: 6-17-25

Todd Parfitt
Director
Department of Environmental Quality

cc: WQD UIC – Lily Barkau

Department of Environmental Quality

To protect, conserve and enhance the quality of Wyoming's environment for the benefit of current and future generations.

Mark Gordon, Governor

Todd Parfitt, Director

March 6, 2025

Tallgrass High Plains Carbon Storage, LLC
ATTN: Craig Spreadbury
370 Van Gordon St.
Lakewood, CO 80228

Sent Via Email: Craig.Spreadbury@Tallgrass.com

RE: Tallgrass High Plains Carbon Storage, LLC, Juniper I-1
2025 Financial Assurance Cost Estimate Update
UIC Permit to Construct 2022-235, Facility ID No. WYS-021-00149
Laramie County, Wyoming

Dear Mr. Spreadbury:

The Wyoming Department of Environmental Quality Water Quality Division (WDEQ/WQD), Underground Injection Control (UIC) Program has reviewed the Financial Assurance Cost Estimate Update (Cost Estimate) completed by Tallgrass High Plains, LLC, dated February 13, 2025 for the Juniper I-1 UIC Class VI well.

Based on WDEQ/WQD's review of the Cost Estimate, the following cost estimate is approved:

1. Corrective Action on other wells in the area of review that require corrective action under Wyoming Water Quality Rule (WWQR) Chapter 24, Section 13: <u>$256,000.</u>
2. Injection Well Plugging and Abandonment that meets the requirements of WWQR Chapter 24, Section 23: <u>$611,328.</u>
3. Testing and monitoring that meets the requirements of WWQR Chapter 24, Section 20: <u>$6,522,035.</u>
4. PISC and Site Closure that meets the requirements of WWQR Chapter 24, Section 24: <u>$10,665,677.</u>
5. PISC and Site Closure – Monitor Well Plugging: <u>$534,528.</u>
6. Emergency and Remedial Response: <u>$9,601,587.</u>

<u>**Total: $28,191,155.**</u>

Financial assurance is required for item nos. 2, 4, 5, and 6 above for a total of <u>**$21,413,120**</u> prior to authorization to inject being issued.

Financial assurance instruments are identified in Water Quality Rules, Chapter 24, Section 26. Public liability insurance is also required in accordance with WWQR Chapter 24, Section 26(l). Item no. 6 may be covered under the public liability insurance.

The WDEQ Bonding Program will review and approve the instrument forms. Please visit https://deq.wyoming.gov/administration/bonding/ or contact Frances Tormey, Bond Analyst at (307) 777- 3767.

If you have any questions regarding this letter or feel that a meeting is necessary, please do not hesitate to contact me at (307) 777-7189 or hunter.hubbard@wyo.gov.

Sincerely,

Hunter Hubbard, P.G.
Senior Project Geologist, Water Quality Division
Wyoming Department of Environmental Quality

cc: Lily Barkau, P.G., Tyler Harris, P.G., WDEQ/WQD
Frances Tormey, WDEQ
Katy Larson, Geoscience Compliance Manager, Tallgrass Energy (katy.larson@tallgrass.com)
file

13 February 2025

VIA E-MAIL AND WDEQ PORTAL

Wyoming Department of Environmental Quality
c/o Tyler Harris
200 West 17th Street
Cheyenne, Wyoming 82002
Tyler.Harris@wyo.gov;
cc: Lily.Barkau@wyo.gov ; hunter.hubbard@wyo.gov

Submitted electronically: WDEQ Water Quality Division Document Uploads (smartsheet.com)
Permit: 2022-235

Dear Mr. Harris:

Tallgrass High Plains Carbon Storage, LLC. (High Plains) is submitting an annual update to the financial assurance cost estimations for Juniper I-1 Class VI permit to adjust for inflation for DEQ review. The attachments to this letter include the following:

Attachment 1: Juniper I-1 Annual Financial Assurance Update

- Appendix 1: United States Bureau of Economic Gross Domestic Product, 4th Quarter and Year 2024 New Release and Associated Tables

Kind Regards,

Katy Larson

Katy Larson
Geoscience Compliance Manager
Tallgrass Energy Partners, LP
cc: matt.hess@tallgrass.com; jessica.gregg@tallgrass.com; pete.feutz@tallgrass.com

Attachment 1

High Plains is submitting an annual update to the approved financial assurance cost estimations for Juniper I-1. As stipulated by the Juniper I-1 permit (Final Permit No. 2022-235) issued September 2024, annual cost estimates are required within 30 days of the anniversary date of the original permit submission.

High Plains utilized the gross domestic product (GDP) price deflator to adjust annual financial assurance cost estimates for inflation. The GDP price deflator index was selected because it is a measure of the inflation of in the prices of goods and services produced in the United States, including exports. In 2024 the GDP price deflator was 2.4%, as discussed in Line 37 of Table 4 in Appendix 1, and the value was used as a multiplier to adjust financial assurance cost estimates.

An updated financial assurance cost estimate is provided in Table 1. The total financial assurance cost estimate rose from $27,530,425 to $28,191,155. High Plains will issue updated financial assurance instruments within 60 days prior to the establishment of the mechanism.

TALLGRASS
Leading Energy Solutions

Table 1—Summary of financial assurance cost estimations.

Financial Responsibility Element	Approved Cost Estimate	2025 Update to the Cost Estimate	Financial Assurance Required/When Funded	Financial Assurance Instrument
A. Corrective Action on other wells in the area of review that require corrective action under WWQR Chapter 24, Section 13	$250,000	$256,000	No	N/A
B. Injection Well Plugging and Abandonment that meets the requirements of WWQR Chapter 24, Section 23	$597,000	$611,328	Yes, Prior to well Permit to Construct Issuance	*WWQR Chapter 24, Section 26(c):* (i) Irrevocable Trust Funds with government-backed securities, or (ii) Surety Bonds, or (iii)Irrevocable Letter of Credit, or (iv)Cash, or (v) Federally Insured Certificates of Deposit.
C. Testing and monitoring that meets the requirements of WWQR Chapter 24, Section 20	$6,369,175 (for 25 years)	$6,522,035	No	N/A
D. PISC and Site Closure that meets the requirements of WWQR Chapter 24, Section 24	$10,415,700	$10,665,677	Yes, Prior to Authorization to Inject	*WWQR Chapter 24, Section 26(c):* (i) Irrevocable Trust Funds with government-backed securities, or (ii) Surety Bonds, or (iii) Irrevocable Letter of Credit, or (iv) Cash, or (v) Federally Insured Certificates of Deposit.
E. PISC and Site Closure – Monitor Well Plugging	$522,000	$534,528	Yes, Prior to Permit to Construct	
F. ERR	$9,376,550	$9,601,587	Yes, Prior to Authorization to Inject	*WWQR Chapter 24, Section 26(c):* (i) Irrevocable Trust Funds with government-backed securities, or (ii) Surety Bonds, or (iii)Irrevocable Letter of Credit, or (iv)Cash, or Federally Insured Certificates of Deposit. The Permittee may also cover this as part of the Public Liability Insurance *WWQR Chapter 24, Section 26(l)*
Total	$27,530,425	$28,191,155		

Appendix 1: United States Bureau of Economic Gross Domestic Product, 4th Quarter and Year 2024 New Release and Associated Tables

@BEA_News
www.bea.gov

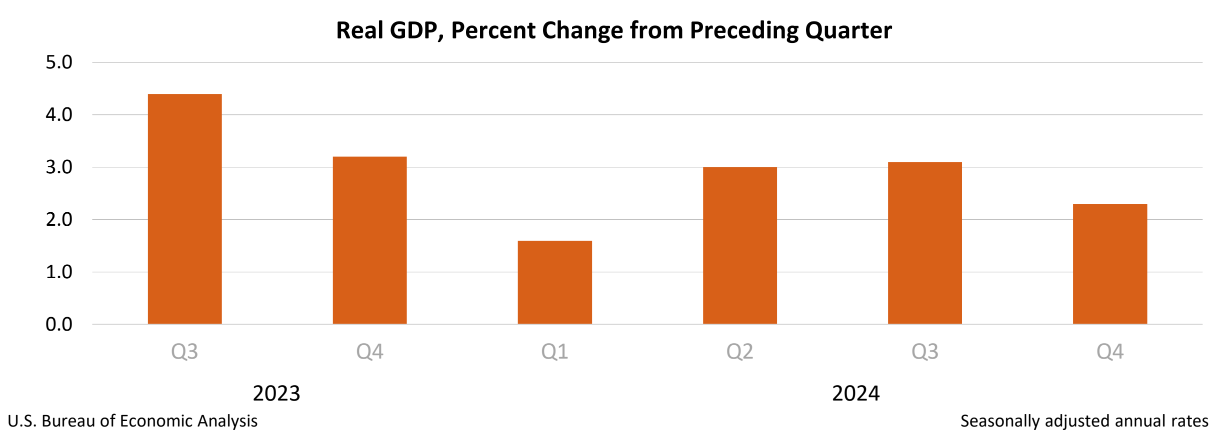
News Release

EMBARGOED UNTIL RELEASE AT 8:30 a.m. EST, Thursday, January 30, 2025 BEA 25–02

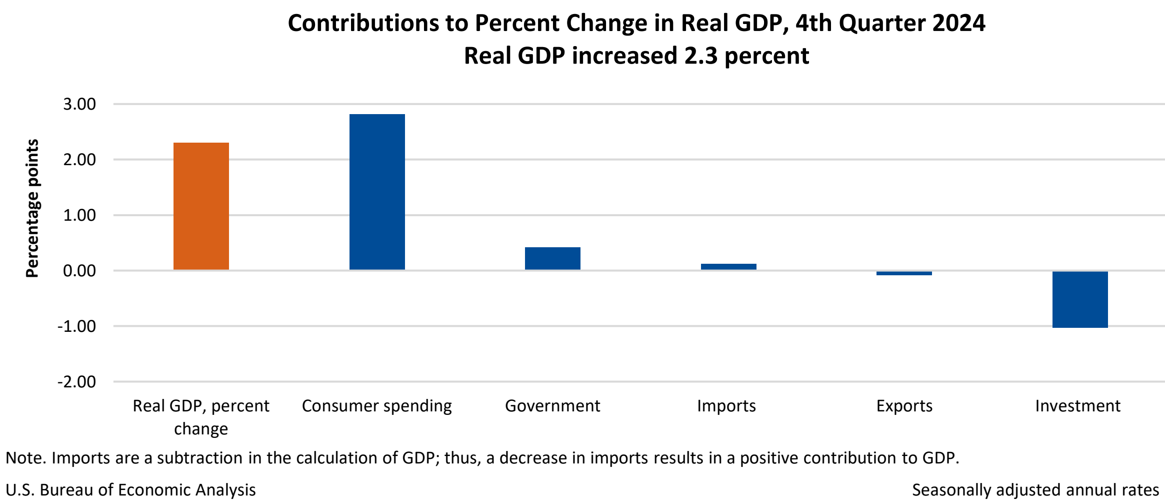
Technical:	Lisa Mataloni (GDP)	301-278-9083	GDPNIWD@bea.gov
Media:	Connie O'Connell	301-278-9003	Connie.OConnell@bea.gov

Gross Domestic Product, 4th Quarter and Year 2024
(Advance Estimate)

Real gross domestic product (GDP) increased at an annual rate of 2.3 percent in the fourth quarter of 2024 (October, November, and December), according to the advance estimate released by the U.S. Bureau of Economic Analysis. In the third quarter, real GDP increased 3.1 percent.

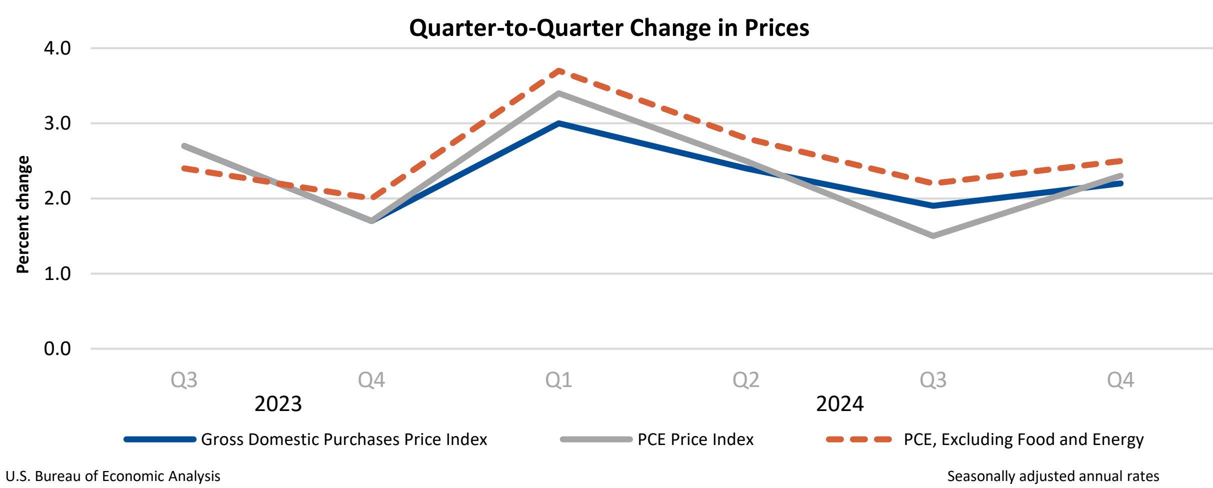


The increase in **real GDP** in the fourth quarter primarily reflected increases in consumer spending and government spending that were partly offset by a decrease in investment. Imports, which are a subtraction in the calculation of GDP, decreased. For more information, refer to the "Technical Notes" below.



Compared to the third quarter, the deceleration in **real GDP** in the fourth quarter primarily reflected downturns in investment and exports. Imports turned down.

The **price index for gross domestic purchases** increased 2.2 percent in the fourth quarter, compared with an increase of 1.9 percent in the third quarter. The **personal consumption expenditures (PCE) price index** increased 2.3 percent, compared with an increase of 1.5 percent. Excluding food and energy prices, the PCE price index increased 2.5 percent, compared with an increase of 2.2 percent.



Real GDP and Related Measures
[Percent change from Q3 to Q4]

Real GDP	2.3
Current-dollar GDP	4.5
Gross domestic purchases price index	2.2
PCE price index	2.3
PCE price index excluding food and energy	2.5

GDP for 2024

Real GDP increased 2.8 percent in 2024 (from the 2023 annual level to the 2024 annual level), compared with an increase of 2.9 percent in 2023. The increase in real GDP in 2024 reflected increases in consumer spending, investment, government spending, and exports. Imports increased.

The **price index for gross domestic purchases** increased 2.3 percent in 2024, compared with an increase of 3.3 percent in 2023. The **PCE price index** increased 2.5 percent, compared with an increase of 3.8 percent. Excluding food and energy prices, the PCE price index increased 2.8 percent, compared with an increase of 4.1 percent.

Next release: February 27, 2025, at 8:30 a.m. EST
Gross Domestic Product, 4th Quarter and Year 2024 (Second Estimate)

For definitions, statistical conventions, updates to GDP, and more, visit "Additional Information."

Technical Notes

Sources of change for real GDP

Real GDP increased at an annual rate of 2.3 percent (0.6 percent at a quarterly rate[1]), primarily reflecting increases in both consumer and government spending. Imports, which are a subtraction in the calculation of GDP, decreased.

- The increase in consumer spending reflected increases in both services and goods. Within services, the leading contributor to the increase was health care. Within goods, the leading contributors to the increase were recreational goods and vehicles as well as motor vehicles and parts.
    - Within health care, hospital and nursing home services (notably hospital services) and outpatient services increased, based primarily on Bureau of Labor Statistics (BLS) Current Employment Statistics (CES) employment, earnings, and hours data.
    - The increase in recreational goods and vehicles was led by information processing equipment, based on Census Bureau Monthly Retail Trade Survey data.
    - The increase in motor vehicles and parts was led by new light trucks, based primarily on unit sales data from Wards Intelligence.

- The increase in government spending reflected increases in state and local as well as federal government spending.
    - Within state and local government spending, the increase was led by compensation of employees, based primarily on employment data from the BLS CES.
    - Within federal government spending, the increase was led by defense consumption expenditures, based primarily on Monthly Treasury Statement data.

More information on the source data and BEA assumptions that underlie the fourth-quarter estimate is shown in the key source data and assumptions table.

Impact of Hurricane Milton on fourth-quarter 2024 estimates

Hurricane Milton made landfall as a Category 3 hurricane just south of Tampa Bay, Florida, on October 9, 2024, bringing damage from high winds, including significant tornado activity, and extensive inland flooding.

This disaster disrupted usual consumer and business activities and prompted emergency services and remediation activities. The responses to this disaster are included, but not separately identified, in the source data that BEA uses to prepare the estimates of GDP; consequently, it is not possible to estimate the overall impact of Hurricane Milton on fourth-quarter GDP. The destruction of fixed assets, such as residential and nonresidential structures, does not directly affect GDP or personal income. BEA estimates of disaster losses are presented in NIPA table 5.1, “Saving and Investment.” BEA's preliminary estimates show that Hurricane Milton resulted in losses of $27.0 billion in privately owned fixed assets

1. Percent changes in quarterly seasonally adjusted series are displayed at annual rates, unless otherwise specified. For more information, refer to the FAQ Why does BEA publish percent changes in quarterly series at annual rates?.

($108.0 billion at an annual rate) and $3.0 billion in state and local government-owned fixed assets ($12.0 billion at an annual rate).

For additional information, refer to "How are the measures of production and income in the national accounts affected by a disaster?" and "How are the fixed assets accounts (FAAs) and consumption of fixed capital (CFC) impacted by disasters?"

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Table 1. Real Gross Domestic Product and Related Measures: Percent Change from Preceding Period

Line		2022	2023	2024	Seasonally adjusted at annual rates																Line
					2021				2022				2023				2024				
					Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	
1	**Gross domestic product (GDP)**	**2.5**	**2.9**	**2.8**	**5.6**	**6.4**	**3.5**	**7.4**	**-1.0**	**0.3**	**2.7**	**3.4**	**2.8**	**2.4**	**4.4**	**3.2**	**1.6**	**3.0**	**3.1**	**2.3**	1
2	**Personal consumption expenditures**	**3.0**	**2.5**	**2.8**	**9.5**	**14.1**	**3.1**	**4.4**	**1.0**	**2.6**	**1.5**	**1.2**	**4.9**	**1.0**	**2.5**	**3.5**	**1.9**	**2.8**	**3.7**	**4.2**	2
3	Goods	-0.6	1.9	2.4	17.9	14.4	-9.6	4.6	-1.7	-1.5	-2.3	-0.7	7.4	-0.3	3.5	3.4	-1.2	3.0	5.6	6.6	3
4	Durable goods	-1.9	3.9	3.3	31.0	14.7	-24.8	8.6	0.1	-2.2	-1.9	-2.0	17.1	-0.3	4.2	2.9	-1.8	5.5	7.6	12.1	4
5	Nondurable goods	0.1	0.8	1.9	10.9	14.2	0.4	2.5	-2.7	-1.2	-2.5	0.1	2.5	-0.4	3.1	3.6	-0.8	1.7	4.6	3.8	5
6	Services	5.0	2.9	2.9	5.4	13.9	10.4	4.3	2.4	4.7	3.5	2.2	3.8	1.6	2.1	3.5	3.4	2.7	2.8	3.1	6
7	**Gross private domestic investment**	**6.0**	**0.1**	**4.0**	**-2.4**	**-6.4**	**16.3**	**28.3**	**7.4**	**-8.5**	**-5.7**	**5.8**	**-8.9**	**8.0**	**10.1**	**0.7**	**3.6**	**8.3**	**0.8**	**-5.6**	7
8	Fixed investment	2.7	2.4	3.8	9.4	5.5	-2.1	2.9	8.5	2.0	-1.8	-1.9	3.1	8.6	2.6	3.5	6.5	2.3	2.1	-0.6	8
9	Nonresidential	7.0	6.0	3.7	9.6	8.9	-1.8	3.4	13.6	7.3	7.7	5.7	5.3	9.9	1.1	3.8	4.5	3.9	4.0	-2.2	9
10	Structures	3.6	10.8	3.2	8.8	0.6	-3.8	-9.5	10.9	8.8	9.2	9.8	14.9	16.4	1.7	6.5	6.3	0.2	-5.0	-1.1	10
11	Equipment	4.4	3.5	3.4	5.3	8.7	-10.6	1.5	16.4	1.1	6.6	1.1	0.9	12.5	-1.1	0.7	0.3	9.8	10.8	-7.8	11
12	Intellectual property products	11.2	5.8	4.1	14.3	13.8	8.6	12.4	12.6	12.7	8.0	7.9	4.5	3.9	2.8	5.2	7.5	0.7	3.1	2.6	12
13	Residential	-8.6	-8.3	4.2	8.7	-3.7	-3.4	1.2	-4.5	-11.6	-25.2	-22.8	-4.3	4.5	7.7	2.5	13.7	-2.8	-4.3	5.3	13
14	Change in private inventories	....	....	....	....	....	....	....	....	....	....	....	....	....	....	....	....	....	....	....	14
15	**Net exports of goods and services**	....	....	....	....	....	....	....	....	....	....	....	....	....	....	....	....	....	....	....	15
16	Exports	7.5	2.8	3.2	0.3	3.2	0.9	25.5	-4.6	12.7	14.5	-1.1	2.0	-4.8	4.9	6.2	1.9	1.0	9.6	-0.8	16
17	Goods	5.9	2.3	2.2	-1.2	1.2	-2.7	27.6	-9.4	10.9	20.3	-5.4	5.3	-10.9	7.5	5.3	-0.2	0.9	10.3	-5.0	17
18	Services	11.1	3.8	5.3	3.3	7.4	8.9	21.1	6.9	16.8	2.6	8.7	-4.5	8.8	0.0	8.0	6.1	1.2	8.4	7.2	18
19	Imports	8.6	-1.2	5.4	8.3	8.3	8.6	20.8	13.4	5.9	-5.4	-4.5	-0.8	-3.1	4.7	4.2	6.1	7.6	10.7	-0.8	19
20	Goods	6.7	-1.8	4.9	8.0	5.3	0.9	21.7	13.6	3.1	-8.2	-4.0	0.1	-5.0	5.1	1.8	6.5	8.4	10.7	-4.0	20
21	Services	17.8	1.6	7.5	9.9	25.5	55.3	16.6	12.4	20.4	8.1	-6.9	-4.8	5.0	2.6	14.8	4.8	4.3	11.0	12.8	21
22	**Government consumption expenditures and gross investment**	**-1.1**	**3.9**	**3.4**	**5.2**	**-4.2**	**-1.5**	**-0.3**	**-3.4**	**-1.5**	**1.6**	**5.4**	**5.1**	**2.9**	**5.7**	**3.6**	**1.8**	**3.1**	**5.1**	**2.5**	22
23	Federal	-3.2	2.9	2.5	17.2	-8.0	-7.5	3.1	-8.5	-3.3	-0.4	9.0	4.6	-1.1	5.3	-0.3	-0.4	4.3	8.9	3.2	23
24	National defense	-3.9	3.2	3.0	-7.9	-2.8	-4.6	-3.7	-11.2	2.0	-2.9	7.6	4.9	0.8	6.7	-1.3	-2.5	6.4	13.9	3.3	24
25	Nondefense	-2.3	2.5	1.8	63.0	-14.3	-11.3	13.0	-5.0	-9.7	2.9	10.8	4.3	-3.5	3.4	0.9	2.6	1.5	2.6	3.1	25
26	State and local	0.2	4.4	3.9	-1.6	-1.8	2.3	-2.3	-0.1	-0.4	2.7	3.4	5.3	5.4	5.9	6.1	3.1	2.3	2.9	2.0	26
	Addenda:																				
27	Gross domestic income (GDI) [1]	2.8	1.7	....	4.2	5.3	4.4	6.4	1.7	-0.3	3.9	-1.4	1.7	2.1	2.7	5.1	3.0	2.0	2.1	....	27
28	Average of GDP and GDI	2.7	2.3	....	4.9	5.9	3.9	6.9	0.3	0.0	3.3	1.0	2.3	2.3	3.5	4.1	2.3	2.5	2.6	....	28
29	Final sales of domestic product	1.9	3.3	2.7	7.8	8.7	0.4	3.2	-0.9	2.3	3.5	1.9	5.1	2.6	3.0	3.7	2.1	1.9	3.3	3.2	29
30	Gross domestic purchases	2.8	2.3	3.1	6.5	7.0	4.4	7.4	1.4	-0.2	0.2	2.7	2.4	2.5	4.4	3.0	2.2	3.8	3.4	2.2	30
31	Final sales to domestic purchasers	2.3	2.7	3.0	8.7	9.2	1.4	3.4	1.5	1.8	0.9	1.3	4.6	2.6	3.1	3.5	2.7	2.8	3.7	3.1	31
32	Final sales to private domestic purchasers	3.0	2.5	3.0	9.5	12.3	2.0	4.1	2.5	2.4	0.8	0.6	4.6	2.5	2.6	3.5	2.9	2.7	3.4	3.2	32
33	Gross national product (GNP)	2.4	2.7	....	5.5	5.4	3.5	7.8	-1.8	0.9	2.9	2.8	2.1	2.5	4.3	3.1	1.4	2.7	2.4	....	33
34	Disposable personal income	-5.5	5.1	2.9	57.6	-27.7	-4.5	-4.5	-10.9	-1.8	6.6	3.8	10.9	3.4	1.4	3.2	5.6	1.0	1.1	2.8	34
	Current-dollar measures:																				
35	GDP	9.8	6.6	5.3	11.1	13.2	9.8	15.1	7.3	9.7	7.4	7.2	6.6	4.3	7.7	4.8	4.7	5.6	5.0	4.5	35
36	GDI	10.1	5.3	....	9.6	12.0	10.8	14.0	10.2	9.1	8.6	2.3	5.5	4.0	6.0	6.7	6.1	4.6	4.1	....	36
37	Average of GDP and GDI	10.0	6.0	....	10.3	12.6	10.3	14.5	8.7	9.4	8.0	4.7	6.0	4.2	6.8	5.8	5.4	5.1	4.6	....	37
38	Final sales of domestic product	9.2	7.0	5.2	13.5	15.6	6.7	10.5	7.5	12.0	8.2	5.8	8.9	4.7	6.3	5.3	5.2	4.5	5.3	5.5	38
39	Gross domestic purchases	9.9	5.8	5.5	11.4	13.4	10.4	15.1	9.6	8.4	5.0	6.4	5.8	4.1	7.1	4.8	5.3	6.4	5.4	4.4	39
40	Final sales to domestic purchasers	9.3	6.2	5.5	13.8	15.7	7.4	10.7	9.8	10.6	5.7	5.1	8.0	4.4	5.8	5.3	5.8	5.3	5.7	5.3	40
41	Final sales to private domestic purchasers	10.0	6.3	5.4	14.0	18.8	8.1	11.5	10.9	10.7	6.1	4.6	8.6	4.9	5.0	5.3	5.9	5.3	5.3	5.4	41
42	GNP	9.7	6.4	....	10.9	12.0	9.9	15.5	6.5	10.4	7.6	6.6	5.9	4.4	7.6	4.7	4.5	5.3	4.4	....	42
43	Disposable personal income	0.7	9.0	5.4	64.8	-23.1	0.9	2.0	-4.0	5.6	11.7	7.9	15.3	6.4	4.1	4.9	9.2	3.6	2.7	5.2	43

1. Gross domestic income deflated by the implicit price deflator for gross domestic product.

Source: U.S. Bureau of Economic Analysis

Table 2. Contributions to Percent Change in Real Gross Domestic Product

Line		2022	2023	2024	Seasonally adjusted at annual rates																Line
					2021				2022				2023				2024				
					Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	
	Percent change at annual rate:																				
1	**Gross domestic product**	**2.5**	**2.9**	**2.8**	**5.6**	**6.4**	**3.5**	**7.4**	**-1.0**	**0.3**	**2.7**	**3.4**	**2.8**	**2.4**	**4.4**	**3.2**	**1.6**	**3.0**	**3.1**	**2.3**	1
	Percentage points at annual rates:																				
2	**Personal consumption expenditures**	**2.06**	**1.72**	**1.87**	**6.10**	**9.04**	**2.11**	**3.00**	**0.64**	**1.71**	**1.02**	**0.81**	**3.27**	**0.65**	**1.72**	**2.33**	**1.30**	**1.90**	**2.48**	**2.82**	2
3	**Goods**	**-0.14**	**0.42**	**0.52**	**3.80**	**3.19**	**-2.38**	**1.05**	**-0.41**	**-0.37**	**-0.54**	**-0.15**	**1.59**	**-0.08**	**0.76**	**0.73**	**-0.25**	**0.63**	**1.18**	**1.37**	3
4	Durable goods	-0.16	0.31	0.24	2.26	1.20	-2.43	0.69	0.01	-0.18	-0.15	-0.16	1.24	-0.03	0.32	0.22	-0.13	0.40	0.54	0.85	4
5	Motor vehicles and parts	-0.20	0.08	-0.03	1.18	0.48	-1.91	0.16	0.08	-0.13	-0.16	-0.05	0.75	-0.19	-0.16	-0.15	-0.20	0.16	0.22	0.33	5
6	Furnishings and durable household equipment	-0.07	0.03	0.07	0.52	0.06	-0.28	0.01	-0.11	-0.01	-0.04	0.01	0.10	-0.03	0.09	0.07	0.00	0.13	0.15	0.10	6
7	Recreational goods and vehicles	0.06	0.18	0.15	0.35	0.42	-0.25	0.38	0.07	-0.11	0.06	-0.03	0.33	0.21	0.34	0.21	-0.04	0.11	0.16	0.34	7
8	Other durable goods	0.04	0.01	0.05	0.20	0.24	0.01	0.15	-0.03	0.07	-0.01	-0.09	0.05	-0.01	0.05	0.09	0.10	0.00	0.02	0.08	8
9	Nondurable goods	0.02	0.12	0.28	1.54	2.00	0.05	0.36	-0.42	-0.19	-0.38	0.01	0.36	-0.05	0.44	0.51	-0.12	0.23	0.63	0.52	9
10	Food and beverages purchased for off-premises consumption	-0.11	-0.08	0.07	0.72	0.33	-0.05	0.03	-0.17	-0.28	-0.27	-0.07	-0.10	-0.04	0.09	0.08	-0.01	0.11	0.14	0.13	10
11	Clothing and footwear	-0.01	0.02	0.03	0.52	0.66	-0.14	-0.02	-0.17	0.12	-0.05	0.00	0.09	-0.11	0.09	0.07	0.05	-0.06	0.03	0.13	11
12	Gasoline and other energy goods	0.02	0.02	-0.01	0.17	0.44	0.18	0.05	-0.10	-0.12	-0.06	0.01	0.13	0.02	-0.07	0.05	-0.14	0.11	0.05	-0.03	12
13	Other nondurable goods	0.13	0.16	0.18	0.14	0.57	0.06	0.30	0.02	0.10	-0.01	0.06	0.25	0.08	0.32	0.32	-0.02	0.07	0.41	0.29	13
14	**Services**	**2.20**	**1.30**	**1.35**	**2.30**	**5.85**	**4.48**	**1.95**	**1.05**	**2.09**	**1.55**	**0.96**	**1.67**	**0.73**	**0.96**	**1.60**	**1.55**	**1.27**	**1.31**	**1.45**	14
15	Household consumption expenditures (for services)	2.03	1.41	1.21	2.76	6.35	4.40	1.68	0.69	1.79	1.48	1.17	2.00	0.81	0.95	1.63	1.27	0.94	1.14	1.38	15
16	Housing and utilities	0.34	0.06	0.12	0.46	0.19	0.34	0.19	0.67	0.33	-0.05	0.30	-0.22	0.06	0.25	-0.03	0.09	0.23	0.10	0.17	16
17	Health care	0.46	0.66	0.61	-0.14	1.38	0.78	0.58	0.05	0.14	0.61	0.79	1.04	0.31	0.35	0.85	0.76	0.35	0.79	0.46	17
18	Transportation services	0.20	0.01	0.08	0.20	1.01	0.95	0.19	-0.05	-0.01	-0.01	-0.02	0.02	0.05	0.00	0.11	0.01	0.31	-0.10	0.08	18
19	Recreation services	0.28	0.10	0.04	0.56	0.82	0.66	0.44	0.04	0.23	0.05	0.14	0.16	-0.01	0.08	0.02	0.07	0.05	0.01	0.05	19
20	Food services and accommodations	0.42	0.19	0.06	0.78	2.09	0.75	-0.01	-0.06	0.98	0.20	-0.04	0.31	-0.11	0.28	0.27	-0.12	-0.01	0.07	0.12	20
21	Financial services and insurance	-0.01	0.20	0.14	0.24	0.01	0.09	0.16	-0.22	-0.11	0.18	0.11	0.29	0.46	0.07	-0.01	0.31	-0.04	0.21	0.18	21
22	Other services	0.35	0.19	0.15	0.66	0.86	0.82	0.13	0.26	0.23	0.50	-0.10	0.41	0.04	-0.06	0.42	0.16	0.05	0.07	0.31	22
23	Final consumption expenditures of nonprofit institutions serving households	0.18	-0.11	0.15	-0.46	-0.51	0.08	0.28	0.37	0.30	0.08	-0.21	-0.33	-0.08	0.01	-0.03	0.28	0.33	0.17	0.08	23
24	Gross output of nonprofit institutions	0.26	0.15	0.37	-0.53	0.41	0.25	0.53	-0.01	0.08	0.55	0.28	-0.08	0.04	0.05	0.38	0.64	0.17	0.61	0.32	24
25	Less: Receipts from sales of goods and services by nonprofit institutions	0.08	0.26	0.22	-0.07	0.91	0.16	0.25	-0.38	-0.21	0.48	0.49	0.25	0.12	0.04	0.41	0.36	-0.16	0.44	0.24	25
26	**Gross private domestic investment**	**1.07**	**0.02**	**0.73**	**-0.28**	**-1.01**	**2.73**	**4.68**	**1.34**	**-1.67**	**-1.05**	**1.08**	**-1.63**	**1.42**	**1.80**	**0.16**	**0.64**	**1.47**	**0.16**	**-1.03**	26
27	**Fixed investment**	**0.48**	**0.43**	**0.67**	**1.65**	**0.99**	**-0.38**	**0.53**	**1.44**	**0.35**	**-0.33**	**-0.36**	**0.53**	**1.48**	**0.45**	**0.62**	**1.14**	**0.42**	**0.38**	**-0.10**	27
28	Nonresidential	0.90	0.81	0.50	1.25	1.17	-0.21	0.47	1.66	0.94	1.01	0.76	0.71	1.30	0.16	0.52	0.61	0.53	0.55	-0.31	28
29	Structures	0.10	0.32	0.10	0.21	0.01	-0.11	-0.26	0.28	0.24	0.26	0.28	0.43	0.49	0.06	0.20	0.20	0.01	-0.16	-0.03	29
30	Equipment	0.22	0.18	0.18	0.31	0.46	-0.54	0.10	0.75	0.05	0.33	0.05	0.04	0.61	-0.05	0.04	0.02	0.49	0.54	-0.42	30
31	Information processing equipment	0.13	-0.08	0.09	0.22	-0.01	-0.08	0.49	0.34	-0.15	0.14	-0.33	-0.07	-0.07	-0.04	0.16	0.06	0.13	0.29	-0.17	31
32	Industrial equipment	0.04	0.01	0.02	-0.02	0.20	0.07	0.06	0.07	-0.06	-0.06	0.08	0.02	0.01	-0.03	0.01	0.09	-0.05	0.06	0.01	32
33	Transportation equipment	0.00	0.25	0.07	0.08	0.33	-0.51	-0.42	0.13	0.22	0.27	0.32	0.15	0.61	0.03	-0.17	-0.15	0.41	0.25	-0.19	33
34	Other equipment	0.05	-0.01	0.00	0.03	-0.05	-0.03	-0.02	0.20	0.05	-0.03	-0.01	-0.06	0.06	-0.01	0.03	0.02	0.00	-0.06	-0.08	34
35	Intellectual property products	0.58	0.31	0.22	0.72	0.70	0.44	0.63	0.63	0.65	0.42	0.42	0.24	0.21	0.15	0.28	0.40	0.04	0.17	0.15	35
36	Software	0.32	0.16	0.15	0.49	0.35	0.22	0.26	0.45	0.31	0.22	0.27	0.06	0.11	0.14	0.21	0.24	0.05	0.06	0.10	36
37	Research and development	0.24	0.14	0.08	0.26	0.33	0.18	0.32	0.20	0.27	0.16	0.16	0.18	0.09	0.01	0.10	0.16	-0.01	0.11	0.05	37
38	Entertainment, literary, and artistic originals	0.03	0.01	0.00	-0.03	0.02	0.04	0.05	-0.02	0.06	0.05	-0.01	0.00	0.01	0.00	-0.02	0.00	-0.01	0.00	0.00	38
39	Residential	-0.42	-0.37	0.17	0.40	-0.18	-0.17	0.06	-0.22	-0.59	-1.34	-1.12	-0.18	0.17	0.30	0.10	0.53	-0.11	-0.18	0.21	39
40	**Change in private inventories**	**0.59**	**-0.41**	**0.06**	**-1.93**	**-2.00**	**3.10**	**4.14**	**-0.10**	**-2.01**	**-0.72**	**1.44**	**-2.16**	**-0.06**	**1.34**	**-0.47**	**-0.49**	**1.05**	**-0.22**	**-0.93**	40
41	Farm	-0.04	0.04	0.04	0.24	-0.09	0.00	-0.08	0.01	-0.09	-0.05	0.12	-0.10	0.28	0.05	-0.05	-0.02	0.17	0.04	-0.04	41
42	Nonfarm	0.63	-0.45	0.01	-2.16	-1.91	3.11	4.23	-0.11	-1.92	-0.67	1.32	-2.06	-0.34	1.29	-0.42	-0.47	0.88	-0.26	-0.89	42
43	**Net exports of goods and services**	**-0.42**	**0.49**	**-0.39**	**-1.14**	**-0.82**	**-1.10**	**-0.22**	**-2.40**	**0.50**	**2.50**	**0.56**	**0.33**	**-0.11**	**-0.10**	**0.09**	**-0.61**	**-0.90**	**-0.43**	**0.04**	43
44	**Exports**	**0.82**	**0.31**	**0.35**	**0.00**	**0.33**	**0.09**	**2.54**	**-0.51**	**1.40**	**1.63**	**-0.12**	**0.23**	**-0.54**	**0.53**	**0.66**	**0.21**	**0.12**	**1.01**	**-0.08**	44
45	Goods	0.45	0.17	0.16	-0.10	0.09	-0.19	1.87	-0.74	0.84	1.53	-0.43	0.39	-0.86	0.53	0.37	-0.02	0.07	0.70	-0.35	45
46	Services	0.38	0.14	0.20	0.10	0.24	0.29	0.67	0.23	0.56	0.09	0.31	-0.17	0.31	0.00	0.29	0.23	0.05	0.31	0.27	46
47	**Imports**	**-1.24**	**0.17**	**-0.74**	**-1.14**	**-1.15**	**-1.19**	**-2.77**	**-1.90**	**-0.90**	**0.87**	**0.68**	**0.10**	**0.44**	**-0.63**	**-0.57**	**-0.82**	**-1.01**	**-1.44**	**0.12**	47
48	Goods	-0.81	0.22	-0.54	-0.94	-0.64	-0.12	-2.38	-1.60	-0.40	1.08	0.48	-0.04	0.57	-0.56	-0.19	-0.69	-0.90	-1.14	0.46	48
49	Services	-0.43	-0.05	-0.20	-0.20	-0.51	-1.07	-0.39	-0.29	-0.50	-0.21	0.21	0.14	-0.13	-0.07	-0.38	-0.13	-0.12	-0.29	-0.35	49
50	**Government consumption expenditures and gross investment**	**-0.20**	**0.66**	**0.57**	**0.95**	**-0.78**	**-0.28**	**-0.04**	**-0.60**	**-0.27**	**0.26**	**0.90**	**0.84**	**0.48**	**0.94**	**0.61**	**0.30**	**0.52**	**0.86**	**0.42**	50
51	**Federal**	**-0.22**	**0.19**	**0.16**	**1.14**	**-0.58**	**-0.53**	**0.21**	**-0.58**	**-0.22**	**-0.04**	**0.54**	**0.28**	**-0.08**	**0.33**	**-0.02**	**-0.02**	**0.27**	**0.55**	**0.21**	51
52	National defense	-0.15	0.12	0.11	-0.33	-0.11	-0.18	-0.14	-0.43	0.07	-0.11	0.26	0.17	0.03	0.24	-0.05	-0.09	0.23	0.48	0.12	52
53	Consumption expenditures	-0.15	0.06	0.08	-0.14	-0.09	-0.18	-0.18	-0.35	0.00	-0.02	0.03	0.18	-0.04	0.22	-0.05	-0.01	0.10	0.32	0.09	53
54	Gross investment	0.00	0.05	0.03	-0.19	-0.02	0.00	0.04	-0.08	0.07	-0.09	0.24	-0.01	0.07	0.01	0.00	-0.08	0.13	0.16	0.03	54
55	Nondefense	-0.07	0.07	0.05	1.47	-0.47	-0.35	0.35	-0.15	-0.29	0.07	0.28	0.11	-0.11	0.09	0.02	0.07	0.04	0.07	0.09	55
56	Consumption expenditures	-0.09	0.03	0.04	1.40	-0.53	-0.40	0.32	-0.16	-0.30	0.05	0.20	0.03	-0.14	0.10	-0.01	0.09	0.03	0.06	0.06	56
57	Gross investment	0.03	0.04	0.01	0.07	0.06	0.05	0.03	0.01	0.01	0.02	0.07	0.07	0.03	-0.01	0.03	-0.02	0.01	0.01	0.02	57
58	**State and local**	**0.02**	**0.47**	**0.41**	**-0.19**	**-0.20**	**0.26**	**-0.25**	**-0.01**	**-0.05**	**0.29**	**0.36**	**0.56**	**0.56**	**0.62**	**0.63**	**0.32**	**0.25**	**0.31**	**0.22**	58
59	Consumption expenditures	0.09	0.31	0.20	-0.01	0.08	0.44	-0.12	-0.04	0.07	0.27	0.29	0.44	0.28	0.28	0.21	0.18	0.16	0.22	0.18	59
60	Gross investment	-0.07	0.16	0.21	-0.17	-0.28	-0.19	-0.13	0.03	-0.12	0.02	0.07	0.12	0.29	0.33	0.42	0.14	0.09	0.09	0.04	60

Source: U.S. Bureau of Economic Analysis

Table 3. Gross Domestic Product: Level and Change from Preceding Period--Continues

Line		Billions of dollars						Billions of chained (2017) dollars									Line
		2024	Seasonally adjusted at annual rates					2024	Seasonally adjusted at annual rates					Change from preceding period			
			2023	2024					2023	2024				2024	2024		
			Q4	Q1	Q2	Q3	Q4		Q4	Q1	Q2	Q3	Q4		Q3	Q4	
1	**Gross domestic product (GDP)**	**29,179.1**	**28,297.0**	**28,624.1**	**29,016.7**	**29,374.9**	**29,700.6**	**23,302.2**	**22,960.6**	**23,053.5**	**23,223.9**	**23,400.3**	**23,530.9**	**631.1**	**176.4**	**130.6**	1
2	**Personal consumption expenditures**	**19,826.1**	**19,170.2**	**19,424.8**	**19,682.7**	**19,938.4**	**20,258.4**	**16,054.3**	**15,781.4**	**15,856.9**	**15,967.3**	**16,113.0**	**16,280.1**	**432.6**	**145.8**	**167.1**	2
3	**Goods**	**6,244.3**	**6,174.8**	**6,148.9**	**6,204.6**	**6,265.1**	**6,358.5**	**5,451.5**	**5,378.5**	**5,362.8**	**5,402.1**	**5,476.7**	**5,564.6**	**127.8**	**74.6**	**87.9**	3
4	Durable goods	2,167.6	2,139.3	2,127.3	2,141.8	2,168.4	2,232.9	2,049.3	2,004.5	1,995.7	2,022.3	2,059.8	2,119.2	65.0	37.4	59.5	4
5	Motor vehicles and parts	727.5	730.7	711.9	715.6	723.2	759.1	580.3	573.7	562.5	571.5	584.0	603.3	-6.7	12.5	19.3	5
6	Furnishings and durable household equipment	486.2	479.1	478.3	480.5	489.3	496.9	437.6	424.5	424.6	432.9	442.9	449.8	18.6	9.9	6.9	6
7	Recreational goods and vehicles	663.9	648.2	651.7	658.4	665.3	680.3	771.6	753.7	750.7	760.0	773.1	802.7	47.9	13.0	29.6	7
8	Other durable goods	290.0	281.2	285.5	287.4	290.6	296.6	298.7	289.2	296.7	296.4	298.1	303.8	15.7	1.7	5.7	8
9	Nondurable goods	4,076.6	4,035.4	4,021.5	4,062.8	4,096.7	4,125.5	3,412.2	3,381.7	3,374.5	3,388.6	3,427.0	3,458.7	65.0	38.4	31.7	9
10	Food and beverages purchased for off-premises consumption	1,482.0	1,457.6	1,464.9	1,471.4	1,487.3	1,504.3	1,167.3	1,157.2	1,156.8	1,163.0	1,171.1	1,178.3	15.2	8.0	7.2	10
11	Clothing and footwear	522.9	514.5	517.3	521.2	523.4	529.6	502.7	498.5	502.2	498.2	500.6	509.7	8.9	2.4	9.2	11
12	Gasoline and other energy goods	440.3	464.0	443.3	456.2	436.6	425.0	315.9	317.7	310.6	316.3	319.1	317.7	-1.4	2.7	-1.4	12
13	Other nondurable goods	1,631.5	1,599.4	1,596.2	1,614.0	1,649.3	1,666.6	1,438.5	1,419.2	1,417.7	1,422.0	1,447.9	1,466.3	45.5	25.9	18.5	13
14	**Services**	**13,581.8**	**12,995.4**	**13,275.9**	**13,478.1**	**13,673.3**	**13,899.9**	**10,622.6**	**10,423.6**	**10,511.3**	**10,582.7**	**10,656.7**	**10,739.6**	**303.9**	**74.0**	**82.9**	14
15	Household consumption expenditures (for services)	12,955.8	12,433.4	12,688.9	12,856.8	13,029.8	13,247.9	10,189.8	10,025.3	10,097.7	10,151.0	10,215.7	10,294.8	272.3	64.8	79.1	15
16	Housing and utilities	3,553.6	3,421.2	3,479.7	3,534.0	3,575.3	3,625.5	2,636.0	2,617.1	2,621.9	2,634.2	2,639.3	2,648.6	25.3	5.1	9.3	16
17	Health care	3,313.1	3,148.8	3,233.6	3,274.3	3,344.0	3,400.4	2,815.0	2,720.9	2,767.3	2,789.0	2,837.5	2,866.1	148.0	48.5	28.6	17
18	Transportation services	656.2	632.0	637.6	659.4	654.4	673.5	497.7	486.1	486.8	503.7	498.1	502.3	16.6	-5.6	4.2	18
19	Recreation services	778.1	754.6	769.1	773.6	778.9	790.8	618.1	611.1	614.9	617.9	618.2	621.3	10.0	0.3	3.1	19
20	Food services and accommodations	1,428.2	1,403.4	1,409.4	1,417.5	1,431.5	1,454.3	1,067.0	1,070.4	1,063.9	1,063.2	1,067.1	1,073.7	13.4	3.9	6.6	20
21	Financial services and insurance	1,557.2	1,459.2	1,516.4	1,535.8	1,572.1	1,604.6	1,162.7	1,139.4	1,156.2	1,153.9	1,165.4	1,175.3	31.0	11.5	9.9	21
22	Other services	1,669.4	1,614.3	1,643.1	1,662.2	1,673.5	1,698.7	1,411.6	1,392.8	1,402.6	1,405.5	1,409.5	1,428.7	36.5	4.0	19.3	22
23	Final consumption expenditures of nonprofit institutions serving households	626.0	562.0	587.0	621.3	643.5	652.0	433.9	402.4	416.4	432.8	441.3	445.1	29.4	8.5	3.8	23
24	Gross output of nonprofit institutions	2,223.5	2,090.7	2,158.0	2,190.4	2,253.6	2,292.1	1,744.2	1,679.1	1,715.3	1,724.8	1,759.3	1,777.4	82.9	34.5	18.1	24
25	Less: Receipts from sales of goods and services by nonprofit institutions	1,597.6	1,528.7	1,571.0	1,569.1	1,610.1	1,640.0	1,311.8	1,280.9	1,302.1	1,292.9	1,318.9	1,333.3	51.9	26.1	14.4	25
26	**Gross private domestic investment**	**5,272.9**	**5,102.8**	**5,159.9**	**5,297.8**	**5,345.2**	**5,288.8**	**4,336.2**	**4,244.8**	**4,282.5**	**4,369.2**	**4,377.7**	**4,315.4**	**167.0**	**8.6**	**-62.4**	26
27	**Fixed investment**	**5,222.4**	**5,046.1**	**5,138.5**	**5,201.1**	**5,269.2**	**5,280.9**	**4,259.1**	**4,164.9**	**4,231.4**	**4,255.7**	**4,277.7**	**4,271.5**	**155.2**	**22.0**	**-6.2**	27
28	Nonresidential	4,036.7	3,901.5	3,957.8	4,018.5	4,089.4	4,081.0	3,508.2	3,432.9	3,471.0	3,504.1	3,538.8	3,519.0	123.7	34.7	-19.8	28
29	Structures	911.2	905.8	914.9	916.0	908.6	905.2	675.4	669.7	679.9	680.2	671.6	669.8	21.1	-8.6	-1.8	29
30	Equipment	1,506.2	1,443.9	1,458.8	1,499.7	1,548.1	1,518.1	1,329.2	1,294.6	1,295.7	1,326.5	1,361.0	1,333.6	44.0	34.5	-27.4	30
31	Information processing equipment	501.3	475.3	483.7	495.1	518.4	508.0	516.8	497.7	502.0	511.7	533.3	520.1	25.3	21.6	-13.2	31
32	Industrial equipment	326.8	314.5	324.0	323.2	329.1	331.0	260.8	255.8	260.9	258.2	261.7	262.5	4.9	3.6	0.7	32
33	Transportation equipment	349.7	327.6	320.6	349.8	372.4	355.9	306.8	292.4	282.7	308.3	324.1	312.1	16.6	15.8	-12.0	33
34	Other equipment	328.3	326.6	330.4	331.5	328.2	323.3	253.1	254.7	256.0	255.8	252.4	248.2	0.3	-3.3	-4.3	34
35	Intellectual property products	1,619.3	1,551.7	1,584.1	1,602.7	1,632.8	1,657.6	1,505.3	1,468.3	1,495.0	1,497.7	1,509.2	1,519.1	59.4	11.5	9.9	35
36	Software	698.1	660.6	675.2	690.7	707.3	719.1	768.6	741.8	760.9	765.3	769.9	778.1	46.4	4.7	8.2	36
37	Research and development	807.4	779.7	795.0	798.6	811.6	824.5	663.9	650.9	660.1	659.7	666.6	669.4	18.9	6.9	2.8	37
38	Entertainment, literary, and artistic originals	113.8	111.5	113.9	113.5	113.8	114.0	91.9	92.2	92.4	91.9	91.8	91.6	-1.0	-0.1	-0.2	38
39	Residential	1,185.7	1,144.7	1,180.7	1,182.6	1,179.7	1,199.9	794.8	775.5	800.8	795.2	786.5	796.7	32.1	-8.7	10.1	39
40	**Change in private inventories**	**50.5**	**56.7**	**21.4**	**96.8**	**76.0**	**7.9**	**37.9**	**44.6**	**17.7**	**71.7**	**57.9**	**4.4**	**4.9**	**-13.8**	**-53.5**	40
41	Farm	5.3	-2.9	-3.5	7.7	9.7	7.4	1.4	-3.8	-3.1	2.7	3.7	2.4	3.9	0.9	-1.2	41
42	Nonfarm	45.2	59.6	24.9	89.1	66.3	0.5	36.4	48.6	21.2	68.9	54.0	1.6	0.9	-15.0	-52.4	42

1. Real gross domestic income is gross domestic income deflated by the implicit price deflator for gross domestic product.

Note. Users are cautioned that particularly for components that exhibit rapid change in prices relative to other prices in the economy, the chained-dollar estimates should not be used to measure the component's relative importance or its contribution to the growth rate of more aggregate series. For accurate estimates of the contributions to percent changes in real gross domestic product, use table 2.

Source: U.S. Bureau of Economic Analysis

Table 3. Gross Domestic Product: Level and Change from Preceding Period--Table Ends

Line		Billions of dollars						Billions of chained (2017) dollars									Line
		2024	Seasonally adjusted at annual rates					2024	Seasonally adjusted at annual rates					Change from preceding period			
			2023	2024					2023	2024				2024	2024		
			Q4	Q1	Q2	Q3	Q4		Q4	Q1	Q2	Q3	Q4		Q3	Q4	
43	**Net exports of goods and services**	**-908.8**	**-791.2**	**-841.6**	**-906.9**	**-943.7**	**-943.2**	**-1,037.2**	**-936.7**	**-977.0**	**-1,035.7**	**-1,069.2**	**-1,066.8**	**-104.4**	**-33.6**	**2.4**	43
44	**Exports**	**3,178.9**	**3,091.7**	**3,125.4**	**3,154.3**	**3,220.3**	**3,215.6**	**2,605.4**	**2,559.6**	**2,571.8**	**2,578.4**	**2,638.2**	**2,633.1**	**81.6**	**59.8**	**-5.1**	44
45	Goods	2,058.5	2,034.3	2,037.0	2,053.4	2,088.3	2,055.3	1,731.2	1,713.6	1,712.5	1,716.5	1,759.0	1,736.8	36.9	42.5	-22.2	45
46	Services	1,120.4	1,057.4	1,088.4	1,100.9	1,132.0	1,160.3	877.5	850.0	862.8	865.5	883.0	898.6	44.0	17.6	15.6	46
47	**Imports**	**4,087.7**	**3,882.9**	**3,967.0**	**4,061.2**	**4,164.0**	**4,158.8**	**3,642.5**	**3,496.3**	**3,548.7**	**3,614.0**	**3,707.4**	**3,699.9**	**185.9**	**93.4**	**-7.5**	47
48	Goods	3,263.4	3,106.5	3,170.1	3,252.8	3,331.8	3,298.7	2,965.4	2,846.1	2,891.1	2,949.9	3,025.6	2,994.8	137.2	75.7	-30.8	48
49	Services	824.4	776.4	796.9	808.4	832.2	860.1	676.7	649.8	657.4	664.4	682.1	702.9	47.3	17.6	20.9	49
50	**Government consumption expenditures and gross investment**	**4,988.9**	**4,815.2**	**4,881.0**	**4,943.0**	**5,035.0**	**5,096.6**	**3,940.4**	**3,870.7**	**3,887.7**	**3,917.0**	**3,966.2**	**3,990.7**	**128.7**	**49.2**	**24.5**	50
51	**Federal**	**1,867.0**	**1,796.2**	**1,810.3**	**1,842.2**	**1,893.4**	**1,922.0**	**1,503.0**	**1,473.5**	**1,472.2**	**1,487.8**	**1,520.0**	**1,532.1**	**36.9**	**32.2**	**12.1**	51
52	National defense	1,069.7	1,025.4	1,028.4	1,051.5	1,091.3	1,107.8	850.4	830.3	825.0	838.0	865.7	872.8	25.1	27.8	7.0	52
53	Consumption expenditures	837.3	802.7	810.8	823.7	851.2	863.6	651.5	637.3	636.8	642.5	660.7	666.0	17.7	18.3	5.2	53
54	Gross investment	232.4	222.7	217.6	227.8	240.1	244.2	200.1	194.1	188.9	196.7	206.5	208.4	7.7	9.8	1.8	54
55	Nondefense	797.2	770.8	781.9	790.7	802.1	814.2	652.5	643.2	647.3	649.8	654.0	659.0	11.7	4.2	5.1	55
56	Consumption expenditures	567.8	544.3	556.6	562.7	571.5	580.2	454.4	445.4	450.5	452.2	455.6	459.3	9.7	3.4	3.7	56
57	Gross investment	229.4	226.5	225.3	228.0	230.6	233.9	198.8	198.7	197.5	198.3	199.0	200.4	1.8	0.7	1.4	57
58	**State and local**	**3,121.9**	**3,019.0**	**3,070.7**	**3,100.9**	**3,141.6**	**3,174.7**	**2,436.2**	**2,395.9**	**2,414.0**	**2,427.9**	**2,445.3**	**2,457.7**	**91.1**	**17.4**	**12.4**	58
59	Consumption expenditures	2,511.5	2,434.7	2,472.7	2,495.7	2,525.0	2,552.6	1,980.0	1,954.6	1,964.6	1,973.4	1,985.8	1,995.9	46.0	12.3	10.2	59
60	Gross investment	610.4	584.3	598.0	605.1	616.6	622.0	453.5	439.1	446.8	451.7	456.7	458.9	43.4	4.9	2.3	60
61	Residual	....	....	....	....	....	....	-123.6	-120.8	-119.2	-114.1	-123.4	-137.8	....	....	....	61
	Addenda:																
62	Gross domestic income (GDI) [1]	....	28,082.7	28,499.2	28,821.9	29,111.4	....	....	22,786.7	22,953.0	23,068.0	23,190.4	....	....	122.4	....	62
63	Average of GDP and GDI	....	28,189.8	28,561.6	28,919.3	29,243.2	....	....	22,873.7	23,003.3	23,145.9	23,295.4	....	....	149.4	....	63
64	Final sales of domestic product	29,128.6	28,240.3	28,602.7	28,919.9	29,298.9	29,692.7	23,226.5	22,881.9	23,003.2	23,113.1	23,302.4	23,487.3	619.9	189.3	184.9	64
65	Gross domestic purchases	30,087.9	29,088.1	29,465.6	29,923.6	30,318.6	30,643.8	24,321.0	23,887.4	24,017.2	24,242.6	24,446.9	24,577.3	727.9	204.3	130.5	65
66	Final sales to domestic purchasers	30,037.4	29,031.4	29,444.2	29,826.8	30,242.6	30,635.9	24,245.1	23,808.6	23,967.1	24,131.2	24,348.5	24,533.9	716.6	217.3	185.4	66
67	Final sales to private domestic purchasers	25,048.5	24,216.3	24,563.3	24,883.8	25,207.6	25,539.3	20,313.4	19,946.4	20,088.1	20,222.9	20,390.7	20,551.9	587.8	167.8	161.1	67
68	**GDP**	**29,179.1**	**28,297.0**	**28,624.1**	**29,016.7**	**29,374.9**	**29,700.6**	**23,302.2**	**22,960.6**	**23,053.5**	**23,223.9**	**23,400.3**	**23,530.9**	**631.1**	**176.4**	**130.6**	68
69	Plus: Income receipts from the rest of the world	....	1,454.2	1,493.0	1,504.0	1,442.0	....	....	1,247.9	1,271.2	1,272.7	1,214.4	....	....	-58.3	....	69
70	Less: Income payments to the rest of the world	....	1,359.3	1,410.8	1,444.1	1,428.9	....	....	1,166.8	1,201.5	1,222.3	1,203.6	....	....	-18.7	....	70
71	**Equals: Gross national product**	**...............**	**28,391.8**	**28,706.3**	**29,076.6**	**29,388.1**	**...............**	**...............**	**23,054.3**	**23,136.5**	**23,288.7**	**23,427.7**	**...............**	**............**	**139.0**	**............**	71
72	Net domestic product	24,362.7	23,628.5	23,910.0	24,235.7	24,521.0	24,784.1	19,381.0	19,111.9	19,177.9	19,317.6	19,463.7	19,564.8	516.8	146.0	101.2	72

1. Real gross domestic income is gross domestic income deflated by the implicit price deflator for gross domestic product.

Note. Users are cautioned that particularly for components that exhibit rapid change in prices relative to other prices in the economy, the chained-dollar estimates should not be used to measure the component's relative importance or its contribution to the growth rate of more aggregate series. For accurate estimates of the contributions to percent changes in real gross domestic product, use table 2.

Source: U.S. Bureau of Economic Analysis

Table 4. Price Indexes for Gross Domestic Product and Related Measures: Percent Change from Preceding Period

Line		2022	2023	2024	Seasonally adjusted at annual rates																Line
					2021				2022				2023				2024				
					Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	
1	**Gross domestic product (GDP)**	**7.1**	**3.6**	**2.4**	**5.2**	**6.2**	**6.2**	**7.0**	**8.5**	**9.3**	**4.5**	**3.7**	**3.6**	**1.9**	**3.2**	**1.5**	**3.0**	**2.5**	**1.9**	**2.2**	1
2	**Personal consumption expenditures**	**6.6**	**3.8**	**2.5**	**4.6**	**6.4**	**5.6**	**6.8**	**7.7**	**7.6**	**4.7**	**4.0**	**3.9**	**2.9**	**2.7**	**1.7**	**3.4**	**2.5**	**1.5**	**2.3**	2
3	Goods	8.6	1.2	-0.4	5.6	8.7	7.3	10.6	12.0	10.5	2.4	0.2	0.8	0.6	0.5	-1.6	-0.5	0.7	-1.6	-0.5	3
4	Durable goods	6.5	-0.8	-2.0	1.4	13.8	9.5	9.6	9.0	1.2	2.9	-1.4	-0.5	-0.3	-4.3	-3.2	-0.5	-2.6	-2.4	0.3	4
5	Nondurable goods	9.9	2.3	0.5	8.0	5.9	6.1	11.2	13.7	16.0	2.2	1.1	1.4	1.1	3.2	-0.7	-0.5	2.5	-1.2	-0.9	5
6	Services	5.5	5.1	3.9	4.1	5.2	4.8	4.9	5.6	6.1	5.9	6.0	5.6	4.1	3.8	3.2	5.3	3.4	3.0	3.5	6
7	**Gross private domestic investment**	**7.8**	**3.2**	**1.7**	**2.5**	**3.1**	**6.2**	**8.1**	**9.7**	**9.3**	**7.2**	**3.6**	**3.8**	**-1.0**	**1.7**	**2.2**	**0.9**	**2.5**	**3.0**	**1.5**	7
8	Fixed investment	8.0	3.3	1.8	2.8	3.9	7.0	8.2	9.7	9.8	7.0	3.8	3.5	-0.1	1.4	2.3	0.9	2.6	3.2	1.5	8
9	Nonresidential	6.1	3.5	1.6	-0.2	0.3	4.3	6.8	6.9	8.0	6.5	3.4	5.5	0.2	0.5	1.7	1.3	2.3	3.1	1.4	9
10	Structures	16.1	5.5	-0.2	0.5	6.1	9.0	23.7	17.2	17.9	17.0	8.1	6.0	-1.1	-3.8	3.4	-2.0	0.3	1.9	-0.5	10
11	Equipment	6.2	4.6	2.1	2.3	-2.9	5.3	5.3	7.7	9.0	6.4	5.9	7.0	0.2	2.5	1.1	3.8	1.7	2.5	0.3	11
12	Intellectual property products	1.1	1.4	2.2	-3.1	0.4	1.0	0.5	1.2	2.3	1.3	-1.5	3.9	1.0	1.1	1.2	1.0	4.0	4.4	3.5	12
13	Residential	13.8	2.8	2.4	11.8	14.9	15.1	12.5	18.1	15.0	8.7	5.5	-2.9	-1.2	4.9	4.5	-0.4	3.5	3.5	1.7	13
14	Change in private inventories	....	....	....	....	....	....	....	....	....	....	....	....	....	....	....	....	....	....	....	14
15	**Net exports of goods and services**	**........**	**........**	**........**	**........**	**........**	**........**	**........**	**........**	**........**	**........**	**........**	**........**	**........**	**........**	**........**	**........**	**........**	**........**	**........**	15
16	Exports	9.8	-1.6	0.9	20.7	18.5	9.7	6.7	18.0	19.9	-9.1	-5.9	-0.1	-3.6	4.1	-2.1	2.5	2.7	-0.9	0.2	16
17	Goods	11.6	-4.3	-0.4	26.1	24.0	11.1	7.4	23.2	26.5	-13.9	-11.2	-3.0	-6.4	4.4	-3.4	0.8	2.3	-3.0	-1.3	17
18	Services	6.1	4.2	3.3	10.3	7.5	6.7	5.3	7.4	6.6	2.5	6.3	6.1	2.0	3.5	0.3	5.8	3.4	3.1	2.9	18
19	Imports	7.2	-2.0	0.8	12.0	12.7	5.9	6.7	13.4	11.6	-4.7	-4.5	-1.6	-4.6	0.1	0.0	2.6	2.1	-0.2	0.3	19
20	Goods	7.5	-3.2	0.5	13.3	13.6	5.7	7.2	15.5	12.2	-6.8	-7.0	-2.6	-5.6	0.1	0.3	1.8	2.3	-0.5	0.1	20
21	Services	6.0	3.1	1.7	5.5	8.8	6.8	4.6	4.1	8.8	5.2	7.1	2.8	0.0	0.0	-1.2	5.9	1.5	1.1	1.2	21
22	**Government consumption expenditures and gross investment**	**7.2**	**1.8**	**2.5**	**6.8**	**6.7**	**5.9**	**7.0**	**8.4**	**11.7**	**2.3**	**2.2**	**0.2**	**-1.0**	**4.0**	**1.3**	**3.7**	**2.1**	**2.4**	**2.4**	22
23	Federal	5.8	4.3	3.3	3.1	4.4	4.8	5.0	6.6	7.5	5.3	4.1	4.3	3.5	3.8	3.8	3.6	2.8	2.4	2.8	23
24	National defense	6.5	4.4	3.6	4.3	4.7	4.7	5.2	8.7	9.5	3.9	3.8	3.6	4.4	4.5	4.9	3.8	2.7	1.9	2.8	24
25	Nondefense	4.8	4.3	2.9	1.5	3.9	5.0	4.8	3.8	4.9	7.2	4.6	5.2	2.4	3.0	2.5	3.2	3.0	3.2	2.9	25
26	State and local	8.0	0.4	1.9	9.2	8.1	6.6	8.1	9.6	14.3	0.6	1.1	-2.1	-3.7	4.0	-0.1	3.9	1.6	2.4	2.2	26
	Addenda:																				
27	Final sales of domestic product	7.2	3.6	2.4	5.3	6.3	6.3	7.1	8.5	9.4	4.5	3.8	3.6	2.0	3.2	1.5	3.0	2.5	2.0	2.2	27
28	Gross domestic purchases	6.9	3.3	2.3	4.6	5.9	5.8	7.0	8.2	8.5	4.7	3.6	3.3	1.6	2.7	1.7	3.0	2.4	1.9	2.2	28
29	Final sales to domestic purchasers	6.9	3.4	2.4	4.7	6.0	5.9	7.0	8.2	8.6	4.7	3.7	3.2	1.7	2.7	1.7	3.0	2.5	2.0	2.2	29
30	Final sales to private domestic purchasers	6.9	3.7	2.3	4.2	5.9	5.9	7.1	8.1	8.0	5.2	4.0	3.9	2.3	2.4	1.8	2.9	2.5	1.9	2.1	30
31	Gross national product (GNP)	7.1	3.6	....	5.2	6.2	6.2	7.0	8.5	9.3	4.5	3.7	3.6	1.9	3.2	1.5	3.0	2.5	1.9	....	31
32	GDP excluding food and energy [1]	6.3	3.9	2.7	4.2	5.9	5.6	6.5	7.0	7.4	5.3	4.1	4.2	2.5	2.8	2.4	3.1	2.7	2.5	2.5	32
33	Gross domestic purchases excluding food and energy [1]	6.2	3.5	2.5	3.9	5.6	5.4	6.2	7.2	7.0	5.0	4.0	3.6	2.2	2.5	1.9	3.2	2.6	2.4	2.3	33
34	PCE excluding food and energy [1]	5.4	4.1	2.8	3.4	5.9	4.9	5.3	6.1	4.8	5.2	4.7	4.7	3.8	2.4	2.0	3.7	2.8	2.2	2.5	34
35	Market-based PCE [2]	6.4	3.6	2.2	4.0	5.7	5.1	6.5	7.8	7.9	4.6	3.6	3.8	2.6	2.6	1.9	2.8	2.1	1.3	2.0	35
36	Market-based PCE excluding food and energy [1,2]	5.0	4.0	2.5	2.5	5.0	4.2	4.8	5.9	4.8	5.2	4.3	4.7	3.7	2.1	2.4	3.1	2.3	2.0	2.3	36
	Implicit price deflators:																				
37	GDP	7.1	3.6	2.4	5.2	6.3	6.1	7.1	8.4	9.4	4.6	3.7	3.7	1.8	3.2	1.6	3.0	2.5	1.9	2.2	37
38	Gross domestic purchases	6.9	3.4	2.3	4.6	6.0	5.7	7.1	8.1	8.6	4.8	3.6	3.3	1.5	2.7	1.7	3.0	2.5	1.9	2.2	38
39	GNP	7.1	3.6	....	5.2	6.3	6.1	7.1	8.4	9.4	4.6	3.7	3.7	1.8	3.2	1.6	3.0	2.5	1.9	....	39

1. Food excludes personal consumption expenditures for purchased meals and beverages, which are classified in food services.

2. This index is a supplemental measure that is based on household expenditures for which there are observable price measures. It excludes most implicit prices (for example, financial services furnished without payment) and the final consumption expenditures of nonprofit institutions serving households.

Source: U.S. Bureau of Economic Analysis

Table 5. Real Gross Domestic Product: Annual Percent Change

Line		Percent change from preceding year								Percent change from fourth quarter to fourth quarter one year ago								Line
		2017	2018	2019	2020	2021	2022	2023	2024	2017	2018	2019	2020	2021	2022	2023	2024	
1	**Gross domestic product (GDP)**	**2.5**	**3.0**	**2.6**	**-2.2**	**6.1**	**2.5**	**2.9**	**2.8**	**3.0**	**2.1**	**3.4**	**-1.0**	**5.7**	**1.3**	**3.2**	**2.5**	1
2	**Personal consumption expenditures (PCE)**	**2.6**	**2.7**	**2.1**	**-2.5**	**8.8**	**3.0**	**2.5**	**2.8**	**3.1**	**2.0**	**2.8**	**-0.8**	**7.7**	**1.6**	**3.0**	**3.2**	2
3	Goods	4.1	4.0	3.1	4.6	11.3	-0.6	1.9	2.4	5.4	2.1	3.8	8.6	6.3	-1.5	3.4	3.5	3
4	Durable goods	6.8	6.6	3.3	7.1	16.6	-1.9	3.9	3.3	8.6	2.8	5.2	14.4	5.2	-1.5	5.8	5.7	4
5	Nondurable goods	2.8	2.6	3.0	3.4	8.6	0.1	0.8	1.9	3.8	1.8	3.1	5.6	6.8	-1.6	2.2	2.3	5
6	Services	1.9	2.2	1.7	-5.8	7.5	5.0	2.9	2.9	2.0	2.0	2.4	-5.1	8.4	3.2	2.8	3.0	6
7	**Gross private domestic investment**	**4.4**	**5.8**	**3.2**	**-4.5**	**8.8**	**6.0**	**0.1**	**4.0**	**4.9**	**4.7**	**1.2**	**2.5**	**8.1**	**-0.5**	**2.2**	**1.7**	7
8	Fixed investment	4.5	5.1	2.7	-1.9	7.3	2.7	2.4	3.8	5.5	3.3	2.9	1.1	3.8	1.6	4.4	2.6	8
9	Nonresidential	4.6	6.9	3.8	-4.6	6.0	7.0	6.0	3.7	5.6	5.6	3.1	-3.3	4.9	8.5	5.0	2.5	9
10	Structures	2.6	5.8	2.3	-9.2	-2.6	3.6	10.8	3.2	-0.4	3.5	5.9	-13.8	-1.2	9.7	9.7	0.0	10
11	Equipment	3.8	5.9	1.0	-10.1	6.7	4.4	3.5	3.4	7.5	3.3	-2.2	-3.5	1.0	6.1	3.1	3.0	11
12	Intellectual property products	6.9	8.9	8.2	4.5	10.2	11.2	5.8	4.1	7.2	9.9	7.8	3.3	12.3	10.3	4.1	3.5	12
13	Residential	4.3	-0.7	-0.9	7.7	10.9	-8.6	-8.3	4.2	5.1	-4.1	2.3	16.6	0.6	-16.4	2.5	2.7	13
14	Change in private inventories	....	....	....	....	....	....	....	....	....	....	....	....	....	....	....	....	14
15	**Net exports of goods and services**	....	....	....	....	....	....	....	....	....	....	....	....	....	....	....	....	15
16	Exports	4.1	2.9	0.5	-13.1	6.5	7.5	2.8	3.2	6.1	0.3	1.1	-9.9	7.0	5.0	2.0	2.9	16
17	Goods	4.1	4.2	0.2	-10.1	7.7	5.9	2.3	2.2	6.1	1.6	0.2	-4.5	5.6	3.4	1.5	1.4	17
18	Services	4.1	0.3	1.2	-18.7	4.0	11.1	3.8	5.3	6.0	-1.9	2.7	-19.5	10.0	8.6	2.9	5.7	18
19	Imports	4.7	4.0	1.2	-9.0	14.7	8.6	-1.2	5.4	5.8	3.0	-1.8	0.0	11.4	2.0	1.2	5.8	19
20	Goods	4.5	5.1	0.5	-5.9	14.5	6.7	-1.8	4.9	5.5	3.7	-2.6	5.1	8.7	0.8	0.4	5.2	20
21	Services	5.7	-0.6	4.0	-21.8	15.7	17.8	1.6	7.5	7.1	-0.1	1.5	-20.4	25.7	8.0	4.2	8.2	21
22	**Government consumption expenditures and gross investment**	**0.6**	**2.0**	**3.9**	**3.4**	**-0.3**	**-1.1**	**3.9**	**3.4**	**1.0**	**1.9**	**4.8**	**1.3**	**-0.3**	**0.5**	**4.3**	**3.1**	22
23	Federal	0.5	3.5	3.8	6.3	1.8	-3.2	2.9	2.5	1.4	3.5	4.0	5.1	0.7	-1.0	2.1	4.0	23
24	National defense	1.0	3.5	5.4	3.0	-1.0	-3.9	3.2	3.0	2.1	4.5	4.3	4.2	-4.8	-1.4	2.7	5.1	24
25	Nondefense	-0.2	3.4	1.6	11.2	5.8	-2.3	2.5	1.8	0.4	2.1	3.5	6.4	8.8	-0.5	1.2	2.5	25
26	State and local	0.6	1.1	3.9	1.7	-1.6	0.2	4.4	3.9	0.8	0.9	5.3	-1.0	-0.9	1.4	5.7	2.6	26
	Addenda:																	
27	Gross domestic income (GDI) [1]	2.4	3.0	2.6	-2.4	6.6	2.8	1.7	....	3.0	2.8	2.6	0.1	5.1	1.0	2.9	....	27
28	Average of GDP and GDI	2.4	3.0	2.6	-2.3	6.3	2.7	2.3	....	3.0	2.4	3.0	-0.5	5.4	1.1	3.1	....	28
29	Final sales of domestic product	2.5	2.9	2.5	-1.7	5.8	1.9	3.3	2.7	3.1	1.9	3.7	-1.3	5.0	1.7	3.6	2.6	29
30	Gross domestic purchases	2.6	3.1	2.6	-1.9	7.1	2.8	2.3	3.1	3.0	2.5	2.9	0.1	6.4	1.0	3.1	2.9	30
31	Final sales to domestic purchasers	2.6	3.0	2.5	-1.4	6.9	2.3	2.7	3.0	3.1	2.2	3.2	-0.1	5.6	1.4	3.5	3.0	31
32	Final sales to private domestic purchasers	3.0	3.2	2.3	-2.4	8.5	3.0	2.5	3.0	3.6	2.3	2.9	-0.4	6.9	1.6	3.3	3.0	32
33	Gross national product	2.7	2.9	2.5	-2.5	5.7	2.4	2.7	....	3.3	1.8	3.2	-1.4	5.5	1.2	3.0	....	33
34	Real disposable personal income	3.1	3.6	3.1	6.3	3.4	-5.5	5.1	2.9	3.5	4.0	2.3	4.5	1.0	-0.8	4.6	2.6	34
	Price indexes:																	
35	Gross domestic purchases	1.8	2.2	1.4	1.3	4.2	6.9	3.3	2.3	1.9	2.1	1.3	1.6	5.8	6.3	2.3	2.4	35
36	Gross domestic purchases excluding food and energy [2]	1.7	2.1	1.6	1.5	3.9	6.2	3.5	2.5	1.7	2.2	1.4	1.8	5.3	5.8	2.6	2.6	36
37	GDP	1.8	2.3	1.7	1.3	4.5	7.1	3.6	2.4	1.9	2.2	1.5	1.7	6.2	6.5	2.6	2.4	37
38	GDP excluding food and energy [2]	1.8	2.3	1.8	1.5	4.1	6.3	3.9	2.7	1.9	2.4	1.6	1.8	5.5	6.0	3.0	2.7	38
39	PCE	1.7	2.0	1.4	1.1	4.1	6.6	3.8	2.5	1.7	2.0	1.4	1.2	5.8	6.0	2.8	2.4	39
40	PCE excluding food and energy [2]	1.6	1.9	1.6	1.3	3.6	5.4	4.1	2.8	1.6	2.0	1.6	1.4	4.9	5.2	3.2	2.8	40
41	Market-based PCE [3]	1.4	1.8	1.3	1.0	3.6	6.4	3.6	2.2	1.4	1.7	1.3	1.0	5.3	6.0	2.7	2.0	41
42	Market-based PCE excluding food and energy [2,3]	1.2	1.6	1.5	1.3	2.9	5.0	4.0	2.5	1.2	1.7	1.5	1.3	4.1	5.0	3.2	2.4	42

1. Gross domestic income deflated by the implicit price deflator for gross domestic product.

2. Food excludes personal consumption expenditures for purchased meals and beverages, which are classified in food services.

3. This index is a supplemental measure that is based on household expenditures for which there are observable price measures. It excludes most implicit prices (for example, financial services furnished without payment) and the final consumption expenditures of nonprofit institutions serving households.

Note. Estimates under the *Percent change from preceding year* columns are calculated from annual data. Estimates under the *Percent change from fourth quarter to fourth quarter* columns are calculated from fourth quarter values relative to the same quarter one year prior.

Source: U.S. Bureau of Economic Analysis

Table 6. Real Gross Domestic Product: Percent Change from Quarter One Year Ago

Line		2021				2022				2023				2024				Line
		Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	
1	**Gross domestic product (GDP)**	**1.8**	**12.2**	**5.0**	**5.7**	**4.0**	**2.5**	**2.3**	**1.3**	**2.3**	**2.8**	**3.2**	**3.2**	**2.9**	**3.0**	**2.7**	**2.5**	1
2	**Personal consumption expenditures (PCE)**	**3.2**	**16.9**	**8.0**	**7.7**	**5.5**	**2.8**	**2.4**	**1.6**	**2.6**	**2.2**	**2.4**	**3.0**	**2.2**	**2.7**	**3.0**	**3.2**	2
3	Goods	13.8	20.5	5.9	6.3	1.6	-2.2	-0.2	-1.5	0.7	1.0	2.4	3.4	1.3	2.1	2.7	3.5	3
4	Durable goods	28.3	33.3	4.3	5.2	-1.6	-5.4	1.1	-1.5	2.5	2.9	4.5	5.8	1.2	2.6	3.5	5.7	4
5	Nondurable goods	6.8	14.2	6.8	6.8	3.4	-0.3	-1.0	-1.6	-0.3	-0.1	1.3	2.2	1.4	1.9	2.2	2.3	5
6	Services	-1.7	15.0	9.2	8.4	7.7	5.4	3.7	3.2	3.5	2.8	2.4	2.8	2.7	2.9	3.1	3.0	6
7	**Gross private domestic investment**	**4.5**	**19.4**	**4.7**	**8.1**	**10.7**	**10.0**	**4.4**	**-0.5**	**-4.5**	**-0.5**	**3.4**	**2.2**	**5.5**	**5.6**	**3.3**	**1.7**	7
8	Fixed investment	4.2	14.6	7.0	3.8	3.6	2.7	2.8	1.6	0.3	1.9	3.0	4.4	5.3	3.7	3.6	2.6	8
9	Nonresidential	0.8	12.0	6.8	4.9	5.9	5.5	7.9	8.5	6.5	7.1	5.4	5.0	4.8	3.3	4.1	2.5	9
10	Structures	-10.9	1.0	1.7	-1.2	-0.7	1.3	4.5	9.7	10.6	12.5	10.5	9.7	7.6	3.6	1.9	0.0	10
11	Equipment	3.5	19.2	4.7	1.0	3.5	1.7	6.2	6.1	2.4	5.2	3.2	3.1	3.0	2.4	5.3	3.0	11
12	Intellectual property products	5.3	11.5	11.7	12.3	11.8	11.5	11.4	10.3	8.2	6.1	4.8	4.1	4.9	4.0	4.1	3.5	12
13	Residential	15.2	22.9	7.3	0.6	-2.6	-4.7	-10.6	-16.4	-16.4	-12.8	-4.5	2.5	7.0	5.1	2.1	2.7	13
14	Change in private inventories	....	....	....	....	....	....	....	....	....	....	....	....	....	....	....	....	14
15	**Net exports of goods and services**	....	....	....	....	....	....	....	....	....	....	....	....	....	....	....	....	15
16	Exports	-5.8	20.4	7.3	7.0	5.7	8.0	11.5	5.0	6.8	2.4	0.2	2.0	2.0	3.5	4.6	2.9	16
17	Goods	-3.5	27.4	5.8	5.6	3.3	5.7	11.4	3.4	7.4	1.7	-1.2	1.5	0.1	3.3	4.0	1.4	17
18	Services	-10.2	8.3	10.4	10.0	10.9	13.3	11.6	8.6	5.6	3.7	3.1	2.9	5.7	3.8	5.9	5.7	18
19	Imports	5.9	30.3	13.9	11.4	12.6	12.0	8.2	2.0	-1.3	-3.5	-1.0	1.2	2.9	5.6	7.1	5.8	19
20	Goods	10.0	31.6	10.8	8.7	10.1	9.5	6.9	0.8	-2.3	-4.3	-1.0	0.4	2.0	5.4	6.8	5.2	20
21	Services	-11.6	24.1	31.0	25.7	26.4	25.1	14.3	8.0	3.6	0.1	-1.2	4.2	6.7	6.5	8.7	8.2	21
22	**Government consumption expenditures and gross investment**	**1.5**	**-1.7**	**-0.6**	**-0.3**	**-2.4**	**-1.7**	**-0.9**	**0.5**	**2.6**	**3.7**	**4.8**	**4.3**	**3.5**	**3.5**	**3.4**	**3.1**	22
23	Federal	8.2	-1.3	0.0	0.7	-5.3	-4.2	-2.4	-1.0	2.4	2.9	4.4	2.1	0.8	2.2	3.1	4.0	23
24	National defense	1.5	0.2	-0.9	-4.8	-5.6	-4.5	-4.1	-1.4	2.8	2.5	5.0	2.7	0.9	2.2	3.9	5.1	24
25	Nondefense	18.2	-3.2	1.2	8.8	-4.9	-3.7	-0.1	-0.5	1.8	3.5	3.6	1.2	0.8	2.1	1.9	2.5	25
26	State and local	-2.4	-2.0	-0.9	-0.9	-0.5	-0.1	0.0	1.4	2.7	4.2	5.0	5.7	5.1	4.3	3.6	2.6	26
	Addenda:																	
27	Gross domestic income (GDI) [1]	1.7	12.9	7.2	5.1	4.5	3.0	2.9	1.0	1.0	1.6	1.3	2.9	3.2	3.2	3.0	....	27
28	Average of GDP and GDI	1.8	12.6	6.1	5.4	4.2	2.8	2.6	1.1	1.6	2.2	2.3	3.1	3.1	3.1	2.9	....	28
29	Final sales of domestic product	1.7	11.5	5.4	5.0	2.8	1.2	2.0	1.7	3.2	3.3	3.2	3.6	2.9	2.7	2.8	2.6	29
30	Gross domestic purchases	3.1	13.6	5.9	6.4	5.0	3.2	2.2	1.0	1.3	1.9	3.0	3.1	3.0	3.3	3.1	2.9	30
31	Final sales to domestic purchasers	3.1	12.9	6.3	5.6	3.8	2.0	1.9	1.4	2.2	2.4	2.9	3.5	3.0	3.0	3.2	3.0	31
32	Final sales to private domestic purchasers	3.4	16.4	7.8	6.9	5.1	2.8	2.5	1.6	2.1	2.1	2.5	3.3	2.9	2.9	3.1	3.0	32
33	Gross national product	1.3	11.9	4.6	5.5	3.7	2.5	2.4	1.2	2.2	2.6	2.9	3.0	2.8	2.9	2.4	....	33
34	Real disposable personal income	16.3	-2.4	0.0	1.0	-12.5	-5.5	-2.9	-0.8	4.8	6.1	4.8	4.6	3.4	2.8	2.7	2.6	34
	Price indexes:																	
35	Gross domestic purchases	2.3	4.0	4.7	5.8	6.7	7.4	7.1	6.3	5.0	3.3	2.8	2.3	2.3	2.5	2.3	2.4	35
36	Gross domestic purchases excluding food and energy [2]	2.2	3.7	4.3	5.3	6.1	6.4	6.3	5.8	4.9	3.7	3.1	2.6	2.4	2.6	2.5	2.6	36
37	GDP	2.5	4.4	5.1	6.2	7.0	7.8	7.3	6.5	5.3	3.4	3.1	2.6	2.4	2.6	2.2	2.4	37
38	GDP excluding food and energy [2]	2.3	4.0	4.6	5.5	6.2	6.6	6.5	6.0	5.3	4.0	3.4	3.0	2.7	2.8	2.7	2.7	38
39	PCE	2.0	4.0	4.6	5.8	6.6	6.9	6.7	6.0	5.0	3.9	3.4	2.8	2.7	2.6	2.3	2.4	39
40	PCE excluding food and energy [2]	1.9	3.5	4.0	4.9	5.6	5.3	5.4	5.2	4.9	4.6	3.9	3.2	3.0	2.7	2.7	2.8	40
41	Market-based PCE [3]	1.7	3.4	4.0	5.3	6.3	6.8	6.7	6.0	5.0	3.7	3.1	2.7	2.5	2.3	2.0	2.0	41
42	Market-based PCE excluding food and energy [2,3]	1.5	2.7	3.2	4.1	5.0	4.9	5.2	5.0	4.7	4.5	3.7	3.2	2.8	2.5	2.4	2.4	42

1. Gross domestic income deflated by the implicit price deflator for gross domestic product.

2. Food excludes personal consumption expenditures for purchased meals and beverages, which are classified in food services.

3. This index is a supplemental measure that is based on household expenditures for which there are observable price measures. It excludes most implicit prices (for example, financial services furnished without payment) and the final consumption expenditures of nonprofit institutions serving households.

Source: U.S. Bureau of Economic Analysis

Table 7. Relation of Gross Domestic Product, Gross National Product, and National Income

[Billions of dollars]

Line		2022	2023	2024	Seasonally adjusted at annual rates					Line
					2023	2024				
					Q4	Q1	Q2	Q3	Q4	
1	**Gross domestic product (GDP)**	**26,006.9**	**27,720.7**	**29,179.1**	**28,297.0**	**28,624.1**	**29,016.7**	**29,374.9**	**29,700.6**	1
2	Plus: Income receipts from the rest of the world	1,219.2	1,411.4	....	1,454.2	1,493.0	1,504.0	1,442.0	....	2
3	Less: Income payments to the rest of the world	1,069.9	1,311.3	....	1,359.3	1,410.8	1,444.1	1,428.9	....	3
4	**Equals: Gross national product**	**26,156.2**	**27,820.8**	**...............**	**28,391.8**	**28,706.3**	**29,076.6**	**29,388.1**	**...............**	4
5	Less: Consumption of fixed capital	4,313.4	4,587.7	4,816.4	4,668.5	4,714.1	4,781.0	4,853.9	4,916.5	5
6	Less: Statistical discrepancy	-75.6	244.6	....	214.3	124.9	194.8	263.5	....	6
7	**Equals: National income**	**21,918.4**	**22,988.4**	**...............**	**23,509.1**	**23,867.3**	**24,100.8**	**24,270.7**	**...............**	7
8	Compensation of employees	13,436.7	14,190.2	15,041.9	14,481.2	14,823.7	14,945.6	15,092.1	15,306.1	8
9	Wages and salaries	11,123.1	11,725.2	12,421.6	11,955.3	12,251.0	12,343.0	12,456.5	12,636.0	9
10	Supplements to wages and salaries	2,313.6	2,464.9	2,620.3	2,525.9	2,572.8	2,602.6	2,635.7	2,670.1	10
11	Proprietors' income with inventory valuation and capital consumption adjustments	1,873.6	1,949.0	2,003.8	1,970.1	1,972.1	2,002.3	2,013.5	2,027.3	11
12	Rental income of persons with capital consumption adjustment	870.3	989.1	1,057.3	1,013.6	1,046.1	1,053.4	1,055.7	1,073.8	12
13	Corporate profits with inventory valuation and capital consumption adjustments	3,316.7	3,546.5	....	3,749.9	3,684.8	3,817.2	3,802.2	....	13
14	Net interest and miscellaneous payments	461.5	319.9	203.4	273.1	228.3	203.8	181.9	199.5	14
15	Taxes on production and imports less subsidies	1,722.2	1,790.3	1,874.2	1,814.0	1,841.1	1,860.3	1,883.1	1,912.4	15
16	Business current transfer payments (net)	245.2	236.2	290.5	245.3	311.7	259.8	282.4	308.2	16
17	Current surplus of government enterprises	-7.9	-32.8	-40.5	-38.2	-40.5	-41.8	-40.2	-39.6	17
	Addenda:									
18	Gross domestic income (GDI)	26,082.5	27,476.1	....	28,082.7	28,499.2	28,821.9	29,111.4	....	18
19	Average of GDP and GDI	26,044.7	27,598.4	....	28,189.8	28,561.6	28,919.3	29,243.2	....	19
20	Statistical discrepancy as a percentage of GDP	-0.3	0.9	....	0.8	0.4	0.7	0.9	....	20

Source: U.S. Bureau of Economic Analysis

Table 8. Personal Income and Its Disposition

[Billions of dollars]

Line		2022	2023	2024	Seasonally adjusted at annual rates: 2023 Q4	2024 Q1	2024 Q2	2024 Q3	2024 Q4	Line
1	**Personal income** [1]	**22,088.9**	**23,402.5**	**24,692.3**	**23,807.8**	**24,344.2**	**24,574.0**	**24,765.8**	**25,085.3**	1
2	Compensation of employees	13,436.7	14,190.2	15,041.9	14,481.2	14,823.7	14,945.6	15,092.1	15,306.1	2
3	Wages and salaries	11,123.1	11,725.2	12,421.6	11,955.3	12,251.0	12,343.0	12,456.5	12,636.0	3
4	Private industries	9,499.0	9,992.5	10,566.1	10,174.7	10,434.7	10,499.7	10,589.9	10,739.9	4
5	Goods-producing industries	1,744.2	1,847.2	1,921.3	1,884.0	1,928.3	1,910.6	1,914.3	1,932.0	5
6	Manufacturing	1,034.9	1,084.0	1,112.3	1,102.8	1,123.2	1,107.1	1,106.2	1,112.6	6
7	Services-producing industries	7,754.7	8,145.2	8,644.8	8,290.7	8,506.4	8,589.1	8,675.6	8,807.9	7
8	Trade, transportation, and utilities	1,717.9	1,797.8	1,882.1	1,823.9	1,858.5	1,870.4	1,887.3	1,912.2	8
9	Other services-producing industries	6,036.9	6,347.5	6,762.7	6,466.8	6,648.0	6,718.7	6,788.3	6,895.7	9
10	Government	1,624.2	1,732.8	1,855.5	1,780.7	1,816.2	1,843.3	1,866.6	1,896.1	10
11	Supplements to wages and salaries	2,313.6	2,464.9	2,620.3	2,525.9	2,572.8	2,602.6	2,635.7	2,670.1	11
12	Employer contributions for employee pension and insurance funds [2]	1,548.3	1,643.9	1,762.3	1,687.4	1,722.7	1,750.3	1,776.6	1,799.5	12
13	Employer contributions for government social insurance	765.3	821.0	858.0	838.5	850.1	852.3	859.0	870.7	13
14	Proprietors' income with inventory valuation and capital consumption adjustments	1,873.6	1,949.0	2,003.8	1,970.1	1,972.1	2,002.3	2,013.5	2,027.3	14
15	Farm	95.9	71.3	44.2	50.2	38.5	41.1	46.4	50.9	15
16	Nonfarm	1,777.6	1,877.7	1,959.6	1,920.0	1,933.6	1,961.2	1,967.1	1,976.4	16
17	Rental income of persons with capital consumption adjustment	870.3	989.1	1,057.3	1,013.6	1,046.1	1,053.4	1,055.7	1,073.8	17
18	Personal income receipts on assets	3,474.0	3,822.9	3,948.4	3,919.1	3,938.9	3,950.2	3,938.8	3,965.5	18
19	Personal interest income	1,634.9	1,892.0	1,966.4	1,965.3	1,951.0	1,966.2	1,966.3	1,982.2	19
20	Personal dividend income	1,839.2	1,930.9	1,981.9	1,953.8	1,988.0	1,984.0	1,972.4	1,983.3	20
21	Personal current transfer receipts	4,139.2	4,268.0	4,542.5	4,276.5	4,446.1	4,512.3	4,570.4	4,641.1	21
22	Government social benefits to persons	4,013.8	4,146.5	4,409.5	4,156.5	4,314.6	4,380.1	4,437.8	4,505.6	22
23	Social security [3]	1,211.5	1,357.0	1,447.0	1,374.0	1,426.5	1,439.7	1,453.1	1,468.4	23
24	Medicare [4]	935.0	1,009.5	1,081.3	1,035.3	1,049.2	1,067.1	1,090.2	1,118.5	24
25	Medicaid	814.4	878.1	929.9	856.2	904.8	924.7	932.4	957.6	25
26	Unemployment insurance	23.8	33.2	35.4	35.3	34.9	34.9	35.7	36.1	26
27	Veterans' benefits	168.8	196.9	219.1	206.7	211.7	216.7	221.5	226.3	27
28	Other	860.3	671.7	696.9	649.1	687.4	696.8	704.8	698.7	28
29	Other current transfer receipts, from business (net)	125.4	121.6	133.0	120.0	131.5	132.3	132.6	135.5	29
30	Less: Contributions for government social insurance, domestic	1,704.8	1,816.6	1,901.5	1,852.8	1,882.9	1,889.9	1,904.8	1,928.5	30
31	Less: Personal current taxes	3,244.9	2,855.7	3,031.8	2,894.3	2,965.6	3,005.4	3,055.6	3,100.5	31
32	**Equals: Disposable personal income**	**18,844.0**	**20,546.8**	**21,660.5**	**20,913.5**	**21,378.6**	**21,568.6**	**21,710.2**	**21,984.8**	32
33	Less: Personal outlays	18,277.9	19,579.6	20,650.0	19,971.3	20,230.5	20,507.5	20,773.6	21,088.4	33
34	Personal consumption expenditures	17,690.8	18,822.8	19,826.1	19,170.2	19,424.8	19,682.7	19,938.4	20,258.4	34
35	Goods	5,939.1	6,123.9	6,244.3	6,174.8	6,148.9	6,204.6	6,265.1	6,358.5	35
36	Durable goods	2,078.0	2,142.6	2,167.6	2,139.3	2,127.3	2,141.8	2,168.4	2,232.9	36
37	Nondurable goods	3,861.0	3,981.3	4,076.6	4,035.4	4,021.5	4,062.8	4,096.7	4,125.5	37
38	Services	11,751.8	12,698.9	13,581.8	12,995.4	13,275.9	13,478.1	13,673.3	13,899.9	38
39	Personal interest payments [5]	334.4	493.1	550.0	532.2	534.4	551.7	560.5	553.5	39
40	Personal current transfer payments	252.6	263.7	273.9	268.9	271.4	273.1	274.7	276.4	40
41	To government	131.5	135.5	139.7	136.9	137.9	139.0	140.3	141.7	41
42	To the rest of the world (net)	121.1	128.1	134.2	132.0	133.5	134.1	134.4	134.8	42
43	**Equals: Personal saving**	**566.1**	**967.2**	**1,010.5**	**942.2**	**1,148.1**	**1,061.1**	**936.6**	**896.4**	43
44	Personal saving as a percentage of disposable personal income	3.0	4.7	4.7	4.5	5.4	4.9	4.3	4.1	44
	Addenda:									
45	**Personal income excluding current transfer receipts, billions of chained (2017) dollars** [6]	**15,459.2**	**15,880.4**	**16,316.5**	**16,078.6**	**16,243.2**	**16,274.7**	**16,320.7**	**16,429.5**	45
	Disposable personal income:									
46	Total, billions of chained (2017) dollars [6]	16,229.4	17,052.5	17,539.8	17,216.5	17,451.8	17,497.2	17,544.8	17,667.5	46
	Per capita:									
47	Current dollars	56,356	60,944	63,668	61,808	63,041	63,450	63,734	64,441	47
48	Chained (2017) dollars	48,537	50,580	51,555	50,882	51,462	51,473	51,506	51,786	48
49	Population (midperiod, thousands) [7]	334,372	337,141	340,212	338,360	339,119	339,929	340,637	341,164	49

1. Personal income is also equal to national income less corporate profits with inventory valuation and capital consumption adjustments, taxes on production and imports less subsidies, contributions for government social insurance, net interest and miscellaneous payments, business current transfer payments (net), and current surplus of government enterprises, plus personal income receipts on assets, and personal current transfer receipts.
2. Includes actual employer contributions and actuarially imputed employer contributions to reflect benefits accrued by defined benefit pension plan participants through service to employers in the current period.
3. Social security benefits include old-age, survivors, and disability insurance benefits that are distributed from the federal old-age and survivors insurance trust fund and the disability insurance trust fund.
4. Medicare benefits include hospital and supplementary medical insurance benefits that are distributed from the federal hospital insurance trust fund and the supplementary medical insurance trust fund.
5. Consists of nonmortgage interest paid by households. Note that mortgage interest paid by households is an expense item in the calculation of rental income of persons.
6. The current-dollar measure is deflated by the implicit price deflator for personal consumption expenditures.
7. Population is the total population of the United States, including the Armed Forces overseas and the institutionalized population.

Source: U.S. Bureau of Economic Analysis

January 30, 2025

Appendix Table A. Real Gross Domestic Product and Related Aggregates: Percent Change from Preceding Period and Contributions to Percent Change

Line		2022	2023	2024	Seasonally adjusted at annual rates																Line
					2021				2022				2023				2024				
					Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	
	Percent change from preceding period																				
	Gross domestic product (GDP) and related aggregates:																				
1	GDP	2.5	2.9	2.8	5.6	6.4	3.5	7.4	-1.0	0.3	2.7	3.4	2.8	2.4	4.4	3.2	1.6	3.0	3.1	2.3	1
2	Goods	3.0	3.2	2.1	5.4	5.6	0.8	18.6	-4.6	-3.6	6.7	6.8	0.3	1.6	7.1	2.5	-3.6	5.2	4.7	1.0	2
3	Services	3.3	3.0	2.8	5.9	8.6	6.1	3.7	0.7	3.3	2.9	3.4	3.9	1.7	2.5	2.8	3.2	2.4	3.2	2.8	3
4	Structures	-4.6	1.0	5.2	4.6	-4.6	-4.5	-4.0	0.2	-5.4	-11.6	-8.3	4.4	11.2	7.5	8.6	9.9	-0.6	-2.9	2.6	4
5	Motor vehicle output	-1.9	7.3	-2.4	20.1	-11.0	-41.8	32.6	-5.4	2.6	11.9	0.0	24.6	13.3	-8.2	-19.0	3.4	20.2	-18.3	0.7	5
6	GDP excluding motor vehicle output	2.6	2.8	2.9	5.2	7.0	5.0	6.8	-0.9	0.2	2.5	3.5	2.2	2.2	4.7	3.9	1.6	2.6	3.7	2.3	6
7	Nonfarm business gross value added [1]	2.5	2.9	2.9	7.2	7.6	3.4	9.1	-2.0	-0.3	2.6	3.7	2.5	2.4	5.0	3.4	1.3	3.0	3.6	2.3	7
	Contributions to percent change in real gross domestic product																				
	Percent change at annual rate:																				
8	**Gross domestic product**	**2.5**	**2.9**	**2.8**	**5.6**	**6.4**	**3.5**	**7.4**	**-1.0**	**0.3**	**2.7**	**3.4**	**2.8**	**2.4**	**4.4**	**3.2**	**1.6**	**3.0**	**3.1**	**2.3**	8
	Percentage points at annual rates:																				
9	Goods	0.94	1.01	0.65	1.80	1.84	0.32	5.51	-1.50	-1.14	2.09	2.12	0.14	0.53	2.22	0.80	-1.12	1.56	1.41	0.31	9
10	Services	2.00	1.80	1.67	3.45	5.04	3.56	2.26	0.44	1.92	1.74	2.00	2.29	1.01	1.50	1.67	1.91	1.48	1.92	1.71	10
11	Structures	-0.42	0.09	0.46	0.38	-0.45	-0.42	-0.36	0.02	-0.50	-1.10	-0.77	0.36	0.91	0.64	0.73	0.85	-0.05	-0.26	0.23	11
12	Motor vehicle output	-0.05	0.19	-0.06	0.50	-0.32	-1.40	0.72	-0.15	0.07	0.30	0.00	0.60	0.35	-0.24	-0.56	0.09	0.47	-0.51	0.02	12

1. Consists of GDP less gross value added of farm, of households and institutions, and of general government.

Source: U.S. Bureau of Economic Analysis

Appendix Table B. Not Seasonally Adjusted Real Gross Domestic Product: Level and Percent Change from Quarter One Year Ago

Line		Billions of chained (2017) dollars at quarterly rates										Percent change from quarter one year ago									Line
		2022		2023				2024				2022	2023				2024				
		Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	
1	**Gross domestic product (GDP)**	**5,544.4**	**5,668.9**	**5,469.2**	**5,646.3**	**5,724.1**	**5,831.6**	**5,638.5**	**5,817.2**	**5,866.8**	**5,997.0**	**1.4**	**2.5**	**3.0**	**3.2**	**2.9**	**3.1**	**3.0**	**2.5**	**2.8**	1
2	Personal consumption expenditures	3,815.1	3,937.8	3,766.5	3,898.9	3,911.2	4,045.1	3,871.4	4,006.2	4,024.5	4,186.5	1.6	2.7	2.2	2.5	2.7	2.8	2.8	2.9	3.5	2
3	Gross private domestic investment	1,077.5	1,026.6	995.8	1,030.3	1,098.0	1,045.1	1,047.0	1,091.1	1,129.7	1,073.0	-1.1	-3.5	0.2	1.9	1.8	5.1	5.9	2.9	2.7	3
4	Net exports of goods and services	-271.1	-230.1	-211.9	-235.8	-254.2	-230.9	-225.9	-263.9	-289.9	-263.6	....	....	....	....	....	....	....	....	....	4
5	Exports	626.9	640.9	614.6	627.7	629.8	651.7	626.7	649.6	659.9	671.8	4.9	6.6	2.6	0.4	1.7	2.0	3.5	4.8	3.1	5
6	Imports	898.1	871.0	826.6	863.5	883.9	882.6	852.6	913.5	949.7	935.4	1.3	-1.2	-3.2	-1.6	1.3	3.2	5.8	7.4	6.0	6
7	Government consumption expenditures and gross investment	920.3	934.2	918.7	952.3	968.3	972.5	946.6	981.4	997.8	998.8	0.8	2.6	3.5	5.2	4.1	3.0	3.1	3.0	2.7	7
	Addenda:																				
	Current dollar measures: (Billions of dollars)																				
8	GDP	6,614.8	6,794.8	6,639.8	6,897.7	7,029.1	7,159.3	6,997.8	7,290.5	7,364.7	7,550.2	8.0	8.2	6.5	6.3	5.4	5.4	5.7	4.8	5.5	8
9	Gross domestic income	6,594.5	6,743.4	6,872.3	6,729.3	6,803.5	7,071.0	7,245.5	7,120.8	7,199.7	....	5.8	8.2	5.3	3.2	4.9	5.4	5.8	5.8	....	9

Source: U.S. Bureau of Economic Analysis

Kyle Quackenbush
Tallgrass High Plains Carbon Storage LLC
370 Van Gordon Street
Lakewood, CO 80228

RE: Bond Approval: WQD Facility UIC Permit No. WYS-021-00149
Endurance Assurance Corporation Bond No. EACX4044408
Endurance Assurance Corporation Bond No. EACX4044409

Dear Mr. Quackenbush:

The above referenced bonds in the amounts of $597,000.00 and $522,000.00 respectively, have been accepted by the Wyoming Department of Environmental Quality and a copy of each has been enclosed for your records. The total aggregate amount required at this time for permit no. WYS-021-00149 is $1,119,000.00 as set by the Water Quality Division in the letter dated June 5, 2024. Please see the details of the bond acceptance below;

Bond Action	Bonder	Bond Type	Injection Well Plugging	PISC & Site Closure - Monitor Well Plugging	Total Current Financial Assurance	Total Required Financial Assurance
			A	B	C=SUM (A+B)	D
Acceptance	Endurance Assurance Corporation	Surety	$597,000.00			
Acceptance	Endurance Assurance Corporation	Surety		$522,000.00		
Totals			**$597,000.00**	**$522,000.00**	**$1,119,000.00**	**$1,119,000.00**

Should you have any questions regarding your bond, please contact the Bond Analyst at (307-777-3767) or frances.tormey@wyo.gov. Be sure to reference your permit/facility number in all voicemails and emails.

Sincerely,

Brenda Wichman for

Todd Parfitt
Director
Department of Environmental Quality

Date: 7-23-24

cc: WQD UIC Program – Lily Barkau

ATTACHMENT B-4: WELL PLUGGING PLAN

4.5 Plugging Plan

This section provides an overview of plugging operations after injection operations have ceased at Juniper I-1. High Plains intends to properly plug and abandon the injection well under the requirements of WYDEQ Chapter 24 **§23.** In addition to regulatory requirements, sound engineering and operational practices will be applied during this program to prevent fluid migration and contamination of the USDW. All materials used during this plugging operation will be compatible with carbon dioxide and carbon dioxide-water mixtures. The procedure below outlines the plugging plan, including notification, the wellbore preparation, and the final plugging and abandonment procedure. After the abandonment operations, a notarized Subsequent Report of Abandonment (Form 4, Sundry Notice) will be filed with the Administrator within 30 days of the plugging date, per the WOGCC Chapter 3 **§17.** The report will include the following:

1. Certification of completion in accordance with approved plans and specifications by a licensed professional engineer or licensed professional geologist.
2. Certification of accuracy by the owner or operator and by the person who performed the plugging operation.

Pre-plugging Procedures

1. **Issue Notifications**
    a. Notify the Administrator at least 60 days before plugging a well (WYDEQ Chapter 24 **§23(d)**).
    b. Provide a revised plugging plan that will capture changes and revisions that are not projected at the time of this draft.
    c. Notify the Administrator at least 24 hours in advance of the Blow Out Preventer (BOP) test.

2. **Determination of Bottomhole Reservoir Pressure** (WYDEQ Chapter 24 **§23(a)**)

Bottomhole pressure will be measured with a wireline gauge run through tubing. The well should be shut in for a sufficient time to ensure the reservoir pressures are stabilized.

3. **External Mechanical Integrity Testing and Well Flush** (WYDEQ Chapter 24 **§23(b)(ii)**)

External mechanical integrity will be demonstrated through approved temperature logging methods.

a. Shut in injection well and move in and rig up workover rig and equipment.
b. Kill and flush well (WYDEQ Chapter 24 **§23(a)**).
    i. Determine appropriate CO_2-compatible fluid based on BHP reading.
    ii. Bullhead buffer fluid selected based on BHP down 4 ½ in. production tubing.
    iii. Pump wellbore volume plus 50 barrels (bbl) to flush into formation.
    iv. Ensure well has achieved static equilibrium.
c. Install Back-Pressure Valve (BPV) in the tubing hanger.
d. Nipple-down the wellhead.
e. Nipple-up the BOP.
f. Function test the BOP.
g. Conduct a low-pressure test of the BOP system at 250 psi.
    i. Pressure must not decrease more than 10 psi during a five-minute test period.
h. Conduct a high-pressure test of the BOP system at the maximum working pressure.
    i. Pressure must not decrease more than 10 psi during the five-minute test period.
i. Document pressure and times on the daily reports or provide third-party test reports with daily reports.
    i. Bleed pressure, remove joint of work string, and remove test plug.
j. Move in and rig up (MIRU) wireline, pressure control, and logging tools.
k. Perform approved temperature logging to confirm wellbore integrity.
    i. If integrity cannot be confirmed, prepare and submit a remediation plan for approval.
l. Pressure test casing (tubing-casing annulus) with packer fluid to maximum established well casing operating pressure, to ensure integrity.
m. Run tubing punch on wireline, punch tubing just above packer. Circulate well and annulus to kill weight fluid.
n. Make up landing joint to tubing hanger or spear 4 ½ in. tubing if necessary.
o. Run mechanical cutting tool on wireline. Cut retrievable packer mandrel.
p. Rig down wireline.
q. Pick up tubing hanger and release the packer.
r. Pull out of hole laying down 4 ½ in. tubing and packer.

s. Pick up 7 in. casing scraper with workstring.
t. Run in hole with casing scraper to top perforation.
u. Pull out of hole racking back workstring.
v. Rig up wireline, pressure control equipment, and logging tools.
w. Run casing inspection log and cement bong log. Evaluate logs and confirm wellbore integrity.

4.5.1 CO_2 Injection Well Plugging and Abandonment Program

a. **Isolate Lyons formation.**
    i. Rig up setting tool and 7 in. cement retainer on workstring (WOGCC Chapter 3 **§18(b)(iii)(B)**).
    ii. Run in hole and set cement retainer at ~ 9,078 ft.
        i. Set 50 ft above the top perforation.
        ii. Set at least 5 ft from collar.
    iii. Rig up cementing equipment.
    iv. Mix and pump volume to be no less than the volume between the retainer and deepest perforation (66') plus 50% excess cement volume. Set corrosion-resistant cement plug from ~9,078 ft-9,194 ft, ensuring not to exceed the fracture pressure gradient. Sting out from retainer and place 100 ft corrosion-resistant plug from ~8,978 ft-9,078 ft.
        i. Below retainer: Class G – 19 Sacks, 22 ft^3 (3.9 bbls)
        ii. Above retainer: Class G – 19 Sacks, 22 ft^3 (3.9 bbls)
    v. Pull out of hole to ~8,878 ft and reverse circulate to clear cement from workstring and wait on cement.
    vi. Run in hole and tag top of cement plug at ~ 8,978 ft.
        i. If the plug is tagged deeper than expected or does not pass the pressure test, cement may be required.
    vii. Pressure up to 500 psig and record the chart for 30 minutes.
    viii. Pull out of hole.
b. **Set confinement zone plug; protect Sundance & Dakota.**
    i. Make up and run in hole with corrosion-resistant alloy bridge plug. Set the plug 50 ft below the top of the Chugwater at ~ 8,681 ft.
    ii. Rig up cementing equipment.
    iii. Mix and pump 500 ft plug from ~8,681 ft to 8,181 ft TOC.
        i. 18 bbls of cement
    iv. Pull out of hole to ~8,081 ft and reverse circulate to clear cement from the workstring and wait on cement.
    v. Run in hole and tag resin plug at ~8,181 ft.
    vi. Pressure up to 500 psig chart for 30 minutes.
c. **Set Niobrara plug**
    i. Pull out of hole, laying down to ~7,053 ft.
    ii. Mix and pump 100 ft (Class G, 91 sacks) balance cement plug from ~7,053 to 6,953 ft.
    iii. Pull out of hole to ~6,853 ft and reverse circulate to clear cement from work string and wait on cement.

iv. Run in hole to ~6,953 ft and tag cement. If plug is tagged deeper or does not pressure test, additional cement may be required.
v. Pressure up to 500 psi and chart for 30 minutes.

d. **Set Shannon plug**
   i. Pull out of hole, laying down to ~5,391 ft.
   ii. Mix and pump 100 ft (Class G, 19 sacks) balance cement plug from ~5,391 to 5,291 ft.
   iii. Pull out of hole to ~5,191 ft and reverse circulate to clear cement from work string and wait on cement.
   iv. Run in hole to ~5,291 ft and tag cement. If plug is tagged deeper or does not pressure test, additional cement may be required.
   v. Pressure up to 500 psi and chart for 30 minutes.

e. **Set Surface Casing plug.**
   i. Pull out of hole, laying down to ~1,600 ft.
   ii. Mix and pump 200 ft balanced cement plug from ~1,600 ft to 1400 ft (100 ft below and obove the surface casing shoe).
      i. Class G – 38 sacks, 44 ft^3
   iii. Pull out of hole to ~1300 ft and reverse circulate to clear cement from workstring and wait on cement.
   iv. Run in hole and tag cement plug at ~1400 ft.
      i. If the plug is tagged deeper than expected or does not pressure test, additional cement may be required.
   v. Pressure up to 500 psi and chart for 30 minutes.

f. **Set surface plug.**
   i. Pull out of hole, laying down to 200 ft.
   ii. Mix and pump the 200 ft balanced cement plug from 200 ft to the surface.
      i. Class H – 38 sacks, 44 ft^3

g. **Nipple-down the BOP.**

h. **Nipple-up the wellhead.**

i. **Cut casing at ground level and weld on ½ in. steel plate.**

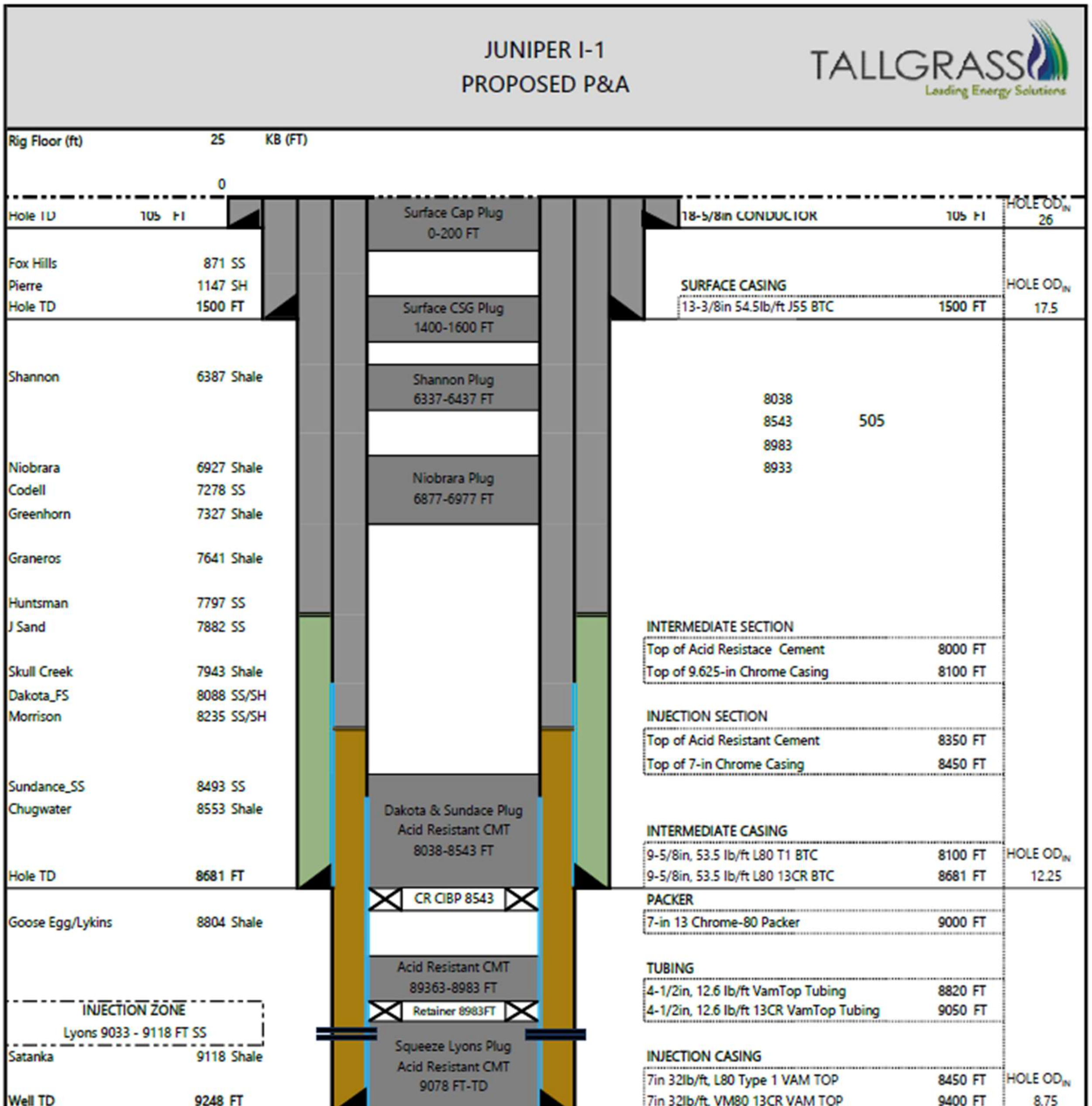
j. **Erect a permanent marker on the well with the following:**
   i. Company name
   ii. Lease
   iii. Well number
   iv. Date of plugging
   v. Location of the well

k. **Rig down and move out all equipment.**

Table 59 provides the plug summary and Figure 76 shows the proposed P&A schematic for Juniper I-1.

Table 59 – Summary of P&A Plan, Injection Well (Modified from Original Juniper I-1 Permit)

Cement Plug Number	Interval Range, ft (approx.)		Thickness, ft	Volume, sacks	Note
1	9,194	8,978	216	48	Cement retainer 50 ft above top perforation, acid resistant 116 ft cement plug below and 100 ft above.
2	8,181	8,681	500	110	USDW Dakota & Sundance 500 ft acid resistant plug above CRA composite bridge plug.
3	6,953	7,053	100	22	Niobrara 100 ft acid resistant cement plug.
4	5,291	5,391	100	22	Shannon 100 ft acid resistant cement plug
5	1400	1600	200	44	Surface casing plug, 100 ft above and below surface casing shoe.
6	0	200	200	44	Surface plug



CASING SECTION	DRILL HOLE INTERVAL FT	DRILL HOLE LENGTH FT	DRILL HOLE ID IN	OD IN	ID IN	WT LB/FT	WALL TH. IN	DRIFT ID IN	GRADE	CONNECTION	CONNECTION OD IN
CONDUCTOR	0 - 105 FT	0	26	18.625	17.875	78.6	0.375				
SURFACE	0 - 1500	1500	17.5	13.375	12.615	54.5	0.380	12.459	J55	BTC	14.375
INTERMEDIATE	1500 - 8681	7181	12.25	9.625	8.535	53.5	0.545	8.379	L80	BTC	10.625
INJECTION	8681 - 9248	567	8.75	7.0	6.094	32.0	0.453	5.969	L80 Type 1	VAM TOP	7.717
	INJECTION SECTION (CR13 CSC SPECS)			7.0	6.094	32.0	0.453	6.000	VM80 13CR	VAM TOP	7.717
TUBING SECTION	CARBON STEEL TUBING 0-8820 FT			4.5	3.958	12.6	0.271	3.833	L80 Type 1	VAM TOP	3.913
	CHROME13 TUBING 8820-9050 FT			4.5	3.958	12.6	0.271	3.833	VM 80 13CR	VAM TOP	3.913

Figure 76 – Proposed P&A Schematic, Juniper I-1 (Modified from Original Juniper I-1 Permit).

4.5.2 Monitoring Well Plugging and Abandonment Program

After the PISC phase of the Class VI project—and as the primary part of site closure activities—the Juniper M-1 well will be abandoned. The monitoring wells will be appropriately plugged and abandoned under the requirements of WYDEQ Chapter 24 **§23**. In addition to regulatory requirements, sound engineering and operational practices will be applied during this program to prevent fluid migration and contamination of the USDW. All materials used during this plugging operation will be compatible with carbon dioxide and carbon dioxide-water mixtures. The procedure below outlines the plugging plan to include notification, preparation of the wellbore, and the final plugging and abandonment procedure. After the abandonment operations, a notarized Subsequent Report of Abandonment (Form 4, Sundry Notice) will be filed with the Administrator within 30 days of the plugging date per WOGCC Chapter 3 **§17.** The report will include the following:

1. Certification of completion in accordance with approved plans and specifications by a licensed professional engineer or licensed professional geologist.
2. Certification of accuracy by the owner or operator and by the person who performed the plugging operation.

<u>Plugging Plan</u>

Pre-plugging Procedures

1. **Issue notifications.**
    a. Notify the Administrator at least 60 days before plugging a well (WYDEQ Chapter 24 **§23(d)**).
    b. Provide a revised plugging plan that will capture changes and revisions that are not projected at the time of this draft.
    c. Notify the Administrator at least 24 hours in advance of the BOP test.
2. **Determination of bottomhole reservoir pressure** (WYDEQ Chapter 24 **§23(a)**).
   Bottomhole pressure will be measured using the fiber optic sensing array permanently installed behind the seven-inch production casing string in Juniper M-1. The well should be shut in for a sufficient time to ensure the reservoir pressures are stabilized.
3. **External mechanical integrity testing and well flush** (WYDEQ Chapter 24 **§23(b)(ii)**).
   External mechanical integrity will be demonstrated through approved temperature logging methods.
    a. Shut in injection well and move in and rig up workover rig and equipment.
    b. Kill and flush monitoring well (WYDEQ Chapter 24 **§23(a)**).
        i. Determine appropriate CO_2 compatible fluid based on BHP reading.
        ii. Bullhead buffer fluid selected based on BHP down 5 ½ in. production string.
        iii. Pump wellbore volume plus 50 bbl to flush into formation.
        iv. Ensure well has achieved static equilibrium.

c. Install BPV in the tubing hanger**.**
d. Nipple-down wellhead
e. Nipple-up the BOP.
f. Function test the BOP.
g. Conduct a low-pressure test of the BOP system at 250 psi.
    i. Pressure must not decrease more than 10 psi during a five-minute test period.
h. Conduct a high-pressure test of the BOP system at the maximum working pressure.
    i. Pressure must not decrease more than 10 psi during the five-minute test period.
i. Document pressure and times on the daily reports or provide third-party test reports with daily reports.
    i. Bleed pressure, remove joint of work string, and remove test plug.
j. MIRU wireline, pressure control, and logging tools.
k. Perform approved temperature logging to confirm wellbore integrity.
    i. If integrity cannot be confirmed, prepare and submit a remediation plan for approval.
l. Rig down the wireline.
m. Pick up 7 in. casing scraper with workstring
n. Run in hole with casing scraper to top of plug
o. Pull out of hole racking back workstring
p. Rig up wireline, pressure control equipment and logging tools
q. Run casing inspection log and cement bong log
r. Evaluate logs and confirm wellbore integrity

4. Monitoring Well Plugging and Abandonment Program

a. **Isolate Lyons formation.**
    i. Rig up setting tool and 5 ½ in. cement retainer on workstring (WOGCC Chapter 3 **§18(b)(iii)(B)**).
    ii. Run in hole and set cement retainer at 100ft above Lyons.
        a. Set above the top perforation.
        b. Set at least 5 ft from collar.
    iii. Rig up cementing equipment.
    iv. Mix and pump volume to be no less than the volume between the retainer and deepest perforation plus 50% excess cement volume. Set corrosion-resistant cement plug of 100ft across the injection zone after performing a squeeze cement job into Lyons perforations.
    iv. Pull out of hole 50-100ft above plug and reverse circulate to clear cement from workstring and wait on cement.
    vi. Run in hole and tag top of cement plug.
        a. If the plug is tagged deeper than expected or does not pass pressure test, additional cement may be required.
    vii. Pressure up to 500 psig and record chart for 30 minutes.
    viii. Pull out of hole.

ix. Make up and run in hole with corrosion resistant alloy bridge plug. Set the plug 50 ft above the bottom of the Chugwater.
x. Rig up cementing equipment.
xi. Mix and pump 50 ft cement plug to place above CIBP.
    a. 1.2 bbl of corrosion resistant cement, or equivalent
xii. Pull out of hole 100ft above plug and reverse circulate to clear cement from workstring and wait on cement.
xiii. Run in hole and tag plug.
xiv. Pressure up to 500 psig chart for 30 minutes.

b. **Set USDW plug.**
    i. Pull out of hole laying down to ~1,650 ft.
    ii. Mix and pump 505 ft balanced cement plug from ~1,650 ft to 940 ft (50 ft below casing shoe to 55 ft into the USDW).
        a. Class H – 100 sacks, 106 ft^3
    iii. Pull out of hole 100ft above plug and reverse circulate to clear cement from workstring and wait on cement.
    iv. Run in hole and tag cement plug.
        a. If the plug is tagged deeper than expected or does not pressure test, additional cement may be required.
    v. Pressure up to 500 psi and chart for 30 minutes.

c. **Set surface plug.**
    i. Pull out of hole, laying down to 50 ft.
    ii. Mix and pump the 100 ft balanced cement plug from 100 ft to the surface.
        a. Class H – 10 sacks, 22 ft^3

d. **Nipple-down the BOP.**
e. **Nipple-up wellhead.**
f. **Cut casing at ground level and weld on ½ in. steel plate.**
g. **Erect a permanent marker on the well with the following:**
    i. Company name
    ii. Lease
    iii. Well number
    iv. Date of plugging
    v. Location of the well

h. **Rig down and move out all equipment.**

Table 60 provides the plug summary and Figure 77 shows the proposed P&A schematic for Juniper M-1.

Table 60 – Summary of P&A Plan, Monitoring Wells (Modified from Original Juniper I-1 Permit)

Cement Plug Number	**Interval Range, ft (approx.)**		**Thickness, ft**	**Note**
1	8979	9079	100	Cement retainer with 50 ft cement plug (additional 50% excess) below and 100 ft above
2	8630	8830	200	Corrosion resistant alloy or composite bridge plug with acid resistant cement or equivalent
3	1,650	940	710	USDW 710 ft CO_2-resistant cement plug
4	100	0	100	50 ft CO_2-resistant cement surface plug

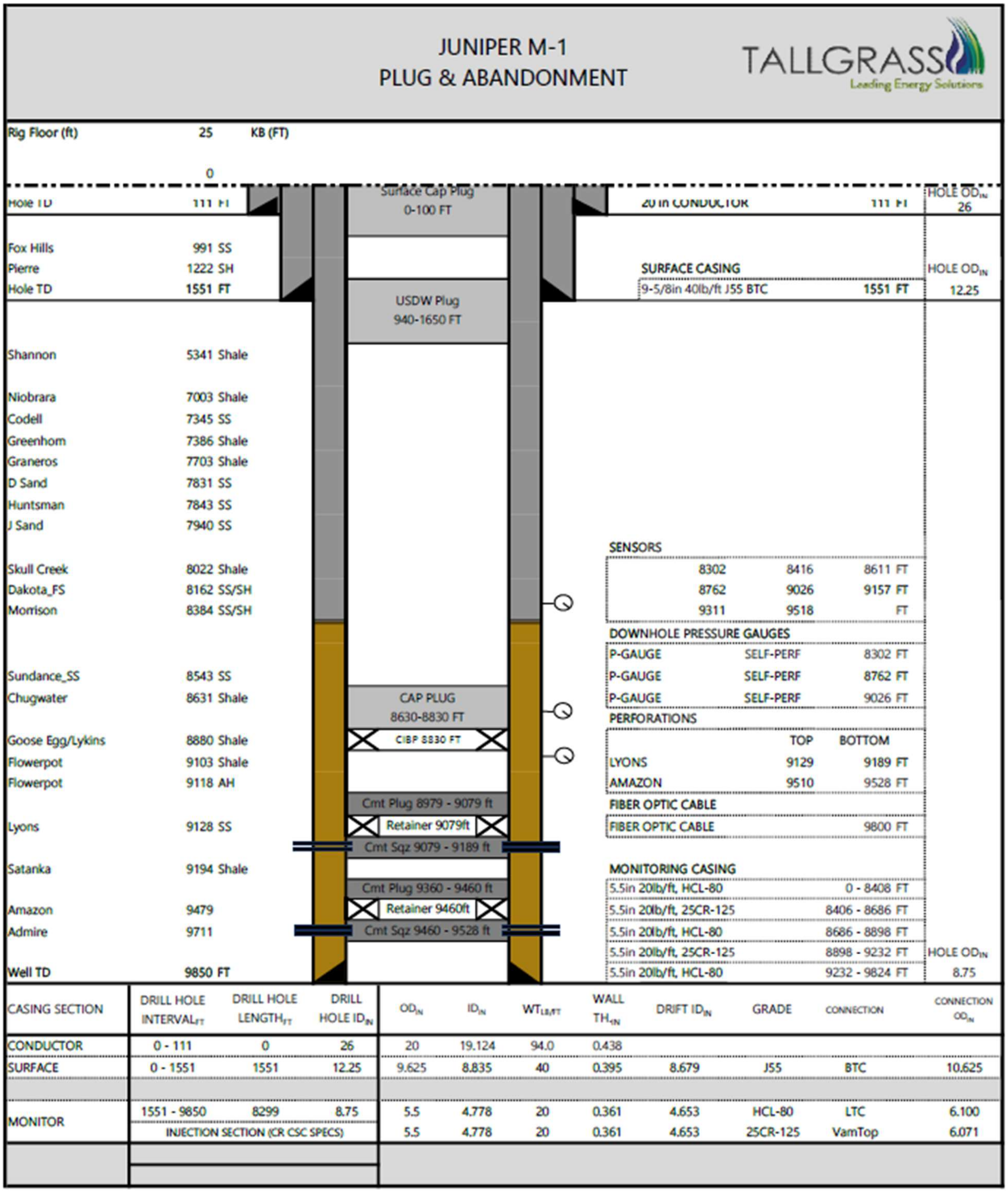


Figure 77 – Proposed P&A Schematic, Juniper M-1 (Modified from Original Juniper I-1 Permit).

ATTACHMENT B-5: TESTING AND MONITORING PLAN

TALLGRASS
Leading Energy Solutions

19 June 2025

VIA E-MAIL AND WDEQ PORTAL

Wyoming Department of Environmental Quality
c/o Tyler Harris
200 West 17th Street
Cheyenne, Wyoming 82002
Tyler.Harris@wyo.gov;
cc: Lily.Barkau@wyo.gov ; hunter.hubbard@wyo.gov

Submitted electronically: WDEQ Water Quality Division Document Uploads (smartsheet.com)
Permit: 2022-235

Dear Mr. Harris:

Tallgrass High Plains Carbon Storage, LLC. is resubmitting the proposed procedure for the perforation and fluid sampling for the Juniper M-1 well. The attachment to this letter is the following:

Attachment 1: Juniper M-1 Perforation and Sampling Procedure

The start date is to be determined and remains contingent upon WDEQ approval. High Plains will notify the WDEQ promptly of revisions to the schedule.

Kind Regards,
Katy Larson

Katy Larson
Geoscience Compliance Manager
Tallgrass Energy Partners, LP
cc: jessica.gregg@tallgrass.com; pete.feutz@tallgrass.com; michael.hilmes@tallgrass.com

ACRONYMS AND ABBREVIATIONS

Note: All terms are written as used in the text.

AL	Artificial Lift
API	American Petroleum Institute
BBLS	barrels
BHA	bottom hole assembly
BL	Braided Line
BOP	blowout preventer
CIBP	cast iron bridge plug
CICR	cast iron cement retainer
FO	fiber optic
FT	feet
KB	kelly bushing
LD	lay down
MIRU	move in and rig up
MIT	mechanical integrity
ND	nipple down
NU	nipple up
P&T	pressure and temperature
P&ID	piping and instrumentation diagram
POOH	pull out of hole
PSI	pounds per square inch
PU	pull up
RBP	removable bridge plug

RD	rig down
RIH	run in hole
RU	rig up
SB	SIT-BO log
SL	Slick Line
TBG	tubing
TD	total depth
TEC	tubing encased conductor
TIH	trip in hole
TOOH	trip out of hole
WH	wellhead
WL	wireline
WS	work string

The following tables contain the Juniper M-1 wellbore data that corresponds to the objectives and procedures detailed in the following sections. The as-plugged wellbore diagram is illustrated in Figure 1.

Monitoring Well Information (referenced from KB in feet)			
Well Name	**Monitoring Formation Name**	**Well Total Depth**	**Monitoring Zone Perforation Depths (Proposed)**
Juniper M-1	Sundance Formation	9854 ft	8569 – 8584 ft

Casing Information (referenced below ground surface in feet)					
Casing Type	**Casing o.d., in**	**Weight, lb/ft**	**Grade**	**Connection**	**Bottom Depth, ft**
Surface	9-5/8	40	J55	BTC	1551
Intermediate	N/A	N/A	N/A	N/A	N/A
Production	5-1/2	20	L-80HC & 25CR-125	BTC	9824
Tubing	N/A	N/A	N/A	N/A	N/A

Geologic Tops	
Formation	**Formation Top, ft**
Fox Hills Aquifer	982
Sundance	8569
Lyons	9127
Amazon	9480

Plugged Back Perforations	
Formation	**Depths, ft**
Lyons	9129 - 9189
Amazon	9510 - 9528

Section 1: Juniper M-1 Perforation and Fluid Sampling Procedure

The following are the objectives and procedures to perforate the Sundance Formation and recover representative fluid samples by swabbing or artificial lift. The procedures have been updated to confirm all wellbore materials and fluids will be in compliance with the Wyoming Chapter 8 Water Quality Regulation to protect the Sundance Formation for all uses which it is suitable. Figure 1 illustrates the as-plugged wellbore diagram for the Juniper M-1 well. Figure 2 shows the wellbore diagram for the perforations and tubing to be installed.

1.1 Objective

The scope of this procedure is to:

1) Install tubing spool, with tubing hanger profile.
2) Perforate the Sundance, oriented with zero-degree phasing to avoid damaging existing external fiber optics and TEC lines.
3) Install 2-3/8” tubing.
4) Recover fluid sample(s)

1.2 Construction Procedure

1) Prior to MIRU, ensure deadmen are certified and pull tested. Refer to the wellsite P&ID and pad layout drawings to locate deadmen. Inspect the well pad for any damage. Record and report the monitoring long-string casing and surface-casing pressures.
2) Mobilize to location. Spot in Rig, pipe wrangler, work tanks, rig pump, 2-3/8" completion tubing, packer, and required completion accessories.
3) RU rig, hook up to deadmen, RU 2" hardline between tanks, rig and pump: 100' apart.
4) Flow check well, ensure well static for 15 minutes. ND WH, test 7-1/16" BOP per API standards.
5) NU tubing spool with tubing hanger profile and 7-1/6" BOP. Tally 2-3/8", 4.7#, L-80 completion tubing string.
6) RU wireline. RIH w/gauge ring and junk basket to top of cement at 8630 ft. RIH and set CIBP at 8620 ft.
7) TIH with open ended 2-3/8" tubing and tag CIBP at 8620 ft. Circulate fresh water around to ensure the wellbore is clean. Pressure test wellbore to 2,500 psi for 30 minutes. Record MIT. Circulate thoroughly.
   Note: As the Sundance was proposed by High Plains as a USDW zone in the Juniper I-1 Authorization to inject, ensure that only fresh water, sourced from the local supply well, remains in the well before continuing this procedure.
8) Swab the well down to ~1,800 ft, about 40 bbls. The Sundance will be about 70 psi underbalanced. Objective is for the Sundance water/brine to inflow after perforating.
9) TOOH & stand back w/tubing.

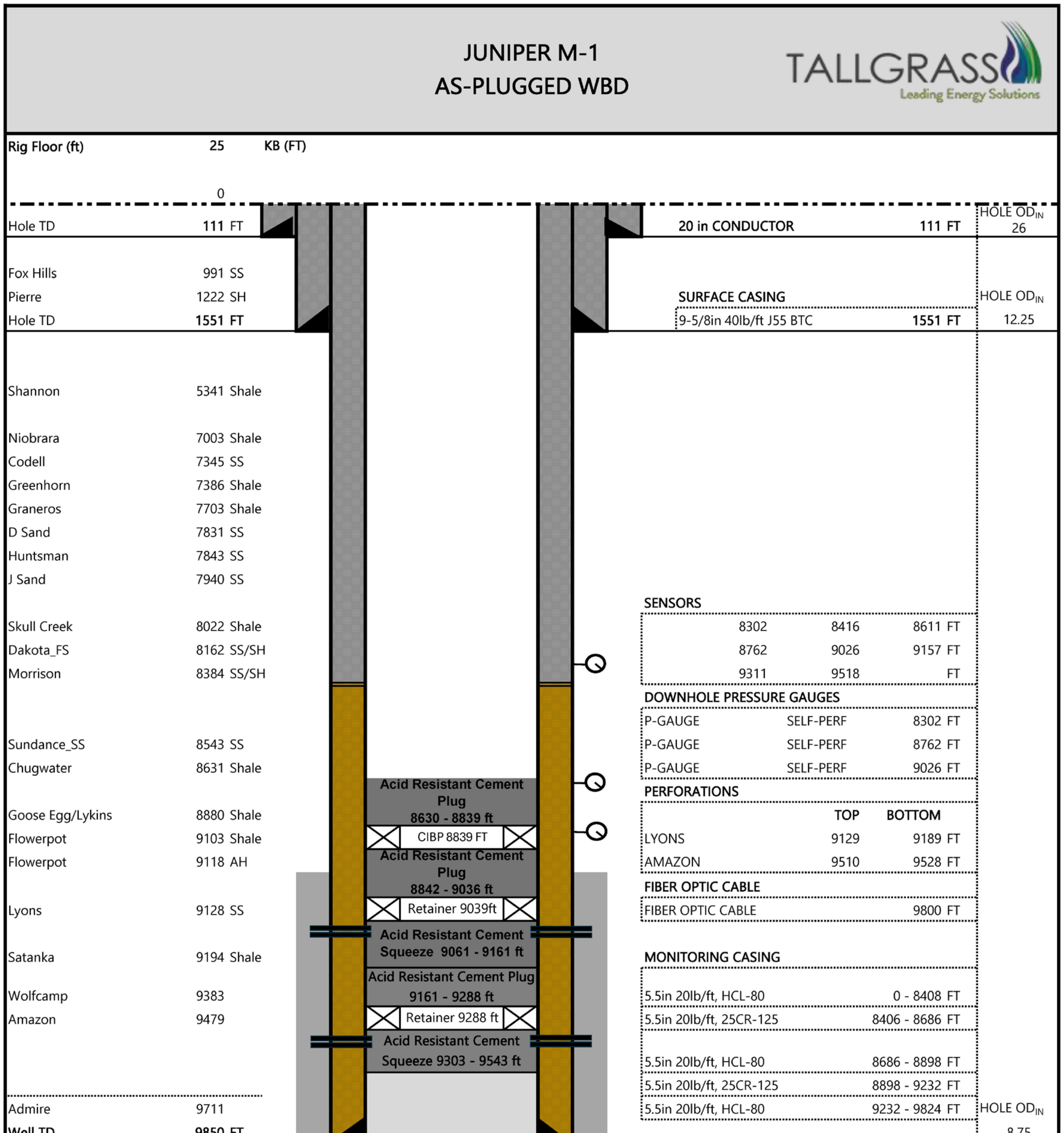
10) RIH w/wireline, gyro, & perforation gun to **perforate the Sundance from 8569' to 8584'** (15 ft), 4 shots/ft, zero-degree phasing, oriented away from FO & TEC lines. Refer to DarkVision log of 8th March 2025 for perforation orientation to avoid control line damage.
11) To ensure a representative sample, the well will be swabbed/purged by parameter stabilization or by volume (at minimum 3 borehole volumes) in accordance with the Wyoming Department of Environmental Quality Standard Operating Procedures Volume II Part 2 Sampling: General Procedures: Sampling Dedicated Monitoring Wells. *Note: If the purged water recovered at surface is deemed suitable for irrigation, High Plains will return it to the landowner at their discretion.*
12) Verify salinity, comparing fluid against those collected from the Sundance during wireline operation with the RDT.
13) RIH with 2-3/8" L-80 tubing string.
14) Land tubing in tubing hanger.
15) Set a plug in XN-nipple located in the tail pipe.
16) Pressure test tubing to 2,000 psi for 30 minutes. Chart the results.
17) Remove plug in XN-nipple.
18) RD floor, ND 7-1/16" BOP, NU WH with gauges.
19) RD rig and ancillary equipment.
20) Move out/demobilize.

1.3 Sampling Procedure | Method 1 Swabbing

1) MIRU SL/BL unit
2) Assemble appropriately sized swab cups
3) RIH, establish liquid level
4) Swab as required to recover an adequate amount of Sundance Formation fluid for testing
5) Move out/demobilize.

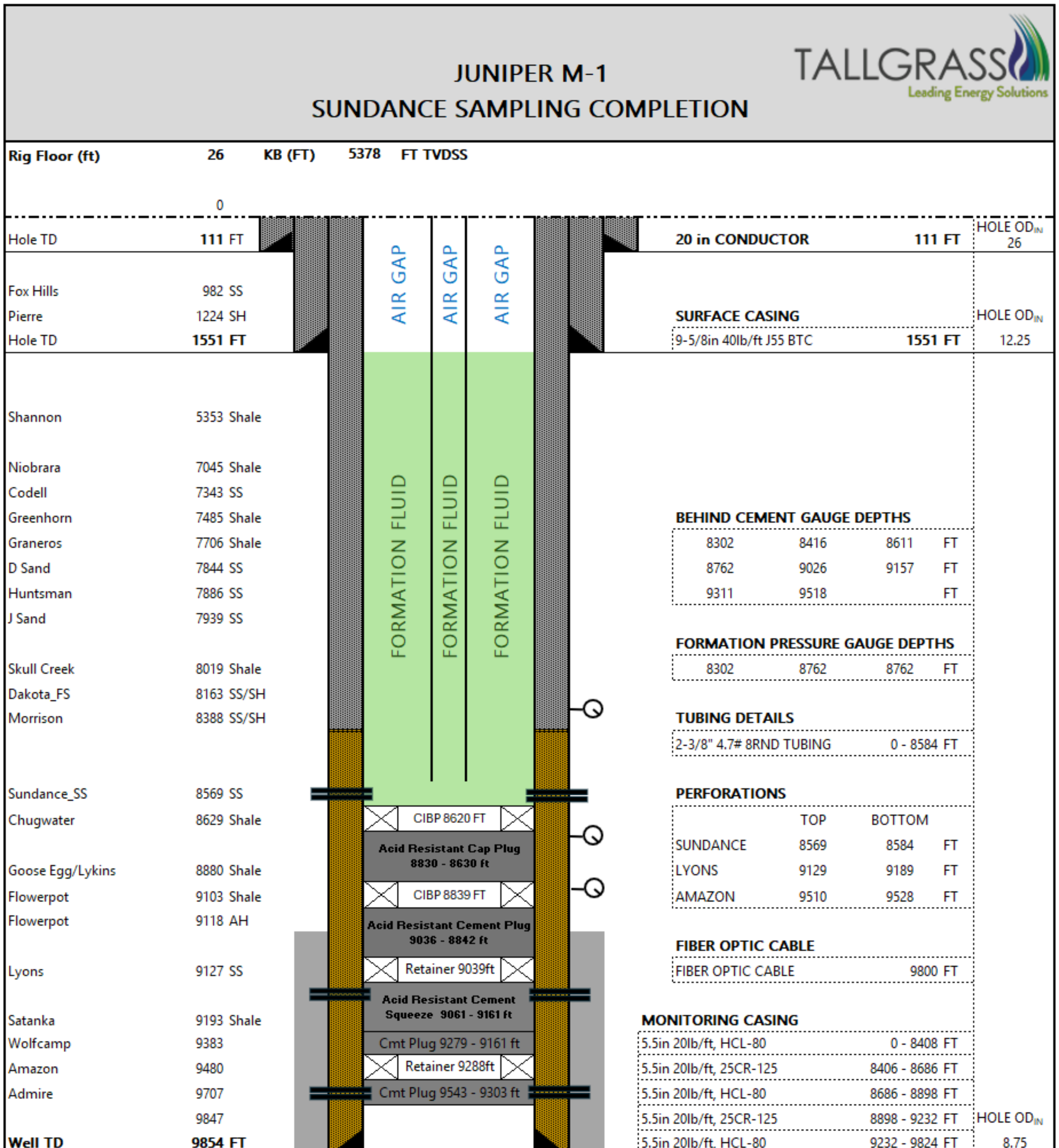
1.4 Sampling Procedure | Method 2 Artificial Lift

1) MIRU AL equipment
2) Deploy AL, establish liquid level, install 2,000ft below fluid level.
   Note: AL setting depth may be adjusted during sampling. This will be dependent on pump rate and observed formation fluid inflow.
3) Activate AL and recover an adequate amount of Sundance formation fluid for testing
4) Move out/demobilize.



CASING SECTION	DRILL HOLE INTERVAL $_{FT}$	DRILL HOLE LENGTH $_{FT}$	DRILL HOLE ID $_{IN}$	OD $_{IN}$	ID $_{IN}$	WT $_{LB/FT}$	WALL TH. $_{IN}$	DRIFT ID $_{IN}$	GRADE	CONNECTION	CONNECTION OD $_{IN}$
CONDUCTOR	0 - 111	0	26	20	19.124	94.0	0.438				
SURFACE	0 - 1551	1551	12.25	9.625	8.835	40	0.395	8.679	J55	BTC	10.625
MONITOR	1551 - 9850	8299	8.75	5.5	4.778	20	0.361	4.653	HCL-80	LTC	6.100
	INJECTION SECTION (CR CSC SPECS)			5.5	4.778	20	0.361	4.653	25CR-125	VamTop	6.071

Figure 1: Juniper M-1 As-Plugged Wellbore Diagram. Figure is not drawn to scale.



CASING SECTION	DRILL HOLE INTERVAL$_{FT}$	DRILL HOLE LENGTH$_{FT}$	DRILL HOLE ID$_{IN}$	OD$_{IN}$	ID$_{IN}$	WT$_{LB/FT}$	WALL TH.$_{IN}$	DRIFT ID$_{IN}$	GRADE	CONNECTION	CONNECTION OD$_{IN}$
CONDUCTOR	0 - 111	0	26	20	19.124	94.0	0.438				
SURFACE	0 - 1551	1551	12.25	9.625	8.835	40	0.395	8.679	J55	BTC	10.625
MONITOR	1551 - 9854	8303	8.75	5.5	4.778	20	0.361	4.653	HCL-80	LTC	6.100
	INJECTION SECTION (CR CSC SPECS)			5.5	4.778	20	0.361	4.653	25CR-125	VamTop	6.071

Figure 2: Juniper M-1 illustrating the planned Sundance perforation and tubing installation. Figure is not drawn to scale.

4.3 Testing and Monitoring Plan

The following Testing and Monitoring Plan is designed to meet the requirements of WYDEQ Chapter 24 **§20** of the WYDEQ Water Quality Rules and Regulations. This plan aims to ensure that the sequestering of CO_2 is operating as planned, the CO_2 plume is developing as projected, and the USDWs remain protected. The monitoring results will also be used to refine and update the plume model as necessary.

This monitoring program will be periodically reviewed at least once every five years and will consider any operational data collected, including the most recent AOR. The plan will also be amended following significant changes to the EWS Hub, such as the addition of monitoring wells and new injection wells within the AOR and within one year after an AOR reevaluation. The amended plan will be submitted to the Administrator or demonstrate that no amendments to the Testing and Monitoring Plan are needed.

High Plains will create and retain records of all monitoring information. This information will include the following:

1. Date, time, and location of all samplings or measurements
2. Individuals who performed samplings or measurements
3. Dates of when analyses were performed
4. Individuals who performed analyses
5. Analytical techniques or methods used

This section discusses the critical details of this program, as summarized in Table 46.

Table 42 – Overview of Monitoring Program

Monitoring Type	Monitoring Program	Target Structure/Project Area
CO_2 Injection Stream Composition	• CO_2 sampling station	Upstream or downstream of the flowmeter
CO_2 Flow Line	• Corrosion coupon monitoring	Capture facility to the well site
Continuous Recording of Injection Pressure, Rate, and Volume	• Surface pressure and temperature gauges • Coriolis mass flowmeter at the wellhead	Surface-to-reservoir (injection well)
Well Annulus Pressure Between Tubing and Casing	• Annular pressure gauge for continuous monitoring	Surface-to-reservoir (injection well)
Atmospheric Monitoring	• CO_2 monitoring stations	Surface
Near-Surface Monitoring	• Groundwater wells in the AOR, monitoring well • Soil gas sampling and analysis	Near-surface environment, USDWs
Above Confining Zone Monitoring	• Monitoring well with fiber optic and gauges behind casing	The first permeable formation above confining zone
Direct Reservoir Monitoring	• Fiber optic and gauges behind casing – temperature, reservoir pressures	Storage reservoir and primary sealing formation
Indirect Reservoir Monitoring	• 2D time-lapse seismic surveys	Entire storage complex
Internal and External Mechanical Integrity	• Annulus pressure test • Temperature logs • Pulsed neutron logging • Casing pressure test • Pressure falloff test • Ultrasonic logs	Well infrastructure
Corrosion Monitoring	• Corrosion coupon system	Well infrastructure
Seismicity Monitoring	• Seismic Monitoring stations	Entire storage complex

4.3.1 Analysis of Injected CO_2 and Injection Well Testing

4.3.1.1 CO_2 Analysis

High Plains will collect continuous samples of the CO_2 injection stream and perform analysis to meet the requirements of WYDEQ Chapter 24 **§20(b)(i)**, to obtain data representative of the injectate stream's chemical and physical characteristics. The purpose of analyzing the CO_2 stream is to evaluate potential interactions of the carbon dioxide and other components of the injectate. The CO_2 stream must meet High Plains's pipeline specifications and will be approximately 95% CO_2. Table 47 identifies the chemical components that will be analyzed from the injection stream.

Table 43 – Chemical Components Targeted for Characterization in the Injected CO_2

Components
CO_2
Methane
Ethane
Propane
n-Butane
Hydrogen
Nitrogen
Sulfur
Oxygen
Water (ppm)

<u>Sampling Methods</u>

The CO_2 stream samples will be continuously collected from the CO_2 pipeline using a gas chromatograph on the flowline before the injection flowmeter.

4.3.1.2 Injection Well Integrity Tests

Before beginning injection, and as required, the following tests will be run to ensure well integrity. Per WYDEQ Chapter 24 **§17(e),** High Plains will provide the Administrator with the opportunity to witness the logging and testing discussed in this section. High Plains will submit a schedule of these activities to the Administrator prior to conducting the first test and submit any changes to the schedule 30 days prior to the next scheduled test.

1. Cement Evaluation and Casing Inspection Logs

Per the requirements in WYDEQ Chapter 24 **§17(a)(ii)(B) and §17(a)(iii)(B),** cement bond logs and variable density logs will be run after each casing string (surface and long) is set and cemented. These logs will be used to evaluate cement quality radially and will have sufficient resolution to identify channels, voids, or areas of missing cement, and a temperature log—after the casing is set and cemented.

Per the requirements in WYDEQ Chapter 24 **§17(a)(iv)(D)**, casing inspection logs will be run after the surface casing and long string is set and cemented. Casing inspection logs will then be run every five years or as the tubing is removed for workover operations. The following logging tools will be run:

- Cement bond log (CBL)
- Through-tubing inspection log upon installation of tubing and packer
- Multiple-armed calipers to measure the inner diameter of the casing as the tool is raised or lowered into the well
- Ultrasonic tools to measure wall thickness and provide information about the outer surface of the casing or tubing, the quality of the cement bonding, and the presence of cement channeling or micro annulus (optional)
- Electromagnetic tools that measure the magnetic flux of the tubulars and can provide mapped circumferential images to indicate potential pitting (optional)

<u>Evaluation</u>
High Plains will provide the CBL to the Administrator with an evaluation, certified by a licensed professional engineer or a licensed professional geologist of the following:

- Quantitative estimations of the cement compressive strength
- A bond index
- Qualitative interpretation of the cement-to formation bond

2. Pressure Fall-Off Testing

Per the requirements of WYDEQ Chapter 24 **§17(d)** and **§20(b)(vii)**, High Plains will conduct a baseline pressure falloff test before injection and then every five years. The data provided from these tests will be used to measure formation properties near the injection well, and monitor for any near-wellbore environment changes that may impact injectivity and increase pressures.

<u>Testing Method</u>
The injection rate and pressure for the well will be consistently maintained and continuously recorded before the pressure falloff test begins. Once the well is shut in, continuous pressure measurements will be recorded from two BHP gauges. The second gauge will be used as a backup and for verification in the event of data inconsistencies. The falloff period will continue until radial flow conditions are observed, as indicated by a straight line of pressure decay on a semi-log plot.

<u>Analytical Methods</u>
The calculation of specific near-well bore conditions, including well skin, prevailing flow regimes, and hydraulic property and boundary conditions, will be determined from standard diagnostic log-log and semi-log plots. Performing baseline pressure fall-off testing before injection allows for future comparison of subsequent tests and indicates whether significant changes in the well or reservoir conditions have occurred. Such analysis will consider the impact of two-phase flow effects. The parameters determined from the falloff tests will be compared to those used in the

site computational modeling and AOR determination. The AOR will be reevaluated if any significant changes in reservoir properties are identified.

Quality Assurance/Control
All field equipment will be inspected and tested before use, and the pressure gauges used in the falloff test will be calibrated per manufacturers' recommendations. Calibration certificates will be provided with the test results. The use of the second BHP gauge will provide further validation of the test results.

The results of the pressure falloff tests will be submitted to the Administrator within 30 days of the test.

3. Mechanical Integrity Testing – Annulus Pressure Test

Per the requirements of WYDEQ Chapter 24 **§19(b),** High Plains will perform internal mechanical integrity tests (MITs) before initial injection and after any subsequent workovers. These annular pressure tests will be performed to demonstrate the mechanical integrity of the casing, tubing, and packer at the initial completion and after any workovers.

Testing Procedure
The annulus between the casing and tubing will be pressured to a minimum of 500 psi (fluid pressure). Once the test has started, a block valve will be used to isolate the test pressure source from the test pressure gauge, and all the ports into the casing annulus will be closed except the one used for monitoring the test pressure gauge. The test pressure will be monitored and recorded for a minimum of 30 minutes. A loss of test pressure greater than 10% during the minimum 30 minutes will indicate a potential lack of mechanical integrity and will be further reviewed for mitigation needs. The pressure gauge used during the test will be sensitive enough to show a loss of 10%.

The results of this annulus pressure test will be reported to the Administrator within 30 days of the test.

4. External Mechanical Integrity Testing – Temperature Log

As required by WYDEQ Chapter 24 **§24.19(c)** and **§24.20(b)(v),** a through-tubing temperature log will be run annually to determine the absence of significant fluid movement, thus ensuring mechanical integrity. Before beginning injection operations, a temperature log will be run to establish a baseline for future log comparisons.

Testing Procedure
The well will be shut in until the temperatures have stabilized, at approximately 36 hours before running the temperature log. Correlation between the baseline and subsequent logs will demonstrate mechanical integrity.

Temperature logs will be provided to the Administrator within 30 days after the log is run.

4.3.2 Corrosion Monitoring and Prevention Plan

1. Corrosion Prevention Plan

As described in *Section 4.4*, the composition of the injectate stream and the injection formation fluids will be considered in determining the appropriate metallurgy for the tubing and long-casing string. Additionally, acid-resistant cement and packer fluids will be used to minimize corrosion in the injection well.

2. Corrosion Coupon Monitoring

To meet the requirements of WYDEQ Chapter 24 **§20(b)(iii),** High Plains will conduct corrosion monitoring of the well's tubing, casing, and pipeline materials using a corrosion coupon monitoring system. This process will monitor for loss of mass and thickness, cracking, pitting, and other signs of corrosion, and ensure that the well components meet the minimum material strength and performance standards as specified in WYDEQ Chapter 24 **§14(b).**

Sampling Methods

Corrosion coupons, made of the same material as the production casing and the injection tubing, will be placed in the CO_2 injection pipeline downstream of any processing equipment. The coupons will be removed quarterly and assessed for corrosion using American Society for Testing and Materials (ATSM) standards at a certified laboratory. When the coupons are removed, they will be inspected visually for any signs of corrosion, including pitting. The weight and size of the coupons will be measured each time they are removed. The corrosion rate will be calculated using a weight loss method where the rate equals the weight loss during the exposure period divided by the duration of the period.

Other Methods

Casing inspection logs, annulus pressure tests, and temperature logs will be run as described in *Section 4.3.1.2*, in addition to the corrosion coupon monitoring.

4.3.3 Surface Leak Detection and Monitoring Plan

Surface equipment at the injection site will be monitored with CO_2 leak detection equipment. The areas to be monitored include the wellhead and the CO_2 flowline. The CO_2 detection system will be monitored using a SCADA system that will alert system operators of any conditions that may require the operator to adjust or intervene. CO_2 detectors will be located at the injection wellhead and around the EWS Hub. The surface leak detection equipment will be part of the automated warning system and inspected and tested every six months. If any detection equipment is determined to have issues, it will be repaired or replaced as soon as possible. The operator will maintain all inspection reports and make them available to the Administrator as requested.

4.3.4 Subsurface Leak Detection and Monitoring Plan

Pressure falloff tests, as described in *Section 4.3.1.2*, will be performed every five years to monitor for changes in the near-wellbore environment that could indicate the presence of a subsurface leak. Surface monitoring, groundwater monitoring, and continuous pressure and temperature data from the monitoring well will all be used to analyze any leak detections above the confining interval.

The Juniper M-1 monitoring well will be located approximately 100 ft from the injection well location. It will monitor the first permeable zone above the confining zone, the upper and lower confining zones, and the injection interval. As described in *Appendix D – Quality Assurance and Surveillance Plan*, pressure and temperature gauges will be installed on tubing encapsulated conductor (TEC) line parallel to a fiber optic cable outside the production casing. These gauges will monitor for any changes in the reservoir parameters that would indicate movement of CO_2 into the Sundance formation and provide data to validate and calibrate the plume model.

The Juniper M-2 monitoring well will be located approximately 1.5 miles east of the injection well, within the expected CO_2 plume extent. In addition to direct injection-zone monitoring, pressure and temperature gauges will also be placed on TEC line parallel to a fiber optic cable behind the casing to detect changes in reservoir conditions above the confining interval.

Groundwater and soil gas sampling will further monitor for subsurface leaks, as described in the following sections.

4.3.5 Near-Surface Groundwater and Soil Gas Sampling and Monitoring

To determine the possibility of CO_2 movement from the injection zone into the USDW and above, High Plains will implement groundwater, air, and soil gas monitoring programs. These programs will include baseline and then regular sampling at locations above the plume to allow for early detection of loss of containment from within the storage formation. Sampling stations and sensors will be positioned at locations designed to optimize measurements indicating a possible leakage of CO_2 above the injection interval.

The final groundwater and soil gas monitoring plans are under development. Once completed, High Plains will provide the updated plans and station locations to the Administrator.

4.3.6 Completed Baseline Sampling Program

1. Groundwater Baseline Sampling

A comprehensive groundwater monitoring plan is in development and will include a baseline sampling program. The baseline sampling period will consist of sufficient samples taken over several months to determine the expected levels of CO_2 present and other key compositional parameters present in the groundwater before injection starts. The frequency and duration of the baseline sampling program will be designed to account for seasonal fluctuations. The samples will be taken at locations across the AOR (Table 48). Initial measurements will be taken at temporary locations until permanent sample sites are developed.

Table 44 – Baseline Groundwater Sampling Results

Parameter	pH (s.u.)			SpC, mS/cm			Alkalinity as $CaCO_3$, mg/L		
Well No.	Date	Date	Date	Date	Date	Date	Date	Date	Date
TBD									

2. Air Baseline Sampling

Initial baseline samples were taken at the locations shown in Figure 71. The PID readings show total volatile organic compounds and were collected using a MiniRae meter. The CO_2, O_2, CH_4, H_2S and CO readings were collected with a Landtech GEM 5000 meter. The results of the sample analysis are provided in Table 49. Further baseline samples will be taken at regular time periods prior to injection.

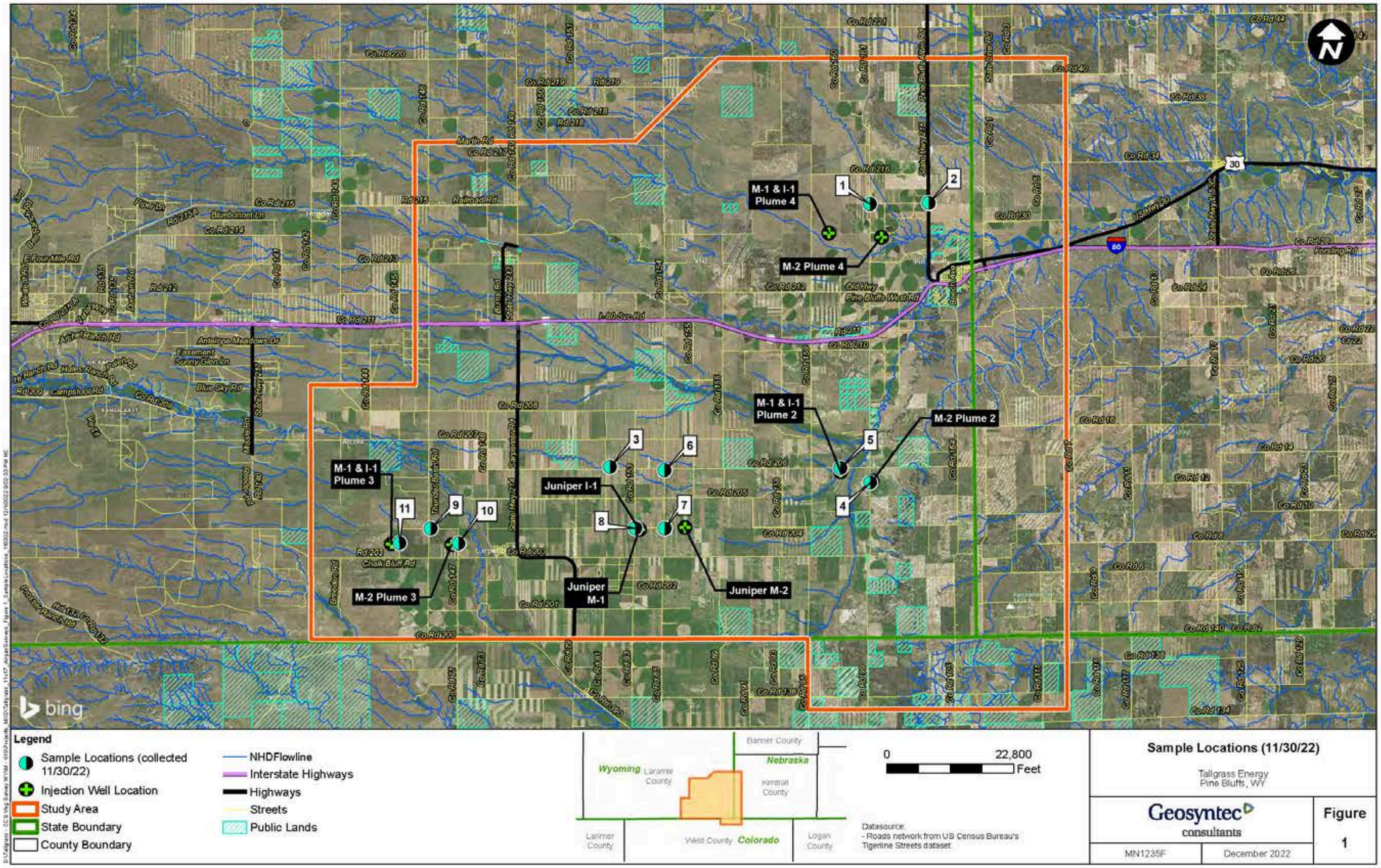


Figure 71 – Baseline Air Sample Locations

Table 45 – Baseline Air Sampling Results

Location ID	Date	Time	Coordinates	PID (ppm)	CO_2 (%)	O_2 (%)	CH_4	H_2S	CO	Barometric Pressure (in Hg)	Wind
1	11/30/2022	9:45	41°12'54"N 104°07'10"W	0.0-0.1	0.1	22	0	0	0	24.98	minimal
2	11/30/2022	10:35	41°12'55"N 104°04'52"W	0	0.1	22	0	0	0	24.98	minimal
3	11/30/2022	10:55	41°05'13"N 104°17'26"W	0	0.1	22	0	0	0	24.98	13 mph S
4	11/30/2022	11:07	41°04'41"N 104°07'16"W	0	0.1	22	0	0	0	24.98	13 mph S
5	11/30/2022	11:18	41°05'07"N 104°08'25"W	0	0.1	22	0	0	0	24.98	13 mph S
6	11/30/2022	11:40	41°05'06"N 104°15'17"W	0	0.1	22	0	0	0	24.98	13 mph S
7	11/30/2022	11:47	41°03'23"N 104°15'18"W	0	0.1	22	0	0	0	24.98	13 mph S
8	11/30/2022	12:00	41°03'24"N 104°16'27"W	0	0.1	22.1	0	0	0	24.74	13 mph S
9	11/30/2022	12:36	41°03'26"N 104°24'26"W	0	0.1	22	0	0	0	24.60	minimal
10	11/30/2022	12:47	41°02'59"N 104°23'21"W	0	0.1	22	0	0	0	24.59	13 mph S
11	11/30/2022	12:58	41°03'00"N 104°25'39"W	0	0.1	22	0	0	0	24.60	13 mph S

3. Soil Gas Baseline Sampling

A baseline soil gas sampling is being developed to include monthly and quarterly measurements once the baseline is established. These samples will be initially obtained with handheld meters and laboratory samples during the initial baseline monitoring period, until permanent soil gas sampling stations are installed.

Table 46 – Soil Gas Sampling Results

Parameter	CO_2, %			O_2, %			N_2, %		
Sample No.	Date	Date	Date	Date	Date	Date	Date	Date	Date
TBD									

4.3.7 Near-Surface (Groundwater and Soil Gas) Monitoring Plan

The groundwater and soil gas monitoring plans are under development and will cover the injection and post-injection monitoring periods. Table 51 describes the complete monitoring program that will be proposed.

Table 47 – Baseline (Pre-injection), Operational, and Post-Operational Monitoring

Monitoring Type	Baseline (Pre-injection)	Operational	Post-Operational
Soil Monitoring			
Soil Monitoring Sensors	Duration: 1 year Frequency: Monthly	Duration: During injection operations Frequency: Quarterly	Duration: Until approved to cease monitoring Frequency: Quarterly
Water Monitoring			
Existing Freshwater Wells	Duration: 1 year Frequency: Quarterly	Duration: During injection operations Frequency: Quarterly	Duration: Until approved to cease monitoring Frequency: Quarterly
Lowest Most USDW Formation	Duration: 1 year Frequency: Quarterly	Duration: During injection operations Frequency: Quarterly	Duration: Until approved to cease monitoring Frequency: Quarterly

4.3.8 Deep Subsurface Monitoring of Free-Phase CO_2 Plume and Pressure Front

Direct and indirect monitoring methods will be used to track the extent of the CO_2 plume within the injection formation throughout the injection and post-injection monitoring periods, per the methods described in Table 52. As data is gathered, the plume model will be updated at a minimum of every two years during the injection period and every five years post-injection. The AOR will be updated as indicated by the model's results. Monitoring results will be used to calibrate the geological and plume model inputs through historical matching between predicted and actual results.

The Juniper M-1 and M-2 monitoring wells will be drilled and located in the predicted direction of plume movement. These wells will be in the vicinity of any known or potential fluid migration pathways for carbon dioxide or mobilized fluids. The Juniper M-1 well will be equipped with multiple pressure gauges and DTS/DAS/DSS (distributed strain sensing) fiber optic technology to continuously monitor pressure and temperature in the injection zone.

Table 48 – Description of Monitoring Program

Monitoring Type	Pre-operational (Baseline)	Operational	Post-Operational
Storage Reservoir Monitoring			
Monitoring During Injection Well Operations: • Flow rates • Volumes • Surface injection pressure • Surface injectate temperature • Annulus pressure between tubing and long-string • Added annulus volumes	Frequency: Initial setup	Duration: 5 years Frequency: Continuously	The well will be plugged and abandoned after injection operations cease. Measurements will continue until the well is plugged.
Packer Fluid (Corrosion Inhibitor) Volume	Record the initial volume of packer fluid necessary to fill the casing/tubing annulus.	Record if additional volumes are needed to fill the annulus. Test the effectiveness of corrosion inhibitors, as needed, during workover operations.	The well will be plugged and abandoned after injection operations cease. Fluid levels will be monitored until the well is plugged.
Downhole Monitoring (Injection Well and Monitoring Well(s))			
Pressures and temperature gauges on fiber optic behind casing (Juniper M-1)	Baseline measurements of the temperature and pressures in the injection interval	Continuous pressure and temperature monitoring of the injection interval	Continuous temperature and pressure measurements until plume stabilization
Wireline Logging and Retrievable Monitoring			
Internal Mechanical Integrity: Tubing-Casing Annulus Pressure Test	Mechanical integrity test before injection	Perform during workovers	Before P&A
External Mechanical Integrity – Casing Inspection Logging	Baseline casing inspection logs before injection	Duration: 5 years Frequency: Every five years across injection	At the cessation of injection and before P&A of the injection well. At the end of injection and

		interval and during any workover options	every five years afterward until the plume stabilizes.
External Mechanical Integrity – Downhole Temperature Logging; DTS on fiber optic cable	Baseline temperature logging through the storage interval to surface (injection and monitoring wells)	Through-tubing logging in injection and monitoring wells annually	Annual temperature logging until plume stabilization
Pressure Fall-Off Test (Injection Zone)	Before injection	Every five years at the injection well	Before P&A
Corrosion Monitoring	Baseline material specifications	Quarterly samples obtained from corrosion coupons placed in the CO_2 stream	N/A
Geophysical Monitoring			
Time-Lapse 2D Seismic Survey	Baseline from existing 2D/3D seismic surveys		
Vertical Seismic Profile	Baseline survey	Annually through fiber optic measurements of vibrations generated by vibrator trucks	Every five years through P&A

A description of the tests and methods used will be included in the mechanical integrity reports submitted to the Administrator.

4.3.9. Direct Monitoring Methods

The CO_2 plume will be directly monitored by temperature and pressure gauges placed via TEC line as well as a fiber optics system behind the casing in both the injection well and the monitoring wells. These gauges will continuously measure the reservoir temperature and pressures for the injection zone and the upper confining interval. Changes in the temperature and pressure within the injection zone allow for the validation and calibration of the plume model. Monitoring of the upper confining layer can provide an early indication that fluids may be migrating out of the injection zone, thus allowing time to adjust the planned injection, to ensure the fluids do not impact a USDW or reach the surface.

4.3.10 Indirect Monitoring Methods

The extent of the CO_2 plume will be monitored using time-lapse 2D seismic surveys. The existing 2D and 3D surveys will establish a baseline view of the injection interval. Subsequent surveys will be performed every two years during injection and five years during post-injection monitoring. The results will be compared to those from the baseline surveys to determine the extent of the CO_2 plume. The acquired data will also be used to refine the plume model and update the AOR. The 2D surveys taken once injection begins will be laid out across the expected plume area in a spoke, as shown in Figure 72.

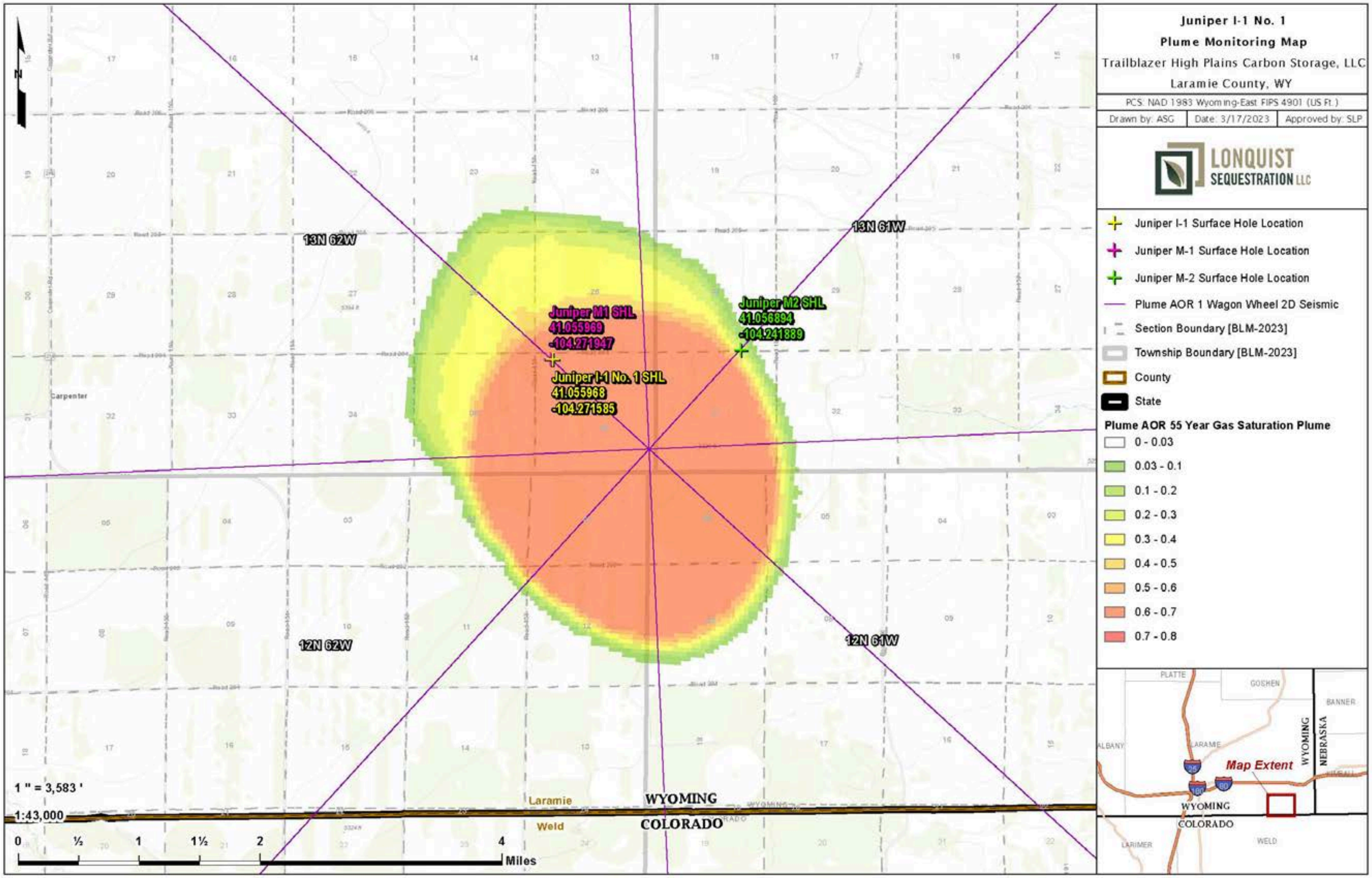


Figure 72 – 2D Seismic Survey Placement for Plume Monitoring.

4.3.11 Quality Assurance and Surveillance Plan

This Testing and Monitoring Plan aims to ensure that the sequestering of CO_2 is operating as planned, the CO_2 plume is developing as projected, and the USDWs are remaining protected from fluid migration. The Quality Assurance and Surveillance Plan is included in *Appendix D.*

4.3.12 Records Retention

High Plains will maintain records, per WYDEQ Chapter 24 **§21,** for the EWS Hub according to the following schedule shown in Table 53.

Table 49 – Records Retention Schedule

Record Description	Minimum Retention Period
Calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation, copies of all reports required by this permit, and records of all data used to complete the application for this permit	3 years from date of sample
The nature and composition of all injected fluids	10 years after the completion of any P&A procedures
Well plugging reports, site closure report, and any post-injection site care data (including data and information used to establish the post-injection site care time frame)	10 years following site closure
All data used to complete permit applications	10 years following site closure
All other monitoring records required by a permit	10 years following site closure

All retained records will be delivered to the Administrator at the conclusion of the retention period.

4.3.13 Reporting and Notice Requirements

Per WYDEQ Chapter 24 **§22**, High Plains will provide semi-annual reports, 30-day reports, and 24-hour reports to the Administrator:

- Semi-annual Reports (within 30 days) will include:
  - Any changes to the physical, chemical, and other relevant characteristics of the carbon dioxide stream from the proposed operating data;
  - Monthly average, maximum, and minimum values for injection pressure, flow rate and volume, and annular pressure;
  - A description of any event that exceeds operating parameters for annulus pressure or injection pressure specified in the permit;
  - The monthly volume of the carbon dioxide stream injected over the reporting period and project cumulatively;
  - Monthly annulus fluid volume added; and

    - The monitoring results as described in Section 4.3.
- 30 Day Reports will include:
    - Periodic tests of mechanical integrity;
    - Any other test of the injection well conducted by the owner or operator as required by the Administrator; and
    - Any well workover.
- 24 Hour Reports will include:
    - Any evidence that the injected carbon dioxide stream or associated pressure front may cause an endangerment to a USDW; any noncompliance with a permit condition, or malfunction of the injection system, which may cause fluid migration into or between USDWs;
    - Any triggering of a shut-off system, either down-hole or at the surface;
    - Any release of carbon dioxide to the atmosphere or biosphere indicated by the surface air or soil gas monitoring; and
    - Any failure to maintain mechanical integrity.

High Plains will notify the Administrator, in writing, 30 days before

- Any planned well workover;
- Any planned stimulation activities, other than stimulation for formation testing; or
- Any other planned test of the injection well conducted by High Plains.

4.3 Testing and Monitoring Plan

Table 42 – Overview of Monitoring Program (Modified from Original Juniper I-1 Permit)

Monitoring Type	Monitoring Program	Target Structure/ Project Area
CO_2 Injection Stream Composition	CO_2 sampling station	Upstream or downstream of the flowmeter
CO_2 Flow Line	Corrosion coupon monitoring	Capture facility to the well site
Continuous Recording of Injection Pressure, Rate, and Volume	Surface pressure and temperature gauges	Surface-to-reservoir (injection well)
	Coriolis mass flowmeter at the wellhead	
Well Annulus Pressure Between Tubing and Casing	Annular pressure gauge for continuous monitoring	Surface-to-reservoir (injection well)
Atmospheric Monitoring	CO_2 monitoring stations	Surface
Near-Surface Monitoring	Direct sampling to monitor shallow groundwater	Near-surface environment USDWs
Above Confining Zone Monitoring	Monitoring well with fiber optic and gauges behind casing	The first permeable formation above confining zone
	Pulsed neutron logging	
Direct Reservoir Monitoring	Juniper I-1: Fiber optic on wireline, continuous pressure and temperature gauges	Storage reservoir and primary sealing formation
	In-Zone Monitoring Well: well placement and necessity being evaluated in consideration of broader EWS Hub program	
Indirect Reservoir Monitoring	2D seismic survey	Injection and confining zones
	Pulsed neutron logging	
Internal and External Mechanical Integrity	Annulus pressure test	Well infrastructure
	Temperature logs	
	Pulsed neutron logging	
	Casing pressure test	
	Pressure falloff test	
	Ultrasonic logs	

Monitoring Type	Monitoring Program	Target Structure/ Project Area
Corrosion Monitoring	Corrosion coupon system	Well infrastructure
Seismicity Monitoring	USGS Stations	Injection and confining zones

4.3.7 Near-Surface (Groundwater and Soil Gas) Monitoring Plan

Pursuant to discussions with WDEQ, High Plains emphasizes that they will employ soil gas monitoring as required in the Chapter 24 regulations.

Table 47—Baseline (pre-injection), operational, and post-operational monitoring. (Modified from Original Juniper I-1 Permit)

Monitoring Type	Baseline (Pre-injection)	Operational	Post-Operational
Soil Monitoring			
Soil Monitoring Sensors	Duration: 1 year Frequency: Semi-Annual	Duration: During injection operations Frequency: Semi-Annual	Duration: Until approved to cease monitoring Frequency: Annual/ other frequency requested by DEQ
Air Monitoring			
Air Monitoring Sensors	Duration: 1 year Frequency: Semi-Annual	Duration: During injection operations Frequency: Semi-Annual	Duration: Until approved to cease monitoring Frequency: Annual/ other frequency requested by DEQ
Water Monitoring			
Three freshwater wells	Duration: 1 year Frequency: Semi-Annual	Duration: During injection operations Frequency: Semi-Annual	Duration: Until approved to cease monitoring Frequency: Annual/ other frequency requested by DEQ

4.3.8 Deep Subsurface Monitoring of Free-Phase CO_2 Plume and Pressure Front

Table 48 – Description of Monitoring Program (Modified from Original Juniper I-1 Permit)

Monitoring Type	**Pre-operational (Baseline)**	**Operational**	**Post-Operational**
Storage Reservoir Monitoring			
Monitoring During Injection Well Operations: • Flow rates • Volumes • Surface injection pressure • Surface injectate temperature • Annulus pressure between tubing and long-string • Added annulus volumes	Frequency: Initial setup	Frequency: Continuously	The well will be plugged and abandoned after injection operations cease. Measurements will continue until the well is plugged.
Packer Fluid (Corrosion Inhibitor) Volume	Record the initial volume of packer fluid necessary to fill the casing/tubing annulus.	Record if additional volumes are needed to fill the annulus. Test the effectiveness of corrosion inhibitors, as needed, during workover operations.	The well will be plugged and abandoned after injection operations cease. Fluid levels will be monitored until the well is plugged.
Downhole Monitoring (Injection Well and Monitoring Well)			
Juniper I-1: Pressure and temperature gauges; fiber optic and pulsed neutron logging on wireline Juniper M-1: Pressure and temperature gauges; fiber optic behind casing; pulsed neutron logging on wireline	Baseline measurements of the temperature and pressures in the injection interval	Juniper I-1: Continuous pressure and temperature monitoring; annual fiber optic and pulsed neutron logging Juniper M-1: Continuous pressure and temperature monitoring; annual pulsed neutron logging	Juniper I-1: Continuous temperature and pressure measurements until plume stabilization; annual fiber optic pulsed neutron logging. Juniper M-1: Continuous pressure and temperature monitoring; annual pulsed neutron logging

Monitoring Type	Pre-operational (Baseline)	Operational	Post-Operational
Wireline Logging and Retrievable Monitoring			
Internal Mechanical Integrity: Tubing-Casing Annulus Pressure Test	Mechanical integrity test before injection	Perform during workovers	Before P&A
External Mechanical Integrity—Casing Inspection Logging	Baseline casing inspection logs before injection	Frequency: Every five years across injection interval and during any workover options	At the cessation of injection and before P&A of the injection well. At the end of injection and every five years afterward until the plume stabilizes.
External Mechanical Integrity—Downhole Temperature Logging; DTS on fiber optic cable	Baseline temperature logging through the storage interval to surface (injection and monitoring wells)	Through-tubing logging in injection and monitoring wells annually	Annual temperature logging until plume stabilization
Pressure Fall-Off Test (Injection Zone)	Before injection	Every five years at the injection well	Before P&A
Corrosion Monitoring	Baseline material specifications	Quarterly samples obtained from corrosion coupons placed in the CO_2 stream	N/A
Geophysical Monitoring			
2D Seismic Survey	Baseline 2D survey	One survey event to confirm plume movement/direction	One survey event to help confirm plume stabilization
Vertical Seismic Profile	Baseline survey	As needed for correlation to 2D seismic.	As needed for correlation to 2D seismic.

ATTACHMENT B-6: POST-INJECTION SITE CARE AND SITE CLOSURE PLAN

4.6 Post-Injection Site Care and Facility Closure Plan

This PISC and Facility Closure plan for the EWS Hub was prepared to meet the requirements of WYDEQ Chapter 24 **§24**. The plan describes various activities that would occur once injection has ceased and during the site closure—once it has been demonstrated that no additional monitoring is needed to ensure that this project does not pose an additional risk to migrating outside of the Project Site boundary. Additionally, the PISC and Facility Closure plan is designed to protect and ensure that no endangerment to people, wildlife, agriculture, and USDW exists within the AOR. The current plume model scenarios indicate that the CO_2 plume will stabilize within the Project Site boundary. Post-injection monitoring will continue for at least 10 years to confirm that the model does not show a risk of migration to the USDW or beyond the Project Site boundary.

Once injection ceases, the injection well(s) will be plugged per the plugging plan described in *Section 4.5*. Surface equipment will be removed except as needed for long-term monitoring. A final closure report will be submitted to document the final status of the well, the monitoring data, and the final plume model.

Post-injection site care shall continue at least until the criteria required by W.S. **§**35-11-313(f)(vi)(F) is met:

- Public notice and a public hearing if requested, for the release of bonds or the termination of insurance instruments not less than 10 years after the date when all wells, excluding monitoring wells, have been appropriately plugged and abandoned;
- All subsurface operations and activities have ceased and all surface equipment and improvements have been removed or appropriately abandoned;
- Or so long as necessary to obtain a completion and release certificate from the Administrator certifying that plume stabilization has been achieved without the use of control equipment based on a minimum of three consecutive years of monitoring data; and
- All required monitoring and remediation shows that the CO2 injected into the site will not harm or present a risk to human health, safety, or the environment.

4.6.1 Predicted Post-Injection Subsurface Conditions

<u>Pre-injection and Post-injection Pressure Differential</u>

Figure 79 represents the expected pressure differential between pre-injection and post-injection pressures in the injection zone. As indicated in the figure, the maximum injection pressure at the time CO_2 operations have ceased is 976 psi. Modeling simulations suggest that the pressure increase is insufficient to move storage formation fluids into the USDW. Additionally, the simulation executed indicates that the formation pressure will decrease to levels that approach the initial formation conditions. Figure 80 shows the simulated areal extent of the CO_2 plume at the end of injection, 25 years after injection, and when the plume has stabilized. Additional simulations after the PISC period also show that the boundary of the plume is not expected to extend beyond the Project Site area.

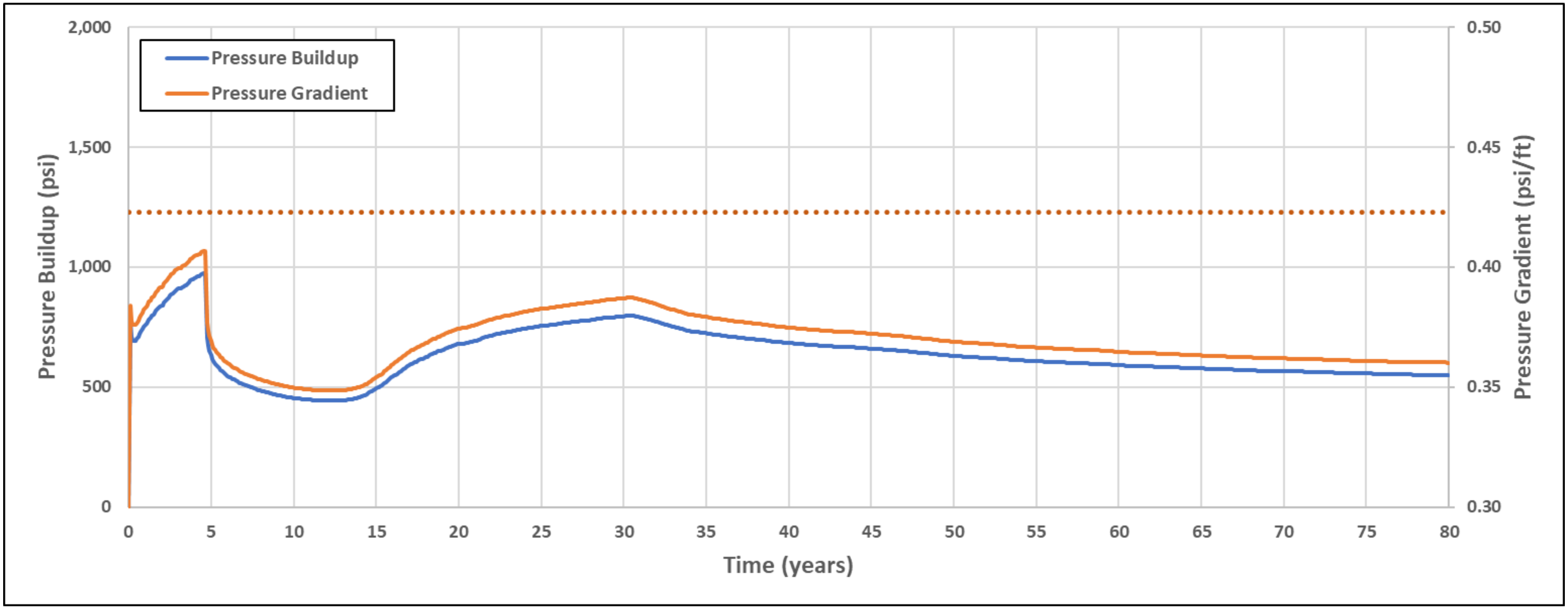


Figure 79 – Predicted Change in Pressure in the Storage Reservoir More Than 50 years Following the Cessation of CO_2 Injection.

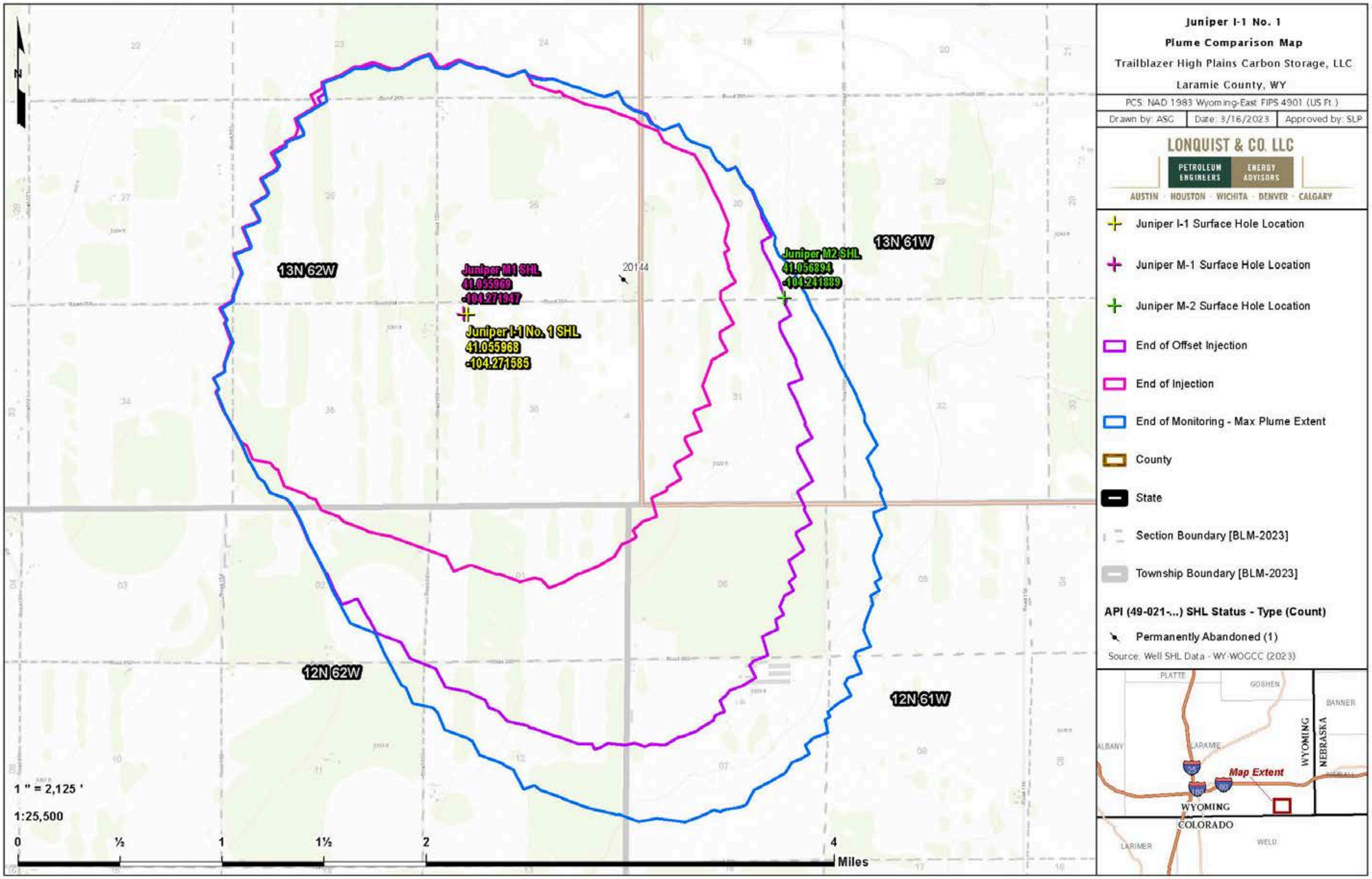


Figure 80 – CO_2 Plume at End of Injection, 25 Years After Injection and After Stabilization.

4.6.2 Post-Injection Monitoring Plan

Table 61 summarizes the types and frequency of monitoring during the post-injection site care.

Table 61 – Summary of Post-injection Site Care-Monitoring Program

Type of Monitoring	Frequency	Comments
Near-Surface Monitoring		
Soil Gas	Quarterly	Until approved to cease monitoring
Groundwater Wells	Quarterly	Until approved to cease monitoring
Formation	Every five years	Deepest USDW
Storage Reservoir Monitoring		
Injection Well	Continuously	Until measurements indicate that plume has reached stabilization
Downhole Monitoring (Injection Well and Monitoring Well(s)		
Downhole Pressure and Temperature Gauges	Continuously	Until measurements indicate that plume has reached stabilization
Geophysical Monitoring		
Time-lapse 2D	Every five years	

4.6.3 Groundwater and Soil Gas Monitoring

The groundwater and soil gas monitoring plans are under development at this time, as discussed in *Section 4.3.*

4.6.4 Monitoring of CO_2 Plume and Pressure Front

As indicated in Table 51, the CO_2 plume and pressure front will be monitored after injection activities cease. Reservoir temperatures and pressures will be measured in the Juniper M-1 and M-2 wells. The extent of the plume will indirectly be measured with time-lapse 2D surveys. Data gathered from these two methods during post-injection will be used to validate the predicted plume model. If data differs from the predicted behavior, the model will be updated.

4.6.5 Schedule for Submitting Post-Injection Monitoring Results

All data and analysis gathered during PISC monitoring activities will be submitted to WYDEQ and the EPA annually within 60 days of the anniversary of injection cessation. The reports will contain soil gas and groundwater data, storage reservoir pressures and temperature, seismic data, and any reservoir simulation results from new data.

These submitted monitoring reports will be used to serve as evidence to show that no additional monitoring is needed and that the EWS Hub does not—and is not expected to—endanger the USDW.

4.6.6 Site Closure Plan

Site closure preparations will begin following immediately after PISC. The objective of the site closure plan is to ensure that all PISC monitoring wells are appropriately plugged, all records are maintained, and that future landowners are made aware of the project and previous land use.

As required by WYDEQ Chapter 24 **§24(b)(vi),** High Plains will provide written notification to the Administrator at least 120 days before filing a request for site closure. If requested, the notification will provide a revised plan to include any changes that have been made since the original post-injection and site closure plan.

After the Administrator approves site closure, High Plains will plug and abandon the monitoring wells Juniper M-1 and Juniper M-2 as described in *Section 4.5*. Surface facilities will be decommissioned and removed, and the surface restored as agreed to with the landowner.

4.6.7 Submission of Site Closure Report, Survey, and Deed

A site closure report will be submitted to the Administrator within 90 days after completing all site closure activities. The report will include the following:

1. Documentation of injection and monitoring well-plugging that meets the requirements of WYDEQ Chapter 24 **§23** and **§24(c).**
2. A copy of a survey plat that has been submitted to the local zoning authority designated by the Administrator.
    a. The plat will indicate the location of the injection well(s) and monitoring wells relative to permanently surveyed benchmarks.
    b. A copy will also be submitted to the EPA Regional Administrator.
3. Documentation of appropriate notification and information to the state, local, and tribal authorities that have oversight of drilling activities, to enable them to impose appropriate conditions on subsequent drilling activities that may penetrate the injection and confining zone.
4. Proof that High Plains has
    a. Published notice of the application for site closure, including a mechanism to request a public hearing, in a newspaper of general circulation in each county of the proposed operation at weekly intervals for four consecutive weeks; and
    b. Mailed notice of the application for site closure to all surface owners, mineral claimants, mineral owners, lessees, and other owners of record of subsurface interests located within one mile of the proposed boundary of the geologic sequestration site.
5. Records of the carbon dioxide stream's nature, composition, and volume.

Lastly, High Plains will record a notation on the deed to the EWS Hub property or any document that is usually examined during the title search that will, in perpetuity, provide notice to any potential purchaser of the property. High Plains will also file an affidavit in accordance with W.S. **§35-11-313-(f)(vi)(G)** that will include the following information:

1. The subsurface pore space below the land has been used to sequester carbon dioxide;
2. The name of the state agency, local authority, or tribe to which the survey plat was filed, as well as the address of the EPA regional office to which it was submitted; and
3. The volume of fluid injected into the injection zone(s) and the time duration the injection occurred.

ATTACHMENT C

These attachments include but are not limited to, permit conditions and plans concerning operating procedures, monitoring, and reporting, in compliance with the WEQA, W.S. §§ 35-11-101 through 1104, specifically 301(a)(i) through 301 (a)(iv), Laws 1973, Ch. 250, Section 1), (W.S. § 31-11-313, Laws 2008, Ch. 30, Section 1), and WWQR, Chapters 24 and 29. The department may issue a permit authorizing geologic sequestration, contingent on obtaining a unitization order, if required, pursuant to W.S. § 35-11-314 through 35-11-320 (W.S. § 35-11-313(f)(ii)(F)(II)). Furthermore, upon issuing a permit, the department shall issue a certificate that includes a statement that the permit has been issued, a description of the area covered by the permit and any other information that the department deems appropriate. The injector shall file a copy of the certificate with the county clerk in the county or counties where the geologic sequestration site is located. The provisions of W.S. § 35-1-318 and 35-11-319 shall apply to any certificate the sequestration of carbon dioxide under this section and to any unitization of geologic sequestration sites under W.S. § 35-11-314 through 35-11-317.

ATTACHMENT C-1: UNITIZATION ORDER

BEFORE THE OIL AND GAS CONSERVATION COMMISSION

OF THE STATE OF WYOMING

IN THE MATTER OF A HEARING BROUGHT ON THE APPLICATION OF TALLGRASS HIGH PLAINS CARBON STORAGE, LLC, FOR AN ORDER FROM THE WYOMING OIL AND GAS CONSERVATION COMMISSION APPROVING A CARBON SEQUESTRATION UNIT FOR THE OPERATION AND ORGANIZATION OF CERTAIN LANDS AS THE EASTERN WYOMING SEQUESTRATION HUB UNIT #1 AND APPROVING A UNIT FOR GEOLOGIC SEQUESTRATION AND THE POOLING OF INTERESTS IN THE PORE SPACE FOR THE PURPOSE OF SUCH UNIT OPERATIONS IN CERTAIN LANDS LOCATED IN LARAMIE COUNTY, WYOMING.	)))))))))))))	DOCKET NO. 183-2025

APPEARANCES:

Matthew J. Micheli and Kasey J. Schlueter, attorneys for Applicant, Tallgrass High Plains Carbon Storage, LLC

Tallgrass High Plains Carbon Storage, LLC	Mr. Kyle Quackenbush, Operations Mr. Cody Wagoner, Land Mr. Craig Spreadbury, Operations Ms. Julia Zohner, Geology Ms. Bonnie Percy, Engineering
State of Wyoming	Mr. Tom Kropatsch Supervisor, Wyoming Oil and Gas Conservation Commission Mr. David DeWald Deputy Attorney General

REPORT OF THE COMMISSION

This cause came for hearing before the Wyoming Oil and Gas Conservation Commission (the “Commission”) at approximately 9:00 a.m. on the 11th day of February 2025, in the Hearing Room of the Commission, 2211 King Boulevard, Casper, Wyoming. Due and legal notice was given as required by law and as required by the Rules and Regulations of the Commission, to consider the above-captioned matter brought by Tallgrass High Plains Carbon Storage, LLC (hereinafter "Tallgrass").

After having considered the sworn testimony of the witnesses and the evidence offered, the Commission makes the following Findings of Fact, Conclusions of Law, and Order:

FINDINGS OF FACT

1. This matter comes before the Commission on Tallgrass's Application for an Order from the Wyoming Oil and Gas Conservation Commission Approving a Carbon Sequestration Unit for the Operation and Organization of Certain Lands as the Eastern Wyoming Sequestration Hub Unit #1 and Approving a Unit for Geologic Sequestration and the Pooling of Interests in the Pore Space for the Purpose of Such Unit Operations in Certain Lands Located in Laramie County, Wyoming ("Application"), pursuant to Wyoming Statute Sections 35-11-314 through 35-11-317, and Chapter 3, Section 43 of the Commission's Rules and Regulations, requesting an order establishing a carbon sequestration unit, referred to as the Eastern Wyoming Sequestration Hub ("EWS Hub"), and unitization of the pore space within the proposed unit area for conducting unit operations in the lands and formations described below.

2. Tallgrass is the owner of the right to conduct geologic sequestration in the Lyons Formation underlying the following described lands ("Unit Area"):

Laramie County, Wyoming:
Township 12 North, Range 60 West, 6th P.M.

Section 2: All	Section 14: All
Section 3: All	Section 15: All
Section 4: All	Section 16: All
Section 5: All	Section 17: All
Section 6: All	Section 18: All
Section 7: All	Section 20: All
Section 8: All	Section 21: All
Section 9: All	Section 22: All
Section 10: All	Section 23: All
Section 11: All	

Township 12 North, Range 61 West, 6th P.M.

Section 1: All	Section 13: All
Section 2: All	Section 14: All
Section 3: All	Section 15: All
Section 4: All	Section 16: All
Section 5: All	Section 17: All
Section 6: All	Section 18: All
Section 7: All	Section 19: All
Section 8: All	Section 20: All
Section 9: All	Section 21: All
Section 10: All	Section 22: All
Section 11: All	Section 23: All
Section 12: All	

Township 12 North, Range 62 West, 6th P.M.

Section 1: All	Section 12: All
Section 2: All	Section 13: All
Section 3: All	Section 14: All
Section 4: All	Section 15: All
Section 5: All	Section 16: All
Section 6: All	Section 17: All
Section 7: All	Section 18: All
Section 8: All	Section 19: All
Section 9: All	Section 20: All
Section 10: All	Section 21: All
Section 11: All	Section 22: All
Section 23: All	Section 24: All

Township 12 North, Range 63 West, 6th P.M.

Section 1: All	Section 13: All
Section 2: All	Section 14: All
Section 3: All	Section 15: All
Section 4: All	Section 16: All
Section 5: All	Section 17: All
Section 6: All	Section 18: All
Section 7: All	Section 20: All
Section 8: All	Section 21: All
Section 9: All	Section 22: All
Section 10: All	Section 23: All
Section 11: All	Section 24: All
Section 12: All	

Township 13 North, Range 60 West, 6th P.M.

Section 2: All	Section 19: All
Section 3: All	Section 20: All
Section 4: All	Section 21: All
Section 5: All	Section 22: All
Section 6: All	Section 23: All

Section 7: All	Section 26: All
Section 8: All	Section 27: All
Section 9: All	Section 28: All
Section 10: All	Section 29: All
Section 11: All	Section 30: All
Section 14: All	Section 31: All
Section 15: All	Section 32: All
Section 16: All	Section 33: All
Section 17: All	Section 34: All
Section 18: All	Section 35: All

<u>Township 13 North, Range 61 West, 6th P.M.</u>

Section 1: All	Section 19: All
Section 2: All	Section 20: All
Section 3: All	Section 21: All
Section 4: All	Section 22: All
Section 5: All	Section 23: All
Section 6: All	Section 24: All
Section 7: All	Section 25: All
Section 8: All	Section 26: All
Section 9: All	Section 27: All
Section 10: All	Section 28: All
Section 11: All	Section 29: All
Section 12: All	Section 30: All
Section 13: All	Section 31: All
Section 14: All	Section 32: All
Section 15: All	Section 33: All
Section 16: All	Section 34: All
Section 17: All	Section 35: All
Section 18: All	Section 36: All

<u>Township 13 North, Range 62 West, 6th P.M.</u>

Section 1: All	Section 19: All
Section 2: All	Section 20: All
Section 3: All	Section 21: All
Section 4: All	Section 22: All
Section 5: All	Section 23: All
Section 6: All	Section 24: All
Section 7: All	Section 25: All
Section 8: All	Section 26: All
Section 9: All	Section 27: All
Section 10: All	Section 28: All
Section 11: All	Section 29: All
Section 12: All	Section 30: All
Section 13: All	Section 31: All
Section 14: All	Section 32: All
Section 15: All	Section 33: All
Section 16: All	Section 34: All

Section 17: All	Section 35: All
Section 18: All	Section 36: All

<u>Township 13 North, Range 63 West, 6th P.M.</u>

Section 1: All	Section 19: All
Section 2: All	Section 20: All
Section 3: All	Section 21: All
Section 4: All	Section 22: All
Section 5: All	Section 23: All
Section 6: All	Section 24: All
Section 7: All	Section 25: All
Section 8: All	Section 26: All
Section 9: All	Section 27: All
Section 10: All	Section 28: All
Section 11: All	Section 29: All
Section 12: All	Section 30: All
Section 13: All	Section 31: All
Section 14: All	Section 32: All
Section 15: All	Section 33: All
Section 16: All	Section 34: All
Section 17: All	Section 35: All
Section 18: All	Section 36: All

<u>Township 14 North, Range 60 West, 6th P.M.</u>

Section 4: All	Section 21: All
Section 5: All	Section 26: All
Section 6: All	Section 27: All
Section 7: All	Section 28: All
Section 8: All	Section 29: All
Section 9: All	Section 30: All
Section 16: All	Section 31: All
Section 17: All	Section 32: All
Section 18: All	Section 33: All
Section 19: All	Section 34: All
Section 20: All	Section 35: All

<u>Township 14 North, Range 61 West, 6th P.M.</u>

Section 1: All	Section 19: All
Section 2: All	Section 20: All
Section 3: All	Section 21: All
Section 4: All	Section 22: All
Section 5: All	Section 23: All
Section 6: All	Section 24: All
Section 7: All	Section 25: All
Section 8: All	Section 26: All
Section 9: All	Section 27: All
Section 10: All	Section 28: All
Section 11: All	Section 29: All

Section 12: All	Section 30: All
Section 13: All	Section 31: All
Section 14: All	Section 32: All
Section 15: All	Section 33: All
Section 16: All	Section 34: All
Section 17: All	Section 35: All
Section 18: All	Section 36: All

<u>Township 14 North, Range 62 West, 6th P.M.</u>

Section 12: All	Section 26: All
Section 13: All	Section 27: All
Section 14: All	Section 28: All
Section 15: All	Section 29: All
Section 16: All	Section 30: All
Section 20: All	Section 31: All
Section 21: All	Section 32: All
Section 22: All	Section 33: All
Section 23: All	Section 34: All
Section 24: All	Section 35: All
Section 25: All	Section 36: All

<u>Township 14 North, Range 63 West, 6th P.M.</u>

Section 25: All
Section 35: All
Section 36: All

<u>Township 15 North, Range 60 West, 6th P.M.</u>

Section 19: All	Section 30: All
Section 20: All	Section 31: All
Section 21: All	Section 32: All
Section 28: All	Section 33: All
Section 29: All	

<u>Township 15 North, Range 61 West, 6th P.M.</u>

Section 21: All	Section 28: All
Section 22: All	Section 32: All
Section 23: All	Section 33: All
Section 24: All	Section 34: All
Section 25: All	Section 35: All
Section 26: All	Section 36: All
Section 27: All	

Containing approximately 193,595.53 acres.

3. Tallgrass has six (6) UIC Class VI Geologic Sequestration Permits from the Wyoming Department of Environmental Quality which were approved on September 11, 2024 and October 28, 2024 for the following wells:

Well Name	**Permit No.**	**Facility ID No.**	**Location**	**County**
Juniper I-1	2023-235	WYS-021-00149	T13N/R62W, Sec: 36: NWNW	Laramie
Spirea I-1	2023-041	WYS-021-00155	T13N/R63W, Sec: 34: SWNW	Laramie
Old Barberry I-1	2023-263	WYS-021-00158	T14N/R61W, Sec. 12: NWNE	Laramie
Cypress I-1	2023-040	WYS-021-00154	T13N/R61W, Sec. 16: SWSW	Laramie
Barberry I-1	2023-039	WYS-021-00153	T14N/R61W, Sec. 31: NWSW	Laramie
Azalea I-1	2023-264	WYS-021-00159	T13N/R62W, Sec: 8: SESE	Laramie

4. Tallgrass submitted copies of the UIC Class VI Geologic Sequestration Permits with its Application.

5. Tallgrass's monitoring plans and other operations comply with the UIC Class VI Geologic Sequestration Permits and other environmental requirements.

6. Tallgrass submitted its proposed Carbon Sequestration Unit Agreement for its EWS Hub within the Lyons Formation in Laramie County, Wyoming (the "Unit Agreement") as an exhibit to its Application that includes the terms and agreements applicable to unitized pore space estate owners. Attached to the Unit Agreement are Tract Maps, a Tract Contribution Summary, and a Tract Ownership List. During the hearing, the Commission recognized Mr. Cody Wagoner as an expert in land matters. *Transcript*, 21:15-23:3. Mr. Wagoner described the key terms of the Unit Agreement. *Transcript*, 33:19-35:4; Ex. 1-00016.

7. Tallgrass has executed pore space leases with 92.5% of the pore space owners within the Unit Area, including 7,315 acres of state lands. *Transcript*, 30:19-31:7; Ex. 1-00014. The Office of State Land and Investments approved the plan of unitization on January 10, 2025. *Id.* at 00016.

8. Approximately 8 acres, or 0.004132%, of the Unit Area is owned by the United States Department of the Air Force. *Id*. Tallgrass must obtain permission from the Air Force through an agency-specific lease, easement or other authorization before occupying any Air Force pore space. Tallgrass has engaged with the United States Department of the Air Force to obtain such authorization. An attorney representing the Air Force appeared at the hearing held in this matter and reiterated that the Air Force reserved all rights and waived none.

9. 480 acres, or approximately 0.24%, of the Unit Area is owned by the BLM. *Id*. Tallgrass has applied for a BLM right-of-way for use of its pore space within the Unit Area. *Id*. The BLM did not protest the Application and did not appear at the hearing held in this matter.

10. All pore space estate interest owners unitized by the Commission's order that are not subject to a pore space lease will receive injection fees at the same rate as leased pore space estate owners of one dollar ($1.00) per metric ton of CO_2 injected.

11. Mr. Conner Nicklas, a representative of the Wyoming-Nebraska Pore Space Owners Association, consisting of landowners who own over 80% of the Unit Area, testified in support of Tallgrass's application – specifically that the method for the allocation of economic benefits was fair and reasonable. *Transcript*, 36:1-41:23. Mr. Nicklas testified that at least 80% of the Unit Area is in agreement with the use of a surface acreage tract allocation factor. *Id.* Additionally, the Commission held an executive session at the February 11, 2025 hearing pursuant to Wyo. Stat. § 16-4-203(d)(v) wherein Tallgrass presented evidence of its trade secrets, privileged information, and confidential commercial and financial data relating to the economic benefits associated with the proposed sequestration operations. After consideration of Mr. Nicklas's testimony and the confidential information presented by Tallgrass, the Commission found that the injection fee of one dollar ($1.00) per metric ton of injected CO_2 is fair, reasonable, equitable and will provide economic benefit to all pore space owners and other corresponding rights owners.

12. During the hearing, the Commission recognized Ms. Julia Zohner as an expert in geology. *Transcript*, 57:15-69:4. Her testimony supports the following findings.

13. The Lyons Formation is the targeted reservoir for sequestration and unitization. *Transcript*, 62:3-9. The Lyons Formation has depths of 9,000 to 9,600 feet. *Id.* There is approximately 420 feet separating the Lyons Formation from the lowermost USDW in the Sundance. Although the Sundance has Total Dissolved Solids (TDS) less than 10,000 ppm (ranging from approximately 3,200 to 8,000), it is not currently utilized for drinking water in the area. There is approximately 7,800 feet separating the Lyons Formation from the Fox Hills Sandstone, which is the deepest utilized aquifer in the area. *Transcript*, 63:12-17; Ex. 1-00032. The confining zones for the Lyons Formation include the Goose Egg Formation (upper confining zone) and the Satanka Formation (lower confining zone). Ex. 1-00032. Most of the deposition across the Unit Area is interpreted to be either dunes or dry interdune deposits with porosities averaging fourteen to twenty-one percent. *Transcript*, 66:7-10; Ex. 1-00038, 40, 45. Based on depositional patterns in the Lyons Formation, there is regional consistency for thickness and porosity, but locally, there are variations in the dune structure – this is supported by the data obtained from Tallgrass's wells. *Transcript*, 66:11-68:7; Ex. 1-00035, 39.

14. Tallgrass delineated the Unit Area utilizing the geologic features such as the top confining zone thickness (the Goose Egg Formation thickness), the injection zone thickness (the Lyons Formation thickness), the base confining zone thickness (the Satanka Formation thickness), and the injection zone average porosity (the porosity of the Lyons Formation). *Transcript*, 67:18-69:4; Ex. 1-00041-42.

15. During the hearing, the Commission recognized Ms. Bonnie Percy as an expert in engineering. *Transcript*, 69:14-71:6. The following findings are supported by her testimony.

16. Tallgrass presented CO_2 plume projections with thirty years of injection, running the model until the plume migration stabilized around fifty years after injection ceases. *Transcript*, 78:3-90:25; Ex. 1-00046. Tallgrass's reservoir simulation shows it is maximizing the use of the pore space within the Unit Area and is thereby preventing waste of pore space storage capacity. *Transcript*, 69:14-96:10. Based upon its testimony, Tallgrass will utilize the pore space as efficiently as possible by adjusting operations, including potentially drilling additional future Class VI Injection wells within the Unit Area, to maximize CO_2 sequestration. The engineering testimony of Ms. Percy, and the geologic testimony of Ms. Zohner support the plume projections.

17. CO_2 plumes are projected to remain within the Unit Area and Tallgrass will utilize both continuous and periodic monitoring and injection controls to monitor plume development. Further, CO_2 plumes are expected to stabilize post-injection. *Transcript,* 78:3-90:25; Ex. 1-00046-51.

18. Tallgrass utilizes a single Tract Allocation Factor: 100% surface acreage. This factor is supported by the engineering testimony of Ms. Percy, and the geologic testimony of Ms. Zohner as there is regional continuity of the Lyons, but local variability in thickness and porosity exists due to the depositional environment. Therefore, it is impractical to assign variable pore space to each tract given the localized geologic variability and it is practical to use regional consistency, with surface acreage as a proxy, to determine each tract's share of the pore space volume in the Unit Area.

19. As explained by Ms. Percy, each parcel of the unitized pore space provides equal value to the Unit Area by contributing the necessary storage, conduit, and/or buffer-zone purposes. *Transcript*, 93:5-94:10.

20. Tallgrass currently plans to drill thirteen wells (not including shallow USDW monitor wells), encompassing six injector/monitor pairs and a stratigraphic test well, with the

ability to drill additional future Class VI injection and monitor wells within the Unit Area. Tallgrass has drilled 5 wells in the area: Juniper M-1, Cypress M-2 (Stratigraphic Test), Juniper I-1, Azalea I-1, Azalea M-1 and it is currently drilling the Spirea I-1. Ex. 1-00030. Tallgrass will construct Class VI injection wells with redundant mechanical barriers including an extra string of casing and a pump system to maintain tubing/casing annulus pressure above injection pressure. *Transcript*, 46:5-47:21. Additionally, Tallgrass will utilize corrosion resistant materials, including acid resistant cement and high chrome steel casing (CR25). *Id.* Tallgrass will meet Class VI well construction standards. Ex. 1-00019.

21. Tallgrass's monitoring program encompasses four categories of monitoring: above and near surface, subsurface geophysical, subsurface wellbores, and wellhead and facilities. *Transcript*, 47:22-50:15; Ex. 1-00020. The Department of Environmental Quality will oversee Tallgrass's monitoring program. *Id.*

22. As described in Exhibit I to the Application, four existing wells are located within the Unit Area: Fritz 1, Miller 1-18, UPRR-Palm 1-21, and Juniper M-1. Application Ex. I. Of those, only one well requires remedial work, Fritz 1. *Id.* Tallgrass will drill out the original plugs of Fritz 1 and re-plug. *Id.* For the Juniper M-1, Tallgrass will plug this well back to the Sundance Formation for use as a monitor well.

23. At the close of the hearing, three individuals offered public comment. The Commission considered these comments in making its decision.

24. After reviewing the application and hearing the evidence, the Commission determined the application contained the information required in Wyo. Stat. § 35-11-315 and approved the Application.

CONCLUSIONS OF LAW

1. Due and legal notice of time, place, and purpose of this hearing has been afforded to all interested parties in all respects as required by law.

2. The Commission has jurisdiction over this matter and over all interested parties and has jurisdiction to make and promulgate the order hereinafter set forth.

3. This hearing was held in accordance with Wyoming statutes and Commission rules.

4. Wyo. Stat. § 35-11-315 states:

> Any interested person may file an application with the [Commission] requesting an order providing for the operation and organization of a unit of one (1) or more parts as a geologic sequestration site and for the pooling of interests in pore space in the proposed unit area for the purpose of conducting the unit operation.

5. The Commission finds, pursuant to Wyo. Stat. § 35-11-316(b), that:

   a. The material allegations of Tallgrass's Application are substantially true;

   b. The purpose specified in Wyo. Stat. § 35-11-314 will be served by granting the Application;

   c. The Application outlines operations that will comply with applicable underground injection control Class VI well permits, draft permits or any applications for permits and any other environmental requirements;

   d. Granting the Application will utilize pore space for geologic sequestration;

   e. The quantity of pore space storage capacity, and method used to determine the quantity of pore space storage capacity allocated to each separately owned tract within the Unit Area represents, so far as can be practically determined, each tract's actual share of the pore space included within the Unit Area;

   f. The method for the allocation of economic benefits provided by the use of pore space within the Unit Area between pore space owners; and between pore space owners and the unit operator or others is fair and reasonable;

   g. The method for providing economic benefits from the use of pore space in the Unit Area is fair and equitable and is reasonably designed to maximize the use of the pore space; and

h. All other requirements specified by rules or regulations adopted by the Commission have been met.

6. Tallgrass's Unit Agreement is fair, reasonable and equitable and contains provisions for:

a. Determining the pore space to be included within the Unit Area;

b. The appointment of Tallgrass as the sole operator and working interest owner;

c. The enlargement or reduction of the Unit Area as may be warranted by review pursuant to Wyo. Stat. § 35-11-316(f);

d. The effective date of the Unit Agreement; and

e. The Term of the Unit Agreement and conditions under which the Unit Agreement may be terminated.

7. Wyo. Stat. § 35-11-316(c) states in part:

> No order of the [Commission] authorizing the commencement of unit operations shall become effective until the plan of unitization has been signed or in writing ratified or approved by those persons who own at least eighty percent (80%) of the pore space storage capacity within the unit area.

8. Tallgrass's plan of unitization has been ratified by 92.5% of the Unit Area.

9. Wyo. Stat. § 35-11-316(h) states:

> A certified copy of any order of the [Commission] entered under the provisions of this section shall be entitled to be recorded in the land records of the county clerk for the counties where all or any portion of the unit area is located, and the recordation shall constitute notice thereof to all persons.

10. The Commission, upon its own motion or upon application, and with notice and hearing, may modify its order regarding the operation, size, and other characteristic of the Unit Area in order to prevent or assist in preventing a substantial inequity resulting from operation of the unit, provided that no such modification may amend any permit issued under Wyo. Stat. § 35-11-313.

11. No provision of the Commission's order shall be construed to confer or grant on any person the right of eminent domain.

12. No order for unitization shall: i) act so as to grant any person a right of use or access to a surface estate if that person would not otherwise have such right; ii) diminish, impair, or otherwise alter the dominance of the mineral estate over the surface estate and pore space interests, and; iii) prohibit a mineral interest owner from developing the owner's minerals above or below the Unit Area.

ORDER

IT IS HEREBY ORDERED BY THE COMMISSION that the Application of Tallgrass requesting an order establishing a carbon sequestration unit for the operation and organization of certain lands as the Eastern Wyoming Sequestration Hub Unit #1 and establishing a unit for geologic sequestration and the pooling of interests in the pore space for the purpose of such unit operations, in certain land located in Laramie County, Wyoming is approved.

IT IS FURTHER ORDERED that the Unit Agreement and its accompanying exhibits are hereby incorporated into this Order and approved to the same extent and with the same force and effect as if set forth herein in its entirety.

IT IS FURTHER ORDERED that Tallgrass shall record a certified copy of this Order, or a Memorandum of the same, together with exhibits in the land records of the county clerk for Laramie County, Wyoming.

IT IS FURTHER ORDERED that the Commission shall retain jurisdiction in this matter to take such additional action, if any, as the Commission deems necessary and appropriate.

DATED this 14 day of March 2025.

WYOMING OIL AND GAS CONSERVATION COMMISSION

Approved as to form:

David DeWald, WSB #7-5538
Deputy Attorney General

Erin Campbell
Acting Chair – Commissioner

Other Commissioners Present:
Ken Hendricks
Jason Crowder

ATTACHMENT C-2: TITLE TO SEQUESTERED AND INJECTED CARBON DIOXIDE

AFFIDAVIT

STATE OF COLORADO)
)   SS.
COUNTY OF JEFFERSON)

I, Kyle Quackenbush, after first being duly sworn, affirms as follows:

1. I am over the age of majority, am competent, and I have personal knowledge of the matters addressed in this Affidavit.

2. I am employed by Tallgrass Management, LLC ("Tallgrass"), and have been employed there for about 8 years. My title is Segment President & VP - Commercial Operations (Liquids & CO2).

3. Title to the carbon dioxide that will be injected by Tallgrass High Plains Carbon Storage, LLC ("High Plains") through the Juniper I-1 well conveys to High Plains under the sequestration agreements High Plains has with its customers.

4. Accordingly, as required by Wyo. Stat. § 35-11-318, High Plains will have title to any carbon dioxide it injects into and stores underground or within a unit area.

5. I declare under penalty of perjury that the above statements are true and correct.

FURTHER AFFIANT SAYETH NOT.

Kyle Quackenbush, Segment President & VP - Commercial Operations (Liquids & CO_2)

Subscribed and sworn to before this 10th day of March 2025.

DAWNELLE MITCHELL
NOTARY PUBLIC
STATE OF COLORADO
NOTARY ID 20234004344
MY COMMISSION EXPIRES FEBRUARY 2, 2027

Dawnelle J. Mitchell
Notary Public

My Commission Expires: 02/02/27