WATER QUALITY DIVISION

GEOLOGIC SEQUESTRATION

PERMIT APPLICATION (Form 1a)

GENERAL INFORMATION AND SIGNATORY AUTHORITY

PLEASE READ THE INSTRUCTIONS BEFORE FILLING OUT THE FORM. APPROVAL MUST BE OBTAINED BEFORE WORK COMMENCES. The geologic sequestration permit application consists of two parts: General Information and Signatory Authority (Form 1a) and Technical Information (Form 1b). Both forms are required to obtain the permit to construct. Operation of a Class VI well is not authorized until authorization to inject is received from the Department. During construction of the Class VI well, information collected may warrant a permit modification. Form 1a and 1b will only require sections pertaining to the modification to be completed and public notice requirements will only pertain to those sections being modified.

1. Application Type

UIC Class I Conversion	☐	UIC Class I Permit Number:	
UIC Class II Conversion	☐	Hearing Number Recommending Transfer:	
UIC Class V Conversion	☐	UIC Class V Permit Number:	
New UIC Class VI	☑		
*UIC Class VI Modification	☐	UIC Class VI Permit Number:	

*For Class VI permit modifications, only the sections requiring a modification should be completed. Permit modifications require a signature for the responsible corporate officer as well as the licensed geologist, or licensed engineer, if applicable.

2. General Information

Carbon Sequestration Project Name: Painter Reservoir CCS 1				
Owner/Operator Name North Shore Exploration and Production, LLC				Telephone Number (303) 892-5616
Responsible Corporate Officer Steve Swanson	Title CEO		Email Address steve@northshoreenergyllc.com	
Owner/Operator Address 105 Edgeview Dr, Suite 400	City Broomfield	State CO	Zip 80021	Telephone Number
Facility Location Address (if different than Operator Address)	City	State WY	Zip	Telephone Number
Facility Mailing Address (if different than Operator Address)	City	State WY	Zip	Telephone Number

3. Site and Facility Description

A description of the proposed geologic sequestration facility and documentation sufficient to demonstrate that the applicant has all legal rights, including but not limited to the right to surface use, necessary to sequester carbon dioxide and associated constituents into the proposed geologic sequestration site.

North Shore Energy is a privately held company that owns and operates the Painter Reservoir Field in southwestern Wyoming. The location of the proposed Class VI well is in Uinta County in township 16 north, range 119 west, section 31. This section and minerals are privately held. The intent of the proposed Class VI well is to inject CO_2 produced on site into the Nugget Formation.

4. SIC Codes

List in descending order of significance the four (4) digit "Standard Industrial Classification Manual" which best describes your facility in terms of the principal products or services you produce or provide. Also, specify each classification in words.	1st 1311	Name Crude Petroleum and Natural Gas
	2nd 3433	Name Oil and Gas Field Machinery and Equipment
	3rd 1381	Name Drilling Oil and Gas Wells
	4th 1382	Name Oil and Gas Field Exploration Services

5. Geologic Sequestration Project Information

	County	Latitude*	Longitude*	Section	Township	Range	Qrt-Qrt
Proposed Facility Location	Uinta			31	16	119	
Proposed Injection Well Location	Uinta	41.3220	-110.8810	31	16	119	
Proposed Monitoring Well Location	Uinta	41.3270	-110.8880	31	16	119	NW-NW

Is the facility located on Indian Land?	Yes	☐	No	☑	Is the facility located on any historic or archeological site?	Yes ☐	No ☑

*Provide latitude and longitude in decimal degree format to four significant figures, using the North American Datum 83 geodetic reference system.

6. Water Quality Management Plan, Wellhead Protection Area, Source Water Protection Area

Is the Geologic Sequestration Project within a state-approved water quality management plan area?	YES	☐	NO	☐
Is the Geologic Sequestration Project within a state-approved wellhead protection area?	YES	☐	NO	☐
Is the Geologic Sequestration Project within a state-approved source water protection area?	YES	☐	NO	☐

7. Existing Environmental Permits

Within the Area of Review, a listing and status of all permits or construction approvals associated with the geologic sequestration project received or applied for under any of the following programs or corresponding state programs:

RCRA – Hazardous Waste Management	Permit No.:	N/A	☑
UIC – Underground Injection of Fluids	Permit No.:	N/A	☑
NPDES – Discharge of Surface Water	Permit No.:	N/A	☑
Prevention of Significant Deterioration – Air Emissions from Proposed Sources	Permit No.:	N/A	☑
Nonattainment Program under the Clean Air Act	Permit No.:	N/A	☑
National Emissions Standards for Hazardous Air Pollutants pre-construction approval under the Clean Air Act	Permit No.:	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	☑

8. Other Permits

Within the Area of Review, a list of other relevant permits associated with the geologic sequestration project that the applicant is required to obtain:

	Permit No.:	N/A	☑
	Permit No.:	N/A	☑
	Permit No.:	N/A	☑
	Permit No.:	N/A	☑
	Permit No.:	N/A	☑

9. Mineral and Surface Ownership for Area of Review

Mineral Ownership:	☐ Applicant	☑ Surface Owner	☐ State	☐ Fed	Mineral Lease # ____________	
Surface Ownership:	☐ Applicant	☐ State	☐ Fed	☐ Indian Lands (Contact EPA Region 8)	☑ Private (Specify) ____________	☐ Other (Specify) ____________

10. Potential Damage to Mineral Estates

Pursuant to Wyoming Water Quality Rules (WWQR), Chapter 8, Section 6(c)(ii), the discharge of waste will not degrade or decrease the availability of mineral resources, including oil and gas. Therefore, prior to submitting an application to construct a UIC Class VI injection well, the WDEQ strongly encourages applicants to collaborate with nearby leases and mineral ownership owners to demonstrate that the proposed injection activities will present no damage to existing or future recovery of sub-surface minerals. Any permit challenge that is upheld by the WOGCC is grounds for the WDEQ to deny the issuance of the Class VI UIC permit.

11. Wyoming Conservation Executive Orders 2019-3 and 2020-1

a. Sage Grouse

Pursuant to the requirements of the Governor's Executive Order 2019-3 (SGEO), applicants for new UIC permits must determine if any part of the project falls within a Greater Sage-Grouse Core Area (SGCA) before applying. If any part of the project falls within an SGCA, the first point of contact for addressing sage-grouse issues is the Wyoming Game and Fish Department (WGFD). Please coordinate with the WGFD and obtain written confirmation of consistency with the Executive Order prior to applying for a UIC permit and submit this documentation as part of the application package. For more information, contact the Wyoming Game and Fish: Wyoming Game and Fish Department Habitat Protection Program (307) 777-4506 or wgfd.hpp@wyo.gov.

Note that the application shall be returned without processing until a letter confirming consistency with the Executive Order has been obtained. Additional information and maps of SGCAs are available at https://wgfd.wyo.gov/Habitat/Sage-Grouse-Management.

Check one of the following, as applicable to the project:

☐ Some part, or all, of my project falls within an SGCA and I have contacted the WGFD for a SGEO review. A letter from the WGFD confirming consistency with the Executive Order is attached.

☐ Some part, or all, of my project falls within an SGCA and I have contacted the WGFD for a SGEO review. It does not comply with the SGEO. I have valid and existing rights related to this permit. I have committed to the following recommendations that will minimize the impact on the sage grouse.

☑ By checking this box, I certify that I have reviewed the SGCAs available online, and determined that no portion of my project falls within an SGCA. *(No additional requirements apply.)*

b. Migration Corridors.

Pursuant to the requirements of the Governor's Executive Order 2020-1, applicants for new UIC permits must determine if any part of the project falls within a Migration Corridor designated under the Executive Order before applying. If any part of the project falls within a Migration Corridor, you must consult with the WGFD. Please coordinate with the WGFD and obtain written confirmation of consistency with the Executive Order prior to applying for a UIC permit and submit this documentation as part of the application package. For more information, contact the Wyoming Game and Fish: Wyoming Game and Fish Department Habitat Protection Program (307) 777-4506 or wgfd.hpp@wyo.gov.

Note that the application shall be returned without processing until a letter confirming consistency with the Executive Order has been obtained. Please also visit the WGFD's Management Page for more information and a map of the currently designated Migration Corridors: https://sites.google.com/view/wywildlifemigrationadvisorygrp/home?fbclid=IwAR3y_HEQxOo4HckAVKzRzT5kdLaOsyiV0vt9NJOtzNu45b_WK0vESwTWVzY#h.bc90kvcpohnu.

Check one of the following, as applicable to the project:

☐ Some part, or all, of my project falls within the area described and I have contacted the WGFD for consultation. A letter from the WGFD confirming consistency with the Executive Order is attached.

☑ By checking this box, I certify that I have reviewed the Migration Corridors information available online, and determined that no portion of my project falls within a Migration Corridor. *(No additional requirements apply.)*

12. Access for Inspections

Wyoming Statute (W.S.) 35-11-303 (a) states: "the administrator of the water quality division at the direction of the director: (i) may conduct on-site compliance inspections of all facilities and work during or following the completion of any construction, installation or modification for which a permit is issued under W.S. 35-11-301 (a)(ii)."

As part of its application, the applicant shall certify under penalty of perjury that the applicant has secured and shall maintain permission for WDEQ personnel to access the permitted facility, including (i) permission to access the land where the facility is located, (ii) permission to collect resource data as defined by W.S. § 6-3-414, and (iii) permission to enter and cross all properties necessary to access the facility if the facility cannot be directly accessed from a public road. A map of the access route(s) to the facility shall accompany the application.

> *I, __________, certify under penalty of perjury that the applicant has secured and shall maintain permission for WDEQ personnel and their invitees to access the permitted facility, including (i) permission to access the land where the facility is located, (ii) permission to collect resource data as defined by Wyoming Statute § 6-3-414, and (iii) permission to enter and cross all properties necessary to access the facility if the facility cannot be directly accessed from a public road.*

13. Contact Information

The owner or operator shall provide a list of contacts for Tribes on Indian lands within the geologic sequestration project as defined by the Area of Review.

Attach a legal description of land ownership within the Area of Review. List ownership by tract or submit in plat form.

14. Comments

15. Certification

All applications for permits, reports, or information submitted to the Administrator shall be signed by a responsible corporate officer.

"I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to ensure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of a fine and imprisonment for knowing violations."

Signature	Printed Name	Title	Date
[signature]	STEVE SWANSON	CEO	11/23/21

16. Application Fee
In accordance with W.S. 35-11-313(h), the applicant shall pay a fee to be determined by the director based upon the estimated costs of reviewing, evaluating, processing, serving notice of an application, and holding any hearings. Unused fees shall be returned to the applicant.

$5,000 application fee. Make checks payable to the "*Wyoming Department of Environmental Quality*". The application fee serves as a credit for the applicant to allow for the department to:

- Review of the permit application.
- Acquire a consultant to assist in the review of the application where the department may need additional expertise (geophysical, geochemical, computational modeling), if necessary.
- Draft and process the permit.
- Public notice advertisement fees.
- Public hearing fees, if applicable.

Any fees incurred over the initial application fee will be invoiced and require payment prior to p issuance.

Form 1b: Class VI Well Permit Application Painter A

north shore exploration and production, llc

<u>Operator Information</u>

Operator Name: North Shore Energy, LLC

Address: 105 Edgeview Dr, Suite 400, Broomfield, CO 80021

Phone: (303) 892-5616

Email: Info@northshoreenergyllc.com

Status: Private Company

Facility Information

Facility Name: TBD

Facility Contact: Name, Address, Phone, and Email - TBD

Well Location: Uinta County, WY., T16N R119W Sec 31

This Class VI Well Permit Application for Painter A contains information pursuant to Wyoming Department of Environmental Quality Form 1b Class VI Permit Application guidelines and requirements.

Narrative:

North Shore Energy, LLC ("North Shore") and Development Partner ("DP", and together with North Shore, the "Developer") are jointly exploring the development of an ammonia facility and associated carbon capture and sequestration system (together, the "Project") adjacent to North Shore's existing natural gas production facilities at the Painter field near Evanston, Wyoming.

Ammonia is projected to become a key energy source and means of transporting hydrogen in a decarbonizing global economy and the Developer believes that the Project could be one of the first "blue" ammonia projects tobe developed, allowing Wyoming to a key participant in the energy transition. The Project would leverage the existing infrastructure at the Painter field, benefit from significant existing Nitrogen reserves, and permanently sequester captured CO_2 in depleted natural gas wells at the same location. Compression and gathering systems are in place and operating currently and will be repurposed for CCS.

North Shore is a natural gas exploration and production company headquartered near Denver, CO. North Shoreowns and operates the Painter complex (Painter A field, East Painter field, and Painter Gas Plant), having purchased these properties, and others nearby, from Merit Energy in 2018. North Shore's E&P assets extend east to the Rock Springs Uplift in the Green River Basin and success at Painter will likely result in multiple CCSprojects being developed - having a long-term positive impact on local economies by increasing both employment and tax base. Engineering estimates project a range of CO_2 storage in the 10 fields controlled by North Shore of approximately 6 tcf (>300 million tons).

Development Partner is a leading energy infrastructure investment firm affiliated with a 27-year-old global private investment group with *over* 4,000 professionals and *over* $60 billion in assets under management. DP is also currently under construction for a separate ammonia production facility in Texas and desires to make its secondinvestment in ammonia facilities in Wyoming, giving access by rail to both the west coast and the Gulf coast.

Carbon capture and sequestration is a key element of the proposed project. Painter has been configured for high volume sequestration as it has continuously cycled *over* 100 mmcfpd of nitrogen, for natural gas liquids production, for decades. Currently, the Painter A field is blow down and the nitrogen sweep is limited to East Painter field. As a result, Painter A field is ideal for CCS and is the target for permanent sequestration in this project.

On-site generation of CO_2 is a second key element of the proposed project. We propose to generate CO_2 on-site through steam methane reforming, using both North Shore natural gas reserves and existing grid power. The CO_2 generated will then be gathered and pumped downhole in a new, Class VI approved well. The on-site generation and sequestration of CO_2 avoids the complicated process of aggregating multiple CO_2 industrial sources and building pipelines to the ultimate sequestration site. We expect this efficiency to save years of development time and millions in cost savings.

In summary, North Shore and Development Partner have signed a binding agreement to develop a large-scale ammonia plant with CCS. We expect this project to have significant, positive impacts on Wyoming and the local communities. We also expect this project to be a prime example of transitioning from hydrocarbons to a low carbon footprint energy project.

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Site Characterization

Regional Geology and Geologic Structure

Geological Setting:

The proposed CO_2 injection well will be in southwest Wyoming to the west of the Green River Basin in the Overthrust Belt within the Fossil Basin in Township 16 North Range 119 West Section 31 (Figure 1). The region contains a complex structural history, with episodes of compression and extension. The geological and structural setting has resulted in a series of compartmentalized anticlinal oil and gas fields. These anticlines typically contain multiple north-south trending faults, with a main fault located on the eastern side of each anticline.

The Fossil Basin is a small, linear, and structurally controlled basin in the southeastern part of the Wyoming overthrust belt. This "overthrust belt" is represented by multiple small mountain ranges and high ridges formed by the "thrusting" of sedimentary rocks over other sedimentary rocks. Topographically, the Fossil Basin is bounded by the Crawford Mountains and Tunp Range on the west, by Oyster Ridge on the east, and by the Uinta Mountains on the south. The Crawford Mountains, Tunp Range, and Oyster Ridge are areas of high relief developed upon southerly extended salient ridges of deformed Paleozoic and Mesozoic strata. In the center of the Fossil Basin, these earlier rocks are covered by a veneer of early Tertiary sediments. Superficially, the Fossil Basin appears to be a broad syncline with tilted beds dipping sharply or gently basinward from the basin margins. The Tertiary sedimentary cover, however, partially obscures what is a more complex structural history. (NPS Occasional Paper No. 3)

The stratigraphic column includes Cambrian through Quaternary sediments overlying crystalline Precambrian basement rocks. The Cenozoic rocks are highly variable fluvial and conglomeritic rocks. Quaternary sediments are comprised of unconsolidated gravel, sand, silt, and clay size grains. The Miocene and Pliocene rocks are primarily conglomerates, claystone, and sandstone. Late Paleocene and Eocene rocks are primarily mudstone and sandstones which become more tuffaceous up section. The Mesozoic are generally clastic sediments deposited in continental shelf environments. The most common rock types in the Mesozoic are shale, mudstone and siltstone with some limestone, dolomite, and sandstone units. The Paleozoic rocks are primarily calcareous passive margin sediments. Crystalline dolomite and limestone are the most common rocks.

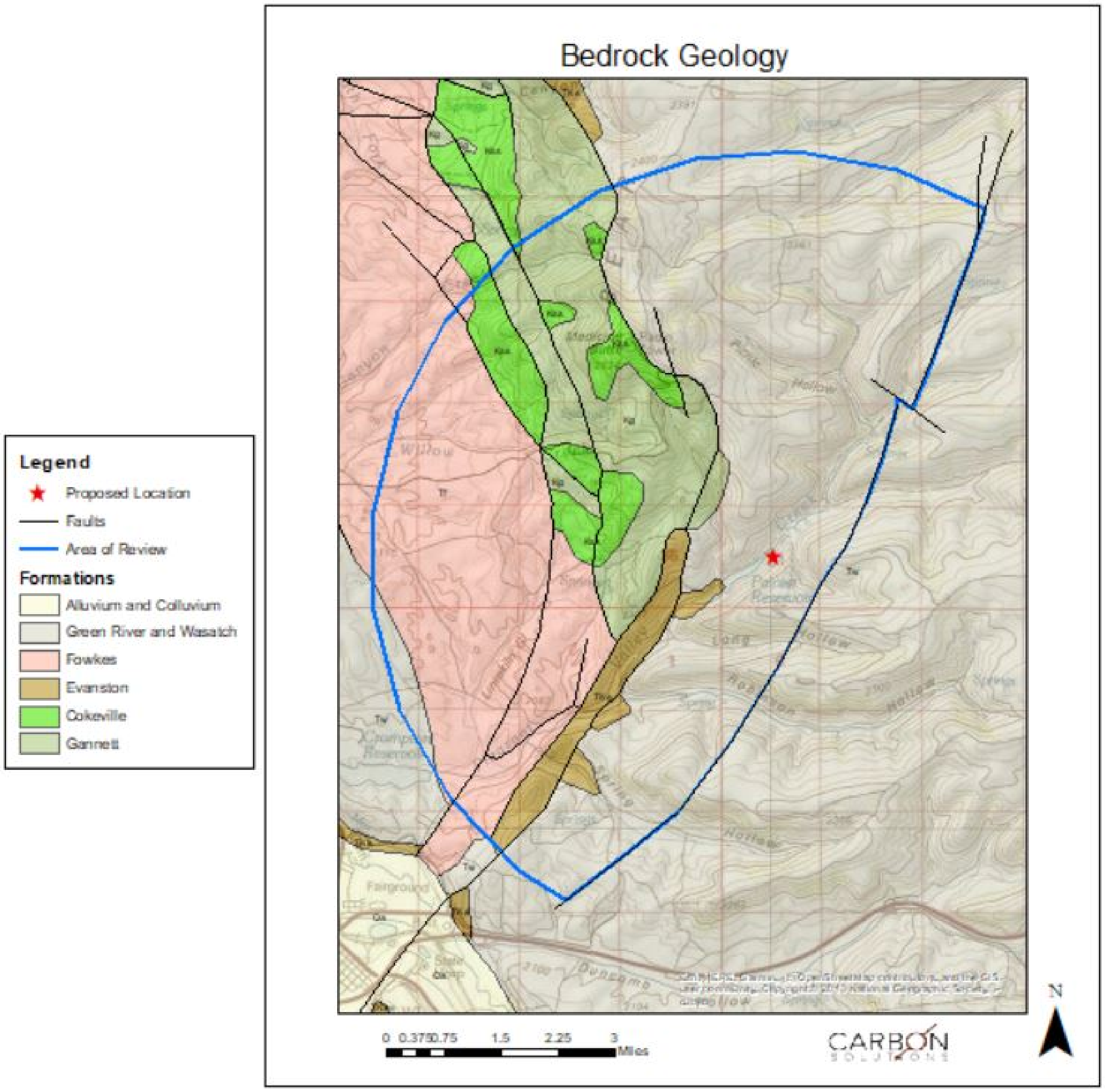


Figure 1. Proposed Well Location and Regional bedrock geology

Tertiary Units:

Green River Formation: Buff laminated marlstone and limestone, brown oil shale, and siltstone. Includes Angelo and Fossil Butte Members (Love and Christiansen, 1985).

Wasatch Formation: Variegated mudstone and sandstone. Includes Tunp and Bullpen Members, other tongues and unnamed members, and main body (variegated red to gray, brown, and gray mudstone and sandstone; conglomerate lenses) (Love and Christiansen, 1985).

Fort Union Formation: Is noted but not described.

Cretaceous/Tertiary Units:
Evanston Formation: Gray siltstone, sparse red sandstone, and lignite beds (Love and Christiansen, 1985).

Cretaceous Units:
Adaville Formation: Gray sandstone, siltstone, and carbonaceous claystone; conglomeratic in upper part; coal-bearing in lower part (Love and Christiansen, 1985).

Hilliard Formation (Upper Cretaceous): Dark-olive-gray marine shale, siltstone, and sandy shale containing thin, tan to light-gray sandstone and limestone interbeds, particularly in upper part (Dover and M'Gonigle, 2004).

Frontier Formation: White to brown sandstone and dark-gray shale; oyster coquina in upper part; coal and lignite in lower part (Love and Christiansen, 1985).

Aspen Shale: Light- to dark-gray siliceous tuffaceous shale and siltstone, thin bentonite beds, and quartzitic sandstone (Love and Christiansen, 1985).

Bear River Formation: Black shale, fine-grained brown sandstone, thin limestone, and bentonite beds (Love and Christiansen, 1985).

Gannett Group: Red sandy mudstone, sandstone, and chert-pebble conglomerate; thin limestone and dark-gray shale in upper part, more conglomeratic in lower part. Includes Smoot Formation (red mudstone and siltstone), Draney Limestone, Bechler Conglomerate, Peterson Limestone, and Ephraim Conglomerate. Upper Jurassic fossils have been reported from the Ephraim (Love and Christiansen, 1985).

Jurassic Formations:
Stump Formation: Glauconitic siltstone, sandstone, and limestone (Love and Christiansen, 1985).

Preuss Sandstone and Redbeds (salt): Purple, maroon, and reddish-gray sandy siltstone and claystone; contains salt and gypsum in thick beds in some subsurface sections (Love and Christiansen, 1985).

Twin Creek Limestone: Greenish-gray shaly limestone and limy siltstone. Includes Gypsum Spring Member (Love and Christiansen, 1985).

Nugget Sandstone: Buff to pink crossbedded well-sized and well-sorted quartz sandstone and quartzite; locally has oil and copper-silver-zinc mineralization (Love and Christiansen, 1985).

Triassic Formations:
Ankareh Formation: Red and maroon shale and purple limestone (Love and Christiansen, 1985).

Thaynes Formation: Gray limestone and limy siltstone (Love and Christiansen, 1985).

Woodside Formation: Red siltstone and shale (Love and Christiansen, 1985).

Dinwoody Formation: Gray to olive-drab dolomitic siltstone (Love and Christiansen, 1985).

Permian Units:
Phosphoria and Park City Formations: Upper part is dark- to light-gray chert and shale with black shale and phosphorite at top; lower part is black shale, phosphorite, and cherty dolomite (Love and Christiansen, 1985).

Pennsylvanian Units:
Wells Formation: Gray limestone interbedded with yellow limy sandstone (Love and Christiansen, 1985).

Weber/Tensleep Sandstone: White to gray sandstone containing thin limestone and dolomite beds. Permian fossils have been found in the topmost beds of the Tensleep at some localities in Washakie Range, Owl Creek Mountains, and southern Bighorn Mountains (Love and Christiansen, 1985).

Amsden Formation: Red and gray cherty limestone and shale, sandstone, and conglomerate (Love and Christiansen, 1985).

Mississippian Units:
Madison Group: Group includes Mission Canyon Limestone underlain by Lodgepole Limestone (Love and Christiansen, 1985).

Mission Canyon Limestone: Blue-gray massive limestone and dolomite (Love and Christiansen, 1985).

Lodgepole Limestone: Gray cherty limestone and dolomite (Love and Christiansen, 1985).

Devonian Units:

Three Forks Formation: Yellow and greenish-gray shale and dolomitic siltstone (Love and Christiansen, 1985).

Jefferson Formation: Fetid brown dolomite and limestone (Love and Christiansen, 1985).

Ordovician Units:

Bighorn Dolomite: Light-gray massive siliceous dolomite (Love and Christiansen, 1985).

Cambrian Units:

Gallatin Formation: Gray and tan limestone (Love and Christiansen, 1985).

Gros Ventre Formation: Greenish-gray micaceous shale (Love and Christiansen, 1985).

Flathead Sandstone: Dull-red quartzitic sandstone (Love and Christiansen, 1985).

Precambrian Rocks:

Cross Sections:

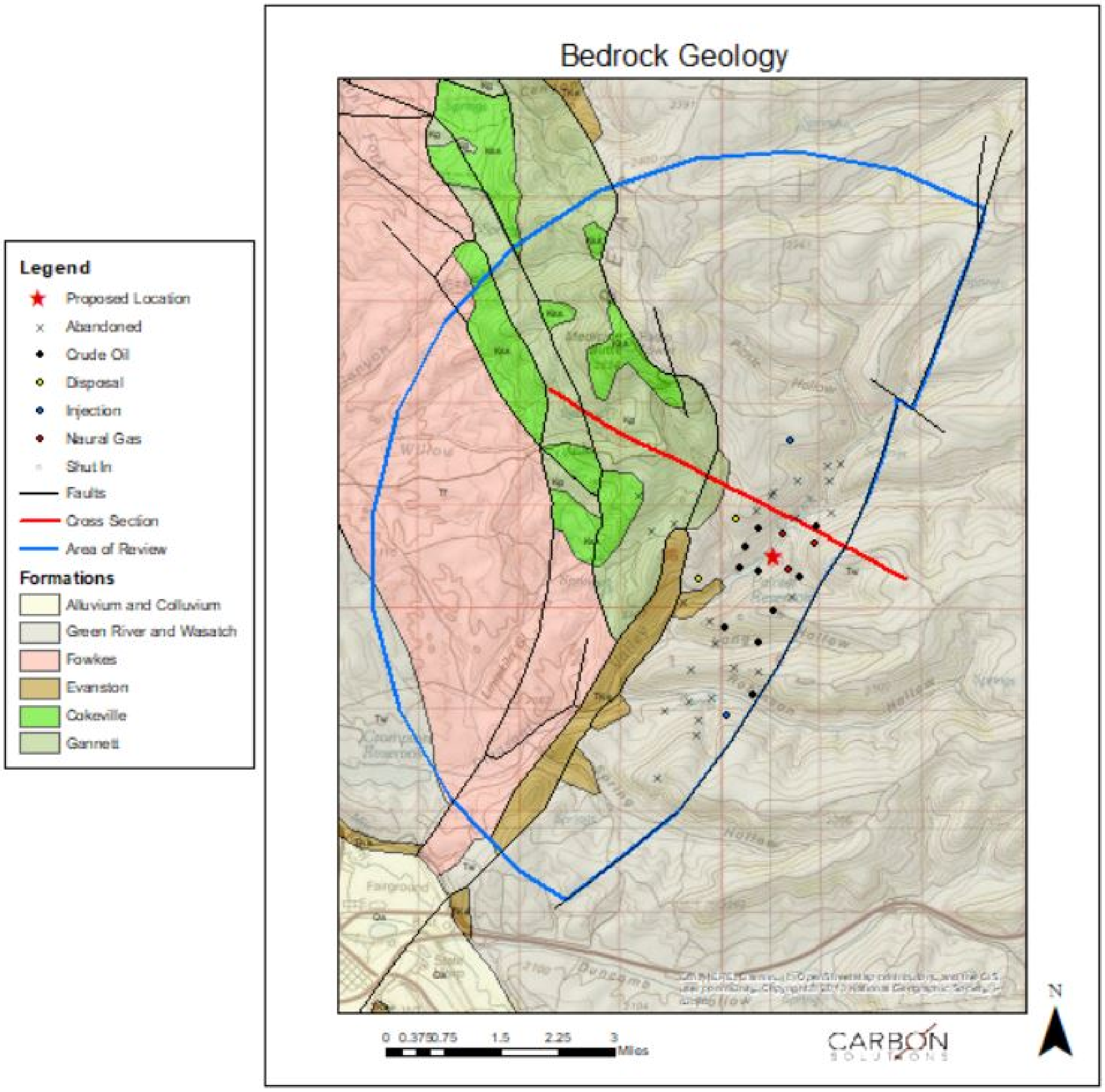


Figure 2. Bedrock geology and location of Cross Section and Wells.

Well locations (Figure 2) denote the extent of the Painter Reservoir (Painter A) within the eastern portion of the Painter Unit. Painter Reservoir is a depleted oil and gas reservoir that produced oil and gas from the Nugget Sandstone Formation. Currently the reservoir is under pressured and all production is Shut-In. A northwest by southeast generalized cross section

(Figure 3) derived from 2D Seismic (denoted by red line in Figure 2) illustrates the structural nature of the strata within the Painter Reservoir portion of the Fold and Thrust Belt.

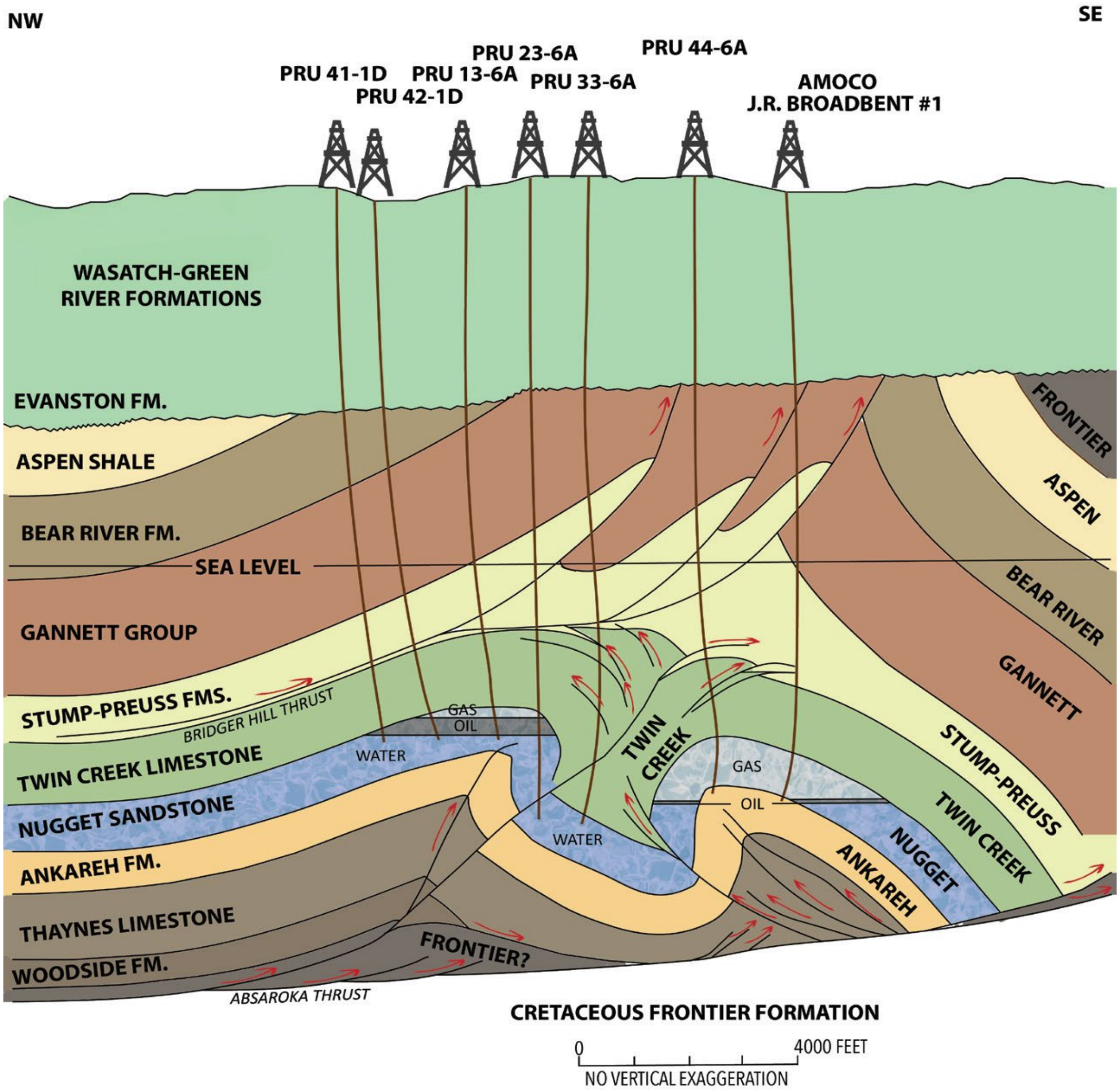


Figure 3. Cross section A-A'

Modified From Lamerson et al.

A gamma ray type log (Figure 4) illustrates the geophysical nature of the various geological formations in the Painter Reservoir area. Figure 4 is a composite log derived from two wells in the Painter Reservoir Field, the upper portion is from Well API 4120155 and the lower portion below the Nugget is from Well API 4120517.

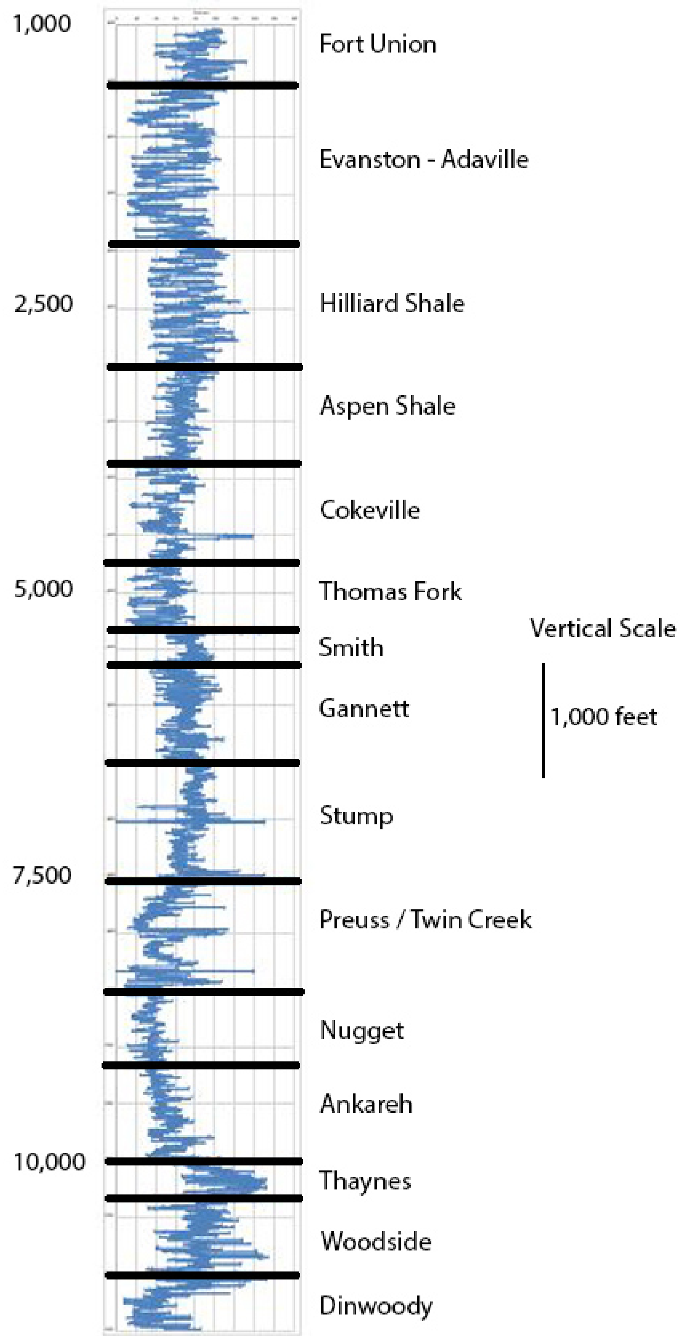


Figure 4. Composite gamma ray type log with stratigraphic delineations.

Faults and Fractures

The fields (Painter Reservoir and Painter East) are comprised of two NNE-SSW trending, double-plunging, asymmetric anticlines (Figure 3) (Cluff and Bauman, 1982) that formed along the Absaroka Thrust decollement zone during the Sevier Orogeny. The fields are separated structurally and hydrodynamically by thrust faults. Painter field is an easterly-verging, duplex structure bound by the Absaroka Thrust decollement zone along the Woodside Formation and by a roof fault along the top of the Twin Creek Limestone; the roof fault splays into a series of eastward-verging imbricate faults (Figure 1). The East Painter field is separated from Painter field by a modified triangle zone (i.e. converging thrust faults). Though bound by the regional Absaroka Thrust decollement, it does not have a roof thrust typical of a duplex. The Jurassic Nugget Sandstone is the target reservoir for production. It is overlain by Jurassic and Cretaceous formations, which are truncated by a regional unconformity. A thick sequence (>4,000ft (1,219m)) of Tertiary sediments were deposited above the unconformity.

As previously studies indicate (e.g. Cluff and Bauman, 1982; Frank et al., 1982), Painter Field is bound by distinct sets of geologic faults existing within a duplex structure. By definition, a duplex structure is a set, or array, of thrust horses bound by a basal (floor) thrust and a roof thrust. All of the faulting within the field area, therefore, are compressional. These thrust faults have varying character, and this character needs to be explained and considered with respect to proposed carbon storage operations.

Figure 5, modified from Frank et al., 1982, highlight major fault types. The bottommost fault, represented by the purple line, is the basal detachment fault that propagated along a regional décollement. At the Painter Field, it propagates along ductile lithofacies within the Thaynes Limestone and/or Woodside Formation and is regionally called the Absaroka Thrust (e.g. Lamb, 1978). This fault has the biggest overall offset of features within the study area and is relatively flat lying (i.e. horizontal). The activation pressures needed to form décollement are normally associated with the orogenic processes. It is unlikely that carbon storage would impose any risk of slip along the nearly-horizontal basal detachment fault. Further, this fault would not serve as a leakage pathway being located below the injection zone.

Corresponding to the basal detachment fault, thrust faults associated with the roof thrust fault are highlighted in red (Figure 5). The roof thrust, named the Bridger Hill Thrust, propagates along the base of the Stump Preuss Formation within evaporitic sediment (e.g. Lamb, 1978) and follows local dip, with corresponding compensatory imbricate, listric thrust splays that verge easterly off the crest of the anticlines at Painter and East Painter fields. These intrude the ductile units that overlay the reservoir, and possibly reach as far as the regional erosional unconformity (where they would have been truncated). With respect to proposed carbon storage, these faults should be characterized as two sets. Similar to the basal thrust, it unlikely that the primary roof thrust, which is relatively flat-lying, would experience the activation pressure necessary during injection to promote slip. The imbricate thrusts that splay at the crest of the fields increase the overall thickness of the sealing lithologies, which is common for overlying ductile lithologies in compressional tectonism (Bonini, 2001). Thicker seals are preferred in sealing units for CCUS projects. Deformation within ductile units rarely produces geologically long-term fluid pathways as permeability becomes limited by the inherent ductility of shale, evaporates, etc. (Guglielmi et al., 2020). The listric shape of these faults would make them more susceptible to reactivation than the roof and basal (floor) thrusts, though lack of evidence for reactivation during previous field activities suggest a degree of stabilization to variance in state of stress associated with normal pressure.

The last fault set within the study area are located between the basal and roof thrusts and highlighted in blue (Figure 5). These faults are the only type that offset the Nugget reservoir and consist of two main structural features; 1. A listric thrust fault that propagated off of the basal thrust and defines the structural control for the eastern boundary of the field (i.e. the Painter Field duplex), and 2. A triangle zone (Price, 1981) and associated imbricate thrusts located between Painter and East Painter fields. Of the two structural features, only the thrust fault is likely to be directly affected by pressure changes associated with injection activities. It is assumed that the proposed pressure changes would not impact this fault; it appears to have remained impervious to fluid flow since the late Jurassic (Powers et al., 1995) and was not reactivated during nitrogen injection.

There are two important observations related to the uncertainty surrounding the stability of structural features unique to the Painter Field that would not be possible to make at a CCUS greenfield type 1. The field is currently at much lower pressures than its initial pre-production pressures, pressures which were sustained through geologic time (Lindquist, 1988). Also, there were no instances of fault reactivation as pressures were depleted, suggesting stability to variations in field-scale states of stress, and 2. Painter Field underwent numerous years of nitrogen injection/flooding without evidence of fault destabilization, during which injectivity pressures varied between ~XXXX and YYYY psig, with reservoir pressures varying between ~4200 and YYYY psig with a goal of reaching 4700 psig (Kuenhe et al., 1990). Both of these observations are interpreted to lower the risks associated with the proposed CCUS injection operations.

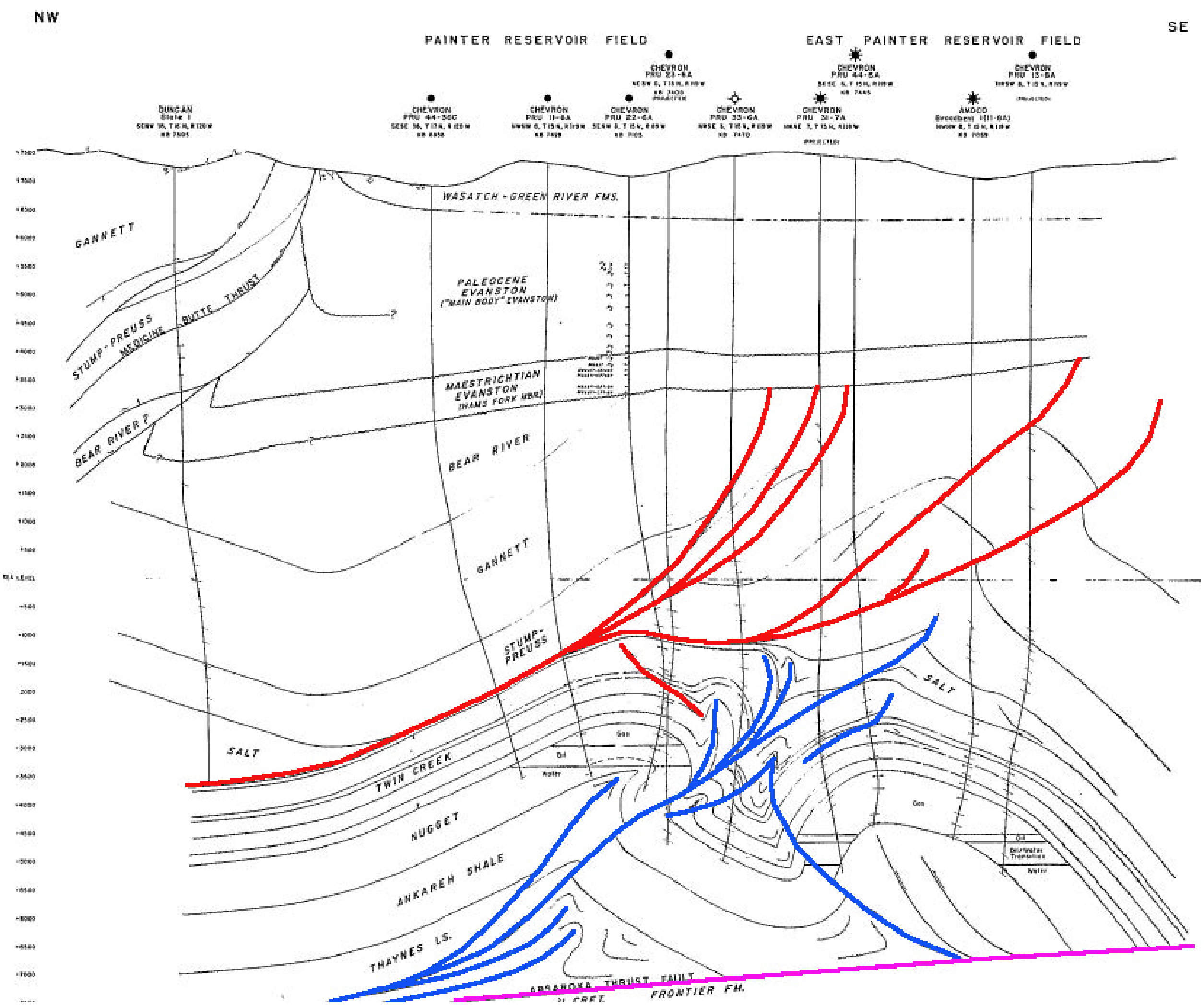


Figure 5. Major Faulting

From Frank et al. and Lamerson et al. 1982.

Regional Hydrostratigraphy

Aquifer Characterization

A characterization of the injection zone and aquifers above and below the injection zone that may be affected, including applicable pressure and fluid chemistry data to describe the projected effects of injection activities, and background water quality data that will facilitate the classification of any groundwaters that may be affected by the proposed discharge. This must include information necessary for the Division to classify the receiver and any secondarily affected aquifers under Water Quality Rules and Regulations;

This section includes an aquifer characterization of the injection zone (Jurassic Nugget Formation) and the aquifers above the injection zone that may be affected. Aquifers below the injection zone are of low risk of being affected and thus are not describe in further detail.

The aquifers at the study site from the surface to the injection formation are as follows:

- Wasatch Formation
- Evanston Formation
- Adaville Formation
- Bear River Formation
- Gannett Group
- Stump Formation
- Preuss Sandstone and Red Beds
- Twin Creek Limestone
- Nugget Sandstone

These aquifers are described in detail by Bartos et al., 2014; Oriel and Tracey, 1970; Lines and Glass, 1975, Sheet 1; Rubey et al., 1980; M'Gonigle and Dover, 1992; Dover and M'Gonigle, 1993; Ahern et al., 1981; Martin, 1996; Naftz, 1996; Glover et al., 1998; Bartos and Hallberg, 7-115 2010; WWWC Engineering et al., 2007 . A summary of these descriptions are provided below.

Wasatch aquifer:
The Eocene Wasatch Formation comprises the Wasatch aquifer at the study site. Currently used as a source of water for domestic, stock, industrial, and public-supply purposes, the Wasatch aquifer is a highly utilized aquifer in the Over Thrust Belt and Bear River Basin.

The Wasatch Formation consists of variegated mudstone, claystone, siltstone, shale, sandstone, conglomeratic sandstone, and conglomerate.

The Wasatch Formation is considered to be an aquifer in the Overthrust Belt by Robinove and Berry, 1963; Lines and Glass, 1975, Sheet 1; Ahern et al., 1981; Forsgren Associates, Inc., 2000; TriHydro Corporation, 2000, 2003. In the Wyoming Water Framework Plan, the Wasatch Formation is classified as a major aquifer (WWC Engineering et al., 2007). Ahern et al. (1981) classified the formation as a major aquifer in the Overthrust Belt.

The chemical composition of groundwater in the Wasatch aquifer in the Bear River Basin was characterized and the quality evaluated by Bartos et al., (2014) on the basis of environmental water samples from 15 wells and nine springs. TDS concentrations were found to be variable and indicated that most of the waters were fresh (90 percent of samples) and remaining waters were slightly to moderately saline. TDS concentrations ranged from 176 to 5,400 mg/L, with a median of 411 mg/L.

Evanston Aquifer:
The Evanston aquifer is composed of the Paleocene and Upper Cretaceous Evanston Formation in the Overthrust Belt. The Evanston Formation consists of interbedded gray siltstone, sparse red sandstone, and minor lignite/coal beds; thickness is about 820 ft (Oriel and Platt, 1980).

Robinove and Berry (1963, Plate 1) speculated that the Evanston Formation in the Bear River valley “may be capable of yielding small supplies of groundwater.” Lines and Glass (1975, Sheet 1) noted that conglomeratic sandstones and conglomerates in the Evanston Formation likely were capable of yielding “moderate to large quantities” of water to wells, and that fine-grained sandstones were capable of yielding “small to moderate” quantities of water, but that well yields were likely “greatly dependent” on saturated sandstone bed thickness. Ahern et al. (1981, Table IV-1) classified the Evanston Formation in the Overthrust Belt as a minor aquifer.

Areas of the Evanston Formation with fine-grained lithologies can act as confining units. Glover (1990) noted that fine-grained impermeable lithologies of the upper Evanston Formation in the area immediately south of the Medicine Butte Fault provide hydraulic isolation between the Bear River alluvial aquifer and underlying bedrock aquifers.

Water quality data is not available for the Evanston Aquifer in the study area, though Bartos et al., 2014 does note that the chemical composition of one produced water sample from the Evanston Aquifer in the Bear River Basin to have a TDS of 4,400 mg/L. The location of this well is not identified.

Adaville Aquifer:

The Upper Cretaceous Adaville Formation comprises the Adaville aquifer and consists of brown-weathering, gray sandstone, siltstone, and carbonaceous shale. The formation is conglomeratic in the upper part with coal beds present in the lower part (Oriel, 1969; Lines and Glass, 1975, Sheet 1; Oriel and Platt, 1980; Rubey et al., 1980; Ahern et al., 1981; M'Gonigle and Dover, 1992; Dover and M'Gonigle, 1993).

Lines and Glass (1975, Sheet 1) speculated that "small quantities" of water were likely available from the Lazeart Sandstone Member of the Adaville Formation in the Overthrust Belt. Bartos et al., (2014) note that no data were located describing the chemical characteristics of the hydrogeologic unit.

Bear River Formation:

The Lower Cretaceous Bear River Formation consists of fissile black shale interbedded with brown fine-grained sandstone, and minor interbedded fossiliferous limestone and bentonite. In the Overthrust Belt, the Bear River Formation was identified as either a "discontinuous aquifer with local confining beds" or "minor aquifer" by Ahern et al. (1981). Interbedded discontinuous sandstone beds compose the aquifer (Ahern et al., 1981; Lines and Glass, 1975). In the Wyoming Water Framework Plan, the Bear River Formation was classified as a marginal aquifer (WWC Engineering et al., 2007).

No water quality data are available for this aquifer in the study area.

Gannett aquifer and confining unit:

The Gannett aquifer and confining unit is composed of the Lower Cretaceous Gannett Group. The Gannett Group consists of red sandy mudstone, sandstone, and chert-pebble conglomerate.

Some thin limestone and dark gray shale are present in the upper part of the unit, and the lower part is more conglomeratic. In the Wyoming Water Framework Plan, the Gannett Group was classified as a marginal aquifer (WWC Engineering et al., 2007). Bartos et al., (2014) agree with that classification, because the unit has low overall permeability, but with distinct zones and formations of higher permeability with potential to yield water to wells. Glover (1990), noted that aquifers in the Gannett Group were hydraulically isolated from the overlying Evanston aquifer and Wasatch aquifer in the Bear River Basin.

No water quality data are available for this aquifer in the study area.

Stump Formation:
The Stump Formation is classified as a confining unit by Ahern et al., 1981. Further information on the hydrogeologic characteristics of the Stump Formation is not available.

Pruess Sandstone:
The Middle Jurassic Preuss Sandstone or Redbeds consists of interbedded purple, maroon, dull red, purple-gray, and red-gray, siltstone, sandy siltstone, silty claystone, and claystone with minor interbedded halite (rock salt), alum, and gypsum locally present in irregular zones (Lines and Glass, 1975, Sheet 1; Oriel and Platt, 1980; Rubey et al., 1980; M Gonigle and Dover, 1992; Dover and M'Gonigle, 1993). Bartos et al. (2014) noted that there is little information available regarding the hydrogeologic characteristics of the Preuss Sandstone.

No water quality data are available for this aquifer in the study area.

Twin Creek Limestone:
The Twin Creek aquifer is composed of the Middle Jurassic Twin Creek Limestone. The Twin Creek Limestone consists of green-gray argillaceous (shaly) limestone and calcareous siltstone. In the Wyoming Water Framework Plan, the Twin Creek Limestone was classified as a minor aquifer (WWC Engineering et al., 2007)

Bartos et al., 2014 characterized the quality evaluated on the basis of seven produced water samples from wells located in the Overthrust Belt. TDS concentrations ranged from 31,100 to 329,000 mg/L, with a median of 137,000 mg/L.

Nugget Aquifer:
The Nugget Sandstone consists of tan to pink, crossbedded, well-sorted, quartz-rich sandstone and is described extensively through this report. The high porosity and permeability have led previous studies to classify the Nugget as an aquifer.

Injection and Confining Zone Characteristics

Injection Zone
The Nugget is a cross-bedded, well sorted sandstone of aeolian deposition. It is a prolific hydrocarbon producer in the Overthrust Belt. The Nugget is found in the WDW-2 between 11,922 feet and 12,928 feet, with the gross perforation interval between 11,926 feet and 12,728 feet. A net receiver thickness of 568 feet within the perforation interval has been identified that contains an average porosity of 10%. The basal portion of the Nugget contains interbedded silts and shales and was likely not perforated due to its less continuous nature.

Confining Zone
Confinement for the Nugget is provided by shaley zones above and below. The Gypsum Spring Member of the Twin Creek Limestone lies unconformably on top of the Nugget. It is shale and limestone that contains no porosity. The Gypsum Spring is 151 feet thick (11,771 feet to 11,922 feet). On top of the Gypsum Spring is the Sliderock Member of the Twin Creek Limestone. The Sliderock in the WDW-2 is primarily a tight limestone. It is 85 feet thick (11,686 feet to 11,771 feet).

The Nugget was deposited conformably on top of the Ankareh Formation, which is primarily red/maroon shale with sandstone and limestone. The sandstones and limestones in the Ankareh are tight. The Ankareh is 844 feet thick (12,928 feet to 13,772 feet).

The WDEQ analyzed confinement and found there to be excellent confinement for the Nugget in UIC Permit 06-618, page 11 of 22.

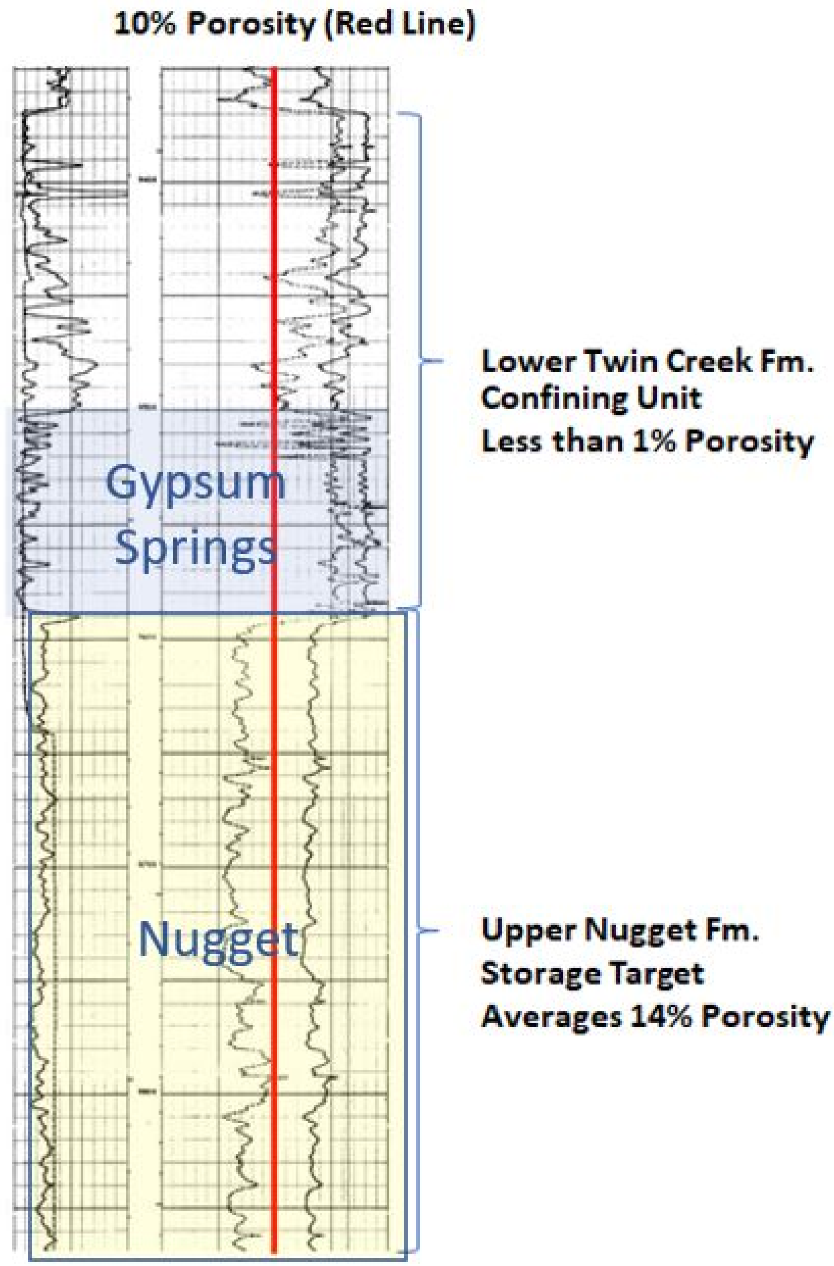


Figure 6. Geophysical type log

The type log (Figure 6) is from Well 32-31B2 API 4120246 showing the geophysical properties of the overlying Gypsum Springs Member of the Twin Creek (Twin Creek MD 8,247) sealing formation and the target injection zone in the Nugget Formation (MD 9,594). This well is located adjacent to the location of proposed injection well

Regional Groundwater Flow

Based on surface topography, existing stream flow directions and subsurface structure the regional groundwater flow is to the west southwest.

Hydrologic and Hydrogeologic Information

A review was conducted of a 39-section area surrounding the proposed location on the Wyoming State Engineer's Office records. Water wells within this area ranged from depths of 2 feet to 800 feet, which is within the Wasatch Formation. The Eocene Wasatch Formation is the second most utilized aquifer in the basin, the Quaternary is the first but is not present at the proposed location. The Wasatch is used for domestic, stock, industrial and public water supply. The Eocene rocks are primarily mudstone and sandstones which become more tuffaceous up section. The Cretaceous Evanston Formation is located beneath the Wasatch and is likely the lowest underground source of drinking water (USDW). Water samples from the area are in the 4,000 mg/L total dissolved solids (TDS) range. No samples from the underlying Gannett were located, but it is likely not a USDW due to limited permeability, the majority of it being confining and not being hydraulically connected to the overlying Evanston. While water quality in the Triassic and Jurassic is fair near recharge zones, it deteriorates quickly with depth. This is typical of all the deeper formations. Nugget TDS values in the area range from 14,616 to 34,900 mg/L.

Geochemical Data

Well Name	Formation	TDS	Charge balance	Na+K (Mg/L)	Mg (Mg/L)	Ca (Mg/L)	HCO3 (Mg/L)	Cl (Mg/L)	SO4 (Mg/L)
Painter Reservoir Unit Pru 31-18ah	Nugget	18,636	0	5,543	292	920	1830	9712	339
Painter Reservoir Unit 13-18ah	Nugget	34,900	0	11,820	389	1200	2196	19,424	260
Painter Reservoir 22-8a	Nugget	51,847	-1.6	17,208	304	1600	NR	28,900	2,540

Painter Reservoir 22-8a	Nugget	52,564	-2.2	17,903	279	1550	NR	30,200	2,570
Painter Reservoir 22-8a	Nugget	43,605	-2.4	11,660	977	4020	NR	24,800	2,030
Painter Reservoir 22-8a	Nugget	56,488	-4.7	18,020	433	2110	NR	33,300	2,550
Painter Reservoir 22-8a	Nugget	54,872	-0.4	18,570	398	2160	13	31,200	2,440
Painter Reservoir 22-8a	Nugget	44,926	-8.2	8,670	1760	4840	NR	27,500	2,100

Figure 7 contains geochemical information for the Nugget Formation.

Geomechanical and Petrophysical Information

The geomechanical and petrophysical data will be collected during drilling, coring, and logging of the proposed injection well. Collected core samples will be analyzed by a certified laboratory to determine the required data and analysis for characterizing the injection and confining zone properties. Geophysical log data including Gamma Ray, dipole sonic, density will be collected, analyzed and used in combination with the core analysis to help further characterize the geomechanical and petrophysical properties of the injection and confining zones.

Injection & Confining Zone Mineralogy, Petrology, and Lithology

The Nugget sandstone contains a high concentration of 62 percent quarts with quartzite and chert making up 2 percent of the matrix (Picard, 1975). K-feldspar comprise 10 percent with plagioclase less than one percent. Accessory minerals are comprised as followed carbonate – 6.6%, secondary silica -1%, micrite < 1 % and rock fragments make up the rest of 1.3%.

Additional mineralogical, petrological, and lithological data for the injection and confining zones will be collected during drilling, coring, and logging of the proposed injection well. Collected core samples will be analyzed by a certified laboratory to determine the required data and analysis for characterizing the injection and confining zone properties. Geophysical log data including X through Z will be collected, analyzed and used in combination with the core analysis to help further characterize the injection and confining zones.

Seismic History, Seismic Sources, and Seismic Risk

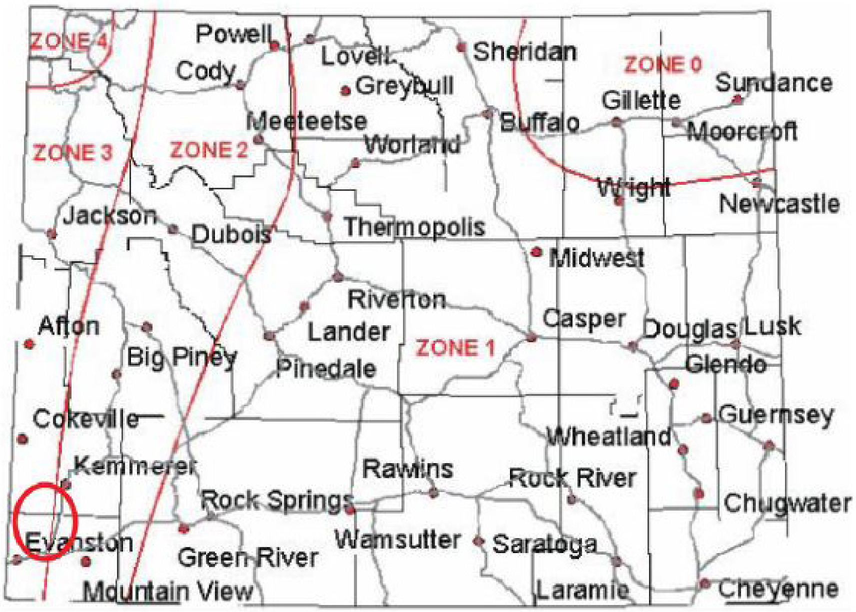
A 2014 report by the Wyoming State Geological Survey identified possible areas of seismicity induced by disposal and injection activities in the state specifically focusing on the time period between 1984 and 2013. There were eight locations identified in the state where further analysis was conducted; none of these sites were in Uinta County. No definitive connection between any seismic activity and injection/disposal well operations was identified in the state. The WDW-2 and its companion WDW-1 (within Whitney Canyon Field), were in operation during the time frame studied.

Case et al, 2002, describes the seismological characteristics for Uinta County, Wyoming. A review of seismic activity was included from the 1960s through the early 2000s. The largest magnitude event mentioned was a 3.4 in 1967. One of the largest seismic events in the area was a 5.3 near Little America, Wyoming in 1995. This was caused by the collapse of a trona mine. There are two exposed regional active fault systems within Uinta County. The Case report also evaluates the probabilities of seismic events of different scales and the potential damage impact of these events (Figure 8).

The International Conference of Building Officials, which focuses on designing buildings and structures to withstand seismic events, created a Seismic Zone Map for Wyoming. These seismic zones are defined in part based on the amount of ground shaking (horizontal acceleration) that may occur. As seen on the Uniform Building Code (UBC) Seismic Zone Map (Exhibit G10), the eastern half of the county lies in Zone 2, with the western half in Zone 3 of the scaling of Effective Peak Acceleration (% gravity (g)). Zone 3 correlates to the UBS by having an effective peak acceleration of 20 to less than 30%g (which corresponds to .2g to .3g in other literature). Peak acceleration is how hard the earth shakes at a geographic location and not a measure of the total energy (or magnitude) of a seismic event.

Case et al, 2002, also identifies literature sources that determine that a “floating earthquake” with a maximum magnitude of 6.0 to 6.5 could occur in the Wyoming Foreland Structural Province, which is defined on the west by the Overthrust Belt. An earthquake event with a maximum peak acceleration of 15%g is reasonably expected; however, accelerations upwards of 20%g would equate to either a Modified Mercalli Intensity event of VI to VII based on a 2,500-year probabilistic acceleration map (2% exceedance in 50 years). A VII intensity event could cause negligible damage to buildings of good design and construction, slight to moderate damage to well-built ordinary structures, considerable damage to poorly built or badly designed structures.

According to the United States Geological Survey (USGS) National Earthquake Information Center (NEIC): Earthquake Database, there have been five earthquakes between 1980 and 2020 within a 32 km radius of the WDW-2. These ranged between 2.5 and 3.3 magnitude. A personal communication with Janie Nelson in 2011 who was the UIC manager for the Wyoming Oil and Gas Conservation Commission (WOGCC) revealed that the WOGCC was not aware of any wells, either UIC or oil and gas, being damaged by an earthquake event in the State of Wyoming. In 1983, a magnitude 6.4 earthquake occurred near an oilfield in California. Out of the 1,725 active wells, only fourteen (14) sustained damage; and it was in a random pattern. Most of the damage was attributed to weak casing caused by corrosion. A review of the likelihood of seismic activity in the Powder River Basin, from probabilistic to worst-case, along with a case-study of an oilfield that has experienced seismic activity, all indicate that there is minimal risk of damage from induced seismic activity. Mechanical integrity testing, and other well integrity confirmation is detailed in another part of this permit application.



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

Modified Mercalli Intensity and peak ground acceleration (PGA) (Wald, et al 1999).

Figure 7. Seismicity Map and Probability Chart for Wyoming

Surface Air and/or Soil Gas Monitoring Data

Collection of this data will begin with the pre-injection testing and monitoring prior to the commencement of operations.

Facies Changes in the Injection and Confining Zones

Due to the coastal and marine nature of the depositional systems of the both the injection zone and confining zone formations facies changes are locally restricted to vertical changes. Lateral changes in facies are considered regional by nature.

The Twin Creek Limestone is a shallow marine deposit that has been divided into seven members: Gypsum Spring, Sliderock, Rich, Boundary Ridge, Watton Canyon, Leeds Creek and Giraffe Creek (Imlay 1967). The bottom most unit, Gypsum Springs, is mostly red soft siltstone and brecciated limestone which is vuggy and chert bearing. Basal brecciated limestone grades into thickening gypsum as you move eastward. Chert bearing limestone become more prevalent and thicker westward. Overall thickness of this unit is between 12 – 400 feet. The Sliderock is a grayish-black medium to thin bedded limestone with basal beds that are oolitic in Wyoming. As you move westward they become more sandy and thicken from 20-285 feet. Rich is a gray shaly limestone that grades eastward into clayey and fossiliferous. It too thickens as you move westward from 40-500 feet. Boundary Ridge is a red-green siltstone that interbedded with silty or sandy or oolitic limestone. It becomes a red siltstone eastward and that transitions westwardly into a limestone. This member thickens westward irregularly from 30-285 feet. Watton Canyon is predominantly gray limestone with basal bed generally massive and oolitic that thin east ward from 400 feet to 60 feet. Leeds Creek is lightly gray shaly limestone with some oolitic silty or sandy ripplemarked limestone. It becomes clayey as you move northwestward in Wyoming thickening westward from 260-1600 feet. Finally the Giraffe Creek is mostly gray silty to sandy ripple marked thin-bedded limestone and sandstone. Some thicker beds of oolitic sandy limestone. This member become sandier and glauconitic westward thickening from 25-295 thick.

It is suggested by Kent (1972) the Nugget sandstone appears to be present throughout much of the western to central Wyoming and is confined above and below by regional unconformities. The Nugget basal unit thickens to the west up to 2000 feet and thin to about 100 feet east of Painter (Jordan, 1965). The Nugget sandstone is divided into two facies, lower thinly bedded facies and an upper cross-stratified facies. The lower member is a variable sequence of clayey siltstone, siltstone, mudstone, silty claystone, sandstone, limestone and dolomite (Picard 1975). Porosity and permeability are of poorer in this unit. The upper cross-stratified facies has been measured in producing oil and gas field range from 0 to 330 feet thick. It is an eolian system that consist of fine to medium grained subangular to subrounded and medium sorted quartz. The cement is calcite or dolomite with some silica cement is present but small amounts. Porosity and permeability are of high reservoir quality.

Compatibility of the CO_2 with Subsurface Fluids and Minerals

Compatibility with subsurface fluids. This section provides geochemical modeling of the target formation brines and the compatibility with CO_2 injectate. Geochemical data was downloaded from the United States Geological Survey produced water data base and cross referenced with data sets housed at the Wyoming Oil and Gas Conservation Commission. Water quality data was selected from Painter Reservoir Unit 13-18ah for the preliminary geochemical models. These data provide the basis for the geochemical modeling to understand the compatibility with CO_2. Thermodynamic calculations and reaction path models based on the analytical results from the were computed using Geochemists Workbench (Bethke 1996).

The project team calculated species activities and saturation states to characterize thermodynamic controls on the water-rock system. The speciation model results are presented in Figure 9 Table 2.

Aqueous species	molality	mg/kg sol'n	act. coef.	log act.
Cl-	0.05471	1928.	0.7471	-1.3885
HCO3-	0.02416	1466.	0.7731	-1.7286
Ca++	0.02323	925.4	0.3850	-2.0485
Mg++	0.01369	330.6	0.4320	-2.2283
CO2(aq)	0.006889	301.4	1.0000	-2.1618
CaHCO3+	0.003555	357.2	0.7836	-2.5551
CaCl+	0.002395	179.8	0.7650	-2.7370
MgHCO3+	0.001477	125.3	0.7650	-2.9468
SO4--	0.001397	133.4	0.3311	-3.3348
CaSO4	0.0008640	116.9	1.0000	-3.0635
MgSO4	0.0004617	55.24	1.0000	-3.3356
MgCl+	0.0004465	26.52	0.7650	-3.4665
CaCO3	7.850e-05	7.810	1.0000	-4.1051
MgCO3	2.609e-05	2.187	1.0000	-4.5835
CO3--	1.546e-05	0.9224	0.3453	-5.2725
Mg2CO3++	1.498e-06	0.1617	0.3590	-6.2694
H+	1.915e-07	0.0001919	0.8275	-6.8000
OH-	8.583e-08	0.001451	0.7564	-7.1876
MgOH+	7.878e-08	0.003235	0.7650	-7.2199
CaOH+	1.508e-08	0.0008556	0.7650	-7.9380

(only species > 1e-8 molal listed)

Figure 8. Table 2

The project team investigated reaction pathways for the Nugget brine in response to CO_2 injection. The modeling parameters were defined by minerals typical of eolian sandstone reservoirs and the water quality data compiled from public resources. The geochemical model simulates CO_2 injection in the reservoir at 100 degrees.

Figure 10 provides the estimated change in aqueous species. Examination of figure 10 shows that as the CO_2 concentration increases there is a corresponding increase in bicarbonate and hydrogen concentration. The increase in H+ corresponds to an overall decrease in formation pH. Figure 11 shows the anticipated reduction in formation pH as a result of increased CO_2 concentrations. These models will be updated with petrophysical analysis performed on the core and with representative fluid samples collected from the stratigraphic test well. For example the amount of carbonate minerals in the petrographic analysis will help to estimate overall pH changes as a result of CO_2 injection. Initial modeling results indicate that while we expect a change in formation pH the other major aqueous components remain unchanged.

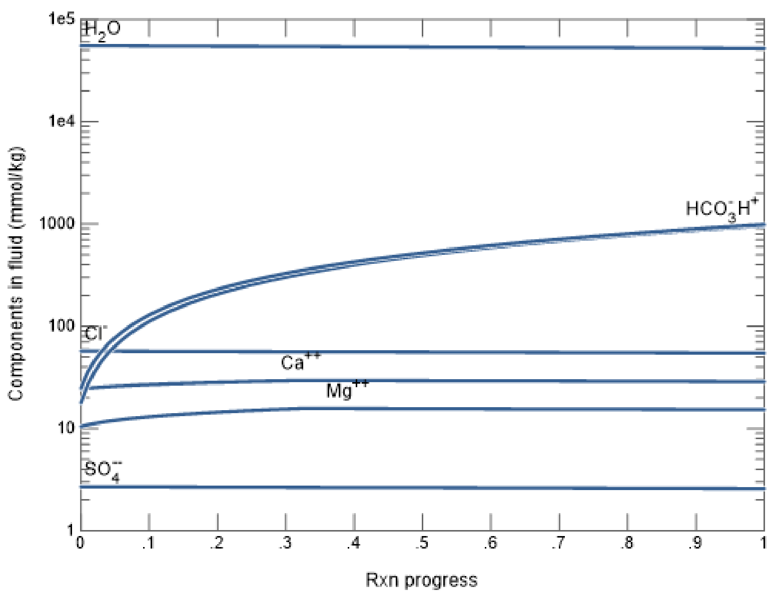


Figure 9. Aqueous Species Results

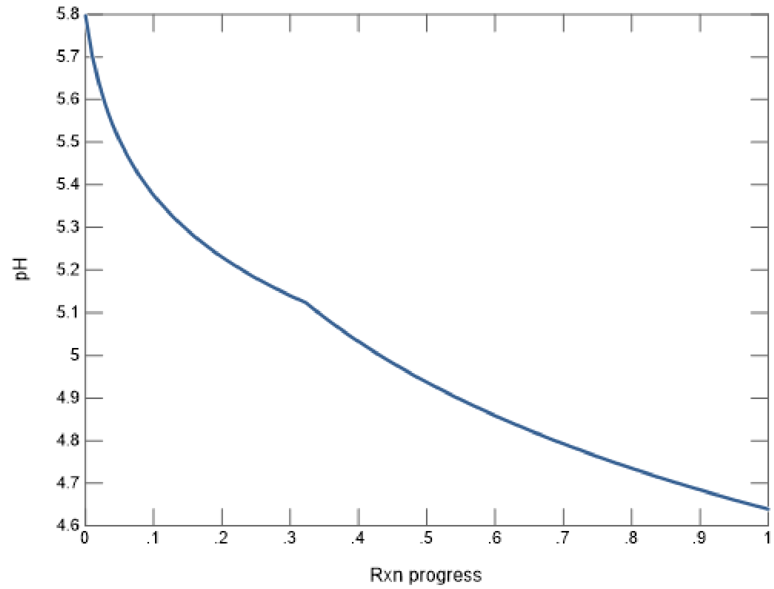


Figure 10. Formation pH Results

Compatibility with subsurface minerals. The Nugget sandstone is a quartz-rich sandstone. Quartz, calcite, anhydrite, and feldspar were added to the geochemical model to estimate potential compatibility and reactions in response to the changes in fluid chemistry. The geochemical models suggest a slight super saturation in quartz with decreasing pH indicated a potential to increase quartz precipitation. The changes are small, however and it is unlikely that increased CO_2 concentrations will have an abnormal effect on quartz-rich formation.

Injection Zone Storage Capacity

Painter Reservoir is a depleted oil and gas reservoir; in April of 2020 the field was shut-in (Figure 12). Hydrocarbon production in the field was from the Nugget Sandstone. The field cumulatively produced 38 mmbo of oil, 803 bcf of natural gas and 30 mmbw. Previous work by North Shore indicate that the depleted hydrocarbon reservoir is capable of storing up to 6 tcf of CO_2.

The area selected for injection and geologic sequestration in section 31 was evaluated by Carbon Solutions for the purposes of modeling and simulation of permanent storage of CO_2. This work resulted in a CO_2 storage capacity of 7.5 MT per section for the Nugget Sandstone reservoir in the Painter A Field.

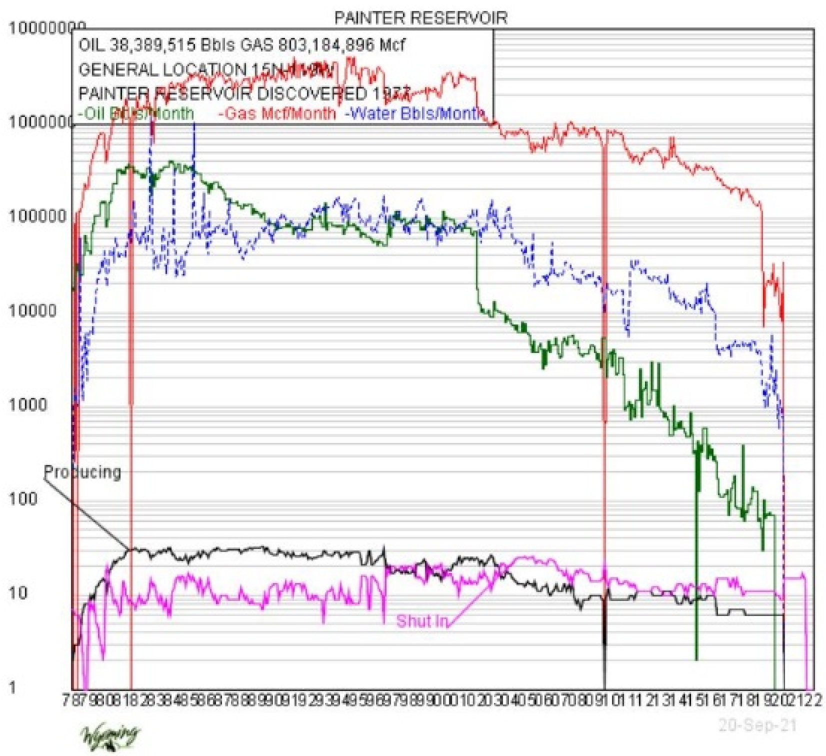


Figure 11. Painter Reservoir Production Graph

Confining Zone Integrity

Within the AOR there are 55 wells that penetrate the confining and injection zone. Of these 12 wells are temporarily abandoned, 9 are permanently abandoned, and 34 are presently shut-in. This data was compiled from the Wyoming Oil & Gas Conservation Commission.

The geological and lithological characteristics of the confining zone that is comprised of the Pruess and Twin Creek Formations make it an ideal seal. The units are primarily highly cemented carbonates consisting of dolomite and limestone. The permeability values within these units average less than 1 md and the porosity values average less than 1 percent. Though the units are likely fractured as a result of tectonic deformation the fractures are filled with calcite cement and have served as sealed network that contained the hydrocarbon accumulations within the Painter Reservoir oil and gas field.

Groundwater/Aquifer Characterization

Injection Zone and Aquifer Characterization

Within the AOR there are a total of 17 groundwater wells. These wells consist of 3 stock wells, 6 industrial wells, 4 MISC wells, and 4 monitoring wells. These wells range in depth from 20 to 4,507 feet except for 1 industrial source water well that was initially drilled as an exploration oil and gas well to a depth of 12,047 feet but was plugged back and converted to a source water well with a screened depth of 543 feet. This data was compiled from the Wyoming State Engineer's Office.

A review was conducted of the 36-section area surrounding the proposed location on the Wyoming State Engineer's Office records. Water wells within this area ranged from depths of 2 feet to 800 feet, which is within the Wasatch Formation. The Eocene Wasatch Formation is the second most utilized aquifer in the basin, the Quaternary is the first but is not present at the proposed location. The Wasatch is used for domestic, stock, industrial and public water supply. The Eocene rocks are primarily mudstone and sandstones which become more tuffaceous up section. The Cretaceous Evanston Formation is located beneath the Wasatch and is likely the lowest underground source of drinking water (USDW). Water samples from the area are in the 4,000 mg/L total dissolved solids (TDS) range. No samples from the underlying Gannett were located, but it is likely not a USDW due to limited permeability, the majority of it being confining and not being hydraulically connected to the overlying Evanston. While water quality in the Triassic and Jurassic is fair near recharge zones, it deteriorates quickly with depth. This is typical of all the deeper formations.

Aquifer Stratigraphy

Figure 13 is a stratigraphic chart for the Painter Reservoir area that denotes underground sources of drinking water and various zone types 1. USDW, 2. Confining, and 3. Saline properties.

Aquifer and Receiver Details

Age	Unit	Thickness-Range	Zone Type	Water Quality
Pliocene and Miocene	Salt Lake Aquifer	Not Present	USDW	Fresh

Oligocene	Bishop Conglomerate	Not Present	Confining	
Eocene	Fowkes Aquifer	Not Present	USDW	Fresh
	Sillem Member	Not Present		
	Bulldog Member	Not Present		
	Hollow Member	Not Present		
	Gooseberry Member	Not Present		
	Green River/Wasatch Formations	At Surface	USDW	Fresh
	Fossil Butte / Bullpen Members	200-325		
	Angelo / Tunp Members	0-200		
Eocene-Paleocene	Conglomerate of Sublette Range	600	Confining	
Paleocene	Fort Union Formation			
Paleocene-Cretaceous	Evanston Formation		USDW	Fresh
	Main Body	650		
	Hamsfork Conglomerate	1000		
	Unnamed Unit			
Upper Cretaceous	Adaville Formation	2100		Saline
	Hilliard Shale	5600-5900	Confining	
	Frontier Formation	2200-3000		Saline
	Sage Junction Formation	3000		Saline

Upper-Lower Cretaceous	Aspen Shale	800-2000	Confining	
	Wayan Formation			Saline
	Quealy Formation	500		Saline
Lower Cretaceous	Cokeville Formation	1900-2500	Confining	
	Bear River Formation	650-1800		Saline
	Thomas Fork Formation	350-2000		Saline
	Smiths Formation	750		Saline
	Gannett Formation	800	Confining	
Upper-Middle Jurassic	Stump Formation	1100		
	Redwater Member			
	Curtis Member			
Middle Jurassic	Preuss Formation	350	Confining	
	Twin Creek Formation	440	Confining	
	Nugget Sandstone	600-1000	Injection Target	
Upper Triassic	Ankareh Formation	920	Confining	
Upper-Lower Triassic	Thaynes Formation	700	Confining	
Lower Triassic	Woodside Formation	650	Confining	
	Dinwoody Formation	545	Confining	
Permian	Phosphoria	230		Saline

Permo-Pennsylvanian	Wells Formation	600		Saline
Penn-Mississippian	Amsden Formation	150		Saline
Upper Mississippian	Madison Formation	1000-1800		Saline
Upper Devonian	Darby Formation	450-885		Saline
Silurian	Laketown Formation	1000	Confining	
Upper Ordovician	Bighorn Formation	400		Saline
Upper Cambrian	Gallatin Formation	230-400		Saline
Upper-Middle Cambrian	Gros Ventre Formation	650		Saline
Lower Cambrian	Flathead Formation	175-200		Saline
Precambrian	Crystaline Rocks			

Figure 12. Table 3. Stratigraphy and Unit Classifications

Baseline Geochemical Data

Baseline geochemical data is currently being collected for analysis. Samples will be collected from surface and ground water sources as well as from the target injection zone withing the Nugget Formation. Core samples will be collected during drilling and coring of the proposed well for compositional, mineralogical, fluid-matrix analysis, and porosity and permeability from both the sealing formation and the target injection formation.

Determination of Underground Sources of Drinking Water (USDW)

The Eocene Wasatch Formation is the second most utilized aquifer in the basin, the Quaternary is the first but is not present at the proposed location. The Wasatch is used for domestic, stock, industrial and public water supply. The Eocene rocks are primarily mudstone and sandstones which become more tuffaceous up section. The Cretaceous Evanston Formation is located beneath the Wasatch and is likely the lowest underground source of drinking water (USDW). Water samples from the area are in the 4,000 mg/L total dissolved solids (TDS) range. No samples from the underlying Gannett were located, but it is likely not a USDW due to limited permeability, the majority of it being confining and not being hydraulically connected to the overlying Evanston. While water quality in the Triassic and Jurassic is fair near recharge zones, it deteriorates quickly with depth. This is typical of all the deeper formations. Nugget TDS values in the area range from 14,616 to 34,900 mg/L.

Groundwater Quality Data

There are two records at the WOGCC one for the Evanston Formation and one for the Nugget Formation. At the present there is an effort in compiling existing analysis and or samples for analysis. Samples will be collected from ground water wells and producing oil and gas wells and will be submitted for analysis and appended to this application once complete.

Water Quality Analysis and Groundwater Classification

Samples will be collected from ground water wells and producing oil and gas wells and will be submitted for analysis and appended to this application once complete.

Aquifer Exemptions

This is not applicable for this permit application because the target injection zone is a depleted hydrocarbon reservoir.

Area of Review

The delineation of the Area of Review (AOR) was determined by modeling and simulation resulting in a pressure front expected from the injection of CO_2. The AOR encompasses portions of townships 15 and 16 north, ranges 119 and 120 west. The proposed location of injection is in township 16 north, range 119 west, section 31. The AOR is restricted on the eastern margin by a sealing, blind fault related to structural deformation related to the Fold and Thrust Belt that evolved during the Sevier Orogeny. The AOR encompasses portions of 39 sections within the previously mention townships and ranges (Figure 14).

Area of Review Map

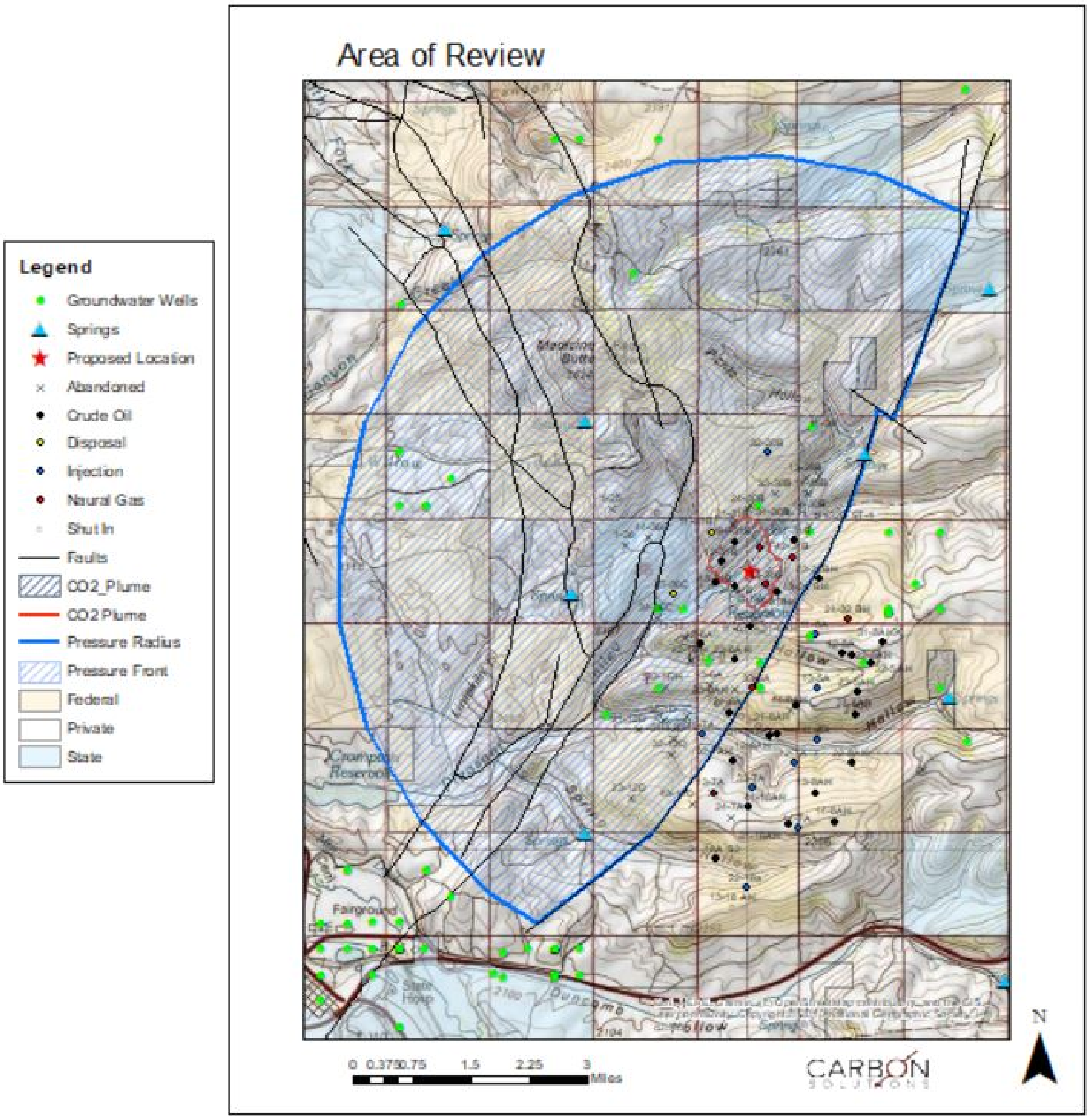


Figure 13. Map showing Area of Review based on Modeling and Simulation

Area of Review Map Based on Modeling

See Attachment 1, Area of Review and Corrective Action Plan.

Structure and Isopach Maps

Structure and Isopach maps were generated from the interpretation of geologic formation characteristics on geophysical well logs. Tops were selected based on previously defined criteria related to log responses. A type log denoting the geophysical responses on a gamma ray log are displayed in figure 4. Figure 15 is a representation of the geological structure of the injection target of the Nugget Formation. Figure 16 shows the relative thickness of the Nugget Formation and Figure 17 represents the thickness of the overlying sealing units of the Pruess and Twin Creek Formations.

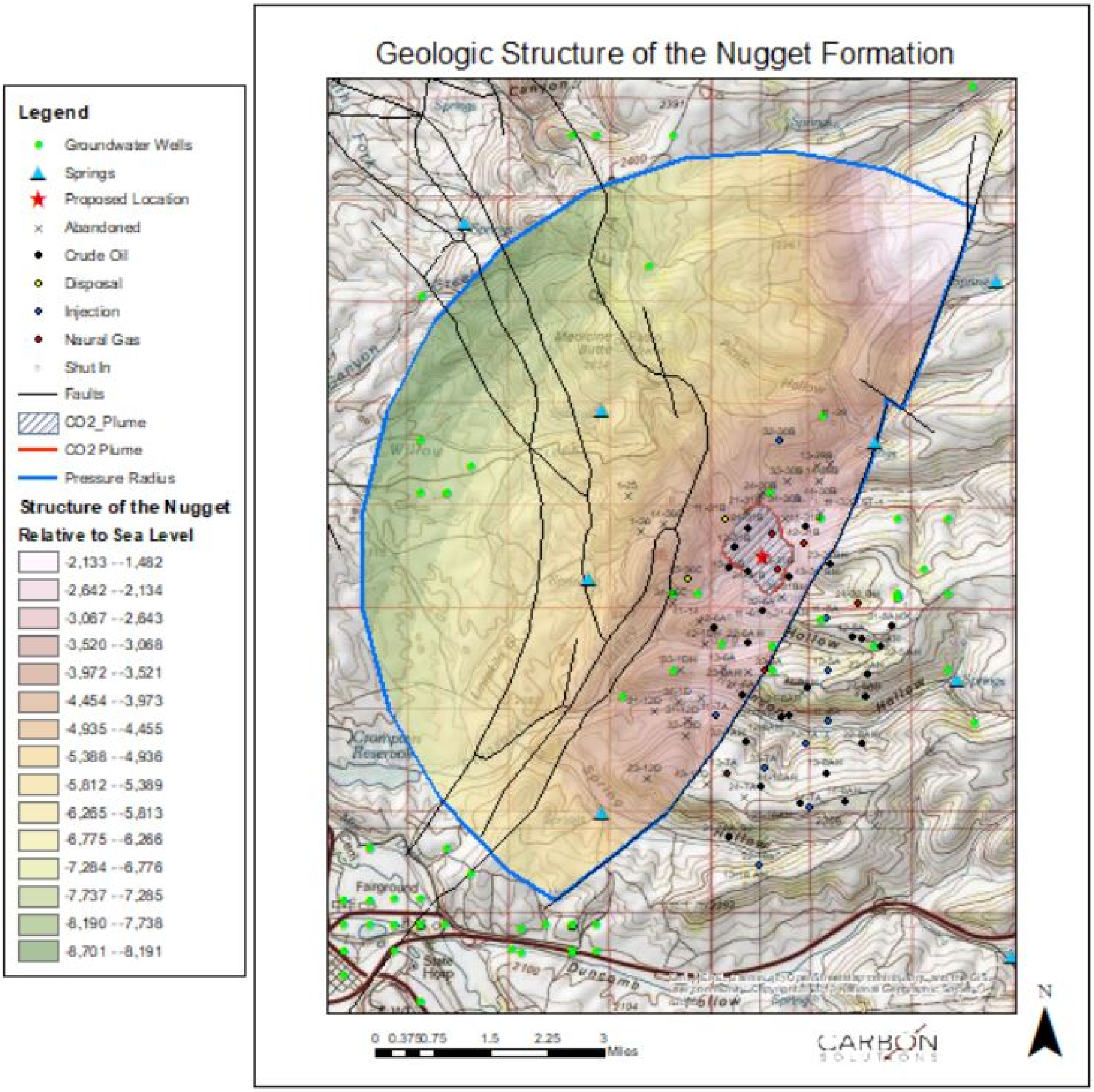


Figure 14. Geologic structure map of the Nugget Formation based on available geophysical well and seismic data.

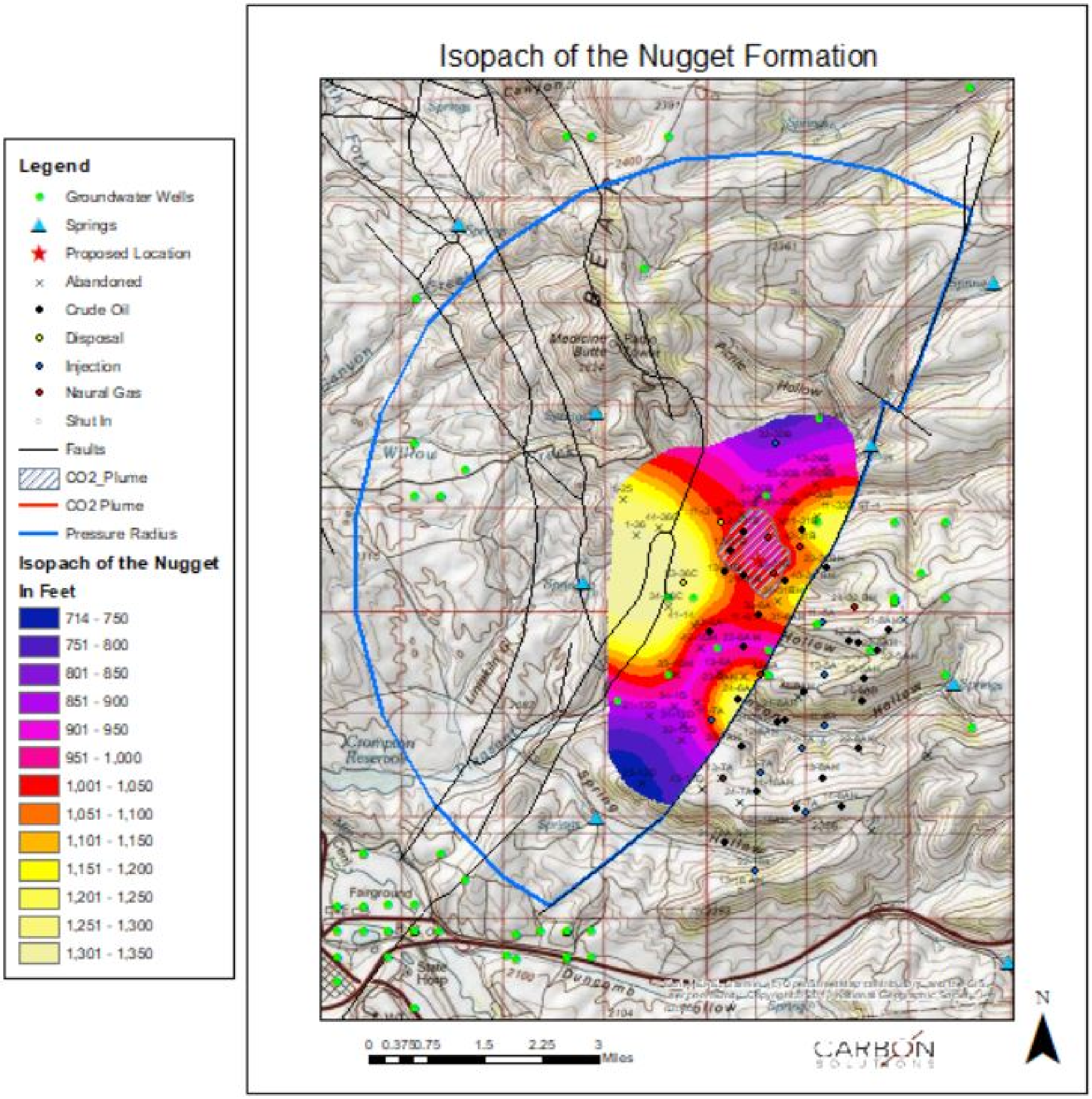


Figure 15. Isopach of the Nugget Formation based on available geophysical well data.

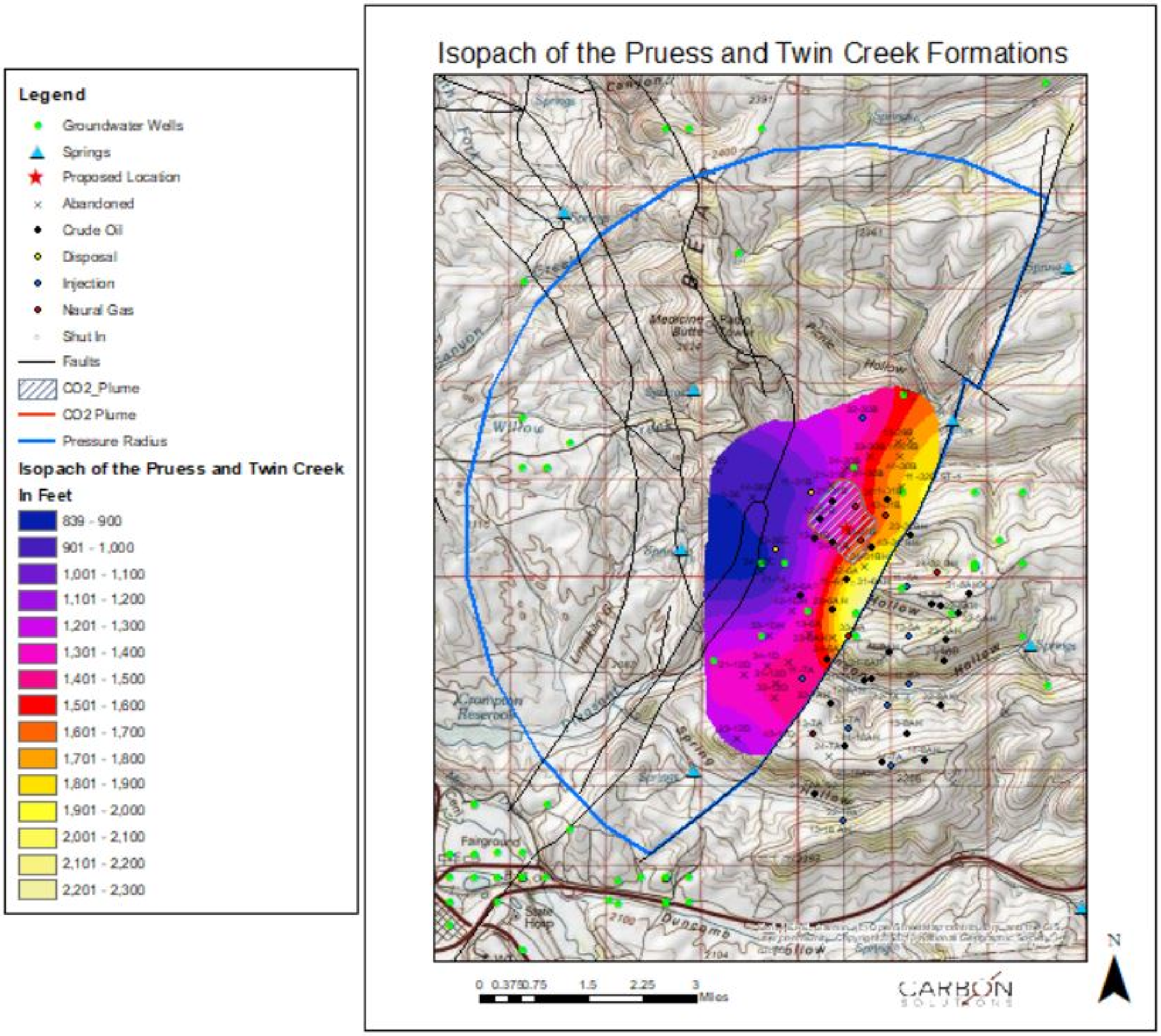


Figure 16. Isopach of the Preuss and Twin Creek Formations based on available geophysical well data.

Modeling and Simulation

In Wyoming DEQ Chapter 24 Class VI Injection Wells and Facilities Underground Injection Control Program, the AOR is defined as 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 CO_2 plume is delineated by the injection simulation, and the pressure front is defined as a zone where there is a pressure differential sufficient to cause movement of injected fluids or formation fluid into the lowest USWD if a migration pathway or conduit were to exist, calculated from the magnitude of elevated pressure that is created by the injection (dynamic simulation) of the CO_2 into the storage reservoir.

The EPA provides guidance about how to determine the AOR by the critical pressure/pressure front (USEPA, 2013). The pressure front corresponds to the minimal pressure increase needed to move fluids from the reservoir into a USDW through a hypothetical open conduit, such as an uncemented borehole or fault. The delineation of an AOR is calculated from the pressure front that is derived from the results of the CO_2 injection simulations.

The critical pressure/front pressure can be determine using the equation:

$Pc = Pu + \rho ig \cdot (zu - zi) - Pi$

where:

Pu =the initial pressure at the base of the USDW (Pa=kg/m·s2),

ρi =the density of the injection zone fluid (kg/m3),

g =the acceleration of gravity (m/s2),

zu =the elevation of the base of the lowermost USDW (m),

zi =the elevation of the top of the injection zone (m), and

Pi =the initial pressure in the injection zone (Pa).

At the injection site (Injector 1), the initial pressure at the base of the USDW (bottom of the Evanston Formation) is 1,687 psi (assuming a typical 0.433 psi/ft gradient) at an elevation of 3,104 ft. The pressure of the storage reservoir is 3,500 psi at an elevation of -2,478 ft (below sea level). The density of reservoir water is 1,100 kg/m^3. Using the above equation, the critical pressure for fluid migration into the Evanston Formation from the targeted storage reservoir Nugget Sandstone is 849 psi. The AOR for the proposed Class VI well can be defined by the 849-psi isoline on the delta-pressure (Dp) map after 15 years of injection.

The Dp map for each simulation case is generated by subtracting the initial pressure distribution from the field pressure distribution after the 15-year CO_2 injection simulation. Figure X shows the increase in reservoir pressure (delta pressure) for Case 1. The circle line on the figure is the critical pressure contour line of 849 psi (estimated, 4 mile from the CO2 injection well, Inj1), which marks the AOR for Case 1, injecting 0.25 MT/year without water extraction). For Case 2, the Dp did not reach the critical pressure even near the injection site (Figure X). In this scenario, the AOR is defined by the maximum extension of the CO_2 plume (Figure X).

Modeling:

The geologic structure framework and property models are developed using formation top picks from 46 wells, which included available well log curves from 26 las files, and core-measured porosity and permeability provided by North Shore Energy LLC (Figure X). The petrophysical data used to build the model and for analysis were obtained from spectral gamma ray, neutron, density, and sonic logs from the 46 wells.

The static geological model that was built includes the injection storage reservoir Nugget Sandstone, the overlying Twin Creek and underlying Ankareh formations, both of which are confining zones. The model covers an area of 1.4 X 3.8 miles (4.6 square miles total area) with elevation ranging from -435 ft to -5,643 ft below sea level. The model is represented by a 128 X 202 X 16 grid that contains a total of 413,696 cells. The average horizontal cell dimensions are 97 ft in the X direction and 99 ft in the Y direction. The vertical cell dimensions vary with geologic intervals, and are smallest in the injection zone, and average 80 ft across the model. The location of the thrust fault that bounds the eastern portion of the field was digitized from a published map (Frank et al., 1982). The northern and western field boundary were determined by the structural map and injection operational goals of plume containment within the anticline.

While the most reliable estimate of porosity and permeability are provided by core and geophysical log measurements, such measurements are typically sparsely distributed within a model domain. Geostatic interpretation methods such as kriging and sequential Gaussian Simulation were used to develop 3D statistic property distributions throughout much of the inter-well model space that are conditioned to honor available well log and core data.

The geologic modeling workflow included the use of gamma ray and density for lithology facies classification. Porosity logs were co-Kriged with the facies model to create the 3D porosity distribution. There is no permeability log available for this study. Instead of co-kriging permeability logs with the porosity model generated in the previous step to create a 3D permeability distribution, the correlation between porosity and permeability was derived from legacy Nugget core data collected from this field.

The anticlinal structure of the Painter A Field for the Nugget reservoir has 1,600 ft of closure within the field boundary. The thickness of the Nugget Sandstone ranges from 700 ft to over 1,200 ft as isochore thickness.

There is no permeability data from the log measurements. The correlation between porosity and permeability was derived from legacy core data (4,903 pairs, Figure 6). The following function was used to create the permeability distributions throughout the model domain from the porosity model.

$$\text{Log } k = -2.65+0.35\Theta-0.0052\Theta^2$$

The modeled permeability ranges from 0.002 to 113 mD, with a mean of 6.6 mD. Both overlying and underlying confining layers have low permeability with an average of less than 0.05 mD.

Simulation:
Reservoir simulation was conducted using ECLIPSE industry-standard reservoir simulator. The main purpose of the CO_2 injection simulation for this study is to evaluate the injection feasibility, CO_2 migration and plume development, storage capacity, injection pressure, reservoir pressure propagation, and determine the AOR for a Class VI well application.

The Nugget Sandstone in Painter A Field is an under-pressured formation and follows a gradient of 0.39 psi/ft for initial reservoir pressure and assumes a 0.35 psi/ft of gradient for current reservoir pressure. The reservoir model was equilibrated following the current reservoir pressure gradient with a reference pressure of 3,500 psi at 10,500 ft.

The injection simulation contains 1 injection well (Injector 1) and two pressure management wells (Producer 1 and 2): this configuration allowed for testing simulations with and without active pressure management. The injection well is located in the center of Section 31, Township 16 North, Range 119 West (X281055, Y239767), with a perforated interval that ranges from

9,478 ft to 10,403 ft (completion length 925 ft). The pressure management well Producer 1 is located in Section 30, T16N, and R119W, with perforated intervals from 10,028 ft to 10,980 ft (completion length 952 ft). Producer 1 is near well Millis WI Unit-A 1, API 4904120262; Producer 2 is located in Section 1, T15N, and R120W, with perforated intervals from 9,896 ft to 10,796 ft (completion length 900 ft). Producer 2 is near well Painter Reservoir UN 13-6A, API 49020133.

Two injection scenarios were tested: Case 1 assessed 0.25 MT/year without fluid extraction and Case 2 assessed 0.25 MT/year of injection with fluid extraction. Both cases were run for 15-years of continuous injection, then 10-year post injection observation. The injection pressure is constrained by the Bottom Hole Pressure (BHP) of 5,175 psi which is 80% of the fracture pressure of rock at injection depth (estimated from Poisson ratio, overburden and pore pressures). The pressure management was controlled by a BHP of 4,120 psi at which fluid was co-produced (artesian flow) based on the reservoir pressure. Table 1 lists parameters used for CO2 injection simulations in the Weber Sandstone.

The CO_2 plume size after 15 years of continuous injection at a rate of 0.25 MT/year (685 T/day) and without active pressure management/fluid extraction (Case 1) requires approximately one square mile. The CO_2 plume stays within Section 31, T16N and R119W. The injection rate can be maintained for the entire injection period (15 years), with a total of 3.75 MT CO_2 injected. The injection pressures (THP) ranged from 2,683 to 4,132 psi, the BHP ranged from 3,412 psi to 5,094 psi, and the field pressures ranged from 3,336 psi to 5,018 psi.

Figure 18 shows the CO_2 plume size after 15 years of injection at a continuous rate of 0.25 MT/year with pressure management/fluid extraction from the 2 producing wells (Case 2). The CO_2 plume stays within Section 31. The injection rate can be maintained for a 15 year injection period, with a total of 3.75 MT CO_2 injected. The injection pressures (THP) ranged from 2,683 to 3,177 psi, the BHP ranged from 3,426 to 4,013 psi, and the field pressures ranged from 3,341 to 3,996 psi, well below the fracture minimum (Figure 11). Compared with the results of CASE 1, THP, BHP and field pressure all are much lower. The maximum rate of fluid extraction reached 3,793 STB/D, cumulative liquid production is 1.46E7 STB at the end of active injection (Figure X).

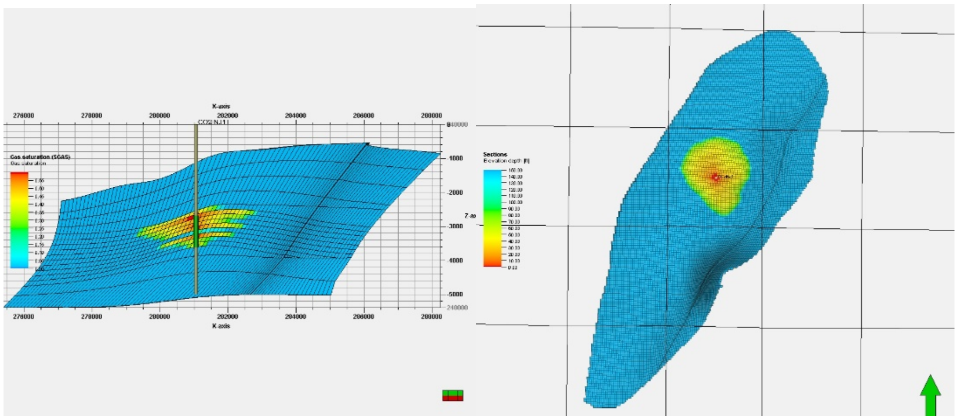


Figure 17. The CO2 plume in map view (right) and cross section (left) for Simulation results after 15 years of injection

Well Construction Information

Open hole diameters and intervals

Name	Depth Interval (feet)	Open Hole Diameter (inches)	Comment
Surface	0-3300	17-1/2	Below lowest USDW
Intermediate	0-7700	12-1/4	To primary seal
Liner	7700-10520	8-1/2	To total depth

Casing Specifications

Name	Depth Interval (feet)	Outside Diameter (inches)	Inside Diameter (inches)	Weight (lb/ft)	Grade (API)	Design Coupling (short or long threaded)
Surface	0-3300	13-3/8	12.515	61	J55	Short
Intermediate	0-7700	9-5/8	8.835	40	J55	Long or Buttress
Production Liner (carbon)	7500-9000	7	6.094	32	L80	Long or Buttress
Production Liner (chrome)	9000-10520	7	6.094	32	L8013CR	Special

Surface Casing is 3300 ft of 13-3/8 inch casing that isolates the bottom more USDW zone in the Ericson formation. Casing is cemented to surface. Coupling outside diameter is 14.375 inches.

Intermediate Casing is 7700 ft of 9-5/8 inch casing that extends into the Gannet which is the first sealing formation below the lowest USDW. Casing is cemented to surface. Coupling outside diameter is 10.625 inches.

Production Liner is hung off at 7500 ft using a hanger made of nickel plated and internally hardened elements, Liner is 3020 ft of 7" casing. The top section 7500 ft to 9000 ft is L80 (carbon) and the lower section 9000 ft to 10520 ft across the injection zone is L80-13CR (chrome). The entire string is cemented with corrosion-resistant cement. Coupling outside diameter is 7.656 inches for L80 and 7.375 inches for L8013CR.

Tubing Specifications

Name	Depth Interval (feet)	Outside Diameter (inches)	Inside Diameter (inches)	Weight (lb/ft)	Grade (API)	Design coupling (short or long thread)	Burst Strength (psi)	Collapse Strength (psi)
Injection Tubing	0-9450	3-1/2	2.75	12.7	L8013CR	Special	15000	15310

Specified yield strength on tubing and connection is 230,990 lbs.

The injection well has approximately 100 feet of cement above the production liner casing shoe to prevent injection fluid from coming in contact with lower zones.

Borehole Diagram

Casing and Tubing Detail

String Name	Open Hole	Outside Diamete	Inside Diamete	Depth Interval	Weig ht	Grade
Conductor	30"	20"	19.124"	0-75	94	J55
Surface	17-1/2"	13-3/8"	12.515"	0-3300'	61	J55
Intermediate	12-1/4"	9-5/8"	8.835"	0-7700'	40	N80
Production Liner (top)	8-1/2"	7"	6.094"	7500-	32	L80
Production Liner (bottom)	8-1/2"	7"	6.094"	9000-	32	L8013CR
Tubing	-	3-1/2"	2.750"	0-9450'	12.7	L8013CR

Formation Tops	MD
Green River/Wasatch Formatio	0
ossil Butte / Bullpen Members	
Angelo / Tunp Members	
Conglomerate of Sublette Range	
Fort Union Formation	1000
Evanston Formation	1500
Main Body	
Hamsfork Conglomerate	
Unnamed Unit	
Thomas Fork Formation	6362
Smiths Formation	7000
Gannett Formation	7500
Stump Formation	8026
Redwater Member	
Curtis Member	
Preuss Formation	8970
Twin Creek Formation	9290
Nugget Sandstone (Injection Zone)	9452
Ankareh Formation	10490
Thaynes Formation	11302

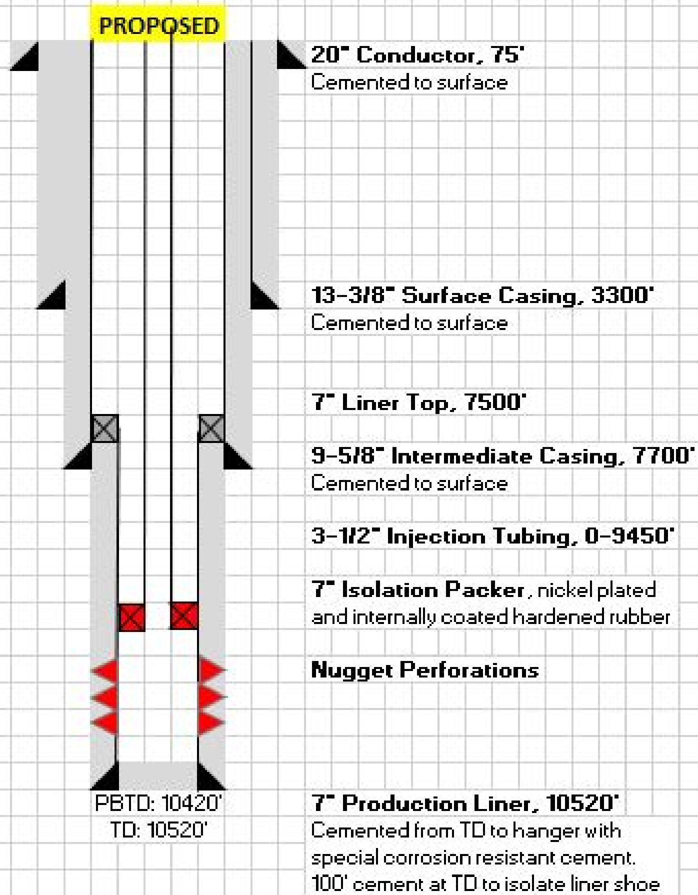


Figure 18. Borehole Diagram

Pre-Operational Testing Plan

The Pre-Operational testing plan will be provided to the Administrator upon its completion.

Operating Data

The daily average expected rate is 12.2 mcf/day up to a maximum of 15.5 mcf/day. The average expected surface injection pressure is 2,680 psi up to a maximum of 3,190 psi. The source of the CO_2 to be injected is from an industrial source that will be generated on site. The injection of CO2 into the Nugget Formation at Painter A is expected to last for 15 years.

Required Plans (See Attachments)

- Area of Review and Corrective Action Plan
- Testing and Monitoring Plan
- Injection and Monitoring Wells Plugging Plan
- Post-Injection Site Care and Site Closure Plan
- Emergency and Remedial Response Plan

Financial Assurance

Financial Assurance will be provided to the Administrator upon its completion.

Phases of geologic sequestration project

Permitting and Characterization
Testing and Monitoring (Section 20)
Operations and Well Plugging (Sections 18 and 23)
Post-Injection Site Care
Emergency and Remedial Response (Section 25)

Financial Cost Assurance Cost Estimates

Corrective Action Plan
Plugging the Injection Well
Post Injection Site Care
Testing and Monitoring
Emergency and Remedial Response

Risk Matrix and Risk Analysis

Risk No.	Major Risk Category	Risk Scenario Description Specific to the Painter Field	Risk Potential	
			Probability	Impact
1	Mineral Rights Infringement (Trespass)	Injection within the Nugget Sandstone at the proposed well site affect adjacent mineral resources, and subsequent mineral lease owners, via trespass, displacement or co-		

		mingling of invaded fluids. Currently, mineral leases are owned by the proposed injection operator, which would negate risks associated with infringement. The largest current concern with respect to impacts is encroachment or displacement of Federal minerals, though the field has been produced, subjected to years of tertiary recovery via nitrogen, and subsequently blown down and is currently under pressured.		
1.1	Leakage migrates into mineral zone or hydraulic front impacts recoverable mineral zone; causes may include plume migration different than modeled.	All mineral resources within the field area are limited to the Nugget Formation, and the economic minerals within this formation have been produced. Migration outside of zone of production would be into water saturated zones. Exploratory wells have been drilled around the field in search of economic minerals. There are no other economic minerals identified in other formations where excursion could happen.	1.5	2
1.2	Post injection discovery of recoverable minerals.	As noted under Risk No. 1.1, this area has extensively explored for recoverable/economic minerals, limiting the potential for new discoveries. This lessens the probability of impact under this risk scenario.	2	2
1.3	New technology (or economic conditions) enables	As described under Risk #s 1.1 and 1.2, this injection zone has already been produced, then flooded with N_2 during tertiary recovery.	1	2

	recovery of previously un-economically recoverable minerals.	There are no residual minerals of quantity. Overlying sealing formations are not described as having quantifiable organic resources, lessening the potential of future unconventional resource production. This lessens the probability of impact under this risk scenario.		
1.4	Act of God (e.g. seismic event).	An unforeseen and uncontrolled event, such as a major earthquake, results in the infringement of mineral rights. The study area is susceptible to natural seismicity. With respect to this risk and impacts to long-term storage, the following observation is provided: The field has held natural gas, at pressure, through geologic time, without evidence of leakage such as seeps. This suggests that historical seismicity is unlikely to impact fluids within the injection zone either through breaching of overlying seals or development of fluid pathways related to faults/fractures. However, surface infrastructure could be impacted by seismicity. Damage of surface structures is unlikely to impact mineral rights. This lessens the probability of impact under this risk scenario.	1	3
1.5	Formation fluid impact due to CO_2 injection.	CO_2 injected into the Nugget Sandstone impacts reservoir fluid quality by geochemical processed.	2	2

		Injection is designed to take place within the gas cap of the geologic structure. Formation fluids do not saturate this zone, lessening impacts from injection via dissolution and geochemical alteration. The largest impact to formation fluids would be displacement related to pressurization.		
1.6	Address also contributing causes 3.1, 3.2, 3.3, 3.5, 4.3, and 4.4	Mineral rights infringement from: Overpressurization (i.e. induced), Caprock/reservoir failure. Well blowout (e.g. at surface or bore failure below ground), includes monitoring wells – Causes could include seal failure (e.g. well, drilling or injection equipment). Orphan well failure (e.g. well not identified prior to injection). Incomplete geological seal (e.g. inaccurate characterization of sub-surface geology). Well seal failure (e.g. well, drilling or injection equipment) including monitor wells. All leasable minerals are located within the proposed injection zone (Nugget Sandstone), so mineral infringement associated with vertical migration is negligible. Contributing causes 3.1, 3.2, 3.3, 3.5, 4.3, and 4.4 are mostly be associated with vertical migration.	1.5	2
2	Water Quality Contamination	Risk of groundwater contamination via leakage of brine, CO_2, liquid or gaseous hydrocarbon and/or other gases into the Evanston Formation, or shallower USDWs.		

2.1	Leakage of CO_2 outside permitted area.	With respect to water quality, leakage of CO_2 into the Evanston Formation outside of the permitted area would necessitate CO_2 migration within the Evanston Formation after infiltration or infiltration along a horizontal pathway that facilitates the migration of CO_2 away from the injection zone.	2.5	2
2.2	Leakage of drilling fluid contaminates potable water aquifer.	Leakage of drilling fluids and subsequent contamination of USDWs could happen by spillage at the, as the well was being drilled, or by loss of fluid to formation during drilling. As a note, this area has seen previous drilling operations without incident of leakage. This lessens the probability of impact under this risk scenario.	2	1
2.3	Rock/acid water (i.e. geochemistry) interaction contaminates potable water by carryover of dissolved contaminants.	Events such as those described in Risk #3 and 4 impacts potable water in the site's USDWs.	2	2
2.4	Act of God (e.g. seismic event).	An unforeseen and uncontrolled event, such as a major earthquake, results in water quality contamination. Act of God risk scenarios could result in well or infrastructure damage, activation of a geologic structure,	1.5	3

		compromise of the sealing lithologies, or impact on-site personnel (weather or storm event such as flash flooding)		
2.5	Formation fluid impact due to CO_2 injection.	During injection, CO_2 could dissolve into the formation brine lower pH and altering the water quality. This fluid would be more reactive in the presence of certain minerals, impacting fluid quality by dissolution. These reactions are modeled in form 1b.	3	1
2.6	See also contributing causes 3.1, 3.2, 3.3, 3.5, 4.3, and 4.4	Water quality contamination from: Overpressurization (i.e. induced), Caprock/reservoir failure. Well blowout (e.g. at surface or bore failure below ground), includes monitoring wells – Causes could include seal failure (e.g. well, drilling or injection equipment). Orphan well failure (e.g. well not identified prior to injection). Incomplete geological seal (e.g. inaccurate characterization of sub-surface geology). Well seal failure (e.g. well, drilling or injection equipment) including monitor wells. All of these contributing causes could allow for the vertical migration of fluids into the Evanston Formation, which could contaminate water quality through the invasion of higher salinity brines, CO_2, or other gases.	2.5	2

3	Single Large Volume CO_2 Release to the Surface – Asphyxiation/Health /Ecological	A massive, and rapid release of CO_2 of a quantity that displaces O_2 at a large-scale. The permit area is rural, with no surrounding residences or businesses aside from the facilities located at Painter Field and described in form 1b.		
3.1	Overpressurization (i.e. induced).	In the event of a major release, the area has no residences or businesses. Induced seismicity and release along activated faults/fractures would lessen the potential for continued operations. The largest impacts from O_2 displacement would be to wildlife and livestock. Environmentally, the study area is not protected, lessening major impacts. The injection zone is currently underpressured, and injection simulations suggest that pressure will remain below original below original field pressure during injection. This field has also been flooded with N_2 without incident. This (lessened pressure/previous injection history) should reduce the risk of large volume of CO_2 release caused by overpressurization. This lessens the probability of impact under this risk scenario.	1.5	2.5
3.2	Caprock/reservoir failure.	In the scenario event of a major CO_2 release through the geologic column, major risk impact could involve on-site personnel, local	1	3

		wildlife and livestock. It could also result in the permanent loss of storage capacities at the site. Both the caprock and reservoir have been subjected to higher pressures over geologic time periods without observed impacts. The proposed injection strategy remains below original reservoir pressure, at which the caprock/reservoir were stable. This lessens the probability of impact under this risk scenario.		
3.3	Well blowout (e.g. at surface or bore failure below ground), includes monitoring wells – Causes could include seal failure (e.g. well, drilling or injection equipment).	The injection zone includes several proposed monitoring wells, which could release CO_2 to surface. Surface release would be away from existing infrastructure, lessening the probability of impacts to on-site personnel. This potential risk is considered in monitoring and corrective action strategies.	1.5	2
3.4	Major mechanical failure of distribution system or storage facilities above ground or below ground (i.e. near the surface).	Mechanical failure resulting in CO_2 release could happen at the CO_2 plant, within/at compression equipment, or the proposed transportation (pipeline) network. The risk associated with major loss at these facilities would impact the area of operations, and could impact on-site personnel.	2	2

3.5	Orphan well failure (e.g. well not identified prior to injection).	Orphan wells that failed would have a similar risk impact as Risk #3.3. However, this field was not developed under modern record keeping rules and all deep (completed to the Nugget wells) are documented. This lessens the probability of impact under this risk scenario.	1	2
3.6	Sabotage/Terrorist attack (e.g. on surface infrastructure).	Sabotage/terrorists could access surface infrastructure at the site, though this facility is not of strategic or cultural importance. Risk impacts would be similar to those described in Risk# 3.4.	1	2
3.7	Act of God (e.g. major seismic event)	The highest probability Act of God risks that may result in large-scale CO_2 volume loss are damage of surface infrastructure from weather events (lightening, high wind, major storms) or wildfires, or seismic events. The resulting major volume loss of CO_2 could impact on-site personnel, livestock or wildlife.	1	3
4	Low Level CO_2 Release to Surface – Ecological damage due to low-level releases; potential asphyxiation of human or ecological receptors	Similar to Risk #3, though the risk scenario involves lower quantities of CO_2.		

4.1	Overpressurization (i.e. induced).	In the event of a minor release, the area has no residences or businesses. Lesser volume leaks would have the largest impact on the long-term injection capacities at the storage site. If leakage occurs below a building or facility, it could impact on-site personnel. The injection zone is currently underpressured, and injection simulations suggest that pressure will remain below original below original field pressure during injection. This field has also been flooded with N_2 without incident. This (lessened pressure/previous injection history) should reduce the risk of CO_2 release caused by overpressurization. This lessens the probability of impact under this risk scenario.	1.5	2
4.2	Caprock/reservoir failure (e.g. Plume migrates along fault line/fissure to surface).	In the scenario event of a minor CO_2 release through the geologic column, risk impact could involve on-site personnel if leakage accumulated within a closed building or other infrastructure. It could also result in the permanent loss of storage capacities at the site. A lower volume leak would have a lesser impact on wildlife/livestock. Both the caprock and reservoir have been subjected to higher pressures over geologic time periods without observed impacts. The proposed injection strategy remains below original reservoir pressure, at which the caprock/reservoir were stable. This lessens	1	2

		the probability of impact under this risk scenario.		
4.3	Incomplete geological seal (e.g. inaccurate characterization of sub-surface geology).	Low volume leakage could occur within, along and through one of the sealing lithologies, eventually migrating into the USWDs or to surface. In the scenario event of a minor CO_2 release through the sealing column, risk impact could involve on-site personnel if leakage accumulated within a closed building or other infrastructure. It could also result in the permanent loss of storage capacities at the site. A lower volume leak would have a lesser impact on wildlife/livestock.	1.5	2
4.4	Well seal failure (e.g. well, drilling or injection equipment) including monitor wells	A similar risk scenario to Risk# 3.3 and 3.5. Minor volume leakage would lessen the potential health impacts for on-site personnel (lower likelihood of full displacement of O_2), as well as costs associated with corrective action. The probability of a low volume leak along a wellbore/annulus at a low level is higher than a complete blowout (i.e. Risk # 3.3)	3	2
4.5	Mechanical failure of distribution system or storage facilities above or below ground (e.g. near surface).	A similar risk scenario to Risk# 3.4. Minor volume leakage would lessen the potential health impacts to on-site personnel in facilities (lowers the probability of full displacement of O_2).	2	2

4.6	Orphan wells (e.g. well not identified prior to injection).	A similar risk scenario to Risk# 4.4, with lesser impact.	1.5	1.5
4.7	Induced seismicity leading to leakage.	During injection, pressurization activates an unknown geologic structure, creating a pathway for CO_2 migration. In the scenario event of a minor CO_2 release through the geologic column, risk impact could involve on-site personnel if leakage accumulated within a closed building or other infrastructure. It could also result in the permanent loss of storage capacities at the site. A lower volume leak would have a lesser impact on wildlife/livestock. Though the field has numerous faulty types (see Form 1b), none are shown to migrate past the regional unconformity. This lessens the probability of this risk scenario.	2	3
4.8	Act of God (e.g. seismic event).	The highest probability Act of God risks that may result in lower volume CO_2 release are damage of surface infrastructure from weather events (lightening, high wind, major storms) or wildfires, or seismic events. The resulting minor volume loss of CO_2 could impact on-site personnel, livestock or wildlife.	3	3
Storage Rights Infringement (CO2 or other entrained contaminant gases) – Form		Risk scenarios that address adjacent pore space rights and resources adjacent to the Painter Field injection zone.		

of Mineral Rights Infringement				
5.1	Leakage migrates into adjacent pore space; causes may include plume migrates faster than modeled.	Horizontal migration occurs at a greater rate of distance than permitted under the model, either along a natural barrier or thief zone. This results in CO_2 infiltration outside of pore space allocated for the project. Breakthrough is a potential issue at Painter Field, as demonstrated by previous floods. Monitoring is needed to account for this potentiality, or acquisition of additional pore space rights. All migration should be contained within the geologic structure, limited pore resource/access needs.	2.5	2
5.2	Post injection decision (e.g. due to new technology or changed economic conditions) to store gas in adjacent pore space.	Under this scenario, adjacent pore space would be used to store non-CO_2 gas. Subsequent risks include loss of injectivity due to pressure interference, CO_2 displacement due to offset injection, reactivity (depending on offset gas storage character), and co-mingling of gases with economic impacts.	1.5	2
5.3	Acts of God affecting storage	There are two risk scenarios that would be considered "Acts of God-type" that could impact pore space resources. One scenario	2.5	3

	capacity of pore space.	would be a seismic event that produced structure that would restrict pore space access. Similarly, subsidence via the collapse or compaction of the sedimentary matrix of the Nugget Sandstone would reduce pore space capacity.		
5.4	Formation fluid impact due to CO2 injection.	Risk scenarios associated with formation fluid and storage/pore rights include: geochemical reactions reduce pore space capacity due to mineral precipitation and cementation, injectivity impacts residual water saturation resulting in reduced CO_2, formation fluid displacement outside of the permitted pore resource reduces adjacent pore resource capacity due to increased pressure.	3.5	1.5
5.5	Will also require primary contributing causes 3.1, 3.2, 3.3, 3.5, 4.3, and 4.4	Storage Rights Infringement from: Overpressurization (i.e. induced), Caprock/reservoir failure. Well blowout (e.g. at surface or bore failure below ground), includes monitoring wells – Causes could include seal failure (e.g. well, drilling or injection equipment). Orphan well failure (e.g. well not identified prior to injection). Incomplete geological seal (e.g. inaccurate characterization of sub-surface geology).	2	2

		Well seal failure (e.g. well, drilling or injection equipment) including monitor wells. The risk scenario with the largest impact to storage/pore space rights would be those events that compromise the geologic column (i.e. seal failure through overpressurization) in a way that adjacent pore space owners would be unable to utilize their pore resources.		
6	Modified Surface Topography (subsidence or uplift) Resulting in Property/Infrastructure Damage	Injection leads to subsidence due to mineral dissolution, or uplift from injection-related seismicity. Both cases alter the surface and cause damages.		
6.1	Induced Seismicity – Pressure from geochemistry induced reactivation of historic fault or dissolution of material caused by subsidence.	Injection leads to subsidence due to dissolution of minerals such as evaporate deposits in the Twin Creek Formation, or uplift associated with increased pressure and seismicity damages surface infrastructure. At Painter Field, there is no evidence of these risk scenarios developing under similar injection operations, lessening the probability of impact. Infrastructure within the field are owned by the operator and are relatively distributed, lessening impacts. Major capture and gas	1	2.5

		processing facilities would have the impact, due to costs associated with these structures.		
6.2	Formation fluid impact due to CO2 injection.	Injection forces formation fluid into strata that is susceptible to dissolution, or interaction with CO_2 increases dissolution of minerals within the Nugget Sandstone. The resulting subsidence under both risk scenarios impacts surface topography. Infrastructure within the field are owned by the operator and are relatively distributed, lessening impacts. Major capture and gas processing facilities would have the impact, due to costs associated with these structures.	3	1.5
7	Entrained Contaminant (Non-CO_2) Releases	Risk scenarios that impact CO_2 composition and/or concentrations.		
7.1	Change in CO_2 composition/properties (e.g. concentration of contaminate in CO_2 supply increases).	Mechanical failures within the CO_2 production and capture facility changes the gas stream composition, resulting in the injection of concentrations of non-CO_2 gases. Risks would include increased reactivity, with impacts similar to those described in Risk# 2.5.	2.5	1

7.2	Microbial activity initiated by injection process or composition.	Injection stimulates/feeds sulfate or methane reducing microbes, which then produce gases such as H_2S. This can result in increased geochemical reactions, impacting dissolution of minerals and wellbore cement. Painter Field has been subjected to N_2 floods without souring the system. The iron-bearing minerals within the Nugget Sandstone would help to mitigate the influence of microbial by-products.	2	1.5
Will also require primary contributing causes 3.1, 3.2, 3.3, 3.5, 4.3, and 4.4		Non-CO_2 releases from: Overpressurization (i.e. induced), Caprock/reservoir failure. Well blowout (e.g. at surface or bore failure below ground), includes monitoring wells – Causes could include seal failure (e.g. well, drilling or injection equipment). Orphan well failure (e.g. well not identified prior to injection). Incomplete geological seal (e.g. inaccurate characterization of sub-surface geology). Well seal failure (e.g. well, drilling or injection equipment) including monitor wells. These types of risk occurrences are not likely to impact the CO_2 concentrations within the field.	2	1.5

8	Accidents/Unplanned Events (Typical Insurable Events)	Risk associated with standard operations, and generally attributed to human error (i.e. accidents).		
8.1	Surface infrastructure damage	During operations, accidents occur that damage surface equipment such as wellheads, pipelines, etc. The damage could result in CO_2 leakage, operational shutdowns, and cost incurrence to the project.	3	2
8.2	Saline water releases from surface storage impoundment.	Under this risk scenario, saline water produced for pressure management, escapes its holding facility, and impacts the local environment. Painter field is underpressured and does not require pressure maintenance, reducing the probability of impact.	1	2

Risk Matrix Scoring Matrices

The risk probability and impact matrices were developed to assess risk under Phase II of the Wyoming CarbonSAFE project. It has been modified to address the proposed operations at Painter Field. Table 1 defines the risk impact variables used to determine a risk impact score. Table 2 defines the parameters used to define probability. Risks were assigned by a working group of CCUS experts and averaged. Generally, probability of risk events remain relatively low at Painter Field, primarily due to the knowledge and experience that was gained during previous injection activities.

Table 1: Risk impact matrices with the variables and parameters used to define risk impact scoring.

Risk Impact Score	Risk Description	Cost Impacts	Schedule/Operational Impacts	Permitting Impact	Project Image Impacts
1	Low	<10%	<1 month	Information requests	Negative local news event
2	Moderate	25%	6 months	Permit violations and fines	Negative national news event; protests
3	High	>50%	>12 months	Shutdowns; legal actions	Stakeholder confidence falls

Table 2: Probability matrices scoring parameters used for risk assessment.

Probability Score	Meaning	Probability of Occurrence During Permitting Period
1	Very low	0.1%

	(virtually impossible)	
2	Low (very unlikely)	1%
3	Moderate (unlikely)	5%
4	High (likely)	25%
5	Very high (very likely)	100%

Section 10. Certification of Professional Geologist

The sections of the permit application that represent geologic work shall be sealed, signed, and dated by a licensed professional geologist.

The geologic interpretations, cross-sections, maps, and hydrologic studies that are included in this application were all completed under the responsible charge or direct supervision of the licensee, who has reviewed this wok and certifies that it is prepared according to the highest standards of Professional Geology.

Printed Name of Professional Geologist P.G. Number (SEAL)

Signature of Professional Geologist Date Signed

Section 11. Certification of Professional Engineer

The sections of the permit application that represent engineering work shall be sealed, signed, and dated by a licensed professional engineer.

The Engineering Designs, Plans, and Specifications that are included in this application were all completed under the responsible charge or direct supervision of the licensee who has reviewed this work and certifies that it is prepared according to the highest standards of Professional Engineering.

Printed Name of Professional Engineer Signature of Professional Engineer

P.E. Number (SEAL) Date Signed

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Wyoming State Engineer’s Office Records

Attachment 1: Area of Review and Corrective Action Plan

Facility Information

Facility Name: TBD

Facility Contact: Name, Address, Phone, and Email (TBD)

Well Location: Uinta County, WY., T16N R119W Sec 31

This Area of Review and Corrective Action Plan describes how North Shore Energy will determine the Area of Review (AOR) and outlines a Corrective Action Plan pursuant to Section 13 of Chapter 24 of the WYDEQ CCS Class VI Guidance Document. The AOR was determined using computer modeling and simulation of reservoir properties regarding the predefined injection scenario. The proposed Corrective Action plan is designed to demonstrate that operations and injection of CO_2 into the Nugget Formation are proceeding as planned and that the plume and pressure front are behaving as predicted. Furthermore, this plan is intended to protect and ensure that there is no endangerment to people, wildlife, the habitat and USDWs within and in proximity to the area of review. Monitoring data will be used to validate and adjust the geological and simulation models used to predict the plume and pressure front in the targeted injection zone.

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Computational Modeling

The computational models generated by Carbon Solution LLC for Painter A CO2 storage project include structural and property models reconstructed using Schlumberger (SLB) Petrel platform and CO2 injection simulation using SLB subsurface fluid flow simulator.

Model Description

Geologic static and dynamic models provide essential information for risk assessment, monitoring, and post-injection site closure plans. The modeling is an ongoing task through the life-time cycle of a CCUS project, including pre-injection site characterization and performance prediction, active reservoir management and monitoring through injection, and post-injection containment assurances. One of the most important CCUS process is to build and maintain these models that will predict the migration of the injected CO_2 and reservoir pressure escalation. These models are also used to optimize predicted injectivity, storage capacity and confining layer integrate; used to design wellbore, completion, and well test; analyze and understand well test results and quantify uncertainties in predictions.

The geologic modeling and CO_2 injection simulation works in this study are focused on evaluating the injection feasibility, injected CO2 migration and plume development, storage capacity, maximum injection pressure, reservoir pressure propagation, and determining the Area of Review for Class VI well application.

The geologic structure framework and property models are developed using formation top picks from 46 wells, well log curves from 26 las files, and core-measured porosity and permeability from Northshore LLC house. The petrophysical data collected and used in the analysis were spectral gamma ray, neutron, density, and sonic (Figure 1).

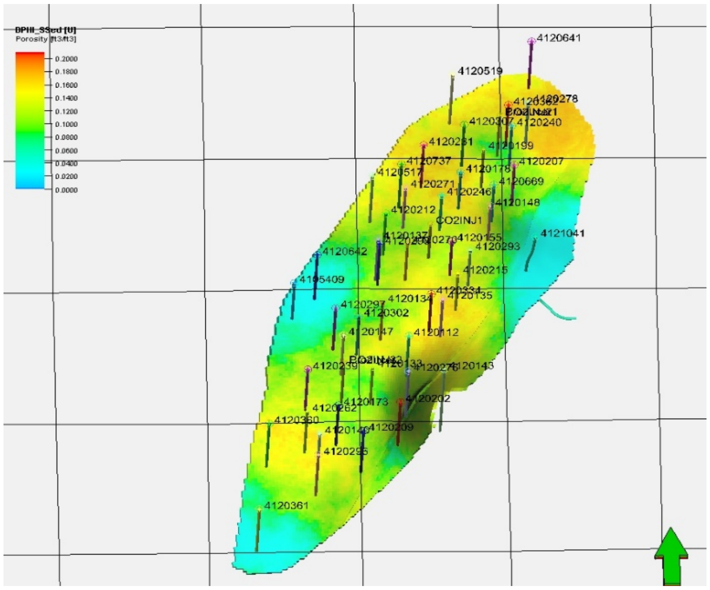

Figure 1. Well Distribution used to Generate the Structural Model

The static geological model includes the entire storage reservoir Nugget Sandstone, overlaying confining layer Twin Creek Formation and underlying confining layer Ankareh Formation. The model covers an area of 4.6 square mile and spans 1.4 mile X 3.8 mile and elevation range from -435 ft to -5,643 ft, which is represented with a 128 X 202 X 16 grid containing a total of 413,696 cells. The average horizontal cell dimensions are 97 ft in the X direction and 99 ft in the Y direction. The vertical cell dimensions vary with geologic intervals, are smallest in the injection zone, and averages 80 ft.

While the most reliable estimate of porosity and permeability are provided by core and geophysical log measurements, such measurements are typically sparsely distributed within a model domain. Geostatic interpretation methods such as kriging and sequential Gaussian Simulation was used to develop 3D statistic property distributions throughout much of the inter-well model space that are conditioned to (honor) available well log and core data.

The geologic modeling workflow included the use of GR and density for lithology facies classification. Porosity logs were co-Kriging with facies model to create the 3D porosity distribution. There is no permeability log available for this study. Instead of co-kriging permeability logs with porosity model generated in the previous step to create the 3D permeability distribution, the correlation between porosity and permeability is derived from the Nugget core measured data.

The dome structure of the Painter A Field for the Nugget reservoir has the 1,600 ft of closure within the field boundary. The thickness of the Nugget Sandstone ranges from 700 ft to over 1,200 ft (Figures 2 A and B).

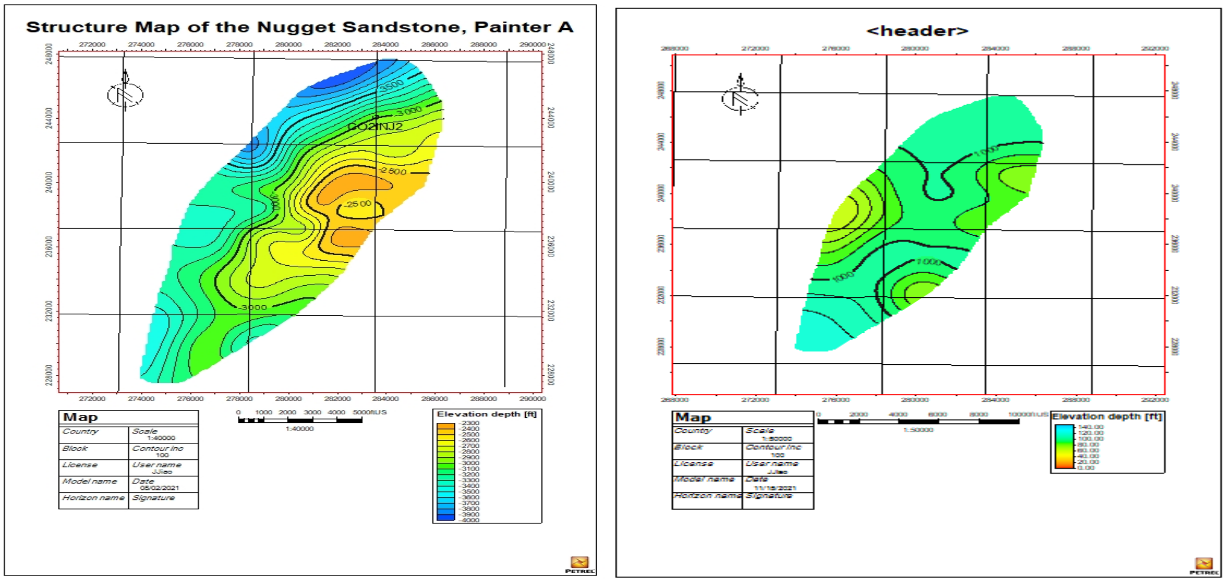

Figure 2. Structure and Isopach Map of the Nugget

Three-dimensional geo-cellular model provides a solid foundation for CO_2 injection simulation. Reservoir simulation was conducted using ECLIPSE industry-reference reservoir simulator. The Nugget Sandstone in Painter A Field is an under-pressured formation and follows a gradient of 0.39 psi/ft for initial reservoir pressure and assume a 0.35 psi/ft of gradient for current reservoir pressure. The reservoir model was equilibrate following the current reservoir pressure gradient with a reference pressure of 3,500 psi at 10,500 ft. The dynamic model contains 1 injection well. The injection well is located in the center of Section 31, Township 16 North, Rang 119 West (SPCS27_4904, X281055, Y239767), and the perforated interval ranges from 9,478 ft to 10,403 ft (completion length 925 ft). Simulation using defined rates, 0.25 MT/year or 685 kg/day, and volumes (2.75 MT) of injected CO_2 over a period of 15 years resulted in the delineation of the CO_2 plume and the extent of the pressure plume. The extent of the pressure plume in combination of the sealing fault define the AOR.

Description of AOR Delineation Modeling Effort

Geologic static and dynamic models provide essential information for risk assessment, monitoring, and post-injection site closure plans required by the EPA. The modeling is an ongoing task through the life-time cycle of a CCUS project, including pre-injection site characterization and performance prediction, active reservoir management and monitoring through injection, and post-injection containment assurances. One of the most important CCUS assessments is to build and maintain these models that will predict the migration of the injected CO_2 and reservoir pressure escalation. These models are also used to optimize predicted injectivity, storage capacity and confining layer integrate; used to design wellbore, completion, and well test; analyze and understand well test results and quantify uncertainties in predictions.

The geologic modeling and CO_2 injection simulation works in this study are focused on evaluating the injection feasibility, injected CO2 migration and plume development, storage capacity, maximum injection pressure, reservoir pressure propagation, and determining the Area of Review for Class VI well application.

The geologic structure framework and property models are developed using formation top picks from 46 wells, well log curves from 26 las files, and core-measured porosity and permeability from Northshore LLC house. The petrophysical data collected and used in the analysis were spectral gamma ray, neutron, density, and sonic.

The static geological model includes the entire storage reservoir Nugget Sandstone, overlaying confining layer Twin Creek Formation and underlying confining layer Ankareh Formation. The model covers an area of 4.6 square miles and spans 1.4 X 3.8 miles and elevation range from -435 ft to -5,643 ft, which is represented with a 128 X 202 X 16 grid containing a total of 413,696 cells. The average horizontal cell dimensions are 97 ft in the X direction and 99 ft in the Y direction. The vertical cell dimensions vary with geologic intervals, are smallest in the injection zone, and averages 80 ft.

While the most reliable estimate of porosity and permeability are provided by core and geophysical log measurements, such measurements are typically sparsely distributed within a model domain. Geostatic interpretation methods such as kriging and sequential Gaussian Simulation was used to develop 3D statistic property distributions throughout much of the inter-well model space that are conditioned to (honor) available well log and core data.

The geologic modeling workflow included the use of GR and density for lithology facies classification. Porosity logs were co-Kriging with facies model to create the 3D porosity distribution. There is no permeability log available for this study. Instead of co-kriging permeability logs with porosity model generated in the previous step to create the 3D permeability distribution, the correlation between porosity and permeability is derived from the Nugget core measured data.

The dome structure of the Painter A Field for the Nugget reservoir has the 1,600 ft of closure within the field boundary. The thickness of the Nugget Sandstone ranges from 700 ft to over 1,200 ft. Boundary conditions of the model include a southwest by north-northeast bounding sealing blind thrust fault along the eastern portion of the Area of Review (AOR) and production and injection data from Painter A and East Painter Fields which further support the sealing nature of the fault and the geologic structure of the target injection reservoir.

Three-dimensional geo-cellular model provide a solid foundation for CO2 injection simulation. Reservoir simulation was conducted using ECLIPSE industry-reference reservoir simulator.

The Nugget Sandstone in Painter A Field is an under-pressured formation and follows a gradient of 0.39 psi/ft for initial reservoir pressure and assume a 0.35 psi/ft of gradient for current reservoir pressure. The reservoir model was equilibrate following the current reservoir pressure gradient with a reference pressure of 3,500 psi at 10,500 ft. The dynamic model contains 1 injection well. The injection well is located in the center of Section 31, Township 16 North, Rang 119 West (X281055, Y239767), and the perforated interval ranges from 9,478 ft to 10,403 ft (completion length 925 ft). Simulation using defined rates, 0.25 MT/year or 685 kg/day, and volumes (2.75 MT) of injected CO_2 over a period of 15 years resulted in the delineation of the CO_2 plume and the extent of the pressure plume. The extent of the pressure plume in combination of the sealing fault define the AOR.

Model Inputs and Assumptions

The geologic and hydrologic and operational information were compiled into a 3D geologic model developed using Schlumberger's Petrel modeling software. Input data for the model include geophysical well logs (LAS files), core analysis, shapefiles, and depths to geological formations. The engineering data inputs include well/borehole locations (Lat, Lon, KB, and TD), perforation intervals, production rates and volumes, and pressure data.

Within Petrel the input data was then used to develop a 3D geo-cellular structural grid model wherein reservoir and confining layer property data was populated as an M value for each cell (50'x50'). M values include porosity, permeability, and pressure.

The input parameters are listed in Table 1.

Table 1 Parameters used for CO_2 injection simulation in the Nugget Sandstone, Painter A Field

Parameters	Symbol	Unit	Values
Reservoir effective permeability	k	mD	Hete (0.02-113)
Reservoir effective Porosity	ø	%	Hete (0.03-0.17)
Reservoir thickness	b	m	700 -1200
Reservoir salinity	s	%	9
Reservoir thermal conductivity	λ_m	W/Km	3.3
Reservoir initial fluid pressure	P_{inf}	MPa	24 at 3200 m
Reservoir initial Temperature	T	◦C	76.7 at 3200 m
Brine viscosity	μ_w	Pa s	1.33×10^{-4}
Brine density	ρ_w	kg/m3	1100
CO2 fluid viscosity	μ_{co2}	Pa s	5.8×10^{-5}
CO2 fluid density	ρ_{co2}	kg/m3	750
Brine compressibility	c_w	Pa−1	3.5×10^{-10}
CO2 fluid compressibility	c_{co2}	Pa−1	1.0×10^{-9}
Pore compressibility	cp	Pa−1	4.5×10^{-10}
Injection time	t	Year	15
Injection rate	Q	kg/s	7.93 (constant)
Gravitational acceleration	g	m/s2	9.8
Residual water saturation	S_{wr}	%	35

Maximum water saturation	S_{ws}	%	65
Residual CO2 saturation	S_{CO2r}	%	35
Maximum CO2 saturation	S_{CO2s}	%	65

Site Geology and Hydrology

See Form 1b Class VI Permit Application sections Site Characterization (page 5) and Regional Hydrostratigraphy (page 15).

Model Domain

The static geological models (structure and property models) include the entire storage reservoir Nugget Sandstone, overlaying confining layer Twin Creek Formation and underlying confining layer Ankareh Formation. The model covers an area of 4.6 square mile and spans 1.4 mile X 3.8 mile and elevation range from -435 ft to -5,643 ft, which is represented with a 128 X 202 X 16 grid containing a total of 413,696 cells. The average horizontal cell dimensions are 97 ft in the X direction and 99 ft in the Y direction. The vertical cell dimensions vary with geologic intervals, are smallest in the injection zone, and averages 80 ft.

Porosity

Porosity of the confining zone was determined from the well logs and calibrated by the core measured data.

Injection Zone Porosity

The porosity modeling results and a histogram show the distribution of the Nugget Sandstone in the Painter A Field. The porosities range from 2% to 18%, with a mean of 10%. (Figure 3).

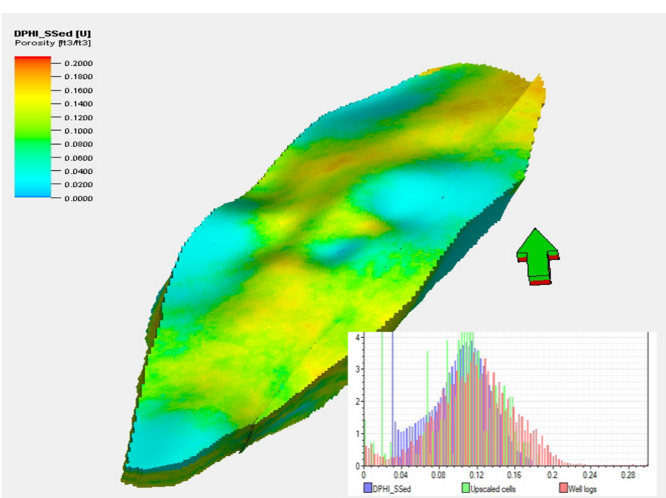

Figure 3. Porosity Distribution Model for the Nugget

Confining Zone Porosity

Both overlaying and underlying confining layers have average porosities less than 5 percent. This was determined from available geophysical well logs.

Permeability

Injection Zone Permeability

There is no intrinsic permeability information from the log measurement. The correlation between porosity and permeability is derived from the Nugget core measured data (Figure 4). Following function is used to create the permeability distributions throughout the model domain from the porosity model.

Log k = $-2.65+0.35\Theta-0.0052\Theta^2$

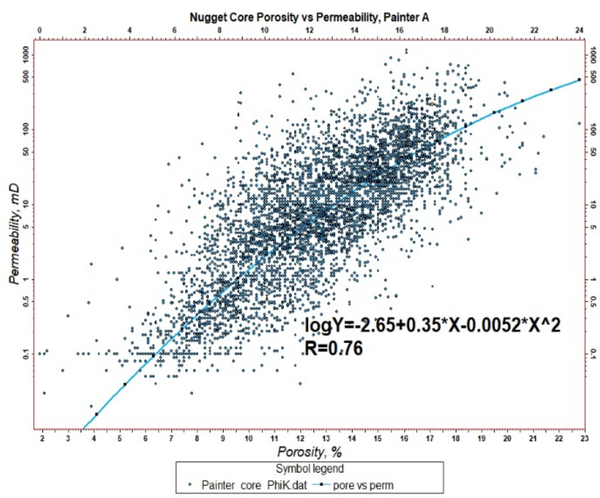

Figure 4. Poro-Perm Crossplot

The modeled permeability ranges from 0.002 mD to 113 mD, with a mean of 6.6 mD. Both overlaying and underlying confining layers has low permeability and average of less than 0.05 mD (Figure 5).

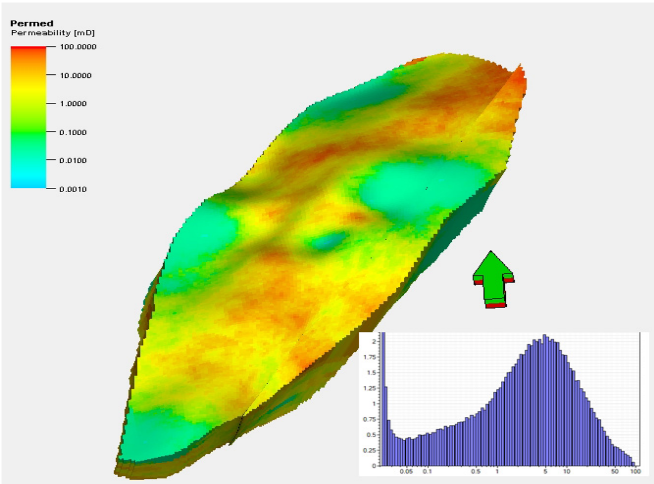

Figure 5. Permeability Distribution Model of the Nugget

Confining Zone Permeability

Intrinsic permeability from core and geophysical borehole data were interpreted from available geophysical well logs wherein average permeability is less than 1 md.

Operational Information

For Operational Information see Form 1b Operating Data (page 39). In the event that changes or modifications occur this plan will be updated and amended with a description of the changes in operational changes.

Fracture Pressure and Fracture Gradient

For information regarding the fracture pressure and pressure gradients see Form 1b Geomechanical and Petrophysical section (page 21). Additional information regarding the geomechanical properties of the injection and confining zone will be determined from core collected during drilling of the proposed well. This information will be provided and amended to this plan.

Boundary Conditions

The model covers an area of 4.6 square mile and spans 1.4 mile X 3.8 mile and elevation range from -435 ft to -5,643 ft, including the entire storage reservoir Nugget Sandstone, overlaying confining layer Twin Creek Formation and underlying confining layer Ankareh Formation. Boundary conditions of the model include a southwest by north-northeast bounding sealing blind thrust fault and production and injection data from Painter A and East Painter Fields which support the sealing nature of the fault and the geologic structure of the target injection reservoir. There is no fluid flowing in or flow out cross the boundary of the model domain.

AOR Pressure Front Delineation

The pressure front corresponds to the minimal pressure increase needed to move fluids from the reservoir into a USDW Fox Hills Sandstone through a hypothetical open conduit, such as an uncemented borehole or fault. The delineation of an AOR is calculated from the pressure front that derived from the results of CO_2 injection simulation.

The critical pressure/front pressure can be determine using equation:

$$Pc = Pu + \rho ig \cdot (zu - zi) - Pi$$

where:

Pu =the initial pressure at the base of the USDW (Pa=kg/m·s2),

ρi =the density of the injection zone fluid (kg/m3),

g =the acceleration of gravity (m/s2),

zu =the elevation of the base of the lowermost USDW (m),

zi =the elevation of to the top of the injection zone (m), and

Pi =the initial pressure in the injection zone (Pa).

At proposed Painter A injection site (Injector 1), the initial pressure of the base of the USDW (Bottom of the Evanston) is 1,773 psi (0.433 psi/ft gradient) at elevation of 3,104 ft. The pressure of targeted Nugget storage reservoir is taken as 3,500 psi at elevation of -2,654 ft. The density of the reservoir water is 1.1 kg/cm^3. Plugging above number into the equation, the critical pressure for the Painter A field is 1,020 psi. The AoR for the proposed Class VI well can be defined by the 1,020-psi isoline on the delta-pressure (Dp) map after 15-year injection.

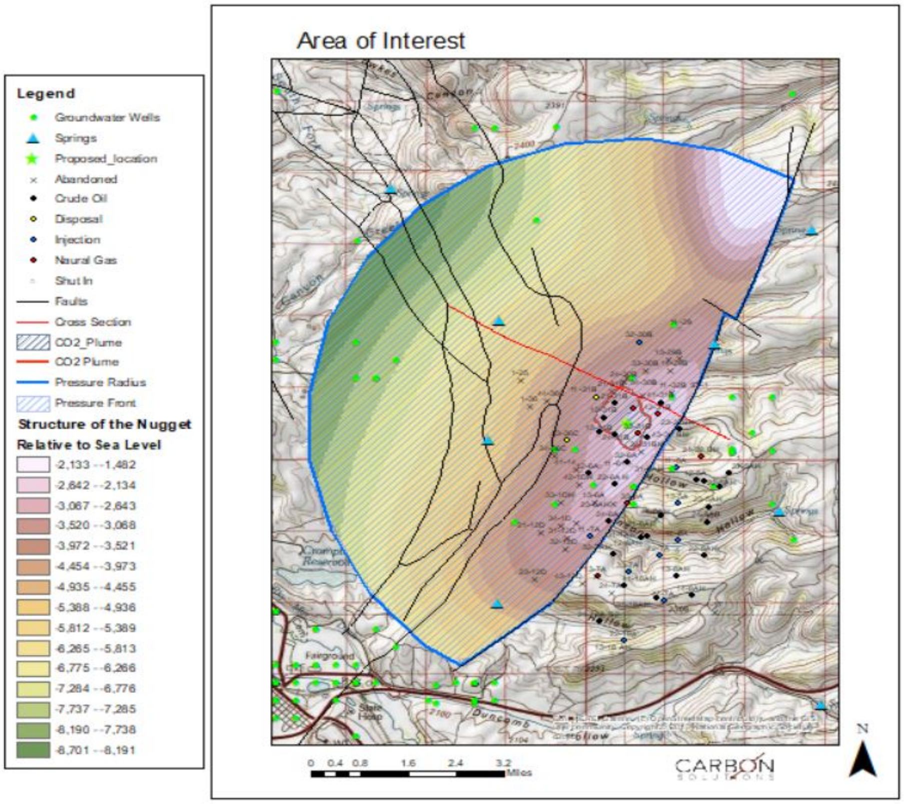

Figure 6. Area of Review as Determined by the Pressure Front

Model Calibration

The geological structural and property models, and CO2 injection simulation were completed with available site-specific data. Modeling and simulations are an ongoing task through the life-time cycle of a CCUS project, including pre-injection site characterization and performance prediction(s), active reservoir management and monitoring through injection operations, and post-injection containment assurances. As more data from the field operation is available, the models will be calibrated and updated.

History Match

N/A

Relative Permeability Curves

There is no a CO2/water relative permeability curve available for the Nugget Sandstone in the Painter A Field. A general relative permeability curve (Figure x) from the Nugget Sandstone in the Rock Springs Uplift is used in this study. The irreducible water saturation is 0.38. the maximum relative permeability of CO2 is 0.48. The assumed relative permeability has a significant impact on the simulated CO_2 injection rate and cumulative injected CO_2 mass. To reduce uncertainty in relative permeability assumptions, future simulation work should account for the heterogeneity of reservoir properties, including additional relative permeability measurements in the laboratory and injection testing to enable history matching and fine-tuning of simulation input variables.

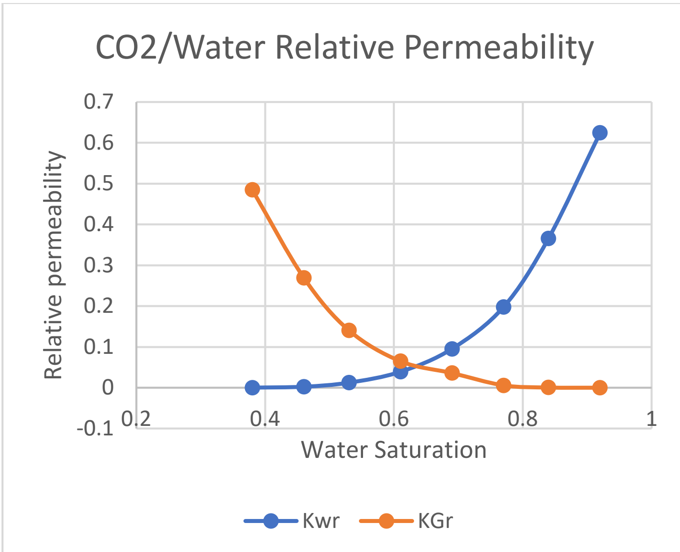

Figure 7. CO2 and Brine Permeability Curves

Hysteresis

N/A

Computational Modeling Results

Figure 8 shows the CO_2 plume size after 15-year injection with rate of 0.25 MT/year and without fluid extraction. The CO2 plume is kept within Section 31, T16N and R119W. The injection rate could be held through 15 year of injection period. The total of 3.75 MT CO_2 injected, the injection pressures (THP) range from 2,944 psi to 4,225 psi, the BHP ranges from 3,900 psi to 5,397 psi, and the field pressures range from 3,337 psi to 5,100 psi (Figure 9).

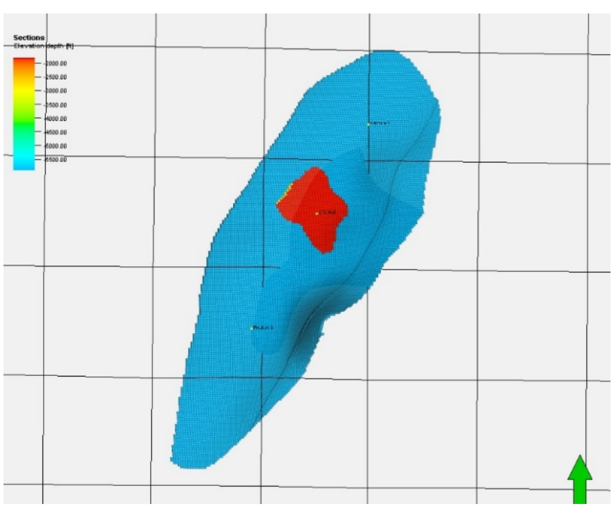

Figure 8. CO2 Plume Size after 15 Years

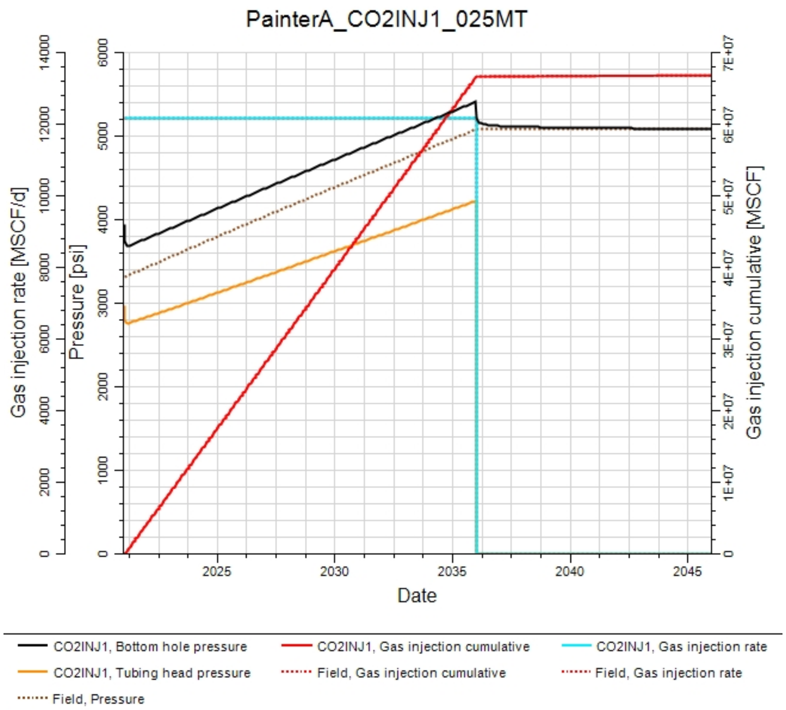

Figure 9. Plot showing Injection Rate, Cumulative, THP, BHP, and Reservoir Pressure

Corrective Action Plan and Schedule

The Corrective Action Plan will be evaluated and updated annually and or as required by the Administrator. In the case that injection operations have deviated from the proposed parameters described in the permit application, corrective action will be applied immediately. Plans address existing and proposed wells, which are identified as the site's primary risk (*see Risk Assessment*).

Tabulation of Wells within the AOR

Wells within the AOR

56 wells within the AOR were identified that penetrate the caprock (Twin Creek) (data from the Wyoming Oil and Gas Conservation Commission records and the Wyoming State Engineer's Office as of November 2021).

Of these, one is an industrial water well (currently plugged back to a depth of 543 feet), 34 are shut-in hydrocarbon wells, 9 are plugged wells, and 12 are temporarily abandoned wells. Information on these wells is available upon request. The available data includes well type, construction, date drilled, location, depth, and record of completion and/or plugging.

Wells Penetrating the Confining Zone

There are 55 wells within the AOR that penetrate the upper confining layer of the Twin Creek. This formation is located at depths of 7,760 ft to greater than 10,800 ft across the AOR.

The evaluation determined that both wells penetrating the storage reservoir within the AOR have sufficient isolation to prevent formation fluids or injected CO2 from vertically migrating outside of the storage reservoir or into USDWs and that no corrective action is necessary.

If these wells are taken out of service during the life of the project, North Shore will provide information to the DEQ to confirm they have been properly plugged to ensure USDW protection. If any additional wells that penetrate the upper confining layer are identified (e.g. if the AOR is delineated to cover a larger area as the result of an AOR reevaluation) North Shore will complete corrective action as needed.

Plan for Site Access

Not applicable because no corrective action is needed at this time…

Justification of Phased Corrective Action

Not applicable because no corrective action is needed at this time…

Area of Review Reevaluation Plan and Schedule

North Shore will evaluate project data, and if necessary, reevaluate the AOR and corrective action plan, with the period between evaluations not to exceed two years during injection and five during the post-injection site care period. Evaluations will be conducted during the injection and post-injection phases via the following method:

- Review available monitoring and operational data from the injection well, monitoring wells, surrounding wells, and other sources to assess whether the predicted CO2 plume migration is consistent with actual data. Monitoring activities to be conducted are described in the Testing and Monitoring Plan (Attachment 2) and the PISC and Closure Plan (Attachment 4 to this permit).

If the information reviewed is consistent with, or is unchanged from, the most recent modeling assumptions or confirms modeled predictions about the maximum extent of plume and pressure front movement, North Shore will prepare a report demonstrating that, based on the monitoring and operating data, no reevaluation of the AOR is needed. The report will include the data and results demonstrating that no changes are necessary.

If material changes have occurred (e.g., in the behavior of the plume and pressure front, operations, or site conditions) such that the actual plume or pressure front may extend beyond the modeled plume and pressure front, North Shore will re-delineate the AOR. The following steps will be taken:

- Revising the site conceptual model based on new site characterization, operational, or monitoring data.
- Calibrating the model in order to minimize the differences between monitoring data and model simulations.
- Performing the AOR delineation as described in the Computational Modeling Section of this AOR and Corrective Action Plan.
    - Review wells in any newly identified areas of the AOR and apply corrective action to deficient wells. Specific steps include:

- Identifying any new wells within the AOR that penetrate the upper confining zone and provide a description of each well's type, construction, date drilled, location, depth, record of plugging and/or completion.
- Determining which abandoned wells in the newly delineated AOR have been plugged in a manner that prevents the movement of carbon dioxide or other fluids that may endanger USDWs.
- Performing corrective action on all deficient wells in the AOR using methods designed to prevent the movement of fluid into or between USDWs, including the use of materials compatible with carbon dioxide.

    - Prepare a report documenting the AOR reevaluation process, data evaluated, any corrective actions determined to be necessary, and the status of corrective action or a schedule for any corrective actions to be performed. The report will be submitted to EPA within one year of the reevaluation. The report will include maps that highlight similarities and differences in comparison with previous AOR delineations.
    - Update the AOR and Corrective Action Plan to reflect the revised AOR, along with other related project plans, as needed.

AOR Reevaluation Cycle

The AOR will be reevaluated every two years during the injection phase and every five years during the post-injection site care period.

In addition, monitoring and operational data will be reviewed periodically (likely annually) by North Shore during the injection and post-injection phases.

Triggers for AOR Reevaluation Prior to the Next Scheduled Reevaluation

Unscheduled reevaluations of the AOR will be based on quantitative changes of the monitoring parameters in the deep monitoring wells, including unexpected changes in the following parameters: pressure, temperature, neutron saturation, and the deep ground water (> 3,000 ft below KB) constituent concentrations indicating that the actual plume or pressure front may extend beyond the modeled plume and pressure front. These changes include:

- Pressure Changes
- Temperature Changes
- Changes in Ground Water Constituents
- Fracture/Pressure Gradient Exceedance
- Exceedance of Established Baseline Parameters
- Mechanical Integrity Issues with the Injection Well
- Seismic Monitoring

An unscheduled AOR reevaluation may also be needed if it is likely that the actual plume or pressure front may extend beyond the modeled plume and pressure front because any of the following has occurred:

- Seismic event greater than M3.5 within 8 miles of the injection well,
- If there is an exceedance of any Class VI operating permit condition (e.g., exceeding the permitted volumes of carbon dioxide injected); or
- If new site characterization data changes the computational model to such an extent that the predicted plume or pressure front extends vertically or horizontally beyond the predicted AOR.

North Shore will discuss any such events with the DEQ to determine if an AOR reevaluation is required. If an unscheduled reevaluation is triggered, North Shore will perform the steps described at the beginning of this section of this Plan.

Attachment 2: Testing and Monitoring Plan

Facility Information

Facility Name: TBD

Facility Contact: Name, Address, Phone, and Email (TBD)

Well Location: Uinta County, WY., T16N R119W Sec 31

This Testing and Monitoring Plan describes how North Shore Energy will monitor the Painter A site pursuant to Section 20 of Chapter 24 of the WYDEQ CCS Class VI Guidance Document. This proposed plan is designed to demonstrate that operations and injection of CO_2 into the Nugget Formation are proceeding as planned and that the plume and pressure front are behaving as predicted. Furthermore, this plan is intended to protect and ensure that there is no endangerment to people, wildlife, the habitat and USDWs within and in proximity to the area of review. Monitoring data will be used to validate and adjust the geological and simulation models used to predict the plume and pressure front in the targeted injection zone.

Contents

Carbon Dioxide Stream Analysis 2

Analytical Parameters 2

Sampling Methods 2

Continuous Recording of Injection Pressure, Rate, and Volume; Annulus Pressure 2

Injection Rate and Pressure Monitoring 2

Calculation of Injection Volumes 3

Continuous Monitoring of Annular Pressure 3

Casing-Tubing Pressure Monitoring 3

Corrosion Monitoring 3

Groundwater Quality Monitoring 4

External Mechanical Integrity Tests (MITs) 4

Pressure Fall-Off Testing 5

CO_2 Plume and Pressure Front Tracking 5

Carbon Dioxide Stream Analysis

North Shore will collect samples of the CO2 stream during the operation period for analysis of its composition, chemical and physical properties. Sampling will occur quarterly beginning with a pre-injection sample for testing of fluid-fluid and fluid-rock compatibility with the source stream of CO2 and target storage reservoir within the Nugget Formation.

Analytical Parameters

Samples of the CO_2 stream will be analyzed for the following:

- Oxygen
- Nitrogen
- Carbon Monoxide
- Oxides of Nitrogen
- Total Hydrocarbons
- Methane
- Sulfur Dioxide
- Hydrogen Sulfide
- Carbonic Acid
- CO_2 purity

Sampling Methods

CO_2 samples will be collected after compression at a designated sampling station. This station will have the ability to purge samples into designated collection containers. The containers will be labeled, sealed, and sent to an authorized laboratory for analysis.

Continuous Recording of Injection Pressure, Rate, and Volume; Annulus Pressure

North Shore will implement an extensive monitoring, verification, and accounting (MVA) system to verify that the project is operating as permitted and that there is no endangerment to USDWs. The objective of the MVA is to account and verify the location of the injected CO_2. This will involve periodic testing of the injection stream pre and post compression, at the well head, and through the use of data collected from monitoring wells.

Injection Rate and Pressure Monitoring

Injection operations will be monitored using available monitoring technology designed to monitor injection pressure, rate, and volume. The pressure on the annulus between the tubing and casing and the volume of added annulus fluids.

The following is a list of monitoring data that is to be collected and the location (surface/downhole) of the monitoring that will be taking place:

- Annular Pressure
- Surface Injection Pressure
- Reservoir Injection Pressure
- Injection Rate
- Injection Volume
- Surface Temperature
- Reservoir Temperature
- Wellbore Temperature
- Surface Pressure
- Reservoir – near packer
- Reservoir – near packer
- Along the wellbore to the packer

Pressure and temperature instruments that are above-ground will be calibrated throughout the operational injection period on an annual basis. Monitoring will occur at designated frequencies and measurements will have tolerance ranges (psi and degrees) that are acceptable to the regulating agency.

Calculation of Injection Volumes

Flow rate will be measured and reported on a mass basis (kg/hr). Downhole pressure and temperature data will be collected and used to calculate the density of the injected CO_2. The volume of injectant will be calculated from a mass flow meter that is installed on the injection line. The mass flow rate will be divided by the density and multiplied by the injection time to determine injection volume.

Continuous Monitoring of Annular Pressure

The following procedures will be used to monitor annular pressure: transducers at the well head will be used to monitor pressure of the various casing and tubing strings within the borehole.

Tubing pressure, injection casing annulus, injection casing and intermittent casing, intermittent to surface casing, surface casing. Monitoring will occur at the well head. Monitoring will be conducted remotely on a predetermined schedule (monthly/quarterly). Continuous monitoring will utilize transducers above the packers where the tubing and casing are isolated.

Casing-Tubing Pressure Monitoring

Throughout the operational timeframe of injection, the casing-tubing pressure will be monitored and recorded in real time. See attachment 5 of the permit application, Emergency and Remedial Response Plan.

Corrosion Monitoring

Materials used to construct the injection well will be monitored for corrosion throughout the operational timeframe. Coupon testing methods will be used along the distribution network in order to evaluate response of materials to the injection stream. Evaluations will include loss of mass, thickness, cracking, pitting and other signs of corrosion. This will be conducted within the surface facility. Evaluation and testing of the coupons will occur quarterly during the initial phases of injection and later will be changed to a semi-annual and then an annual schedule. MITs will be scheduled as regulated during workover perids.

Sample Description

Samples of materials used to construct the well, compression equipment, and pipeline network will be included in the Corrosion Monitoring Program.

Sample Exposure

Samples will be exposed to the injection stream in sample holders and placed in a flow-through pipe arrangement. This apparatus will be located between the compression and dehydration equipment and the wellhead. The material coupons will be exposed to the CO_2 stream while injection is occurring.

Sample Handling and Monitoring

Exposed samples will be analyzed using ASTM standards at a certified lab.

Groundwater Quality Monitoring

North Shore will monitor groundwater quality and geochemical changes in fluids above the confining zone through the use of a monitoring and sampling program utilizing monitoring wells completed within and above the target injection zone. Groundwater monitoring will focus on the Evanston Formation.

External Mechanical Integrity Tests (MITs)

MITs will be initially conducted every 5 years. The MIT procedure will follow the existing protocols of a Class I well MIT for parts 1 and 2 of testing.

Temperature Logging

To ensure mechanical integrity similar to a production log depending on inflow and outflow there may be observable temperature variations. The temperature log will be used to identify where potential integrity issues may exist.

E Line Logging

To detect fluid movement behind pipe other options such as those listed below may be utilized for …other miscellaneous logs depending on the suspected issue

- Noise Logging
- Oxygen Activation Logging

Pressure Fall-Off Testing

Pressure fall-off tests will be conducted during the injection phase of the project on an annual schedule.

Pressure Fall-Off Test Procedure

A baseline will be developed during the pre-injection/initial injection phase.

This test requires a period of injection followed be a period of no-injection again see Class I well protocols. This procedure uses a pressure gauge on a slick line to monitor overall pressure and is set at the bottom of the injection string and will monitor during injection and during a shut-in period to determine if the zone is taking the injectant. This procedure will occur on an annual basis and a compilation of Injection profiles will be generated and submitted to the Administrator.

CO_2 Plume and Pressure Front Tracking

North Shore will employ direct and indirect methods to track and the extent of the plume and pressure front using pressure detectors at the surface on selected monitoring wells and if necessary, then downhole sensors/gauges can be deployed to evaluate both the plume and pressure front. Subsurface fluids will be sampled and analyzed to detect changes to directly monitor the CO_2 plume. Northshore plume and pressure tracking strategy will utilize existing legacy well assets to develop an integrative reservoir and seal monitoring well network.

Attachment 3: Injection and Monitoring Wells Plugging Plan

Facility Information

Facility Name: TBD

Facility Contact: Name, Address, Phone, and Email (TBD)

Well Location: Uinta County, WY., T16N R119W Sec 31

This Injection and Monitoring Wells Plugging Plan describes how North Shore Energy will monitor the Painter A site pursuant to Section 23 of Chapter 24 of the WYDEQ CCS Class VI Guidance Document. This proposed plan is designed to demonstrate that plugging operations after injection of CO_2 into the Nugget Formation are proceeding as planned. Furthermore, this plan is intended to protect and ensure that there is no endangerment to people, wildlife, the habitat and USDWs within and in proximity to the area of review. These plans will be repeated for all monitoring wells within the project area.

Contents

Bottom Hole Reservoir Pressure 2

Determination of Bottomhole Pressure 2

External Mechanical Integrity 2

Mechanical Integrity Testing Frequency 2

Casing Inspection 2

Other Testing Required by the Administrator 2

Testing and Evaluation Reporting 3

Wells Plugging Plan and Design 3

Type and Number of Plugs 4

Placement and depth of Plugs 4

Materials to be Used for Plugging 5

Plugging Method Description 5

Plugging Reports 6

Certification of a Licensed Engineer or Professional Geologist 6

Certification of accuracy by the operator 6

Bottom Hole Reservoir Pressure

Determination of Bottomhole Pressure

Prior to plugging a downhole pressure gauge/bomb will be used to measure BHP.

External Mechanical Integrity

North Shore will utilize the most current available technology to test and ensure external mechanical integrity per Chapter 24 Section 19. Appropriate measures and methods will be deployed to ensure that there is no significant leak in the casing, tubing, or packer and that there is no significant movement or migration of injected or displaced fluids into Underground Sources of Drinking Water (USDW) via channels adjacent to the injection wellbore. For more information see attachment 2, Testing and Monitoring Plan of this permit application.

Mechanical Integrity Testing Frequency

Testing and evaluation of mechanical integrity of the injection well will occur on an annual basis until the well is plugged. The test will involve either an approved tracer survey such as an oxygen-activation log or a temperature or noise log. For more information see attachment 2, Testing and Monitoring Plan of this permit application.

Casing Inspection

Inspection of the well casing will be formed prior to plugging the well, and results will be shared with the Administrator.

Other Testing Required by the Administrator

Northshore will communicate with the Administrator prior to plugging to determine if additional testing is required.

Testing and Evaluation Reporting

Reporting of testing and evaluation data will be compiled and reported to the Administrator within 90 days of plugging, or in a timeframe requested by the Administrator.

Wells Plugging Plan and Design

Open hole diameters and intervals

Name	Depth Interval (feet)	Open Hole Diameter (inches)	Comment
Surface	0-3300	17-1/2	Below lowest USDW
Intermediate	0-7700	12-1/4	To primary seal
Liner	7700-10520	8-1/2	To total depth

Casing Specifications

Name	Depth Interval (feet)	Outside Diameter (inches)	Inside Diameter (inches)	Weight (lb/ft)	Grade (API)	Design Coupling (short or long threaded)
Surface	0-3300	13-3/8	12.515	61	J55	Short
Intermediate	0-7700	9-5/8	8.835	40	J55	Long or Buttress
Production Liner (carbon)	7500-9000	7	6.094	32	L80	Long or Buttress
Production Liner (chrome)	9000-10520	7	6.094	32	L8013CR	Special

Plug Specifications

Name	Type of Plug	Top of Cast Iron Plug (feet)	Top of Cement (feet)	Cement Amount (sacks)	Cement Amount (feet)	Cement Weight (ppg)	Cement Grade
Plug 1	Mechanical	9450	9350	18	100	1.15	Corrosion Resistant
Plug 2	Mechanical	7700	7400	72	300	1.15	Corrosion Resistant

Plug 3	Balance	NA	7400	37	100	1.15	Class G
Plug 4	Mechanical	3300	3200	37	100	1.15	Class G
Plug 5	Balance	NA	1600	37	100	1.15	Class G
Plug 6	Balance	NA	Surface	37	100	1.15	Class G

- Plug 1 isolates injection zone with cast iron bridge plug and cement.
- Plug 2 isolates the casing shoe of the intermediate casing and production liner top with a cast iron bridge plug and cement.
- Plug 3 is a balance plug which infills between plug 2 and 4.
- Plug 4 isolates the surface casing shoe with cast iron bridge plug and cement.
- Plug 5 is a balance plug which infills between plug 4 and the surface plug.
- Plug 6 is a balance plug at surface.
- Inhibited plug fluid pumped between each plug.
- Cement weight will be adjusted according to final cement grade selection.

Final cement plug volumes will be adjusted for depth (additional 10% for every 1000') which will change volume of inhibited fluid between plugs.

Type and Number of Plugs

There will be six total plugs, three mechanical plugs and three balance plugs

Placement and depth of Plugs

Plugs will be placed no further than 2,500 feet apart and will also be located at each change in casing size (Figure 1).

WELL NAME

Casing and Tubing Detail

String Name	Open Hole	Outside Diamete	Inside Diamete	Depth Interval	Weig ht	Grade
Conductor	30"	20"	19.124"	0-75	94	J55
Surface	17-1/2"	13-3/8"	12.515"	0-3300'	61	J55
Intermediate	12-1/4"	9-5/8"	8.835"	0-7700'	40	N80
Production Liner (top)	8-1/2"	7"	6.094"	7500-	32	L80
Production Liner (bottom)	8-1/2"	7"	6.094"	9000-	32	L8013CR
Tubing	-	3-1/2"	2.750"	0-9450'	12.7	L8013CR

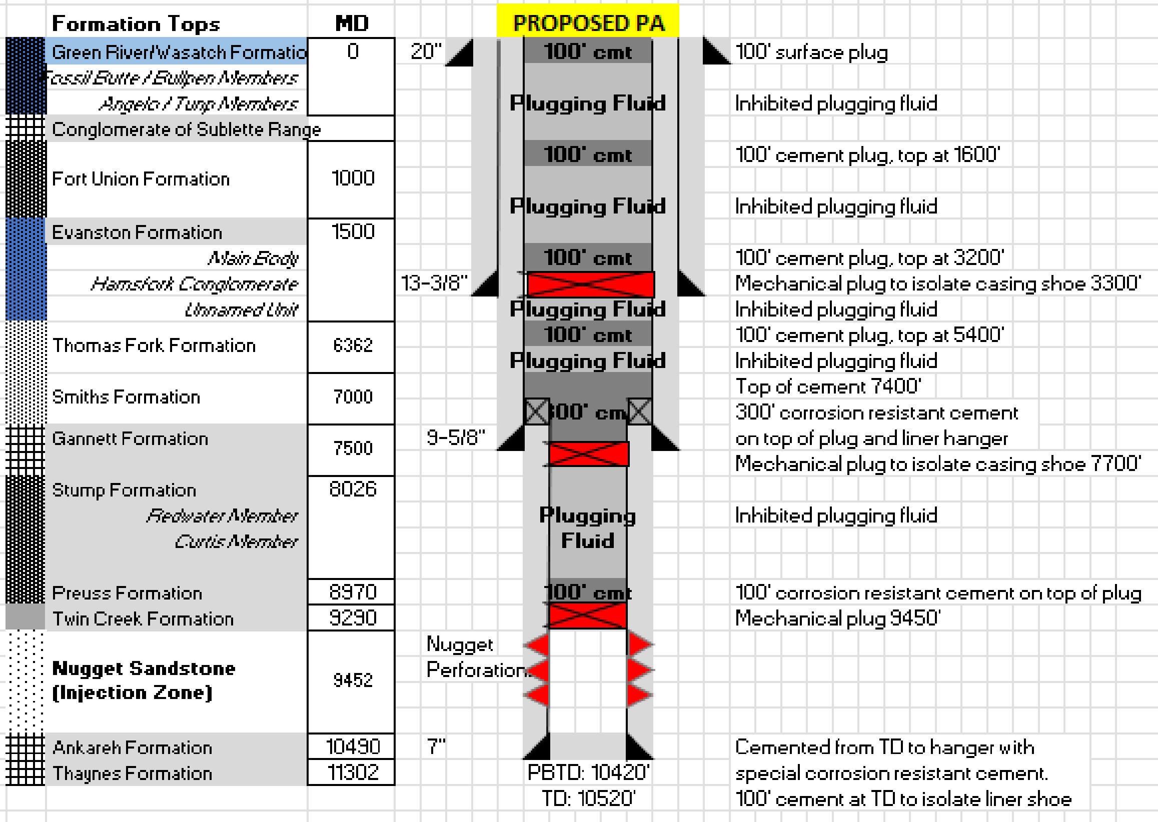

Figure 1. Plugging Diagram

Materials to be Used for Plugging

Materials used for plugging will be corrosion resistant metallurgy (mechanical plugs), cement, and appropriately specified plugging fluid.

Plugging Method Description

Injection string will be pulled, casing inspection will be conducted to identify MIT, plug placement plan will be implemented, setting of individual mechanical and balance plugs each plug will be separated by plugging fluid. Plugs will be placed at each change in casing size. A plug will be set no more than 2,500 feet from the next adjacent plug. Isolate any and all zones classified as a potential USDW.

Plugging Reports

Final reports shall be submitted to the administrator within 60 days after plugging and abandonment have been completed and will include the following certifications.

Certification of a Licensed Engineer or Professional Geologist

The sections of the permit application that represent work related to plugging shall be sealed, signed, and dated by a licensed engineer or professional geologist.

Printed Name Number (SEAL)

Signature Date Signed

Certification of accuracy by the operator

The sections of the permit application that represent work related to plugging shall be signed, and dated by the operator or person who conducted the plugging.

Printed Name Position/Title

Signature Date Signed

Attachment 4: Post Injection Site Care and Site Closure Plan

Facility Information

Facility Name: TBD

Facility Contact: Name, Address, Phone, and Email (TBD)

Well Location: Uinta County, WY., T16N R119W Sec 31

This Post Injection Site Care and Site Closure Plan describes how North Shore Energy will monitor the Painter A site pursuant to Section 24 of Chapter 24 of the WYDEQ CCS Class VI Guidance Document. This proposed plan is designed to demonstrate that Injection Site Care and Site Closure protocols are in place once operations and injection of CO_2 into the Nugget Formation have ended. Furthermore, this plan is intended to protect and ensure that there is no endangerment to people, wildlife, the habitat and USDWs within and in proximity to the area of review. Monitoring data will be used to validate and adjust the geological and simulation models used to predict the plume and pressure front in the targeted injection zone.

Upon receipt of the WYDEQ Administrator's approval of this plan, North Shore will provide the proposed cost estimate for measurement, monitoring, and verification of plume stabilization as part of the financial assurance cost estimate.

Based upon monitoring data and modeling results at end of injection, North Shore will either demonstrate that no change to this plan is necessary or will submit an amended post-injection site care and site closure plan. If amendments are necessary, they will be subject to WYDEQ approval, incorporated into the permit, and subject to permit modification requirements.

North Shore will monitor groundwater quality and track the position of the carbon dioxide plume and pressure front for 10 years post-injection. Monitoring will not cease post-injection until it has been demonstrated to WYDEQ that operations and injection of CO_2 into the Nugget Sandstone has proceeded as planned and that there will not be harm, risk or endangerment to USDWs, human health, safety or the environment.

Following approval for site closure, North Shore will plug all monitoring wells, restore the site to its original condition, and submit a Site Closure report and associated documentation.

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North Shore will provide and maintain updates on the same schedule as the update to the AOR delineation and comply with this plan for post-injection site care and site closure per section 24.

Demonstration that Geologic Sequestration Poses no Risk

Predicted Position of the CO_2 Plume and Pressure Front

Figure 1 shows the predicted extent of the plume and pressure front at the end of the 10-year PISC timeframe, representing the predicted position of the carbon dioxide plume and associated pressure front at the time when plume movement has ceased and pressure differentials sufficient to cause the movement of injected fluids or formation fluids into a USDW are no longer present. This map is based on the final AOR delineation modeling results as presented in Form 1b of this application. The 15-year time frame is based on the predicted simulation results. The extent of the CO2 plume and pressure front will be updated every two years based on observed data.

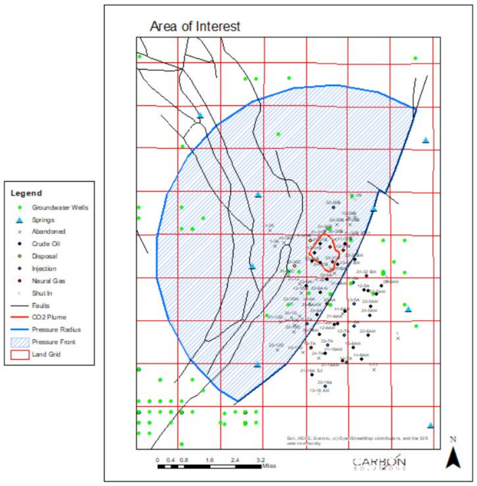

Figure 1. Predicted Extent of Plume and Pressure Front

Within the injection zone and any other zones such that formation fluids may not be forced into any USDWs; or injection pressures that exceed the fracture gradient of the system. Predicted Pressure Decline

The formation pressure at the injection well is predicted to decline rapidly within the first two years following cessation of injection. Based on the modeling of the pressure front as part of the AOR delineation, pressure is expected to decrease to pre-injection levels by the end of the PISC timeframe. Additional information on the projected post-injection pressure declines and differentials is presented in the permit application and the Area of Review and Corrective Action Plan (Attachment 1 to the permit application).

Predicted Fluid Movement

In addition to carbon dioxide, mobilized fluids may pose a risk to USDWs. These include native fluids that are high in TDS and therefore may impair a USDW, and fluids containing mobilized drinking water contaminants (e.g., arsenic, mercury, hydrogen sulfide). The geochemical data collected from monitoring wells will be used to demonstrate that no mobilized fluids have moved above the seal formation and therefore after the PISC period would not pose a risk to USDWs. In order to demonstrate non-endangerment, the operator will compare the operational and PISC period samples from layers above the injection zone, including the lowermost USDW, against the pre-injection baseline samples. This comparison will support a demonstration that no significant changes in the fluid properties of the overlying formations have occurred and that no mobilized formation fluids have moved through the seal formation. This validation of seal integrity will help demonstrate that the injectate and or mobilized fluids would not represent an endangerment to any USDWs. Additionally, RST logs will be used to monitor the salinity of the reservoir fluids in the observation zone above Twin Creek Formation. By comparing the time lapse RST logs against the pre-injection baseline logs, the operator will be able to monitor any changes in reservoir fluid salinity. RST logs indicating steady salinity levels within each zone would indicate no movement of fluids out of the storage unit, confirming the integrity of the well and seal formation.

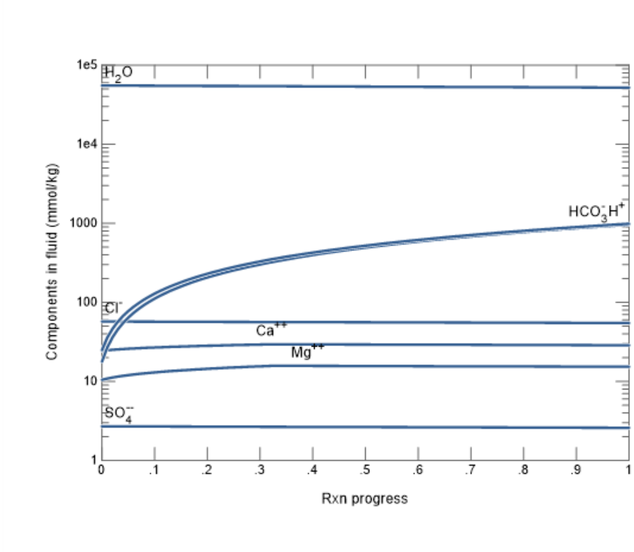

Figure 2. Salinity Relationship

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Comparison of Post-Injection Data with AOR Delineation Modeling

North Shore will employ direct and indirect methods to track the extent of the carbon dioxide plume and the presence or absence of elevated pressure. Table 1 presents the direct and indirect methods that North Shore will use to monitor the CO_2 plume, including the activities, locations, and frequencies North Shore will employ. North Shore will conduct fluid sampling and analysis to detect changes in groundwater in order to directly monitor the carbon dioxide plume. The parameters to be analyzed as part of fluid sampling in the Mt. Simon (and associated analytical methods) are presented in Table 2. Indirect plume monitoring will be employed using pulsed neutron capture/reservoir saturation tool (RST) logs to monitor CO_2 saturation and 3D surface seismic surveys. Quality assurance procedures for seismic monitoring methods are presented in Section B.9 of the QASP.

Table 1. Post-Injection Phase Plume Monitoring. (1,2)

Target Formation	Monitoring Activity	Monitoring Location(s)	Frequency: Year 1	Frequency: Years 2-3	Frequency: Years 4-9	Frequency: Year 10
Direct Plume Monitoring						

Nugget	Fluid Sampling	Well Name	Annual	Annual	Annual	Annual
Indirect Plume Monitoring						
Nugget	Pulse Neutron Logging/RST	Well Name	Year 1	Year 3	Year 5, 7	Year 10
	3D surface seismic survey	Area for this	Once (Year 1)	None	None	Once (Year 10)

Note 1: Sampling and geophysical surveys will occur within 45 days before the anniversary date of cessation of injection or alternatively scheduled with the prior approval of the Administrator. Note 2: Seismic surveys will be performed in the 4th quarter before or the 1st quarter of the calendar year shown or alternatively scheduled with the prior approval of the Administrator.

Table 2. Summary of analytical and field parameters for fluid sampling in the Nugget.

Parameters	Analytical Methods (1)
Nugget	
Cations: Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Sb Se, and Tl	ICP-MS, EPA Method 6020
Cations: Ca, Fe, K, Mg, Na, and Si Anions: Br, Cl, F, NO3, and SO4	ICP-OES, EPA Method 6010B Ion Chromatography, EPA Method 300.0
Dissolved CO2	Coulometric titration, ASTM D513-11
Total Dissolved Solids	Gravimetry; APHA 2540C
Alkalinity	APHA 2320B
pH (field)	EPA 150.1
Specific conductance (field)	APHA 2510
Temperature (field)	Thermocouple

Note 1: ICP = inductively coupled plasma; MS = mass spectrometry; OES = optical emission spectrometry; GC-P = gas chromatography - pyrolysis. An equivalent method may be employed with the prior approval of the Administrator.

Table 3 presents the direct and indirect methods that North Shore will use to monitor the pressure front, including the activities, locations, and frequencies North Shore will employ. North Shore will deploy pressure/temperature monitors and distributed temperature sensors to directly monitor the position of the pressure front. Passive seismic monitoring using a combination of borehole and surface seismic stations to detect local events over M 1.0 within the AOR will also be performed. Quality assurance procedures for seismic monitoring methods are presented in Section B.9 of the QASP.

Table 3. Post-Injection Phase Pressure Front Monitoring. (1,2)

Target Formation	Monitoring Activity	Monitoring Location(s)	Frequency: Year 1	Frequency: Years 2-3	Frequency: Years 4-9	Frequency: Year 10
Direct Pressure Front Monitoring						
Nugget	Pressure/temperature monitoring	Continuous 4 Intervals	Continuous 4 Intervals	Continuous 4 Intervals	Continuous 4 Intervals	Continuous 4 Intervals
	Distributed Temperature Sensing (DTS)	Continuous	None	None	None	None
Other Monitoring						
Multiple	Passive Seismic	A combination of borehole and surface seismic stations located within the AOR.	Continuous	Continuous	Continuous	Continuous

Note 1: Collection and recording of continuous monitoring data will occur at the frequencies described in Table 3. Note 2: Annual monitoring surveys will occur up to 45 days before the anniversary date of cessation of injection or alternatively scheduled with the prior approval of the Administrator.

Monitoring locations relative to the predicted location of the CO_2 plume at 5-year intervals throughout the post-injection phase are shown in figure 3 through 5. Predicted location of the CO_2 plume at 30 years after the commencement of injection is shown in Figure 6.

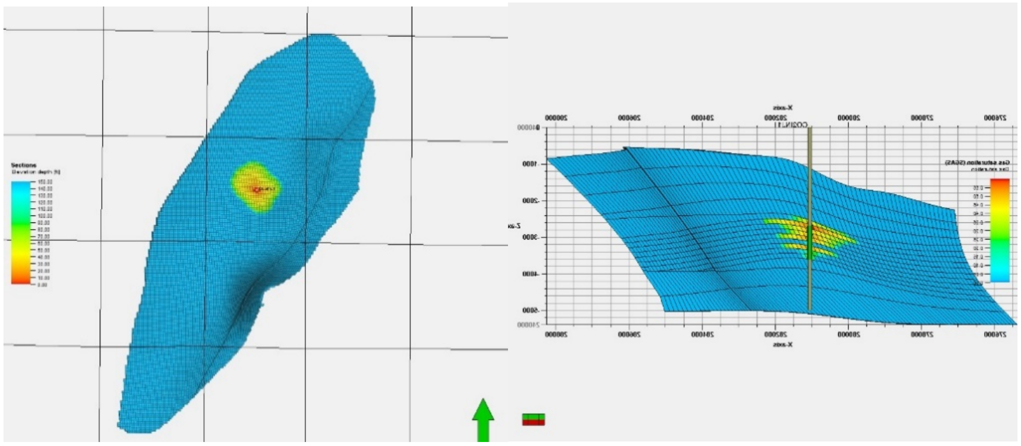

Figure 3. Predicted Extent of Plume after 5 years

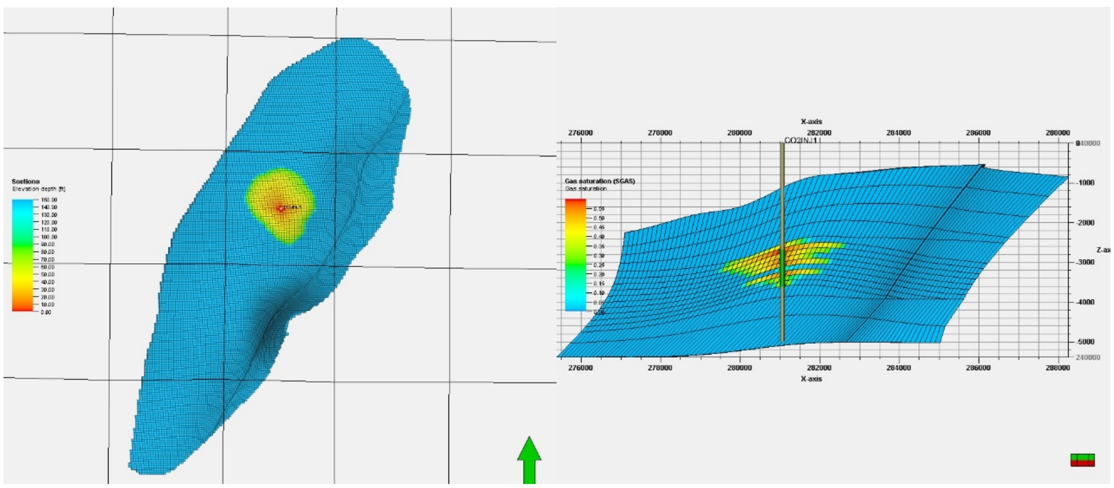

Figure 4. Predicted Extent of Plume after 10 years

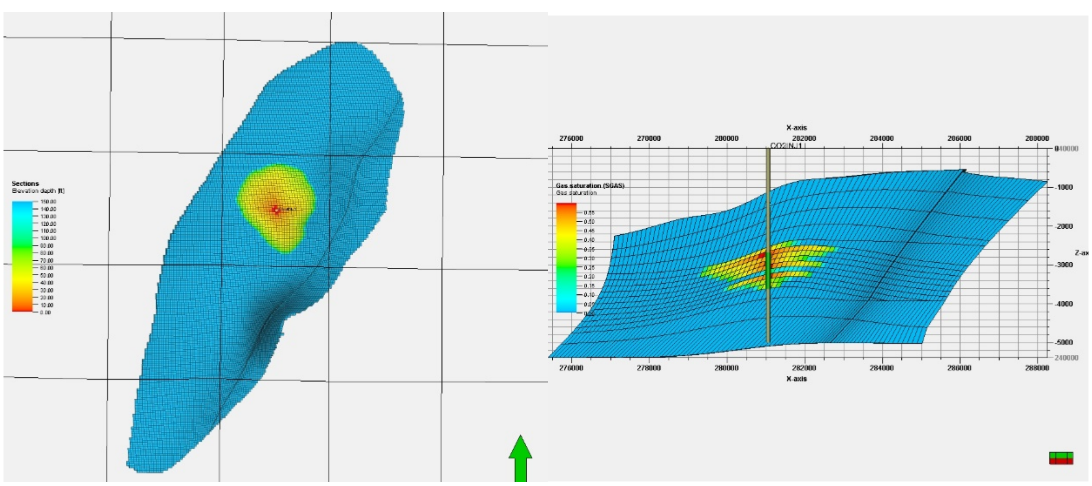

Figure 5. Predicted Extent of Plume after 15 years

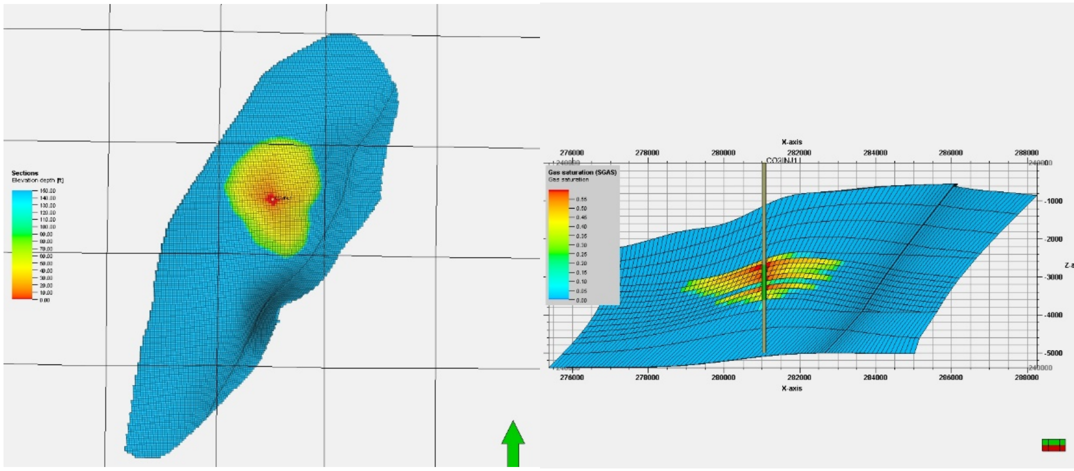

Figure 6. Predicted Extent of Plume after 30 years

Risk to USDWs

Risk to USDWs for this project is considered to be minimal based on the geologic properties of the overlying sealing formation. The existing injection target at project location is a depleted oil and gas field that were trapped by the sealing cap rock for several hundred million years.

Risk to Human Health

Risk to human health for this project is considered to be nonexistent given the location is remote and the nearest human habitation is more than four miles away.

Risk to Safety

Safety is a primary component to this project and any and all precautions will be taken to prevent injuries or death as a result of the injection project

Risk to the Environment

Risk to the environment is considered to be minimal based on the topography, source and location of springs, and the monitoring systems that will be in-place.

Pre and Post-Injection Pressures

The formation pressure at the injection well is predicted to decline rapidly within the first X years following cessation of injection. Based on the modeling of the pressure front as part of the AOR delineation, pressure is expected to decrease to pre-injection levels by the end of the PISC timeframe.

Additional information on the projected post-injection pressure declines and differentials is presented in the permit application and the Area of Review and Corrective Action Plan (Attachment 1 to this permit).

Site Monitoring Design

Monitoring

Table 4 and Table 5 present the planned direct and indirect monitoring methods, locations, and frequencies for groundwater quality monitoring above the confining zone in the Quaternary and/or Pennsylvanian strata, the St. Peter Formation, and the Ironton-Galesville Sandstone. All of the monitoring wells are located within the AOR. Table 6 identifies the parameters to be monitored and the analytical methods North Shore will employ, and Table 7 indicates monitoring frequency.

Table 4. Post-Injection Phase Direct Groundwater Monitoring Above Confining Zone. (1,2)

Target Formation	Monitoring Activity	Monitoring Location(s)	Frequency: Year 1	Frequency: Years 2-3	Frequency: Years 4-9	Frequency: Year 10
	Fluid Sampling	Well names	Annual	Annual	Annual	Annual
	Distributed Temperature Sensing (DTS)		Continuous	None	None	None
			Continuous	None	None	None
	Fluid Sampling		Annual	Annual	Annual	Annual
	Pressure/temperature monitoring		Continuous	Continuous	Annual	Annual
	DTS		Continuous	None	None	None
			Continuous	None	None	None
	Fluid Sampling		Annual	Annual	Annual	Annual
	Pressure/temperature monitoring		Continuous	Continuous	Annual	Annual
	DTS		Continuous	None	None	None
			Continuous	None	None	None

Note 1: Collection and recording of continuous monitoring data will occur at the frequencies described in Table 4. Note 2: Annual sampling and monitoring will occur up to 45 days before the anniversary date of cessation of injection or alternatively scheduled with the prior approval of the North Shore Administrator

Table 5. Post-Injection Phase Indirect Groundwater Monitoring Above the Confining Zone (1)

Target Formation	Monitoring Activity	Monitoring Location(s)	Frequency: Year 1	Frequency: Years 2-3	Frequency: Years 4-9	Frequency: Year 10
	Pulse Neutron Logging/RST		Year 1	Year 3	Year 5, 7	Year 10
			Year 1	Year 3	Year 5, 7	Year 10
			Year 1	Year 3	Year 5, 7	Year 10
			Year 1	Year 3	Year 5, 7	Year 10
	Pulse Neutron Logging/RST		Year 1	Year 3	Year 5, 7	Year 10
			Year 1	Year 3	Year 5, 7	Year 10
			Year 1	Year 3	Year 5, 7	Year 10
			Year 1	Year 3	Year 5, 7	Year 10
	Pulse Neutron Logging/RST		Year 1	Year 3	Year 5, 7	Year 10
			Year 1	Year 3	Year 5, 7	Year 10
			Year 1	Year 3	Year 5, 7	Year 10
			Year 1	Year 3	Year 5, 7	Year 10

Note 1: Logging surveys will occur within 45 days before the anniversary date of cessation of injection or alternatively scheduled with the prior approval of the North Shore Administrator

Table 6. Summary of Analytical and Field Parameters for Groundwater Samples.

Parameters	Analytical Methods (1)
Formation	
Cations: Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Sb Se, and Tl	ICP-MS, EPA Method 6020
Cations: Ca, Fe, K, Mg, Na, and Si Anions: Br, Cl, F, NO3, and SO4	ICP-OES, EPA Method 6010B Ion Chromatography, EPA Method 300.0
Dissolved CO2	Coulometric titration, ASTM D513-11
Total Dissolved Solids	Gravimetry; APHA 2540C

Alkalinity	APHA 2320B
pH (field)	EPA 150.1
Specific conductance (field)	APHA 2510
Temperature (field)	Thermocouple

Note 1: ICP = inductively coupled plasma; MS = mass spectrometry; OES = optical emission spectrometry; GC-P = gas chromatography - pyrolysis. An equivalent method may be employed with prior approval of the North Shore Administrator.

Figure 7 is currently in press and provided to the Administrator once complete

Figure 7. Location of Potential Monitoring Wells

Sampling will be performed as described in section B.2 of the QASP; this section of the QASP describes the groundwater sampling methods to be employed, including sampling SOPs (section B.2.a/b), and sample preservation (section B.2.g).

Sample handling and custody will be performed as described in section B.3 of the QASP. Quality control will be ensured using the methods described in section B.5 of the QASP. Collection and recording of continuous monitoring data will occur at the frequencies described in Table 11.

Table 7. Sampling and Recording Frequencies for Continuous Monitoring.

Well Condition	Minimum sampling frequency: once every(1)(4)	Minimum recording frequency: once every(2)(4)
For continuous monitoring of the injection well:	5 seconds	5 minutes(3)
For the well when shut-in:	4 hours	4 hours

Note 1: Sampling frequency refers to how often the monitoring device obtains data from the well for a particular parameter. For example, a recording device might sample a pressure transducer monitoring injection pressure once every two seconds and save this value in memory. Note 2: Recording frequency refers to how often the sampled information gets recorded to digital format (such as a computer hard drive). Following the same example above, the data from the injection pressure transducer might be recorded to a hard drive once every minute. Note 3: This can be an average of the sampled readings over the previous 5-minute recording interval, or the maximum (or minimum, as appropriate) value identified

over that recording interval. Note 4: DTS sampling frequency is once every 10 seconds and recorded on an hourly basis.

Verification

Maintenance

Mitigation

USDW Risk Mitigation Data

Continuous monitoring of the injection stream including pressure and volumetric estimates will serve as primary indicators to changes in injection behavior. Secondary measures will include monitoring wells within the AOR, MITs and ground water sampling procedures. These data will be used to indicate if the injectant is migrating out of zone and poses potential impact on USDWs.

Non-Endangerment Demonstration

Prior to authorization of site closure, North Shore will submit a demonstration of non-endangerment of USDWs to the Administrator. To make the non-endangerment demonstration, North Shore will issue a report to the Administrator. This report will make a demonstration of USDW non-endangerment based on the evaluation of the site monitoring data used in conjunction with the project's computational model. The report will detail how the non-endangerment demonstration uses site-specific conditions to confirm and demonstrate non-endangerment. The report will include all relevant monitoring data and interpretations upon which the non-endangerment demonstration is based, model documentation and all supporting data, and any other information necessary for the Administrator to review the analysis. The report will include the following components:

A summary of all previous monitoring data collected at the site, pursuant to the Testing and Monitoring Plan (Attachment 2 of this permit) and this PISC and Site Closure Plan, including data collected during the injection and PISC phases of the project, will be submitted to help demonstrate non-endangerment. Data submittals will be in a format acceptable to the Administrator, and will include a narrative explanation of monitoring activities, including the dates of all monitoring events, changes to the monitoring program over time, and an explanation of all monitoring infrastructure that has existed at the site. Data will be compared with baseline data collected during site characterization.

The operator will also support a demonstration of non-endangerment to USDWs by showing that, during the PISC period, the pressure within the Mt. Simon rapidly decreases toward its pre-injection static reservoir pressure. Because the increased pressure during injection is the primary driving force for fluid movement that may endanger a USDW, the decay in the pressure differentials will provide strong justification that the injectate does not pose a risk to any USDWs. The operator will monitor the downhole reservoir pressure at various locations and intervals using a combination of surface and downhole pressure gauges. The measured pressure at a specific depth interval will be compared against the pressure predicted by the computational model. Agreement between the actual and the predicted values will help validate the accuracy of the model and further demonstrate non-endangerment. Figure 8 provides an illustrative example of how the operator will demonstrate agreement between the computational model prediction and the actual measured parameters at the various monitoring wells and respective measurement depths. This figure shows that during the 10 years of the PISC period, the actual reservoir pressure (red line) falls to pre-injection levels and has a decay rate similar to the rate predicted by the model. Based on risk-based criteria listed in the PISC and Site Closure Plan, pressure decline toward pre-injection levels is one factor indicative of USDW non-endangerment. The close alignment between the predicted and actual pressures will further validate the model's accuracy in representing the reservoir system.

Figure 8 is currently in press and provided to the Administrator once complete

Figure 8. Verification of Actual dP vs Predicted dP

One of the key comparisons that may be made is between the observed injection reservoir pressure and the model predicted pressure. Figure 8 shows an illustrative example of differential reservoir pressure predicted for five years after injection ceases, relative to original static reservoir pressure. The contour southwest of the CCS#2 well is the 10 psi contour as predicted by the computational model. Direct observations will be utilized during the PISC period to verify that pressure observations at Painter A have declined in conformance with the model. Pressure decline to this level within this time frame is an indication of the excellent lateral continuity within the regionally extensive, open Nugget reservoir. Observed reduction of reservoir pressure to this extent would help validate the model and indicate substantial reduction in the potential of injection-pressure induced brine or CO_2 migration.

9Plugging of Monitoring Wells and Site Restoration

See attachment 4 of this permit application Post Injection Site Care and Site Closure Plan.

Proposed Schedule for Submitting Post-Injection Site Care Results

All post-injection site care monitoring data and monitoring results (i.e., resulting from the groundwater monitoring and plume and pressure front tracking described above) will be submitted to the Administrator in annual reports. These reports will be submitted each year, within 60 days following the anniversary date of the date on which injection ceases or alternatively with the prior approval of the Administrator.

The annual reports will contain information and data generated during the reporting period; i.e. seismic data acquisition, well-based monitoring data, sample analysis, and the results from updated site models.

Duration of Site Care timeframe

North Shore will conduct post-injection monitoring for ten years following the cessation of injection operations. North Shore demonstrated that an alternative PISC timeframe is appropriate. This demonstration is based on the computational modeling to delineate the AOR; predictions of plume migration, pressure decline, and carbon dioxide trapping; site-specific geology; well construction; and the distance between the injection zone and the nearest USDWs. North Shore will conduct all of the monitoring described under “Groundwater Quality Monitoring” and “Carbon Dioxide Plume and Pressure Front Tracking” above and report the results as described under the “Schedule for Submitting Post-Injection Monitoring Results.” This will continue until North Shore demonstrates, based on monitoring and other site-specific data, that no additional monitoring is needed to ensure that the project does not pose an endangerment to any USDWs. If any of the information on which the demonstration was based changes or the actual behavior of the site varies significantly from modeled predictions, e.g., as a result of an AOR reevaluation, North Shore may update this PISC and Site Closure Plan. North Shore will update the PISC and Site Closure Plan, within six months of ceasing injection or demonstrate that no update is needed and as necessary during the duration of the PISC timeframe.

Predicted Timeframe for Pressure Decline

The results of computational modeling used for AOR delineation and for demonstration of an alternative PISC timeframe will be compared to monitoring data collected during the operational and the PISC period. The data will include the results of time-lapse temperature and pressure monitoring, groundwater quality analysis, passive seismic monitoring, and geophysical surveys (i.e. logging, operating-phase VSP, and 3D surface seismic surveys) used to update the computational model and to monitor the site. Data generated during the PISC period will be used to help show that the computational model accurately represents the storage site and can be used as a proxy to determine the plume’s properties and size. The operator will demonstrate this degree of accuracy by comparing the monitoring data obtained during the PISC period against the model’s predicted properties (i.e. plume location, rate of movement, and pressure decay). Statistical methods will be employed to correlate the data and confirm the model’s ability to accurately represent the storage site. The validation of the computational model with the large volume of available data will be a significant element to support the non-endangerment demonstration. Further, the validation of the complete model over the areas, and at the points, where direct data collection has taken place will help to ensure confidence in the model for those areas where surface infrastructure preclude geophysical data collection and where direct observation wells cannot be placed.

The operator will use a combination of time-lapse RST logs, time-lapse VSP surveys, and other seismic methods (2D or 3D surveys) to locate and track the extent of the CO2 plume. Also, limited 2D and 3D seismic surveys will be employed to determine the plume location at specific times. The data produced by these activities will be compared against the model using statistical methods to validate the model's ability to accurately represent the storage site. Processes that Result in CO2 immobilization

- Capillary Trapping
- Dissolution
- Mineralization

Potential Conduits for Fluid Migration

Other than the 56 existing well bores and the project well, there are no identified potential conduits for fluid movement or leakage pathways within the AOR. Because existing well bores are the existing wells are down dip from the injection well, it is likely the plume will reach several of the locations. Based on this information, the potential for fluid movement through artificial penetrations of the seal formation presents a minimal risk of endangerment to any USDWs.

Well Plugging Descriptions within the AOR

Plugging descriptions of existing PA'd wells within the AOR have been compiled and are available upon request by the Administrator. Plugging of the proposed injection well is described in attachment 3, Injection and Monitoring Wells Plugging Plan.

Testing Standards

Post-Injection Site Care and Site Closure Proposed Cost Estimate

The Post-Injection Site Care and Site Closure cost estimate will be determined and provided to the Administrator following the development of a risk matrix and results of a risk analysis.

Notification to the State and Local Authorities Regarding Site Closure

After the WYDEQ Administrator has approved site closure, North Shore will plug monitoring wells in an approved manner that will not allow movement of injection or formation fluids.

A site closure report will be submitted to the WYDEQ by North Shore within 90 days after completion of all closure operations. This report will include documentation of injection and monitoring well-plugging pursuant to WYDEQ requirements; a copy of the survey plat containing location of injection well and monitoring wells relative to permanent benchmarks that will be submitted to the local zoning authority as identified by WYDEQ and to the US EPA Regional Administrator; documentation of notification and information to State and any local authorities that have authority over drilling activity to enable them to impose appropriate conditions on subsequent drilling activities that may penetrate the injection and confining zones; proof of notification that a notice for application of site closure has been published, including a mechanism to request a public hearing, in a newspaper in circulation in Uinta County of the proposed operation at weekly intervals of 4 consecutive weeks; mailed notice of application for site closure to all surface owners, mineral claimants, mineral owners, lessees, and other owners of record of subsurface interests that are located within 1 mile of the boundary of geologic sequestration site; also the report shall include records of the nature, composition, and volume of the carbon dioxide stream.

Upon site closure, North Shore shall record a notation on the deed to the facility property or any other document that is normally examined during title search that will in perpetuity provide notice to any potential purchaser of the property, and shall file an affidavit in accordance with W.S. § 35-11-313(f)(vi)(G), that states that the land has been used to sequester carbon dioxide, the name of the State agency with which the survey plat was filed, the address of the EPA regional office which maintains a record of the survey plat, and the volume of fluid injected, the injection zone(s), and the period over which injection occurred.

Attachment 5: Emergency and Remedial Response Plan

Facility Information

Facility Name: TBD

Facility Contact: Name, Address, Phone, and Email (TBD)

Well Location: Uinta County, WY., T16N R119W Sec 31

This Emergency and Remedial Response Plan describes how North Shore Energy will monitor the Painter A site pursuant to Section 25 of Chapter 24 of the WYDEQ CCS Class VI Guidance Document. This proposed plan is designed to provide protocols that are to be followed in regard of an event triggering the Emergency and Remedial Response Plan. In the event operations and injection of CO_2 into the Nugget Formation are not proceeding as planned and that the plume and pressure front are not behaving as predicted, this plan will be implemented to notify, address, evaluate and remediate unintended events in order to protect and ensure that there is no endangerment to people, wildlife, the habitat and USDWs within and in proximity to the area of review. Monitoring data will be used to validate and adjust the geological and simulation models used to predict the plume and pressure front in the targeted injection zone.

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Update and Amendment Schedule

The Emergency Response Plan shall be reviewed and updated and or amended annually or as needed in following the occurrence of an event requiring action during any phase of the project.

Emergency Remedial Response Plan

Response Plan Procedure

In the event that monitoring data and or other information indicate that injection is posing a threat or endangerment to a USDW, human health, safety or the environment the following steps will be taken.

- Immediately cease any and all injection
- Take steps to identify any release
- Verbally notify the Administrator within 24 hours
- Provide a written report to the Administrator within 5 days that shall include a description of the noncompliance and its cause, the period of the noncompliance, expected duration, and steps to be taken to reduce or eliminate any recurrence of the event.

Noncompliance Events

In the event that noncompliance is discovered the response plan action will depend on the severity, circumstances and impact of the event. Examples of potential events are shown in figure 1.

Construction Period

- Well control event while drilling or completing the well with loss of containment
- Movement of brine between formations during drilling
- Presence of H_2S while drilling or completing the well

Injection Period

- Loss of mechanical integrity (flowlines, injection, monitoring wells, disposal well)
- Loss of containment (LOC): vertical migration of CO_2/brines via injection wells, monitor wells, Class I wells, P&A wells, and undocumented wells
- LOC: lateral migration of CO_2 outside of defined AOR
- LOC: vertical migration due to failure in the confining zone, faults, and fractures
- External impact in flowlines, wells, and infrastructure
- Monitoring equipment failure or malfunction
- Induced seismicity
- Seismic event
- Other natural disaster

Postinjection Site-Care Period

- Loss of mechanical integrity (monitoring wells)
- LOC: vertical migration of CO_2/brines via monitoring, wells, Class I wells, P&A wells, and undocumented wells
- LOC: lateral migration of CO_2 outside of defined AOR
- LOC: vertical migration due to failure in the confining zone, faults, and fractures
- External impact in monitoring wells
- Monitoring equipment failure or malfunction
- Natural seismicity
- Other natural disaster

Figure 1. Examples of potential noncompliance events adopted from the Minnkota Power Cooperative Draft Fact Sheet North Dakota Fact Sheet.

Discovery of an Excursion

If an unintended release of CO_2 is discovered the Emergency Response Plan will be triggered and all predefined protocols will be put into action regardless of the severity, circumstance or impact of the event.

Impact on USDW

If leakage or upward migration of CO_2 is discovered within a designated USDW injection operations will cease immediately. Monitoring data will be used to determine the volumes released and an assessment of the impact will be made and reported to the Administrator within the specified time period. Any and all available technology will be deployed to mitigate and remediate the impact.