UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 8
1595 Wynkoop Street
DENVER, COLORADO 80202-1129
Phone 800-227-8917
http://www.epa.gov/region8

UNDERGROUND INJECTION CONTROL
DRAFT
CLASS V AREA PERMIT

Area Permit No. SD52173-00000

Class V Deep Injection Well Area Permit
Dewey-Burdock Uranium In-Situ Recovery Project
Custer and Fall River Counties, South Dakota

Issued To

Powertech (USA) Inc.
5575 DTC Parkway, Suite 140,
Greenwood Village, Colorado 80111

PART I. EFFECT OF PERMIT

Under the authority of the Safe Drinking Water Act and Underground Injection Control (UIC) Program regulations of the U. S. Environmental Protection Agency (EPA) codified at Title 40 of the Code of Federal Regulations (40 CFR) Parts 2, 124, 144, 146, and 147, and according to the terms of this Area Permit,

Powertech (USA) Inc.
5575 DTC Parkway, Suite 140,
Greenwood Village, Colorado 80111

is hereby referred to as the "Permittee."

Because this permit authorizes more than one injection well, it is an Area Permit and subject to the requirements found at 40 CFR § 144.33. The Permittee is allowed to engage in underground injection in accordance with the conditions of this Area Permit. The Permittee shall not construct, operate, maintain, convert, plug, abandon, or conduct any other activity in a manner that allows the movement of fluid containing any contaminant into underground sources of drinking water, if the presence of that contaminant may cause a violation of any primary drinking water regulation under 40 CFR part 141 or may otherwise adversely affect the health of persons. Any underground injection activity not authorized by this Permit or by rule is prohibited. Issuance of this Permit does not convey property rights of any sort or any exclusive privilege; nor does it authorize any injury to persons or property, any invasion of other private rights, or any infringement of State or local laws or regulations. Compliance with the terms of this Permit does not constitute a defense to any enforcement action brought under the provisions of Section 1431 of the Safe Drinking Water Act (SDWA) or any other law governing protection of public health or the environment, for any imminent and substantial endangerment to human health or the environment, nor does it serve as a shield to the Permittee's independent obligation to comply with all UIC regulations. Nothing in this Permit relieves the Permittee of any duties under applicable State or local laws or regulations.

This Area Permit authorizes the construction and operation of up to four (4) disposal wells injecting only into the Minnelusa Formation within the Permit Area described below according to the conditions set forth in the Area Permit. The construction of more than four (4) injection wells targeting the Minnelusa Formation injection zone is a violation of this permit. The Permittee may request to construct more than four (4) injection wells through a major modification to this permit according to 40 CFR § 144.39 and § 124.5, which would invoke the public review process required under 40 CFR part 124.

A. Class V Permit Area Boundary

Figure 1 shows the Dewey-Burdock Project Boundary (shown as a thick red line) and the Class V Permit Area in Custer and Fall River Counties, South Dakota. Figure 1 also includes the proposed locations for the two (2) initial Class V deep injection wells.

B. Well Locations

Approximate location information for the two proposed Class V injection wells is shown in Table 1. The anticipated depths of the injection zone are based on well logs provided in the Class V Permit Application. Actual injection zone depths will be determined by well logs performed on each injection well as described in Part II, Section C.

Table 1. Injection Wells Proposed under the Class V Area Permit

Well Permit Number	Well Name	Approximate Latitude	Approximate Longitude	Proposed Injection Zone	Anticipated Injection Zone Depth (ft below ground surface)	Location within Permit Area
SD52173-08764	DW No. 1	43.469772181	-103.971938654	Minnelusa Formation	~1,615 - ~2,205	Burdock Area
SD52173-08766	DW No. 3	43.4971737527	-104.031570321	Minnelusa Formation	~1,950 - ~2,540	Dewey Area

Permit requirements herein are based on regulations found in 40 CFR parts 2, 124, 144, 146, and 147, which are in effect on the Effective Date of this Permit. The UIC regulations specific to South Dakota are found at 40 CFR § 147.2100.

This Area Permit is based on representations made by the applicant and on other information contained in the Administrative Record. Misrepresentation of information or failure to fully disclose all relevant information may be cause for termination, revocation and reissuance, or modification of this Area Permit and/or formal enforcement action.

This Area Permit is issued for a period of ten (10) years unless modified, revoked and reissued, or terminated under 40 CFR § 144.39 or § 144.40. This Permit may be adopted, modified, revoked and reissued, or terminated if primary enforcement authority for this program is delegated to the State of South Dakota. Upon the effective date of delegation, all reports, notifications, questions and other compliance actions shall be directed to the State Program Director or designee.

Issue Date: ___________________________

Effective Date: ___________________________

____

Darcy O'Connor
Assistant Regional Administrator
Office of Water Protection

*NOTE: Throughout this Permit the term "Director" refers to either the Assistant Regional Administrator for the Office of Water Protection (WP) or the Assistant Regional Administrator of Environmental Compliance, Enforcement and Justice (ECEJ).

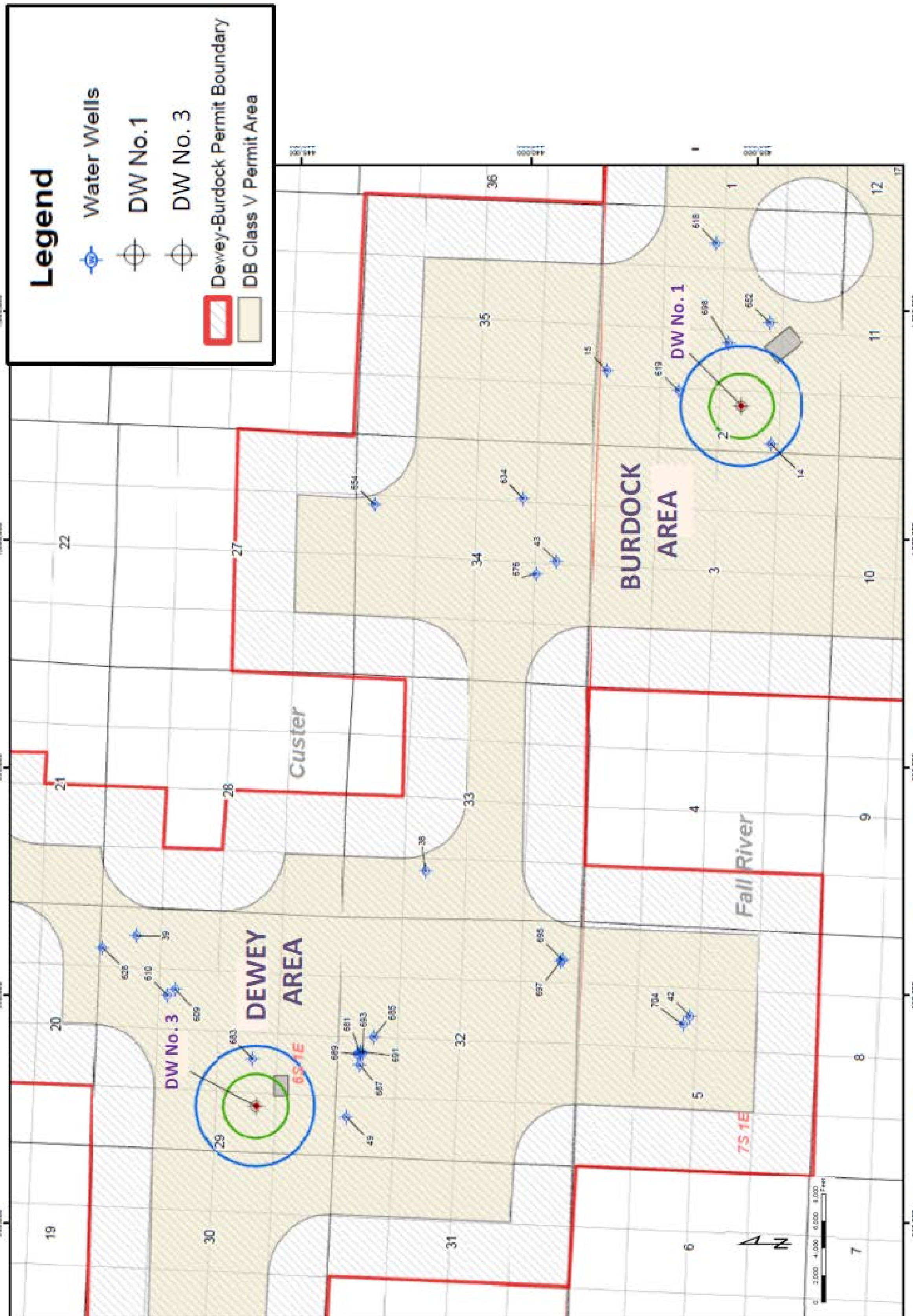


Figure 1. Approximate Dewey-Burdock Class V Permit Area

PART II. REQUIREMENTS FOR AUTHORIZATION TO COMMENCE INJECTION

In order to obtain Authorization to Commence Injection for any injection well under this Permit, the information required under this Section shall be provided to the Director for evaluation in an Injection Authorization Data Package Report which shall include a descriptive narrative interpreting the results of logs and tests prepared by a knowledgeable log analyst. The report shall include a description of the methods used during logging or testing. The Permittee shall ensure the log and test requirements are performed within the time frames specified.

A. Injection Authorization Data Package Report

1. Information to Submit to the Director to Obtain a Limited Authorization to Inject for Testing Purposes

For each injection well, the Permittee shall provide the following information, further described in Sections B through H, to the Director for evaluation. After evaluating the information, the Director will determine if it is appropriate to issue a written Limited Authorization to Inject to authorize the Permittee to commence injection activity for testing purposes only.

a. Well logging information, formation testing data and laboratory data from drillhole core demonstrating the injection zone is separated from underground sources of drinking water (USDWs) by an overlying confining zone identified in well logs and is demonstrated to have low permeability and low hydraulic conductivity. The Permittee shall include annotations on logs, where appropriate, to identify aquifers, injection zone and confining zones.
b. Evaluation of the Minnelusa injection zone aquifer fluids to confirm the injection zone formations is hydraulically isolated from the Madison aquifer at the Dewey-Burdock Project Site.
c. Evaluation of the Minnelusa and Madison aquifer fluids at DW. No. 1, if it is drilled to the base of the Deadwood Formation, AND at the Madison water supply wells, if they are approved by the South Dakota Water Rights Program, to confirm the injection zone formation is hydraulically isolated from the Madison aquifer at the Dewey-Burdock Project Site.
d. The Total Dissolved Solids (TDS) concentration of the injection zone aquifer fluids in order for the Director to determine that the injection zone is ***not*** a USDW. If injection zone TDS is less than 10,000 mg/L, the injection zone is a USDW. The Director will not authorize injection into a USDW under this Area Permit.
e. Calculations of critical pressures and injection-induced injection zone pressures for the injection zone based on site-specific information and 12 years of injection activity. This information shall be used to demonstrate that each injection well is located a sufficient distance from any feature that has the potential to serve as a migration pathway for injection zone fluids to move through confining zones out of the injection zone.
f. Well construction completion report using EPA Form 7520-9 containing information demonstrating that the injection zone is isolated from USDWs by well casing and cement.
g. Well perforations are located within the approved injection zone.
h. Demonstration of internal and external mechanical integrity for each injection well.
i. The testing procedures, results and interpretation of results for the formation testing required under Part II, Section D shall be included in the Injection Authorization Data Package Report.

2. Information to Submit to the Director to Obtain an Authorization to Commence Injection

a. After obtaining the Limited Authorization to Inject, the Permittee shall inject only for the purpose of conducting the following tests:

 i. Step Rate Test and

 ii. Initial Radioactive Tracer Survey

b. The Permittee shall provide the testing results to the Director for evaluation as required under Part II Section K.1.

B. Collection of Drill Core in the Injection Zone and Confining Zones

1. The Permittee shall collect drill core from the injection zone, the overlying confining zone formation and the underlying confining zone as described in Table 2 for the reasons stated in Table 2. Laboratory data may be supplemented by data from pressure transient testing and porosity information from the BHC Sonic log.
2. The information shall be included in the Injection Authorization Data Package Report for each Class V injection well.
3. The effective porosity and permeability of the injection zone formations shall be used as the input values in the equation used to calculate decline of injection zone pressure with distance away from the injection well described in Part II, Section F.2.

Table 2. Drill Core Collection for Laboratory Testing

TYPE OF TEST	PURPOSE	DUE DATE
While drilling each injection well, core samples shall be collected in the Minnelusa Injection Zone.	For laboratory testing to determine the porosity, effective porosity and permeability of the injection zone.	Prior to receiving Limited Authorization to Inject
While drilling each injection well, core samples shall be collected within the lower 50 feet of the Opeche Shale Confining Zone	For laboratory testing to determine the permeability and hydraulic conductivity of the overlying confining zone.	Prior to receiving Limited Authorization to Inject
Samples shall be collected from the top 50 feet of the Lower Minnelusa confining zone while drilling DW No. 1, if the borehole is drilled to the base of the Deadwood Formation OR while drilling the Madison water supply wells, if they are approved by the South Dakota Water Rights Program.	For laboratory testing to determine the permeability and hydraulic conductivity of the underlying confining zone.	Prior to receiving Limited Authorization to Inject

C. Well Logging Requirements

1. The Permittee shall perform the logging operations listed in Tables 3, 4 and 5 on each injection well drillhole and casing.
2. If the borehole for DW No. 1 is drilled to the base of the Deadwood Formation, then the Permittee shall conduct the open hole logs listed in Table 4 on the Lower Minnelusa confining zone.
3. The Permittee shall also conduct a minimum of mud logging, spontaneous potential logging and BHC sonic open-hole logging on the Madison water supply wells and the cement bond logs on the well casing, if these wells are approved by the South Dakota Water Rights Program.

4. The reasons for conducting these well logs include:
    a. Defining the vertical extent of the injection zone and the overlying and underlying confining zones to confirm that the injection zone is separated from overlying and underlying USDWs by the confining zones;
    b. Verifying that there is a bond between the cement and well casing as demonstrated in the cement bond log to prevent the movement of formation fluids through the cement-filled annulus between the well casing and the drillhole wall.
5. The Permittee shall perform deviation checks on all injection well holes constructed by first drilling a pilot hole, and then enlarging the pilot hole by reaming or another method. Such checks shall be conducted at sufficiently frequent intervals to assure that vertical avenues for fluid migration in the form of diverging holes are not created during drilling.

Table 3. Surface Casing Logs

TYPE OF LOG	PURPOSE	DUE DATE
Dual Induction Laterolog	12-1/4” open-hole formation evaluation	Prior to setting 9-5/8” casing
Gamma Ray	12-1/4” open-hole formation evaluation	Prior to setting 9-5/8” casing
BHC Sonic	12-1/4” open-hole formation evaluation	Prior to setting 9-5/8” casing
Formation Density	12-1/4” open-hole formation evaluation	Prior to setting 9-5/8” casing
Caliper	12-1/4” open-hole cement estimate	Prior to setting 9-5/8” casing
Cement Bond Log[1]	Cement quality behind the 9-5/8” casing	Prior to setting 7” or 5-1/2”casing in DW No. 1 Prior to setting 5-1/2” casing in DW No. 3

[1] Recommendations for Cement Bond Log procedures can be found at https://www.epa.gov/uic/uic-epa-region-8. It is the responsibility of the Permittee to obtain and use guidance prior to conducting any well log or test required as a condition of this permit.

Table 4. Longstring Casing: Open Hole Logs

TYPE OF LOG	PURPOSE	DUE DATE
Mud Logging	8-1/2” open-hole formation evaluation	During drilling
Dual Induction Laterolog	8-1/2” open-hole formation evaluation	Prior to setting 7” or 5-1/2”casing in DW No. 1 Prior to setting 5-1/2” casing in DW No. 3
Spontaneous Potential	8-1/2” open-hole formation evaluation	Prior to setting 7” or 5-1/2”casing in DW No. 1 Prior to setting 5-1/2” casing in DW No. 3
Gamma Ray	8-1/2” open-hole formation evaluation	Prior to setting 7” or 5-1/2”casing in DW No. 1 Prior to setting 5-1/2” casing in DW No. 3
BHC Sonic	8-1/2” open-hole formation evaluation	Prior to setting 7” or 5-1/2”casing in DW No. 1 Prior to setting 5-1/2” casing in DW No. 3
Formation Density	8-1/2” open-hole formation evaluation	Prior to setting 7” or 5-1/2”casing in DW No. 1 Prior to setting 5-1/2” casing in DW No. 3
Compensated Neutron	8-1/2” open-hole formation evaluation	Prior to setting 7” or 5-1/2”casing in DW No. 1 Prior to setting 5-1/2” casing in DW No. 3

Fracture Finder	8-1/2” open-hole formation evaluation	Prior to setting 7” or 5-1/2”casing in DW No. 1 Prior to setting 5-1/2” casing in DW No. 3
Caliper	8-1/2” open-hole cement estimate	Prior to setting 7” or 5-1/2”casing in DW No. 1 Prior to setting 5-1/2” casing in DW No. 3

Table 5. Longstring Casing Logs

TYPE OF LOG	PURPOSE	DUE DATE
Cement Bond Log[2]	Cement quality behind the 7” or 5-1/2”casing in DW No. 1 Cement behind the 5-1/2” casing in DW No. 3	Prior to receiving Limited Authorization to Inject
Casing Inspection Log	Casing quality of the 7” or 5-1/2”casing in DW No. 1 Casing quality of the 5-1/2” casing in DW No. 3	Prior to receiving Limited Authorization to Inject

[2] Recommendations for Cement Bond Log procedures can be found at https://www.epa.gov/uic/uic-epa-region-8. It is the responsibility of the Permittee to obtain and use guidance prior to conducting any well log or test required as a condition of this permit.

D. Formation Testing

1. Formation Tests to Conduct

For each aquifer listed in Table 6, the Permittee shall conduct the formation tests listed in Table 7 for the purposes stated in Table 7.

Table 6. Aquifers to be Tested during Injection Well Drilling

Well Drill Hole	**Aquifers to be Tested**
DW No. 1	Fall River Chilson Unkpapa/Sundance Minnekahta Limestone Minnelusa porosity zone
DW No. 3	Fall River Chilson Unkpapa/Sundance Minnekahta Limestone Minnelusa porosity zone
DW No. 1, if it is drilled to the base of the Deadwood Formation AND the Madison water supply wells, if they are approved by the South Dakota Water Rights Program.	Minnelusa aquifer Madison aquifer

Table 7. Formation Testing Program

TYPE OF TEST	PURPOSE	DUE DATE
Isolate each aquifer and measure the potentiometric surface elevation of each aquifer as it is intersected by the wellbore	To determine the potentiometric surface elevation of each aquifer, including the injection zone	Prior to receiving Limited Authorization to Inject
Aquifer fluid sampling and analysis: A minimum of two (2) fluid samples shall be collected from each aquifer for analyses of the parameters in Table 8	To characterize the water quality of each aquifer intersected by the well bore.	Prior to receiving Limited Authorization to Inject
TDS evaluation of the injection zone based on a minimum of five (5) fluids samples from the Minnelusa injection zone according to the requirements under Part II, Section D.2.f and g.	To demonstrate the injection zone is not a USDW	Prior to receiving Limited Authorization to Inject
Further characterization Minnelusa Injection Zone with respect to Bicarbonate, Calcium, Carbonate, Chloride, Fluoride, Magnesium, Potassium, Sodium and Sulfate concentrations. Report results as mg/L, milliequivalents per liter and plot as STIFF diagram show in Figure 2.	To verify the Minnelusa injection zone and Madison aquifer are hydrologically separated as described in Part II, Section E.3.	Prior to receiving Limited Authorization to Inject
Characterization of the Madison Formation at DW No. 1, if it is drilled to the base of the Deadwood Formation AND at the two Madison water supply wells, if they are approved by the South Dakota Water Rights Program, with respect to Bicarbonate, Calcium, Carbonate, Chloride, Fluoride, Magnesium, Potassium, Sodium and Sulfate concentrations. Report results as mg/L, milliequivalents per liter and plot as STIFF diagram show in Figure 2.	To verify the Minnelusa injection zone and Madison aquifer are hydrologically separated as described in Part II, Section E.3.	Prior to receiving Limited Authorization to Inject
Measurement of additional parameters in the Madison aquifer required for updating the drawdown model of the Madison aquifer potentiometric surface described in Section 4.0 of the *Report to Accompany Madison Water Right Permit Application* submitted to the DENR Water Rights Program using site specific data.	To provide the input parameters for the drawdown model that will determine the expected drawdown in the Madison aquifer at each Madison water supply well with 12 years of pumping.	Prior to receiving Limited Authorization to Inject
Initial Temperature Survey Log[3]	To establish baseline temperatures of formations along well bore.	Prior to receiving Limited Authorization to Inject

[3] Recommendations for Temperature Survey Log procedures can be found at https://www.epa.gov/uic/uic-epa-region-8. It is the responsibility of the Permittee to obtain and use guidance prior to conducting any well log or test required as a condition of this permit.

2. Aquifer Fluid Sampling Requirements

a. The drilling program for each well shall include the addition of a tracer in the drilling fluids. The tracer used for this purpose shall be such that the Permittee is able to analyze for the presence of the tracer in aquifer fluids samples using field testing methods. The tracer shall also be included as an analyte for laboratory testing of formation fluids to verify that no drilling fluid residual is present in the formation fluid samples.

b. Before aquifer sample collection, each aquifer shall be isolated within the drill hole to prevent inflow of groundwater from other aquifers.

c. Once the potentiometric surface for each isolated aquifer has been allowed to stabilize for 30 minutes, the Permittee shall collect three potentiometric surface elevation measurements a minimum of 15 minutes apart. After the potentiometric surface elevation measurements have been recorded, fluid samples shall be collected from each aquifer using the procedures in Part V, Section D.1.b and c of this Area Permit.

d. If the potentiometric surface of Minnekahta Formation is not above the top of the formation, the Permittee is not required to collect any fluids samples from the Minnekahta Formation. If the potentiometric surface of the Minnekahta aquifer fluid is above the top elevation of the formation, then the Permittee shall collect aquifer fluid samples to analyze for TDS and the other constituents in Table 8. If the Minnekahta Formation is not able to sustain pumping rates necessary for representative aquifer fluid samples to be collected, then the Permittee shall document sampling efforts, but is not required to collect fluids samples from the Minnekahta Formation.

e. A minimum of two fluid samples from each aquifer shall be collected. The second sample shall be collected after one drill stem volume of groundwater has been removed after the collection of the first sample.

f. The two fluid samples from each aquifer shall be analyzed for the analytes listed in Table 8 using the analytical methods shown. Equivalent analytical methods may be used after prior approval by the Director. Analytical results shall be reported in the units listed in Table 8.

g. In addition to the two samples collected under Part II, Section D.2.f, a minimum of three more samples shall be collected from the injection zone aquifer and analyzed for TDS only. One drill stem volume of groundwater shall be removed between the collection of each sample.[4]

h. The Permittee shall include the following information in the Injection Authorization Data Package Report submitted to the Director:

i. Methods for aquifer isolation;
ii. Sample collection methods;
iii. Methods for insuring fluid sample is representative of the aquifer conditions; and
iv. Methods for drilling fluid tracer sampling, field testing and analysis.

[4] The EPA recommends that the Permittee consider capturing and storing aquifer fluids pumped to the surface in tanks to be used for aquifer testing involving injection.

Table 8. List of Analytes, Approved Analytical Methods and Reporting Units for Aquifer Fluid Testing

Analytes	Analytical Methods	Reporting Units
1. Total Alkalinity	EPA 310.1, 310.2	mg/L
2. Arsenic	200.7, 200.8, 200.9	mg/L
3. Barium	200.7, 200.8	mg/L
4. Bicarbonate	EPA 310.1	mg/L and milliequivalents
5. Cadmium	200.7, 200.8, 200.9	mg/L
6. Calcium	EPA 6010 B, 215.1, 215.2, 200.5, 200.7	mg/L and milliequivalents
7. Carbonate	EPA 310.1, 310.2	mg/L and milliequivalents
8. Chloride	EPA 300.0, 300.1, 325.1, 325.2	mg/L and milliequivalents
9. Chromium	200.7, 200.8, 200.9	mg/L
10. Conductivity	EPA 120.1	μmhos at 25°C
11. Fluoride	EPA 300.0, 300.1	mg/L and milliequivalents
12. Lead	200.8, 200.9	mg/L
13. Lead-210	E905.0 Mod.	pCi/L
14. Magnesium	EPA 200.5, 200.7, 242.1	mg/L and milliequivalents
15. Mercury	245.1, 245.2, 200.8	mg/L
16. pH	EPA 150.1	pH units
17. Potassium	EPA 200.7, EPA 258.1	mg/L and milliequivalents
18. Radium-226	EPA 903.1	pCi/L
19. Radium-228	EPA SW-846 9320	pCi/L
20. Selenium	200.8, 200.9	mg/L
21. Silver	200.7, 200.8, 200.9	mg/L
22. Sodium	EPA 6010 B, 200.5, 200.7, 273.1	mg/L and milliequivalents
23. Specific Gravity	ASTM D1429-13, SM 2710F	Ratio to density of water
24. Strontium	EPA 200.7, 200.8, 200.9	mg/L or μg/l
25. Sulfate	EPA 300.0, 300.1	mg/L and milliequivalents
26. Thorium -230	ASTM D3972-90	pCi/L
27. TDS	EPA 160.1	mg/L
28. Drilling Fluid Tracer		
29. Uranium (Total)	EP200.8	mg/L or μg/l
30. Uranium (Natural)	ASTM D3972-90	pCi/L

3. Demonstration that the Injection Zone Is Not a USDW

USDW means an aquifer or its portion:

a) 1) Which supplies any public water system; or

2) Which contains a sufficient quantity of ground water to supply a public water system; and

(i) Currently supplies drinking water for human consumption; or

(ii) Contains fewer than 10,000 mg/L TDS.

b) Which is not an exempted aquifer

In order for the Director to issue Authorization to Commence Injection, the Permittee must demonstrate the Minnelusa injection zone is not a USDW. If the Permittee is able to demonstrate, based on analytical results from injection zone samples collected as required under Part II, Sections D.2.f and D.2.g, that the TDS of the injection zone fluids are 10,000 mg/l or greater, then the injection zone is not a USDW. If the TDS analyses of injection zone fluids are less than 10,000 mg/L, the injection zone is a USDW, unless the Permittee can demonstrate that the aquifer could not yield a sufficient quantity of ground water to supply a public water system. This permit does not authorize injection into a USDW. If the Minnelusa is determined to be a USDW based on testing, the Permittee must apply for a permit modification as described in Part IV, Section E in order to seek authorization to inject into the aquifer.

E. Evaluation of Confining Zones

The confining zones for the injection zone and approximate depths and thicknesses for each confining zone are shown in Table 9. The approximate depths and thicknesses are estimated from well logs included in the Class V permit application.

Table 9. Average Depths to Confining Zones for the Minnelusa Injection Zone in the Dewey and Burdock Areas

Injection Zone (Area)	Formation Name	Depth to Top (ft)	Depth to Base (ft)	Thickness (ft)
Minnelusa (Burdock)	Upper: Opeche Shale	1,520	1,615	95
	Lower: Lower Minnelusa Formation	2,205	2,765	560
Minnelusa (Dewey)	Upper: Opeche Shale	1,855	1,950	95
	Lower: Lower Minnelusa Formation	2,540	3,100	560

1. **Determination of Actual Depth and Thickness of Confining Zones**
    a. The Opeche Shale is the upper confining zone immediately overlying the Minnelusa porosity zone injection zone. Logs from DW No. 1 and DW No. 3 Class V injection wells shall be submitted to the Director for review of the Opeche Shale thickness at the location of each injection well. The Permittee shall include annotations on the logs indicating the top and the base of the Opeche Shale.
    b. The Lower Minnelusa Formation is the lower confining zone underlying the Minnelusa porosity injection zone. The Permittee shall determine actual depths and thicknesses of the Lower Minnelusa Formation underlying confining zone from well logs performed on DW No. 1, if it is drilled to the base of the Deadwood Formation.
    c. The Permittee shall include annotations on the logs indicating:
        i. the top of the Minnelusa Formation,
        ii. the base of the Minnelusa porosity injection zone (which is the top of the Lower Minnelusa confining zone and
        iii. the base of the Minnelusa Formation.
    d. The Permittee shall also provide logs of the Opeche Shale and the Minnelusa Formation from the Madison water supply wells, if they are approved by the South Dakota Water Rights Program. The Permittee shall include annotations on the logs indicating 1) the top of the Minnelusa Formation, 2) the base of the Minnelusa porosity injection zone (which is the top of the Lower Minnelusa confining zone and 3) the base of the Minnelusa Formation.
    e. If the Madison water supply wells are not drilled and DW No. 1 is not drilled down to the Deadwood Formation, the Permittee shall conduct a formation integrity test on the Lower Minnelusa confining

zone. The formation integrity test shall be conducted by drilling down 50 feet into the top of the Lower Minnelusa confining zone and completing the well, including cement behind the longstring casing, then apply pressure to the bottom of the hole to at least as high as the expected the MAIP. After the formation integrity has been completed, the Permittee shall fill the hole with cement to plug the well back to intended well depth and install a cement retainer if necessary.

2. Core Sample Collection from Confining Zones

a. During the drilling of each injection well, core samples within the lower 50 feet of Opeche confining zone shall be collected.
b. During the drilling of DW No. 1, if it is drilled down to the base of the Deadwood, core samples shall be collected within the top 50 feet of the Lower Minnelusa Formation lower confining zone.
c. If DW No. 1 is not drilled down to the base of the Deadwood, core samples shall be collected within the top 50 feet of the Lower Minnelusa Formation during the drilling of the Madison water supply wells, if they are approved by the South Dakota Water Rights Program.
d. If the Madison water supply wells are not drilled, the Permittee shall drill down into the top 50 feet of the Lower Minnelusa confining zone and collect core from that interval while drilling DW No. 1 and DW No. 3.
e. The core samples shall be analyzed in a laboratory to determine permeability and hydraulic conductivity of each confining zone.

3. Further Characterization of the Minnelusa Injection Zone Fluids and the Madison Aquifer

a. Evaluation of Anion/Cation Concentration and Potentiometric Surface Elevation Differences

i. The analytical results reporting units for samples from the Minnelusa injection zone and Madison aquifer samples shall be provided for the following anions and cations as both mg/L and milliequivalents/L as shown in Table 8. The milliequivalents/L concentrations shall be determined individually and collectively as listed below:

A. Sodium + Potassium
B. Calcium
C. Magnesium
D. Chloride + Fluoride
E. Bicarbonate + Carbonate, and
F. Sulfate

ii. The milliequivalents/L results shall also be plotted in the format of the Stiff Diagram shown in Figure 2.

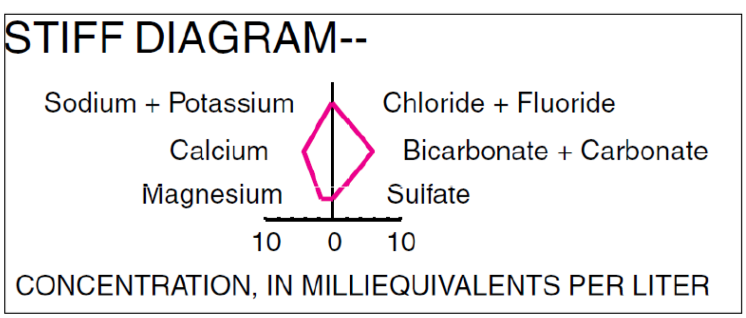


Figure 2. Format of Stiff Diagram for Anion and Cation Concentrations in the Minnelusa Injection Zone and the Madison Aquifer

iii. The Permittee shall include in the Injection Authorization Data Package Report a written summary of the differences in formation fluid water quality and potentiometric surface elevation data of the Minnelusa injection zone and the Madison aquifer, including any data collected during the drilling, logging and testing of the Madison water supply wells.

A. The Permittee shall use this information to evaluate the effectiveness of the lower Minnelusa confining zone as described in Section 3.3.3 of the Class V Area Permit Fact Sheet.

B. The written statement shall include characterization of the Minnelusa injection zone fluids, using the concentrations of the anions and cations listed above and reported in units of milleequivalents/liter, to verify that the concentration distribution matches the expected pattern found in areas where the Minnelusa injection zone and the Madison aquifer are hydrologically separated by a competent confining zone.

b. Calculation of Potentiometric Surface Drawdown at the Madison Water Supply Wells

i. After the testing of the Madison aquifer has provided the information on the potentiometric surface and other parameters required, the Permittee shall generate a drawdown model of the change in the potentiometric surface of the Madison aquifer that can be expected to result from 12 years of pumping the Madison aquifer at each of the Madison water supply wells.

ii. This information shall be used for the calculations required under Part II, Section F.1.

F. Injection Zone Pressure and Maximum Injection Rate Calculations

1. Calculation of Critical Pressure Rise in the Minnelusa Injection Zone

After the depths have been determined to the top and bottom of the injection zone and each aquifer at each injection well location based on drillhole log, and the potentiometric surfaces have been measured for each aquifer intersected by the injection well, the Permittee shall calculate the critical pressure rise that is needed within the injection zone to move fluids into a USDW along a hypothetical pathway through the confining zone. For the Minnelusa injection zone, this would be the critical pressure rise needed to move injection zone fluids into the Unkpapa/Sundance and Madison USDWs, respectively, at DW No.1 and DW No. 3.

2. Calculation of Injection-Induced Injection Zone Pressure

a. For each injection well, the Permittee shall calculate the injection zone formation pressures resulting from 12 years of injection activity at the injection rate needed to dispose of the maximum anticipated volume of treated ISR waste fluids versus distance away from each injection well. Cumulative effects of injection from multiple wells shall be considered as applicable.

b. The Permittee shall compare the injection-induced pressure values calculated in Part II, Section F.2.a with the critical pressures calculated in Part II, Section F.1 to determine the distance from each injection well at which the injection-induced pressure is not greater than the critical pressure to move injection zone fluids out of the injection zone into a USDW.

c. The Permittee shall use this information to demonstrate that each injection well is located a sufficient distance away from abandoned oil and gas test wells and the Dewey Fault to prevent the movement of fluids out of the injection zone into USDWs.

d. The Permittee shall use the diffusivity equation included in the Class V permit application as demonstrated by Lee, 1982, using site-specific data for the input values. The Permittee may use input values from published reports and shall include the reference and justification for using such input values.

3. Calculation of Maximum Injection Rate for Each Class V Injection Well

a. After the Permittee has calculated the critical pressure rise for each injection zone and the injection-induced injection zone pressure according to distance from each injection well using the injection rate needed to dispose of the maximum volume of treated ISR waste fluids and 12 years of injection activity, the Permittee shall calculate a maximum injection rate for each injection well. The maximum injection rate shall be determined such that the critical pressure in each injection zone is not exceeded 1,000 feet away from the nearest potential breech in confining zones, as discussed in Sections 4.4.2, 5.4.3 and 7.7.2 of the Class V Area Permit Fact Sheet. This maximum injection rate shall ensure that no injection zone fluids move out of the injection zone through a pathway through the confining zones.
b. The Permittee shall include the maximum injection rates calculated for each Class V well in the Injection Authorization Data Package Report to be reviewed by the Director to determine the maximum injection rate permit limit for each injection well. The maximum injection rate permit limits set by the Director will be included in the Authorization to Commence Injection document.

4. Calculation of Pressure Effects of Additional Minnelusa Injection Wells

If the Permittee constructs additional Class V injection wells that will be injecting into the Minneslusa injection zone, the critical pressure calculated under Part II, Section F.1 and the injection-induced injection zone pressure calculated under Part II, Sections F.2 shall be performed taking into account the pressure effects of having more than two injection wells injecting into the Minnelusa injection zone.

G. Injection Well Completion Report

1. Each injection well shall be constructed according to the requirements in Part III.
2. After well construction has been completed, the Permittee shall submit for each Class V injection well EPA Completion Form 7520-9 for Injection Wells with attachments. EPA Form 7520-9 can be found at https://www.epa.gov/uic/underground-injection-control-reporting-forms-owners-or-operators.

H. Initial Demonstration of Mechanical Integrity

1. Prior Notification Requirement

Before conducting the initial mechanical integrity tests on each Class V injection well, the Permittee shall notify the EPA Region 8 UIC program a minimum of 30 days prior to testing date to give the EPA an opportunity to witness the test.

2. Internal Mechanical Integrity: Tubing-Casing-Annulus (TCA) Pressure Mechanical Integrity Test

The Permittee shall conduct the TCA pressure test for each injection well to demonstrate internal mechanical integrity. The TCA pressure test procedures are found at Part V, Section C.6.b.

3. External Mechanical Integrity: Cement Bond Logs of the Surface Casing and the Longstring Casing

The Permittee shall submit the results of the cement bond logs conducted on the surface casing and longstring casing of each injection well as required under Part II, Section C, Table 3 and Table 5 to the Director for the demonstration of External Mechanical Integrity. The Cement Bond Log shall demonstrate 80% bonding through the confinement zones. The Director may require remedial cementing if a Cement Bond Log does not demonstrate External Mechanical Integrity.

I. Evaluation of the Injection Authorization Data Package Reports for Limited Authorization to Inject

1. The Director will evaluate the information provided in the Injection Authorization Data Package Reports and may issue a written Limited Authorization to Inject for testing purposes only. The Director will issue Limited Authorization to Inject only after finding:
    a. Stratigraphic logs, aquifer potentiometric surface measurements and water quality data for the Minnelusa injection zone and the Madison aquifer (from DW. No. 1, if it is drilled to the base of the Deadwood Formation AND from the two Madison water supply wells, if they are approved by the South Dakota Water Rights Program) demonstrate that the Minnelusa lower confining zone is present and provides hydrologic isolation of the injection zone from USDWs;
    b. The laboratory analyses of the Opeche Shale upper confining zone core demonstrate that confining zone permeability and hydraulic conductivity values are adequate for preventing migration of fluid out of injection zone;
    c. The laboratory analyses of Lower Minnelusa lower confining zone core (from DW. No. 1, if it is drilled to the base of the Deadwood Formation OR from the two Madison water supply wells, if they are approved by the South Dakota Water Rights Program) demonstrate that confining zone permeability and hydraulic conductivity values are adequate for preventing migration of fluid out of injection zone;
    d. The injection zone TDS concentration is greater than 10,000 mg/L thus demonstrating that the injection zone is not a USDW;
    e. Critical pressure rise and injection zone pressure calculations, considered together with the maximum injection rate permit limit, demonstrate that the injection well is located a sufficient distance from any feature that has the potential to serve as a pathway for fluid migration out of the injection zone into a USDW;
    f. If more than one injection well is targeting the Minnelusa injection zone, the Permittee has accounted for the pressure effects of having more than one injection well in calculating the critical pressure rise, the injection-induced injection zone pressure and the maximum injection rate for each Class V well.
    g. The well construction completion report demonstrates that each injection zone is isolated from USDWs by well casing and cement, meeting the requirements of Part III, Section D, and that there is a bond between at least 80% of the well casing and cement as demonstrated by the cement bond log;
    h. The well perforations are located within the approved injection zone with the top perforation no less than 50 feet below the base of the lowest USDW intersecting the well bore; and
    i. The initial Temperature Survey Log confirms external mechanical integrity and provides baseline conditions for comparison with future logs required under Part V, Section C.6.c.

2. The Limited Authorization to Inject shall have the following conditions:
    a. The well perforations are within the approved injection zone and the top perforation is at least 50 feet below the base of the lowest USDW intersecting the well bore;
    b. The specific gravity of the test injectate shall be no higher than 1.0113; and
    c. The test injectate shall meet the injectate permit limits in Part V, Section D.2.a Table 16.

J. Formation Testing Involving Injection

1. The Permittee shall conduct the formation tests listed in Table 10 for the purposes stated in the table.
2. The formation tests listed in Table 10 involve injection activity and, therefore, shall be conducted only after the Director has issued a written Limited Authorization to Inject.

3. The testing procedures, results and interpretation of results shall be submitted to the Director for evaluation as described in Table 10.

Table 10. Formation Testing Involving Injection

TYPE OF TEST	PURPOSE	DUE DATE
Step Rate Test	Initial test to determine site specific fracture gradient and fracture pressure to use for calculating MAIP permit limit for each well. Injection pressures shall be monitored at surface and bottom hole to determine friction loss for each well.	After receiving Limited Authorization to Inject for testing purposes
Initial Radioactive Tracer Survey	Baseline assessment of ability of the cement behind the longstring casing to prevent movement of injected fluids out of the approved injection formation.	After receiving Limited Authorization to Inject for testing purposes and MAIP has been determined from the Step Rate Test, but prior to receiving Authorization to Commence Injection

4. Step Rate Test and Determination of Maximum Allowable Injection Pressure

a. **Fracture Pressure:** The Permittee shall run an injection Step Rate Test for each well to determine the site-specific pressure at which fractures form in the injection zone at each injection well location. During the Step Rate Test, the Permittee shall monitor pressure within the injection zone, as well as surface injection pressure. The Step Rate Test results shall be submitted to the Director for evaluation.

b. **Fracture Gradient:** After the site-specific fracture pressure for the injection zone has been determined based on the Step Rate Test results, the fracture gradient shall be calculated according to the following formula:

$$fg=FP/d$$

FP = fracture pressure measured in the injection zone (based on Step Rate Test)
fg = fracture gradient (calculated value)
d = depth to pressure sensor in injection zone

c. **Maximum Allowable Injection Pressure:** The site specific maximum allowable injection pressure (MAIP) shall be set at 90% of the surface pressure measured at the wellhead when fracture pressure is reached in the injection zone. The surface pressure calculation shall use the fracture gradient calculated above under Part II, Section J.4.b above and the depth to the top perforation of well. The Area Permit sets a specific gravity limit of 1.0113 and this value shall be used for specific gravity in the calculation. The MAIP permit limit for each injection well will be included in the Authorization to Commence Injection approval document issued by the EPA.

The following equation shall be used to calculate the fracture pressure measured at the surface, taking into account the weight of the injectate in the injection tubing:

$$FP = [fg - (0.433 * sg)] * d$$

FP = fracture pressure measured at the wellhead (calculated value)
fg = fracture gradient (in Part II, Section J.4.b above)
sg = injectate specific gravity permit limit
d = depth to top well perforation

d. **Loss in Pressure due to Friction**: There may be a pressure loss due to friction between the injectate and the injection tubing. During the Step Rate Test, if the pressure measured at the injection zone sensor is less than the pressure measured at the surface gauge plus the pressure from the weight of the injectate in the injection tubing, this is the pressure loss due to friction. This pressure loss at the injection zone fracture pressure may be calculated and added back into the MAIP.

2. Initial Radioactive Tracer Survey

a. After the Step Rate Test has been run to identify injection zone fracture pressure, the Permittee shall conduct an initial radioactive tracer survey for each injection well while injecting at a pressure below the injection zone fracture pressure but not below the MAIP permit limit.
b. The Permittee shall take into account the pressure loss due to friction and the specific gravity of the injectate to ensure that the pressure in the injection zone is below the fracture pressure but not below MAIP.
c. The results of the test shall be submitted to the Director in the Injection Authorization Data Package Report.

Recommendations for Radioactive Tracer Survey procedures can be found at the EPA Region 8 UIC website: https://www.epa.gov/uic/uic-epa-region-8.

K. Information to Submit to the Director to Obtain Authorization to Commence Injection

1. Well Testing Information

The Director will evaluate the information provided in the Injection Authorization Data Package Reports and may issue a written Authorization to Commence Injection for each injection zone only after finding:

a. Both internal and external mechanical integrity are demonstrated for the injection well;
b. Step Rate Test data provide the injection zone fracture pressure for the injection well allowing the Director to set a permit limit for the maximum allowable injection pressure (MAIP) for the injection well calculated using the formula in Part II, Section J.4.b;and
c. The initial Radioactive Tracer Survey provides baseline conditions for comparison with future test required under Part V, Section C.6.c.

2. Pond Design Criteria and Cumulative Effects Analysis of Wellfield Operations

Before the Director will issue written Authorization to Commence Injection, the Permittee must submit information to the Region 8 Air Program for the EPA to determine the applicability of the 40 CFR Part 61 Subpart W regulations, and if necessary, receive construction approval from the EPA.

PART III. WELL CONSTRUCTION REQUIREMENTS

These requirements specify the approved minimum construction standards for well casing and cement, injection tubing, and packer.

A. During well construction intersected aquifers shall be isolated to prevent intermingling of formation fluids.

B. Approved Well Construction Plans

The details of the approved well construction plans are summarized in Table 11 and Figures 3 or 4 and 5.

The proposed construction plans for DW No. 1 includes the original design, in case the Permittee still plans to drill DW No. 1 to the depth of the Precambrian basement to collect information (Figure 3). There is also an approved alternate design for DW No. 1, in case the Permittee decides to drill only to a depth of 200 to 250 feet below the base of the proposed Minnelusa injection zone (Figure 4), as proposed for DW No. 3 (Figure 5).

The proposed construction plans allow the Permittee to drill down as deep as 250 feet below the proposed injection zone without a minor permit modification for the purpose of examining deeper sandstones for suitability to be part of the injection interval. The Permittee is required to document the thickness and lithology of the Lower Minnelusa confining zone in well logs of the Madison water supply wells, if they are approved by the South Dakota Water Rights Program as described under Part II, Section C.

Table 11. Well Casing and Cement Summary

	Burdock		Dewey
	DW No.1 (Figure 3)	DW No.1 alternate (Figure 4)	DW No.3 (Figure 5)
Conductor Casing (in)	13 3/8”	13 3/8”	13 3/8”
Depth (ft)	60’	60’	60’
Surface Hole (in)	12 1/4"	12 1/4"	12 1/4"
Depth (ft)	Top of Minnelusa (~1,615’)	50’ below base of Sundance aquifer (~1,615’)	50’ below base of Sundance aquifer (~1,305’)
Surface Casing (in)	9 5/8”	9 5/8”	9 5/8”
Cement Interval (ft)	From top of Minnelusa to surface (0’ - ~1,615’)	From 50’ below base of Sundance aquifer to surface (0 - ~1,615’)	From 50’ below base of Sundance aquifer to surface (0 - ~1,305’)
Longstring Hole (in)	8 1/2"	8 1/2"	8 1/2"
Depth (ft)	Near base of Minnelusa (~2,765’)	Up to ~250’ below base of Minnelusa Porosity injection zone (~2,455’)	Up to ~250’ below base of Minnelusa Porosity injection zone (~2,790’)
Longstring Casing (in)	7”	5 1/2”	5 1/2”
Cement volume	120% of calculated volume between exterior of casing and surrounding annulus.	120% of calculated volume between exterior of casing and surrounding annulus.	120% of calculated volume between exterior of casing and surrounding annulus.
Cement Interval (ft)	From base of Minnelusa to surface (0’ - < ~2,765’)	Up to ~250’ below base of Minnelusa Porosity injection zone to surface (0’ - ~2,455’)	From ~250’ below base of Minnelusa Porosity injection zone to surface (0’ - ~2,790’)
Open Hole (ft)	6 1/4"	n/a	n/a
Total Depth (ft)	At Precambrian basement (~3,195’)	Up to 250’ below base of Minnelusa Porosity injection zone (~2,455’)	Up to 250’ below base of Minnelusa Porosity injection zone (~2,790’)

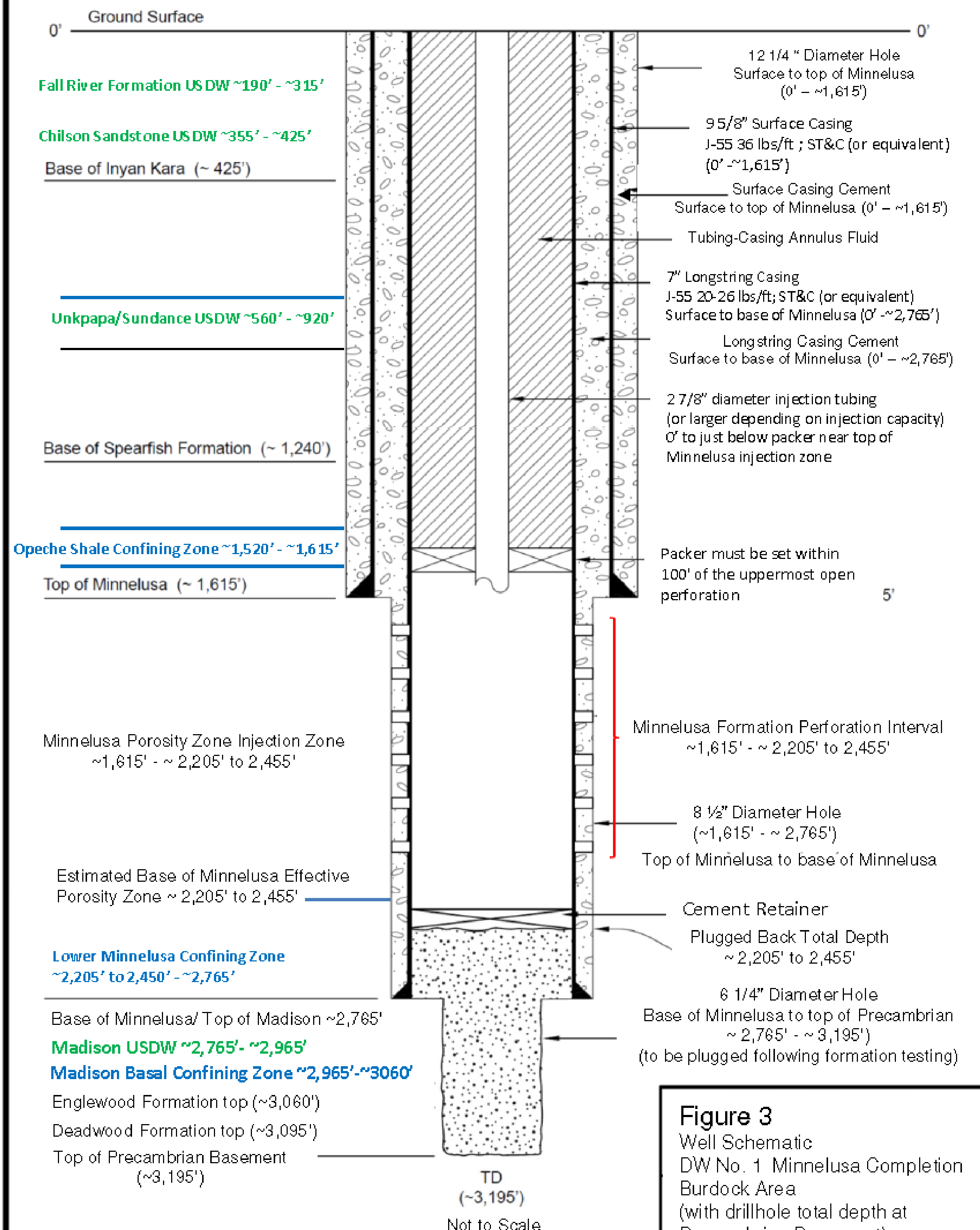


Figure 3
Well Schematic
DW No. 1 Minnelusa Completion
Burdock Area
(with drillhole total depth at Precambrian Basement)

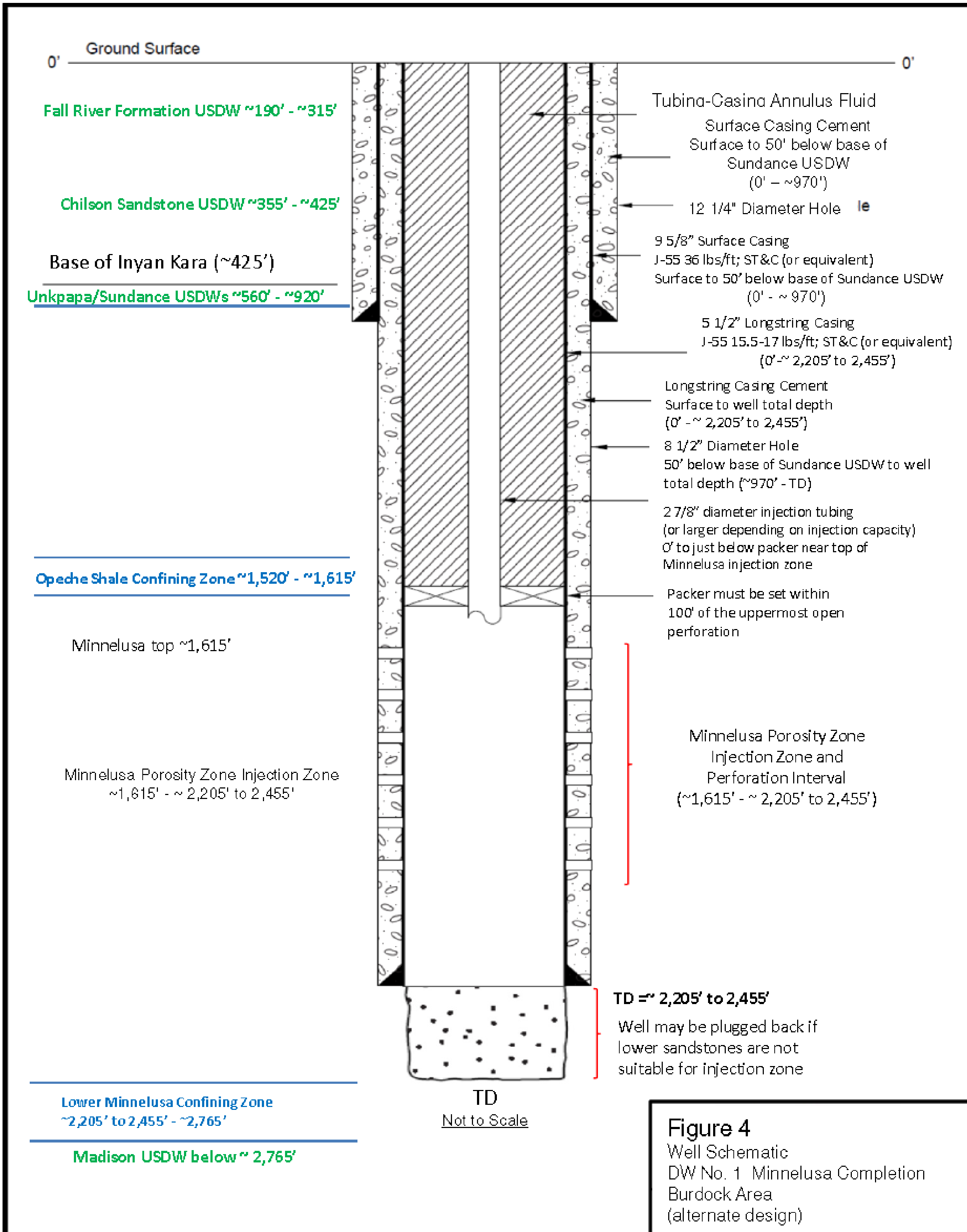


Figure 4
Well Schematic
DW No. 1 Minnelusa Completion
Burdock Area
(alternate design)

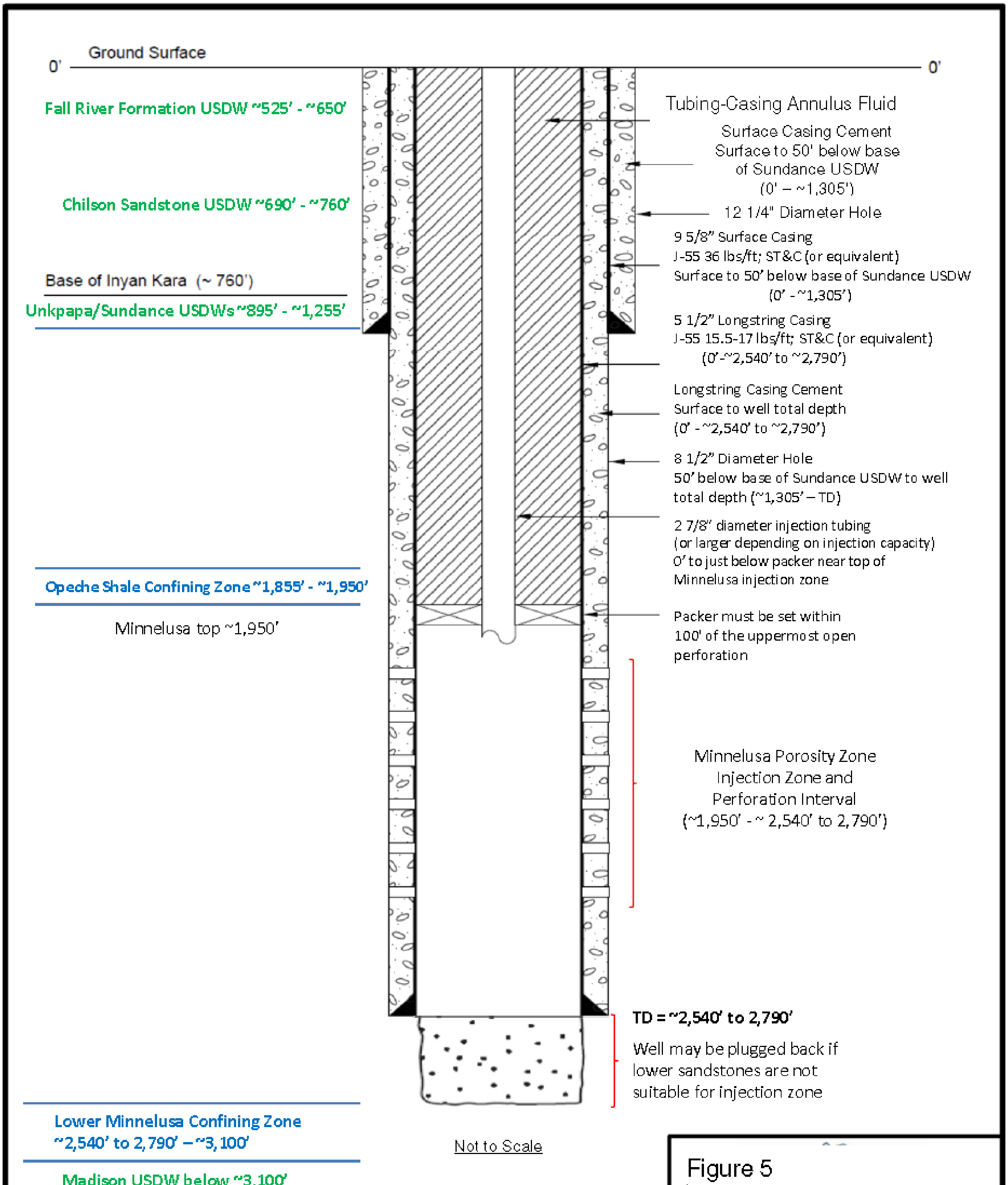


Figure 5
Well Schematic
DW No. 3 Minnelusa Completion
Dewey Area

C. Changes to Approved Well Construction Plans

1. Changes in construction plans during construction may be approved by the Director as minor modifications (40 CFR § 144.41). No such changes may be physically incorporated into construction of the well prior to approval of the modification by the Director in accordance with 40 CFR § 144.52(a)(1).
2. After initial well construction is complete, any subsequent changes in well construction will require a major modification of this Area Permit according to 40 CFR § 144.39 and § 124.5.
3. After well construction has been completed, the Permittee shall submit for each Class V injection well EPA Form 7520-9 *Completion Form for Injection Wells* with attachments. EPA Form 7520-9 is found at https://www.epa.gov/uic/underground-injection-control-reporting-forms-owners-or-operators.

D. Casing and Cement

1. The well or wells shall be cased and cemented to prevent the movement of fluids into or between underground sources of drinking water.
2. The well casing and cement shall be designed for the life expectancy of the well.
3. The surface casing shall extend to 50 feet below the lowermost USDW intersected by the well and must be cemented by recirculating the cement to the surface from a point 50 feet below the lowermost USDW intersected by the well.
4. The Permittee shall isolate all USDWs by placing cement between the outermost casing and the well bore;
5. The Permittee shall isolate the injection zone by placing sufficient cement to fill the calculated space between the casing and the well bore:
   a. For DW No. 1: from base of Minnelusa Formation to surface (if drilled to top of Precambrian Basement) or from ~200' below base of Minnelusa porosity injection zone to surface, depending on drill hole depth; and
   b. For DW No. 3: from ~200' below base of Minnelusa porosity injection zone to surface, depending on drill hole depth.
6. The Permittee shall use cement:
   a. Of sufficient quantity and quality to withstand the maximum operating pressure; and
   b. Which is resistant to deterioration from formation and injection fluids; and
   c. In a quantity no less than 120% of the calculated volume necessary to cement off a zone.
7. A float shoe shall be used with a float collar one or two joints up from the bottom of the casing and centralizers shall be placed at a minimum of one on every fifth casing joint.
8. Remedial cementing may be required if shown to be inadequate by cement bond log or other demonstration of external mechanical integrity.

E. Well Casing Perforations

1. Perforation of an injection well shall not be conducted until after:
   a. All logs and tests have been performed to identify the depths of the injection zone and confining zones; and
   b. The logs and tests have been analyzed by a knowledgeable log analyst to correctly identify the extent of the injection zone for each well.
2. The top perforation shall be no higher than the approved top of the injection zone and at least 50 feet below the base of the lowermost USDW intersecting the well bore

F. Injection Tubing and Packer

1. All Class V deep wells constructed under this Area Permit shall inject fluids through tubing with a packer set immediately above the injection zone. The packer shall be set no more than 100 feet above the uppermost perforation in the approved injection zone. The packer setting depth may be changed provided it remains no more than 100 feet above the uppermost perforation in the approved injection zone and the Permittee provides notice and obtains the Director's approval for the change.
2. The tubing and packer shall be designed for the expected service.
3. The tubing and packer shall be chemically compatible with injected fluids.

G. Tubing-Casing Annulus (TCA) Fluid

1. The annulus space between the injection tubing and the well casing shall be sealed and filled with fresh water containing a corrosion inhibitor.
2. The annulus fluid may contain additives as deemed necessary by the Permittee. A description of annulus fluid additives shall be included in the well construction report.
3. The Permittee shall notify the Director when any changes are made to the annulus fluid additives.

H. Sampling and Monitoring Devices

1. The Permittee shall install and maintain in good operating condition at the wellhead:
    a. A fluid sampling point located at a conveniently accessible location at the wellhead to enable collection of representative samples of the injectate;
    b. Pressure gauges measuring injection pressure and annulus pressure;
    c. One-half (1/2) inch stab fittings, isolated by shut-off valves and located at the wellhead at a conveniently accessible location, for the attachment of a pressure gauge capable of monitoring pressures ranging from normal operating pressures up to at least 500 psi above the Maximum Allowable Injection Pressure (MAIP) specified in Part IV, Section H:
        i. on the injection tubing; and
        ii. on the tubing-casing annulus;
    d. Continuous recording devices located to monitor and record injection pressure, TCA pressure, injection rate, and cumulative volume.
    e. A crown valve on the wellhead that will allow a lubricator and well logging equipment to be rigged up and run into the well while the well remains on injection.
    f. A pressure actuated shut-off device attached to the injection flow line set to shut-off the injection pump when the MAIP specified in Part IV, Section H is exceeded at the wellhead.
    g. Protective automated monitoring and shutoff System with control switches to alarm the operator in the event that any of the Area Permit conditions related to minimum or maximum permit limits are met. The system shall be designed to cause injection operations to cease until the problem is identified and corrected.

2. A diagram of the preliminary wellhead schematic diagram is included as Figure A-1 in Appendix A of this Area Permit. The Permittee shall submit to the EPA an as-built final wellhead schematic diagram as part of the well construction completion report.

I. Surface Facilities

A diagram of the proposed surface facilities to which the Class V injection wells will be connected is included as Figure A-2 in Appendix A or this Area Permit. The Permittee shall provide an as-built final schematic diagram of the surface facilities as part of the well construction completion report.

J. Requirements for Adding Injection Wells to this Area Permit

1. The Permittee shall not construct an additional well under this Area Permit until construction has been approved in accordance with the procedures under this Section.
2. Prior to constructing an additional well under this Area Permit, the Permittee shall seek authorization to construct by submitting the following materials to the EPA:
   a. a cover letter requesting authorization to construct the well and referencing Area UIC Permit **SD52173-08764** for DW No. 1 and **SD52173-08766** for DW No. 3;
   b. a completed EPA 7520-6 injection well application form;
   c. a wellbore diagram of the proposed injection well;
   d. a topographic map showing the location of the additional well within the Dewey-Burdock Project Area; and
   e. a list of all wells penetrating the Confining Zone within the Area of Review (AOR) of the new well including cementing records and cement bond logs any new wells within the AOR not previously evaluated by the EPA.
3. Once the EPA has confirmed that the proposed injection well meets permit conditions, EPA Region 8 will authorize construction by written communication to the Permittee.
4. This Area Permit authorizes the Permittee to construct and test wells only in accordance with the terms and conditions of this Permit.
5. The Permittee shall construct a requested injection well within one year of the EPA construction authorization date as described in Section K.

K. Postponement of Construction

1. The Permittee shall commence construction of at least one of the originally proposed Class V injection wells within one year of the Effective Date of the Permit. Authorization to construct and operate shall expire if construction of at least one of the originally proposed Class V injection wells has not commenced within one year of the Effective Date of the Permit, unless the Permittee has notified the Director and requested an extension prior to expiration. Notification shall be in writing, shall state the reasons for the delay and shall provide an estimated date for which well construction will commence. Once Authorization has expired under this part, the complete permit process including opportunity for public comment shall be required before Authorization to construct and operate can be reissued.
2. To obtain authorization for additional wells for injection into the Minnelusa injection zone, the Permittee shall follow the permit requirements under Part II of this Area Permit.
3. If an additional well is added to this Area Permit, the Permittee shall commence construction of the well within one year of authorization of the additional well. Authorization for construction of the additional well expires after one year from date of issuance, unless the Permittee has notified the Director and requested an extension prior to expiration.
4. After the authorization for well construction has expired, the Permittee shall reapply for authorization to construct an additional well according to the procedures listed in Section J of this Part.

L. Workovers and Alterations

1. Workovers and alterations shall meet all conditions of the Permit.
2. Prior to beginning any addition or physical alteration to an injection well's casing or cement, the Permittee shall give advance notice to the Director.
3. The Permittee shall record all work done on a Well Rework Record (EPA Form 7520-12) found at https://www.epa.gov/uic/underground-injection-control-reporting-forms-owners-or-operators, and shall provide this and any other record of well workover, logging, or test data to EPA in the next Quarterly Monitoring Report. If the activities were conducted within 45 days of the next Quarterly Monitoring Report, then the information shall be submitted with the following Quarterly Monitoring Report.
4. Any modification to well construction that is different from the approved well construction plan is allowed only as a major modification of this Area Permit according to 40 CFR § 144.39 and § 124.5.
5. A successful demonstration of internal mechanical integrity is required following the completion of any well workover or alteration which affects the integrity of the casing, packer or tubing. Injection operations shall not be resumed until the well has successfully demonstrated mechanical integrity. Documentation of mechanical integrity test results shall be included in the next Quarterly Monitoring Report, or sooner if the Permittee chooses. Injection operations shall not be resumed until the well has successfully demonstrated mechanical integrity and the Director has provided written approval to resume injection.
6. If an acidizing operation is conducted on well perforations, then a temperature survey log shall be conducted to verify the integrity of cement above the perforations has not been compromised by exposure to the acid. Documentation of temperature survey log results shall be included in the next Quarterly Monitoring Report.

M. Cementing Requirements to Plug Back DW No. 1

If DW No. 1 is drilled down to the Deadwood Formation, the Permittee shall plug back the well with cement adequate to preserve the integrity of the Lower Minnelusa confining zone and install a cement retainer above the cement plug. The Permittee shall conduct a formation integrity test on the plug to verify that it is adequate to preserve the integrity of the Lower Minnelusa lower confining zone.

PART IV. WELL OPERATION

A. Injection between the outermost casing protecting USDWs and the well bore is prohibited.

B. The Permittee shall not construct, operate, maintain, convert, plug, abandon, or conduct any other injection activity in a manner that allows the movement of fluid containing any contaminant into a USDW, if the presence of that contaminant may cause a violation of any primary drinking water regulation under 40 CFR Part 141 or may otherwise adversely affect the health of persons.

C. Requirements Prior to Commencing Injection.

1. Injection operation is prohibited for an injection well until the requirements herein have been met and the Director issues a written Authorization to Commence Injection.
2. The Permittee shall not commence injection until:
   a. The Permittee has submitted the Injection Approval Data Package to the Director for evaluation;
   b. The Permittee has submitted the results of the Step Rate Test and the Director has set a MAIP for the injection well;
   c. The Permittee has submitted the results from the initial Radioactive Tracer Survey to the Director for evaluation; and

   d. The Director has issued the written Authorization to Commence Injection.

D. Mechanical Integrity

1. The Permittee is required to ensure each injection well maintains mechanical integrity at all times. Injecting into a well that lacks mechanical integrity is prohibited. An injection well has mechanical integrity if:
   a. There is no significant leak in the casing, tubing, or packer (Internal Mechanical Integrity); and
   b. There is no significant fluid movement into an underground source of drinking water through vertical channels adjacent to the injection well bore (External Mechanical Integrity).
2. The methods for demonstrating mechanical integrity are found in Part V, Section C.6 of this Area Permit. The Director, by written notice, may require the Permittee to comply with a schedule describing when mechanical integrity demonstrations shall be made.

E. Requirements if the Injection Zone is a USDW

This Permit only authorizes injection into non-USDWs. If TDS analytical results for a proposed injection zone are below 10,000 mg/L, the Permittee must request a major modification of this Area Permit according to the requirements of 40 CFR § 144.39 and § 124.5.

F. Approved Injection Zone and Perforations

1. The Permittee shall not perforate an injection well until after:
   a. All logs and tests have been performed to identify the depths of the injection zone and confining zones, and
   b. The logs and tests have been analyzed by a knowledgeable log analyst to correctly identify the extent of the injection zone for each well.
2. Injection is allowed only within the approved injection zone depths based on well drillhole logs and only after the Director has issued written Authorization to Commence Injection. Approximate depths to each injection zone are shown in Table 1 of this Area Permit. The site-specific depth to each injection zone for each well under the Area Permit will be established by the well logging required under Part II, Section C. The approved top of the each injection zone shall be no less than 50 feet below the base of the lowest USDW intersected by the well bore. The Authorization to Commence Injection will include the actual top and bottom depths of the approved injection intervals based on well drillhole logs.
3. Additional injection perforations may be added once the following requirements are met:
   a. The new perforations remain within the approved injection zone,
   b. The top perforation is no higher than the approved top of the injection zone
   c. The Permittee has received approval from the Director as a major modification of this Permit in accordance with Part III, Section C.2 of this Permit; and
   d. The Director approves the addition of perforations as a major modification of this Area Permit according to 40 CFR § 144.39 and § 124.5.
   e. After the addition of perforations, the Permittee shall follow the requirements for well Workovers and Alterations under Part III, Section L.
4. In no case shall the operation of the injection well cause the movement of injected or formation fluids outside of the approved injection zone.

G. Injectate Specific Gravity Limit

The injectate specific gravity shall not exceed a specific gravity of 1.0113.

H. Injection Pressure Limit

1. Except during stimulation injection, pressure at the wellhead shall not exceed a maximum which shall be calculated so as to assure that the pressure in the injection zone during injection does not initiate new fractures or propagate existing fractures in the injection zone.
2. In no case shall injection pressure cause the movement of injection or formation fluids into a USDW.
3. The permitted MAIP, measured at the wellhead, shall be established based on site specific conditions at each injection well location according to Part II, Section J.4. The MAIP for each Class V injection wells will be included in the Authorization to Commence Injection.
4. The Permittee may request a change of the MAIP, or the MAIP may be increased or decreased by the Director to ensure that the requirements in paragraph 1 above are fulfilled. The Permittee may be required to conduct a Step Rate Test or other suitable test to provide information for determining the fracture pressure and fracture gradient of the injection zone.

I. Injection Volume Limit

Because there is no aquifer exemption area associated with this Area Permit, there is no injection volume limitation.

J. Injection Rate Limit

The monthly average injection rate shall not exceed the injection rate limits approved by the Director in the written Authorization to Commence Injection based on calculations under Part II, Section F.3.

K. Approved Injectate

1. Injection fluid is limited to waste fluids from the ISR process. These waste fluids include groundwater produced from well construction, laboratory waste fluids, well field production bleed and concentrated brine generated from the reverse osmosis treatment of groundwater produced from wellfield during groundwater restoration. The groundwater pumped from any portion of the Inyan Kara aquifers for the purpose of remediating an excursion is also approved for injection into the Class V Class V injection wells.
2. The injection of fluids with constituent concentrations above the hazardous waste or radioactive waste concentration limits is prohibited. The injectate shall meet the permit limits set in Part V, Section D.2.a, Table 16.

L. TCA Pressure

The Permittee shall ensure that the TCA fluid is maintained under an induced pressure at all times. The tubing-casing annulus pressure shall be maintained at a minimum of 100 psi above the injection pressure. If this pressure cannot be maintained, the Permittee shall cease injection and inspect the longstring casing, cement and the injection tubing and test for mechanical integrity.

PART V. MONITORING, RECORDKEEPING, AND REPORTING OF RESULTS

A. Annual Pressure Falloff Test

1. The pressure falloff test shall be conducted initially within one year after injection begins and annually thereafter. If the well has not injected since the previous pressure falloff test was conducted, another pressure falloff test is not required until injection begins again. The time interval for each test should not be less than nine (9) months or greater than 15 months from the previous test to ensure that the tests will be

performed at relatively even intervals throughout the life of the injection well. The falloff testing report should be submitted to the EPA no later than 60 days following the test. Failure to submit a falloff test report will be considered a violation of the Area Permit and may result in an enforcement action. Any exceptions should be approved by EPA prior to conducting the test.

2. The Permittee is required to prepare a plan for running the yearly pressure falloff test. The Permittee shall use the EPA guideline to develop a site specific plan. The "UIC Pressure Falloff Testing Guideline" is found at https://www.epa.gov/sites/production/files/2015-07/documents/guideline.pdf. The final test plan shall be submitted to Region 8 for review at least 30 days prior to conducting the annual pressure falloff test.
3. The Permittee shall follow the same test procedure for the initial and subsequent tests, so that valid comparisons of reservoir pressure, permeability, and porosity can be made. The Permittee shall analyze test results and provide a report with an appropriate narrative interpretation of the test results, including an estimate of reservoir parameters, information of any reservoir boundaries, and estimate of the well skin effect and reservoir flow conditions. The report shall also compare the test results with the previous year's test data, unless it is the first test performed at that well, and shall be prepared by a knowledgeable analyst.

B. Seismicity

1. The U.S. Geological Survey (USGS) Earthquake Hazards Program operates an email notification service which reports real-time earthquake events for any area specified by the user. The Permittee is required to subscribe to this service, known as the Earthquake Notification Service (ENS). Details for the ENS can be found at:

   https://sslearthquake.usgs.gov/ens/

   and a subscription can be initiated at:

   https://sslearthquake.usgs.gov/ens/register
2. For any seismic event reported within two miles of the permit boundary, the Permittee shall immediately cease injection and report to EPA within twenty-four (24) hours according to Part VII, Section D.11.e of this permit. Injection shall not resume until the Permittee has obtained approval to recommence injection from the EPA.
3. For any seismic event occurring between two and fifty miles of the permit boundary, that event will be recorded and reported to EPA on a quarterly basis.

C. Ongoing Demonstration of Mechanical Integrity

1. The Permittee shall demonstrate mechanical integrity prior to commencing injection and periodically thereafter. The schedule for ongoing demonstration of mechanical integrity is shown in Table 12.

Table 12. Schedule for Ongoing Demonstration of Mechanical Integrity

Well Status	Schedule for Demonstration of Mechanical Integrity
Actively Injecting Well	5 years from last successful demonstration of mechanical integrity
Temporarily Abandoned Well (no injection for 24 consecutive months)	Before the end of 24 months of no active injection and every 2 years from the last successful demonstration of mechanical integrity

2. In addition to these regularly scheduled demonstrations of Mechanical Integrity, the Permittee shall demonstrate Internal Mechanical Integrity following any workover which affects the tubing, packer or casing per Part III, Section L.

3. The Director may require additional or alternative tests if the results presented by the Permittee are not satisfactory to the Director to demonstrate there is no movement of fluid into or between USDWs resulting from injection activity.
4. Mechanical integrity test results shall be submitted to the Director with the next Quarterly Report after completion of the tests, unless the test was conducted within 60 days of the Quarterly Report due date. In that case, mechanical integrity test results shall be included in the subsequent Quarterly Report.
5. **Notification Prior to Testing**
    a. Before conducting the regularly scheduled mechanical integrity tests on each Class V injection well, the Permittee shall notify the EPA Region 8 UIC program a minimum of 30 days prior to the testing date to give the EPA an opportunity to witness the test. The Director may allow a shorter notification period if it would be sufficient to enable EPA to witness the mechanical integrity test.
    b. When the mechanical integrity test is conducted after a well construction, well conversion, or a well rework, any prior notice is sufficient.
    c. Notification may be in the form of a yearly or quarterly schedule of planned mechanical integrity tests, or it may be on an individual basis.
6. **Mechanical Integrity Test Methods and Criteria**
    a. EPA-approved methods shall be used to demonstrate mechanical integrity. The Permittee shall refer to recommendations for well test procedures found at https://www.epa.gov/uic/uic-epa-region-8.
    b. Internal Mechanical Integrity: TCA Pressure Mechanical Integrity Test Procedure
    The Permittee shall conduct the following internal mechanical integrity test to verify there are no leaks in the well tubing, casing or packer.
        i. Stabilize well pressure and temperature.
        ii. Install ball valve or similar type of "bleed" valve on annulus gate valve.
        iii. Pressurize annulus to a minimum of 100 psig with liquid and shut-in pump side gate valve. If typical operating annulus pressures are above 100 psi, higher pressures acceptable to the agency and compatible with the well completion configuration will be utilized. Pressure to be used will be detailed in proposed procedures supplied with notification of testing.
        iv. Install USEPA-certified gauge on "bleed" type valve. The annulus may need to be pressurized and bled off several times to ensure an absence of air.
        v. Monitor and record pressure for one hour.
        vi. Pressure may not fluctuate more than 10 percent during the one-hour test.
        vii. At the conclusion of the test, lower the annulus pressure to normal operating pressure.
    c. External Mechanical Integrity
    The Permittee shall conduct the following external mechanical integrity tests listed in Table 13 to assess the ability of the cement behind the longstring casing to prevent movement of injected fluids out of the approved injection formations.

Table 13. Ongoing External Mechanical Integrity Testing Methods

Test Type	Purpose	Frequency
Temperature Survey	To assess temperature above the upper confining zone of the injection zone to verify that cooler injection zone fluids are not moving out of the injection zone through the cement between the outermost well casing and the borehole wall.	Within 6-12 months after beginning injection operations, and at least once every five (5) years after the last successful demonstration of external mechanical integrity.
Radioactive Tracer Survey	To search for the presence of an injected radioactive tracer in the upper confining zone of the injection zone to verify that zone fluids are not moving out of the injection zone through the cement between the outermost well casing and the borehole wall.	At least once every five (5) years concurrent with the Temperature survey as required above.

7. Unanticipated Loss of Mechanical Integrity

a. If the well fails to demonstrate mechanical integrity during a test, or a loss of mechanical integrity becomes evident during operation (such as increase of pressure in the annulus, water flowing at the surface, etc.), the Permittee shall notify the Director within 24 hours (see Part VII, Section D.11.e of this Permit), and the well shall be shut-in within 48 hours unless the Director requires immediate shut-in.

b. Within five days, the Permittee shall submit a follow-up written report that documents circumstances that resulted in the mechanical integrity loss and how it was addressed. If the mechanical integrity loss has not been resolved, the report should include the proposed plan to reestablish mechanical integrity.

c. Injection operations shall not be resumed until after the well has successfully demonstrated mechanical integrity pursuant to 40 CFR § 146.8, and the Director has provided written approval to resume injection.

d. The annulus pressure shall be maintained at a minimum of 100 psi above the injection pressure.

D. Monitoring Methods, Parameters and Frequency

1. Monitoring Methods

a. Monitoring observations, measurements, samples, etc. taken for the purpose of complying with these requirements shall be representative of the activity or condition being monitored.

b. During drilling, before an aquifer fluid sample is collected for laboratory analysis, the formation shall be swabbed a minimum of three times.

c. Aquifer fluid shall be produced from the well using a submersible pump, swabbing or wireline testing equipment. Aquifer fluid sampling shall occur after the open-hole section has been drilled, but prior to conducting any injection testing. The submersible pump is the preferred method to be used and shall be used, if possible. If a submersible pump is able to be used, the Permittee shall use the *Standard Operating Procedure for Low-Stress (Low Flow) / Minimal Drawdown Ground-Water Sample Collection* and measure the field parameters listed in Table 14 at the surface as fluid is pumped out of the well to determine when collection of a representative sample is possible. When the field parameters meet the stabilization criteria in Table 14, indicating that the water quality indicator parameters have stabilized, then sample collection can take place.

Table 14. Field Parameters to be Monitored and Stabilization Criteria to Meet before Sample Collection

Parameter	Stabilization Criteria
pH	± 0.1 pH units
Specific conductance	± 3% μS/cm
Oxidation-reduction potential	± 10 millivolts
Turbidity	± 10 % NTUs when turbidity is greater than 10 NTUs
Dissolved oxygen	± 0.3 milligrams per liter

d. Injectate samples shall be collected at a location between the last treatment process and the injection wellhead.

e. The analytical methods included in Table 16 shall be used for injectate sample analysis. Equivalent methods may be used after prior approval by the Director.

f. Injection pressure, annulus pressure, injection rate, and cumulative injected volumes shall be observed and recorded under normal operating conditions, and all parameters shall be observed simultaneously to provide a clear depiction of well operation.

g. Pressures are to be measured in pounds per square inch (psi).

h. Fluid volumes are to be measured in standard oilfield barrels (bbl).

i. Fluid rates are to be measured in barrels per day (bbl/day).

2. Monitoring Parameters and Frequency

a. Injectate Monitoring

i. The injectate shall be monitored as required in Tables 15 and 16.

Table 15. Injectate Sampling Requirements

Injectate Parameter	Purpose	Frequency
Injected Fluid Sample Analysis Specific Gravity	To determine if the injected fluid meets permit limit for specific gravity shown in Table 16.	Weekly
Injected Fluid Water Sample Analysis	To determine if the injected fluid meets permit limits in Table 16.	Quarterly and whenever there is a change in the waste stream

Table 16. Analytes to Monitor in Injectate, Reporting Units, Permit Limits and Analytical Methods

Analyte	Reporting Units	Permit Limit	Analytical Methods
Arsenic	mg/L	5.0	200.7, 200.8, 200.9
Barium	mg/L	100.0	200.7, 200.8
Cadmium	mg/L	1.0	200.7, 200.8, 200.9
Chromium	mg/L	5.0	200.7, 200.8, 200.9
Corrosivity	pH units	>2 and <12.5	SW-846 1110,9045
Lead	mg/L	5.0	200.8, 200.9
Lead-210	pCi/L	10	E905.0 Mod.
Mercury	mg/L	0.2	245.1, 245.2, 200.8
Polonium-210	pCi/L	40	RMO-3008
Radium-226	pCi/L	60	E903.0
Specific Gravity	Ratio to density of water	1.0113	ASTM D1429-13, SM 2710F
Selenium	mg/L	1.0	200.8, 200.9
Silver	mg/L	5.0	200.7, 200.8, 200.9
Sulfate	mg/L	None	EPA 300.0
TDS	mg/L	None	EPA 160.1
TSS	mg/L	None	EPA 160.2
Thorium-230	pCi/L	100 pCi/L	ATSM D3972-90M
Uranium (Total)	mg/L or ug/L	None	200.8
Uranium (Natural)	pCi/L	300 pCi/L	ATSM D3972-90M

ii. If thorium -230, lead-210 and polonium-210 are not detected in the waste stream after the first four quarters, the Permittee is not required to analyze for thorium-230, lead-210 and polonium-210 in subsequent quarters. If a new wellfield is brought online, then analysis will be required for the full suite of analytes, including thorium-230, lead-210 and polonium-210. If thorium-230, lead-210 and polonium-210 are not detected in the modified waste stream after the first four subsequent analyses, thorium -230, lead-210 and polonium-210 analyses will not be required for subsequent monitoring until a new wellfield is brought online.

iii. A waste stream change, as referenced in Table 15 above, consists of a new waste stream being added to the injectate such as:

A. a new well field coming on line;
B. aquifer restoration beginning in a wellfield;
C. when laboratory fluid wastes are added in for the first time; or
D. a new laboratory procedure or laboratory chemical is used.

b. Monitoring of Well Operating Parameters

The parameters listed in Table 17 are to be monitored as indicated in Table 17 even during periods when the well is not operating.

3. Monitoring, Recording and Reporting Schedules

The parameters monitoring information listed in Table 17 shall be recorded and reported according to the schedules listed below.

Table 17. Monitoring, Recording and Reporting Requirements for Well Operating Parameters

A.	CONTINUOUS MONITORING
MONITOR	Injection Rate (bbl/day)
	Injection Pressure (psig)
	Cumulative Injected Volume (bbl/day)
	TCA Pressure (psig)
	Differential Pressure between Injection Pressure and TCA Pressure
	Seismic events within a two (2) mile radius of the Area Permit boundary, gathered from USGS Earthquake Hazard Program website or through personal communication.
RECORD	Monthly for Cumulative Injected Volume Daily for other parameters
REPORT	Include in Quarterly Report

B.	WEEKLY MONITORING
OBSERVE	TCA fluid level via level indicator or site glass on TCA fluid head tank when a well is actively injecting. If annulus pressure falls below 100 psi above the injection pressure, or changes more than 10% within a week, observe TCA fluid level at that time and determine why the differential pressure fell below permit limits.
RECORD	TCA fluid level for actively injection well. Any additions or subtractions of fluid to/from the annulus head tank.
ANALYZE	Samples of injectate fluid for specific gravity at the Dewey and the Burdock sites.
REPORT	Include in Quarterly Report

C.	TWICE MONTHLY MONITORING
OBSERVE	TCA fluid level via level indicator or site glass on TCA fluid head tank when a well is NOT actively injecting, if pressure decreases by more than 10% within a month, observe TCA fluid level at that time and determine why the differential pressure fell below permit limits.
RECORD	TCA fluid level for wells NOT actively injection well when pressure decreases by more than 10% within a month. Any additions or subtractions of fluid to/from the annulus head tank.
REPORT	Include in Quarterly Report

D.	MONTHLY MONITORING
RECORD	Maximum, minimum and average values for Injection Pressure (psig)
	Maximum, minimum and average values for Annulus Pressure (psig)
	Maximum, minimum and average values for Daily Injection Rate (bbl/day)
	Maximum, minimum and average values for Injected Fluid Specific Gravity
	Injected volume for that month (bbls)
	Cumulative volume of injectate for that month (bbls)
	TCA fluid level via level indicator or site glass on TCA fluid head tank when a well is NOT actively injecting
REPORT	Include in Quarterly Report

E.	MONITORING IF WASTE STREAM CHANGES
ANALYZE	Injectate fluid for the analytes listed above using the analytical methods shown in Table 16. Equivalent analytical methods may be used with prior approval from the Director.
REPORT	Within 30 days of sample collection

F.	QUARTERLY MONITORING
ANALYZE	Injectate fluid for the analytes listed above using the analytical methods shown in Table 16. Equivalent analytical methods may be used with prior approval from the Director.
REPORT	Monthly average, maximum, and minimum values for Injection Pressure (psig)
	Monthly average, maximum, and minimum values for Annulus Pressure (psig)
	Monthly average, maximum, and minimum values for Daily Injection Rate (bbl/day)
	Monthly average, maximum, and minimum values for Injected Fluid Specific Gravity
	Injected volume for each month during the quarter (bbls)
	Cumulative volume injected since the well began injection operations (bbls)
	Results of injectate fluid analysis in units shown in Table 16.
	Summary of monthly reviews of seismic events within a fifty (50) mile radius of the Area Permit boundary.

G.	ANNUAL MONITORING
ANALYZE	Conduct pressure falloff test. Submit plan to the Director a minimum of 30 days in advance of the test. Use EPA guidelines to develop a site specific plan. "UIC Pressure Falloff Testing Guideline" is found at https://www.epa.gov/sites/production/files/2015-07/documents/guideline.pdf. The Permittee shall follow the same test procedure for the initial and subsequent tests, so that valid comparisons of reservoir pressure, permeability, and porosity can be made.
REPORT	The Permittee shall analyze test results and provide a report, prepared by a knowledgeable analyst, with an appropriate narrative interpretation of the test results, including an estimate of reservoir parameters, information of any reservoir boundaries, and estimate of the well skin effect and reservoir flow conditions. The report shall also compare the test results with previous year's test data, unless it is the first test performed at that well.

H.	MONITORING EVERY TWO YEARS
ANALYZE	Conduct Internal and External Mechanical Integrity Tests before the end of 24 months of non-injection if a well has not been used for injection for 24 consecutive months
REPORT	Mechanical Integrity Test (MIT) results in next Quarterly Report unless the MIT was conducted within 60 days before the due date of the next Quarterly Report. In that case, the MIT results shall be due in the following Quarterly Report. A failed MIT shall be reported verbally within 24 hours with a written report due in 5 days.

I.	MONITORING EVERY FIVE YEARS
ANALYZE	Conduct Internal and External Mechanical Integrity Tests within five (5) years from previous successful demonstration of mechanical integrity.
REPORT	Mechanical Integrity Test results in next Quarterly Report unless the MIT was conducted within 60 days before the due date of the next Quarterly Report. In that case, the MIT results shall be due in the following Quarterly Report. A failed MIT shall be reported verbally within 24 hours with a written report due in 5 days.

4. Monitoring Records

Monitoring records must include:

a. The date, exact place, and time of sampling or measurements;
b. A description of how the sample was collected;
c. The individual(s) who performed the sampling or measurements;
d. The date(s) analyses were performed;
e. The individual(s) who performed the analyses;
f. The analytical techniques or methods used; and
g. The results of such analyses.

E. Records Retention

1. Records of calibration and maintenance, and all original strip chart recordings for continuous monitoring instrumentation, copies of all reports required by this permit, and records of all data used to complete the application for this permit shall be retained for a period of AT LEAST THREE (3) YEARS from the date of the sample, measurement, report, or application. This period may be extended at any time prior to its expiration by request of the Director.
2. Records of the nature and composition of all injected fluids must be retained until three (3) years after the completion of any plugging and abandonment (P&A) procedures specified under 40 CFR § 144.52(a)(6) or under part 146 subpart G, as appropriate. The Director may require the Permittee to deliver the records to the Director at the conclusion of the retention period. The Permittee shall continue to retain the records after the three (3) year retention period unless the Permittee delivers the records to the Director or obtains written approval from the Director to discard the records.
3. The Permittee shall notify the EPA as to the location where injection well records are maintained. The Permittee shall notify the EPA if this location changes.

F. Quarterly Reports

Following authorization to begin injection, the Permittee shall submit Quarterly Reports to the Director summarizing the results of the monitoring required above, and whether the well is operating or not. Reporting periods and due dates for Quarterly Reports are shown in Table 18. EPA Form 7520-8 *Injection Well Monitoring Report* (found at https://www.epa.gov/uic/underground-injection-control-reporting-forms-owners-or-operators) may be used to submit the Quarterly Reports, however, the monitoring requirements specified in this Permit are mandatory even if EPA Form 7520-11 indicates otherwise.

Table 18. Reporting Periods and Due Dates for Quarterly Reports

REPORTING QUARTER	REPORTING PERIOD	REPORT DUE TO EPA
1st Quarter	January 1 – March 31	May 15
2nd Quarter	April 1 – June 30	August 15
3rd Quarter	July 1 – September 30	November 15
4th Quarter	October 1- December 31	February 15

G. Protective Automated Monitoring and Shut-Off Devices

1. Injection activities at each Class V deep injection well shall be monitored with an automated control system with control switches to alarm the operator if certain operating conditions are encountered. A high injection pressure switch (set at or below the Area Permit maximum) and a low annulus differential pressure switch (set above the Area Permit minimum) must shut-off injection pump power and notify the operator so that the well can be fully isolated and secured.
2. In the event that any of the Area Permit condition related minimum or maximum set points are met, injection operations must cease until the problem is identified and corrected. The system shall not be manually restarted by an operator until compliance is verified.
3. The system shall operate continuously except in the event of power failure, when all well operation activities shall halt.
4. Any alarms, automatic shutdowns due to permit limits and power failures shall be recorded in a narrative, along with causes and actions taken to correct the situation, and included in the next Quarterly Report.
5. If fluid injection occurs during the period of any week and the well is being monitored remotely, annulus fluid level shall be visually monitored a minimum of once per week at the annulus fluid head tank by the use of a level indicator or a sight glass. Any additions or subtractions of fluid from the annulus tank shall be recorded for monitoring purposes and reported on a quarterly basis per permit requirements.
6. If the proposed Dewey-Burdock Class V injection wells are monitored and operated remotely, the following special conditions shall be applicable to each well. (For the purpose of this permit, remote monitoring is defined as injection into the wells when a trained operator is not present at the well site or in the monitoring control room but is still able to perceive shut-down alarms and is still able to physically respond to the well controls or the wellhead within 15 minutes of a compliance alarm condition.)
    a. *Local operating system and remote monitoring system:* If remote monitoring is to be used to operate the well, an automatic paging system shall be installed that is designed to alert designated on-call, off-site personnel in the event of a well alarm or shut-in. The paging system will be equipped with a back-up power supply.
    b. *Response to automatic shut-downs related to a Permit condition:* Alarm shut-downs of the operating well related to Area Permit compliance limits established for well operation shall be investigated on-site by a trained operator within three (3) hours of pager notification of the occurrence.
    c. *Loss of power to the control system:* In the event that a power failure beyond the capability of the back-up power supply shuts down the control system, the well shall be automatically shut-in.
    d. *Loss of dial tone:* If the automatic pager cannot get a dial tone for 90 minutes, the well shall automatically be shut-in.
    e. *Restart of the well after an automatic shut-in:* Restart of the well after a shut-in related to a Area Permit condition alarm (including, but not limited to, injection pressure, annulus differential pressure, loss of dial tone for more than 90 minutes or control system power failure) shall require the physical presence of the operator on-site to verify compliance before the well can be restarted.

f. *Restart of the well after shut downs unrelated to a Permit condition:* If the well is shut-in for more than 48 hours for circumstances unrelated to Permit conditions, restart of the well shall require the physical presence of the operator on-site.
g. *Monthly operator inspections:* If fluid injection occurs during the period of any month and the well is being monitored remotely, a trained operator shall physically visit the site to inspect the facility at a minimum frequency of not less than once per month. This inspection shall verify the correct operation of the remote monitoring system by review of items such as, but not limited to, a comparison of the values shown on mechanical gauges with those reported by the remote operating system.
h. *Weekly operator inspections:* Unless annulus pressure changes by more than 10 percent per week while the well is injecting, only one annulus fluid level per week shall be required to be observed, recorded and reported when injection takes place.
i. *Annulus tank fluid level measurements:* When the well is not actively being used for injection, one annulus tank fluid level measurement shall be taken, recorded and reported per month unless annulus fluid pressure decreases more than 10 percent per month. In such cases of increased annulus pressure change, annulus fluid level measurements shall be taken, recorded and reported twice per month.
j. When not in use by a trained well operator, offloading connections shall be secured and shall be locked at the valves leading to waste water tanks so that access is restricted to trained well operators.
k. In the event of well shut-down, it may become necessary to transport treated ISR waste fluids (injectate) by truck to an alternate Class V injection well site within the proposed Class V Area Permit area. Offloading of fluid from transports can only occur with a trained operator physically present on site. A waste related log sheet and/or waste manifest file will be maintained documenting that a trained well operator allowed fluid to be unloaded. At a minimum, waste log entries are to include operator name, date, time, truck identification and approximate volume.

PART VI. PLUGGING AND ABANDONMENT

A. Requirement for EPA Approval before Plugging and Abandonment of Class V Deep Injection Wells

The Permittee shall not commence plugging and abandonment of a Class V Deep injection well until after receiving written authorization from the Director. The Director will not approve the plugging and abandonment of any Class V deep injection wells until all Class III wellfields have been decommissioned by the NRC. At least one Class V deep injection well shall remain active or temporarily abandoned until all Class III wellfields have been decommissioned.

B. Notification of Well Abandonment, Conversion or Closure

The Permittee shall notify the Director in writing at least forty-five (45) days prior to: 1) plugging and abandoning an injection well, 2) converting to a non-injection well, and 3) in the case of an Area Permit, before closure of the project. Notification shall include:

1. The status of Class III wellfields;
2. The number and status of Class III wells that have not been plugged and abandoned as required under the UIC Class III Area Permit; and
3. Any anticipated change to the approved plugging and abandonment plan.

C. Well Plugging Requirements

1. The well shall be plugged in accordance with the Approved Plugging and Abandonment Plan and with 40 CFR § 146.10.
2. Prior to abandonment, the injection well shall be plugged with cement in a manner which prevents the movement of fluids into or between underground sources of drinking water.
3. Prior to placement of the cement plug(s) the well shall be in a state of static equilibrium with the mud weight equalized top to bottom, either by circulating the mud in the well at least once or by a comparable method prescribed by the Director.

D. Approved Plugging and Abandonment Plan

The Permittee shall take the following steps prior to abandonment of the Class V wells:

1. Tubing, packer and other downhole apparatus shall be removed.
2. A Cement Bond Log shall be run to evaluate the cement outside the outermost casing.
3. A temperature survey test must be done to confirm external mechanical integrity, if it has been more than 2 years since the last test was run. If any pathways are discovered in the external casing cement, then remedial cementing will be required.
4. A pressure falloff test shall be run if it has been more than 6 months since the last test.
5. Fill each well with cement from total depth (or in the case of DW No. 1, PBTD) to surface in using a minimum of two cementing stages using enough cement to fill calculated volume of inner casing.
6. Within sixty (60) days after plugging, submit Plugging Record (EPA Form 7520-14) to the Director.
7. The Plugging Record must be certified as accurate and complete by the person responsible for the plugging operation.

E. Changes to the Approved Plugging and Abandonment Plan

Changes to the approved plugging and abandonment plan must be approved by the Director prior to beginning plugging operations. The Director also may require revision of the approved plugging and abandonment plan at any time prior to plugging the well.

F. Plugging and Abandonment Report

Within sixty (60) days after plugging a well, the Permittee shall submit a report (EPA Form 7520-14) to the Director. The plugging report shall be certified as accurate by the person who performed the plugging operation. Such report shall consist of either:

1. A statement that the well was plugged in accordance with the approved plugging and abandonment plan; or
2. Where actual plugging differed from the approved plugging and abandonment plan, an updated version of the plan, on the form supplied by the Director, specifying the differences.

G. Inactive Wells

After any period of 24 months during which there is no injection activity for a well, the Permittee shall:

1. Provide written notice to the Director at the end of 24 months of no injection activity;
2. Demonstrate internal and external MI before the end of 24 months of no injection activity; and
3. Describe any other actions or procedures the Permittee will take to ensure that the well will not endanger USDWs during the period of inactivity. In addition to demonstration of mechanical integrity, these actions shall include demonstration of Financial Responsibility and any other applicable permit requirements designed to protect USDWs.

PART VII. CONDITIONS APPLICABLE TO ALL PERMITS

A. Changes to Permit Conditions

1. Modification, Reissuance or Termination

The Director may, for cause or upon a request from the Permittee, modify, revoke and reissue, or terminate this Permit in accordance with 40 CFR §§ 124.5, 144.12, 144.39, and 144.40. Also, this Permit is subject to minor modification for causes as specified in 40 CFR § 144.41. The filing of a request for modification, revocation and reissuance, termination, or the notification of planned changes or anticipated noncompliance on the part of the Permittee does not stay the applicability or enforceability of any condition of this Permit.

2. Conversions

The Director may, for cause or upon a written request from the Permittee, allow conversion of the well from a Class V injection well to a non-Class V or non-injection well. Conversion to another injection well class shall not proceed until the Permittee receives a major modification to this Area Permit according to 40 CFR § 144.39 and § 124.5, which would invoke the public review process required under 40 CFR part 124. Conditions of such conversion may include but are not limited to, approval of the proposed well rework, follow up demonstration of mechanical integrity, well-specific monitoring and reporting following the conversion, and demonstration of practical use of the converted configuration.

3. Transfer of Permit

Under 40 CFR § 144.38, this Permit is transferable provided the current Permittee notifies the Director at least thirty (30) days in advance of the proposed transfer date (EPA Form 7520-7) and provides a written agreement between the existing and new Permittees containing a specific date for transfer of Permit responsibility, coverage and liability between them. The notice shall adequately demonstrate that the financial responsibility requirements of 40 CFR § 144.52(a)(7) will be met by the new Permittee. The Director may require modification or revocation and reissuance of the Permit to change the name of the Permittee and incorporate such other requirements as may be necessary under the Safe Drinking Water Act; in some cases, modification or revocation and reissuance is mandatory.

4. Permittee Change of Address

Upon the Permittee's change of address, or whenever the Permittee changes the address where monitoring records are kept, the Permittee must provide written notice to the Director within 30 days.

B. Severability

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

C. Confidentiality

In accordance with 40 CFR part 2 and 40 CFR § 144.5, information submitted to EPA pursuant to these regulations may be claimed as confidential by the submitter. Any such claim must be asserted at the time of submission by stamping the words "confidential business information" on each page containing such information. If no claim is made at the time of submission, EPA may make the information available to the public without further notice. If a claim is asserted, the validity of the claim will be assessed in accordance with the procedures in 40 CFR part 2 (Public Information).

Claims of confidentiality for the following information will be denied:
- The name and address of the Permittee, and
- information which deals with the existence, absence or level of contaminants in drinking water.

D. General Permit Requirements

1. **Duty to Comply**
   The Permittee must comply with all conditions of this Permit. Any noncompliance constitutes a violation of the Safe Drinking Water Act (SDWA) and is grounds for enforcement action; for Permit termination, revocation and reissuance, or modification; or for denial of a permit renewal application; except that the Permittee need not comply with the provisions of this Permit to the extent and for the duration such noncompliance is authorized in an emergency permit under 40 CFR § 144.34. All violations of the SDWA may subject the Permittee to penalties and/or criminal prosecution as specified in Section 1423 of the SDWA.

2. **Continuation of Expiring Permits**
   a. Duty to Reapply. If the Permittee wishes to continue an activity regulated by this permit after the expiration date of this permit, the Permittee must submit a complete application for a new permit at least 180 days before this permit expires.
   b. Permit Extensions. The conditions of an expired permit may continue in force in accordance with 5 U.S.C. § 558(c) until the effective date of a new permit, if:
      (i) The Permittee has submitted a timely application which is a complete application for a new permit; and
      (ii) The Director, through no fault of the Permittee, does not issue a new permit with an effective date on or before the expiration date of the previous permit.
   c. Enforcement. When the Permittee is not in compliance with the conditions of the expiring or expired permit the Director may choose to do any or all of the following:
      i. Initiate enforcement action based upon the permit which has been continued;
      ii. Issue a notice of intent to deny the new permit. If the permit is denied, the owner or Permittee would then be required to cease the activities authorized by the continued permit or be subject to enforcement action for operating without a permit;
      iii. Issue a new permit under part 124 with appropriate conditions; or
      iv. Take other actions authorized by these regulations.

   d. State Continuation. An EPA issued permit does not continue in force beyond its expiration date under Federal law if at that time a State has primary enforcement authority. A State authorized to administer the UIC program may continue either EPA or State-issued permits until the effective date of the new permits, if State law allows. Otherwise, the facility or activity is operating without a permit from the time of expiration of the old permit to the effective date of the State-issued new permit.

3. **Need to Halt or Reduce Activity Not a Defense**
   It shall not be a defense for a Permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this Permit.

4. Duty to Mitigate

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

5. Proper Operation and Maintenance

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

6. Permit Actions

This Permit may be modified, revoked and reissued or terminated for cause. The filing of a request by the Permittee for a permit modification, revocation and reissuance, or termination, or a notification of planned changes or anticipated noncompliance, does not stay any permit condition.

7. Property Rights

This Permit does not convey any property rights of any sort, or any exclusive privilege.

8. Duty to Provide Information

The Permittee shall furnish to the Director, within a time specified, any information which the Director may request to determine whether cause exists for modifying, revoking and reissuing, or terminating this permit, or to determine compliance with this permit. The Permittee shall also furnish to the Director, upon request, copies of records required to be kept by this Permit. The Permittee is required to submit any information required by this Permit or by the Director to the mailing address designated in writing by the Director.

9. Inspection and Entry

a. The Permittee shall allow the Director, or an authorized representative, upon the presentation of credentials and other documents as may be required by law, to:
b. Enter upon the Permittee's premises where a regulated facility or activity is located or conducted, or where records must be kept under the conditions of this Permit;
c. Have access to and copy, at reasonable times, any records that must be kept under the conditions of this Permit;
d. Inspect at reasonable times any facilities, equipment (including monitoring and control equipment), practices, or operations regulated or required under this Permit; and
e. Sample or monitor at reasonable times, for the purpose of assuring permit compliance or as otherwise authorized by the SDWA, any substances or parameters at any location.

10. Signatory Requirements

a. All reports required by this permit and other information requested by the Director shall be signed as follows:

i. for a corporation—by a responsible corporate officer, such as a president, secretary treasurer, or vice president of the corporation in charge of principal business function, or any other person who performs similar policy or decision-making functions for the corporation;
ii. for partnership or sole proprietorship—by general partner or the proprietor, respectively; or
iii. for municipality, state, federal, or other public agency—by either a principal executive or a ranking elected official.

b. A duly authorized representative of the official designated in paragraph (a) above also may sign only if:
   i. the authorization is made in writing by a person described in paragraph (a) above;
   ii. the authorization specifies either an individual or a position having responsibility for the overall operation of the regulated facility or activity, such as the position of plant manager, operator of a well or a well field, superintendent, or a position of equivalent responsibility. A duly authorized representative may thus be either a named individual or any individual occupying a named position; and
   iii. the written authorization is submitted to the Director.

c. If an authorization under paragraph (b) of this section is no longer accurate because a different individual or position has responsibility for the overall operation of the facility, a new authorization satisfying the requirements of paragraph (b) of this section shall be submitted to the Director prior to or together with any reports, information or applications to be signed by an authorized representative.

d. Any person signing a document under paragraph (b) of this section shall make the following certification:

> *I certify under the penalty of law that I have personally examined and am familiar with the information submitted in this document and all attachments and that, based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the information is true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fines and imprisonment.*

11. Reporting Requirements

Before written Authorization to Commence Injection is issued by the Director for a well, copies of all reports and notifications required by this Permit shall be signed and certified in accordance with the requirements under Part VII, D.10 of this permit and shall be submitted to the EPA at the following address:

Underground Injection Control Unit Manager, 8WP-SUI
1595 Wynkoop Street
Denver, CO 80202-1129

After written Authorization to Commence Injection is issued by the Director for a well, copies of all reports and notifications required by this Permit shall be signed and certified in accordance with the requirements under Part VII, D.10 of this permit and shall be submitted to the EPA at the following address:

UIC Enforcement Coordinator, 8ENF-W-SWD
1595 Wynkoop Street
Denver, CO 80202-1129

All correspondence should reference the well name and location and include the EPA Permit number.

a. Planned changes. The Permittee shall give notice to the Director as soon as possible of any planned changes, physical alterations or additions to the permitted facility, and prior to commencing such changes.
b. Anticipated noncompliance. The Permittee shall give advance notice to the Director of any planned changes in the permitted facility or activity which may result in noncompliance with permit requirements.
c. Monitoring Reports. Monitoring results shall be reported at the intervals specified in this Permit.
d. Compliance schedules. Reports of compliance or noncompliance with, or any progress reports on, interim and final requirements contained in any compliance schedule of this Permit shall be submitted no later than 30 days following each schedule date.
e. Twenty-four hour reporting. The Permittee shall report to the Director any noncompliance which may endanger human health or the environment, including:
    i. Any monitoring or other information which indicates that any contaminant may cause endangerment to a USDW; or
    ii. Any noncompliance with a permit condition or malfunction of the injection system which may cause fluid migration into or between USDWs.
f. Information shall be provided, either directly or by leaving a message, within twenty-four (24) hours from the time the Permittee becomes aware of the circumstances by telephoning (800) 227-8917 and requesting EPA Region VIII UIC Program Compliance and Technical Enforcement Director, or by contacting the EPA Region VIII Emergency Operations Center at (303) 293-1788.
g. In addition, a follow up written report shall be provided to the Director within five (5) days of the time the Permittee becomes aware of the circumstances. The written submission shall contain a description of the noncompliance and its cause, the period of noncompliance including exact dates and times, and if the noncompliance has not been corrected the anticipated time it is expected to continue; and the steps taken or planned to reduce, eliminate, and prevent recurrence of the noncompliance.
h. The written report shall also be provided to the Director in electronic format for release to the public and tribal governments on the EPA Region 8 UIC website.
i. Oil Spill and Chemical Release Reporting: The Permittee shall comply with all reporting requirements related to the occurrence of oil spills and chemical releases by contacting the National Response Center (NRC) at **(800) 424-8802**.
j. Other Noncompliance. The Permittee shall report all instances of noncompliance not reported under paragraphs Part VII, Section D.11.b, Section D.11.e or Section D.11.i at the time the monitoring reports are submitted. The reports shall contain the information listed in Part VII, Section D.11.g and be provided to the Director in electronic format as required in Part VII, Section D.11.h.
k. Other information. Where the Permittee becomes aware that it failed to submit any relevant facts in the permit application, or submitted incorrect information in a permit application or in any report to the Director, the Permittee shall promptly submit such facts or information to the Director.

PART VIII. FINANCIAL RESPONSIBILITY

A. Method of Providing Financial Responsibility

The Permittee shall maintain continuous compliance with the requirement to maintain financial responsibility and resources to close, plug, and abandon the underground injection well(s). No substitution of a demonstration of financial responsibility shall become effective until the Permittee receives written notification from the Director that the alternative demonstration of financial responsibility is acceptable. The Director may, on a periodic basis, require the holder of a permit to revise the estimate of the resources needed to plug and abandon the well to reflect changes in such costs and may require the Permittee to provide a revised demonstration of financial responsibility.

1. **Types of Adequate Financial Responsibility**

   Adequate financial responsibility to properly plug and abandon injection wells under the Federal UIC requirements must include completed original versions of one of the following:

   a. a surety bond with a standby trust agreement,
   b. a letter of credit with a standby trust agreement,
   c. a fully funded trust agreement, OR
   d. an independently audited financial statement with a Chief Financial Officer's letter.

A surety bond acceptable to the Director shall contain wording identical to EPA's model language and shall be issued by a surety bonding company found to be acceptable to the U.S. Department of Treasury, which can be determined by review of that Department's Circular #570, currently available on the internet at https://www.fiscal.treasury.gov/fsreports/ref/suretyBnd/c570.htm.

A letter of credit acceptable to the Director shall contain wording identical to EPA's model language and be issued by a bank or other institution whose operations are regulated and examined by a State or Federal agency.

A fully funded trust agreement acceptable to the Director shall contain wording identical to EPA's model language. Annual reports from the financial institution managing the trust account shall be submitted to the Director showing the available account balance.

An independently audited financial statement with a Chief Financial Officer's letter acceptable to the Director shall contain wording identical to EPA's model language and shall demonstrate the Permittee meets or exceeds certain financial ratios. If this financial instrument is used, it must be resubmitted annually, within 90 days after the close of the Permittee's fiscal year, using the financial data available from the most recent fiscal year.

A standby trust agreement acceptable to the Director shall contain wording identical to EPA's model language. Annual reports from the financial institution managing the standby trust account shall be submitted to the Director showing the available account balance.

2. **Determining How Much Coverage is Needed**

   The Permittee, when periodically requested to revise the plugging and abandonment cost estimate discussed above, must submit 3 current independent plugging and abandonment cost estimates for EPA to accurately determine the likely cost to plug the well(s).

B. Insolvency

In the event of:

1. the bankruptcy of the trustee or issuing institution of the financial mechanism; or
2. suspension or revocation of the authority of the trustee institution to act as trustee; or
3. the institution issuing the financial mechanism losing its authority to issue such an instrument,

the Permittee must notify the Director in writing, within ten (10) business days, and the Permittee must establish other financial assurance or liability coverage acceptable to the Director within sixty (60) days after any event specified in (a), (b), or (c) above.

The Permittee must also notify the Director by certified mail of the commencement of voluntary or involuntary proceedings under Title 11 (Bankruptcy), of the U.S. Code that names the owner or Permittee as debtor, within ten (10) business days after the commencement of the proceeding. A guarantor, if named as debtor of a corporate guarantee, must make such a notification as required under the terms of the guarantee.

J. Updated Cost Estimate and Timing for Demonstration of Financial Responsibility

An updated cost estimate shall be submitted within 21 days of the Effective Date of the Final Permit. The demonstration of financial responsibility shall be submitted to the EPA within 30 calendar days of the Effective Date of the Final Permit and before the commencement of any Class V well construction activities. Any well construction activities are prohibited until financial responsibility has been approved by the EPA.

K. This surety addresses a portion of the decommissioning activities cited in the U.S. Nuclear Regulatory Commission Materials License SUA-1600, pursuant to Title 10 Code of Federal Regulations Part 40, Appendix A, Criterion 9.

PART IX. REFERENCES

Lee, John, 1982, Well Testing: Society of Petroleum Engineers of AIME: New York, 159 p.

Appendix A
Proposed Schematic Diagrams of the
Wellhead and Surface Facilities

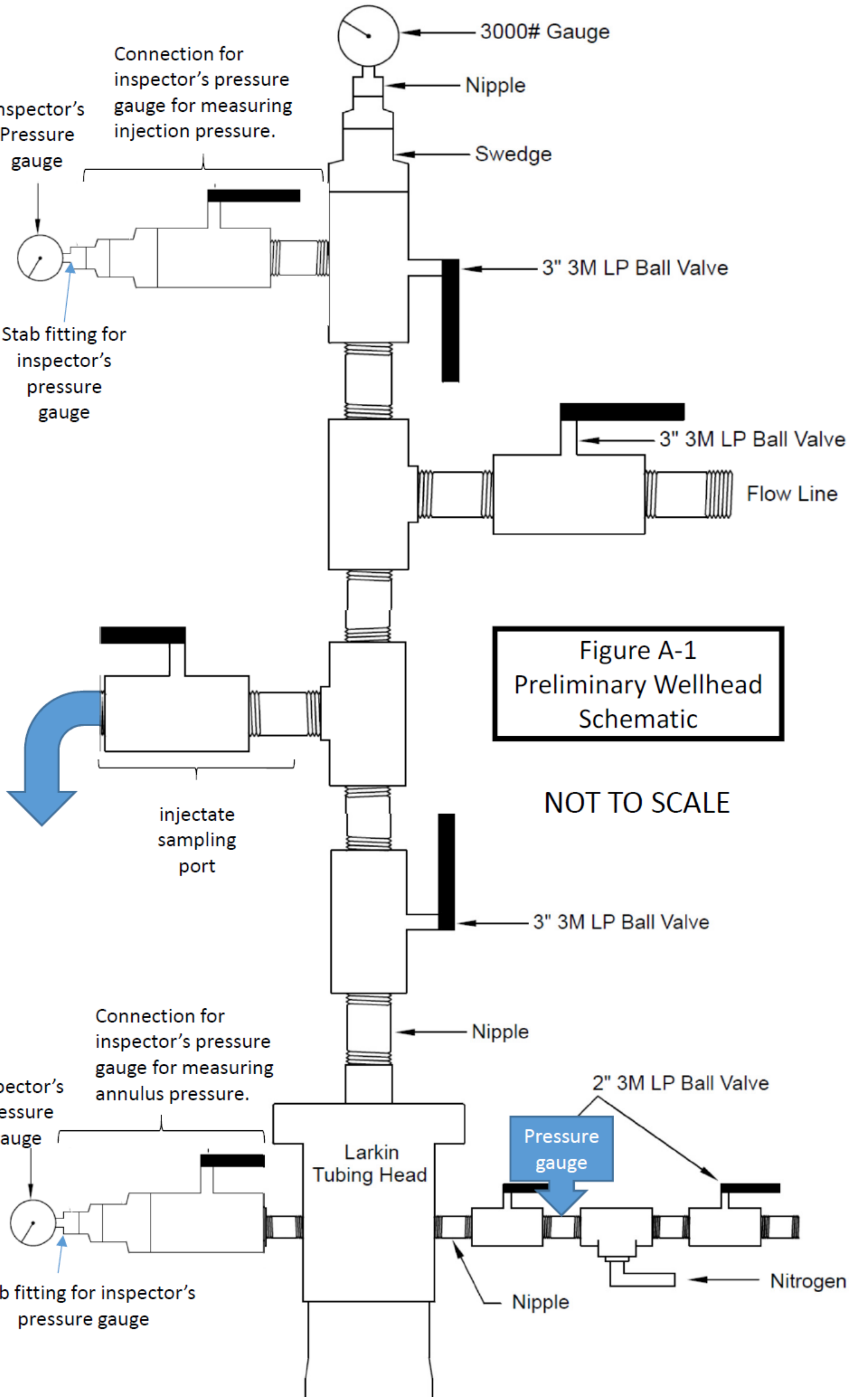
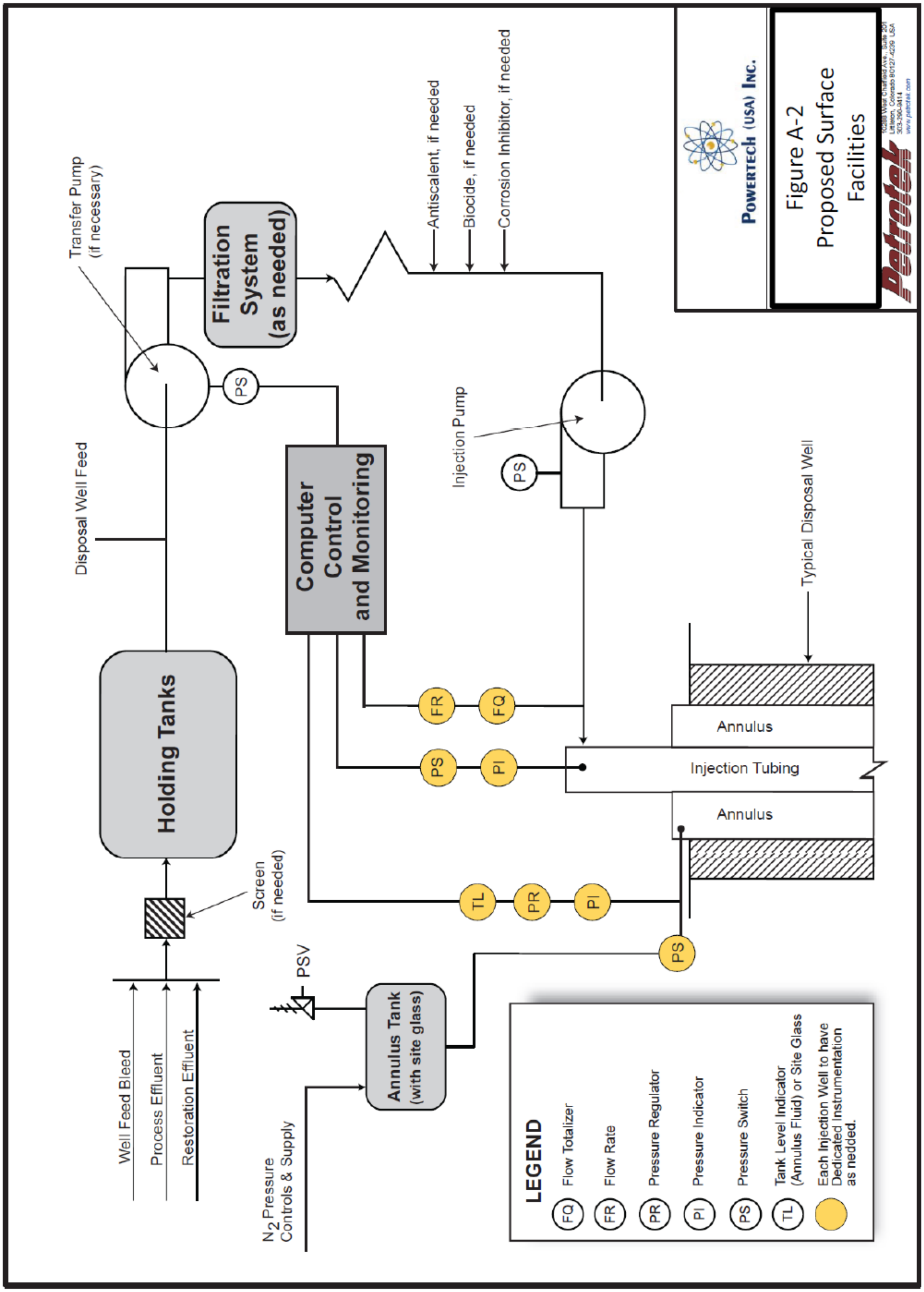


Figure A-1
Preliminary Wellhead
Schematic

NOT TO SCALE


Holding Tanks
Disposal Well Feed
Transfer Pump
(if necessary)
Filtration
System
(as needed)
PS
Computer
Control
and Monitoring
Antiscalent, if needed
Biocide, if needed
Corrosion Inhibitor, if needed
Injection Pump
PS
Typical Disposal Well
Annulus
Injection Tubing
Annulus
FR
FQ
PS
PI
TL
PR
PI
PS
Screen
(if needed)
Well Feed Bleed
Process Effluent
Restoration Effluent
PSV
Annulus Tank
(with site glass)
N_2 Pressure
Controls & Supply
LEGEND
FQ Flow Totalizer
FR Flow Rate
PR Pressure Regulator
PI Pressure Indicator
PS Pressure Switch
TL Tank Level Indicator
(Annulus Fluid) or Site Glass
Each Injection Well to have
Dedicated Instrumentation
as needed.
POWERTECH (USA) INC.
Figure A-2
Proposed Surface
Facilities
Petrotek