EPA REGION 8'S RESPONSE TO PETITION FOR REVIEW

ATTACHMENT Q

Final Class V Area Permit, No. SD52173-00000

Administrative Record Document No. 281

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 8
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UNDERGROUND INJECTION CONTROL
FINAL
CLASS V AREA PERMIT

Date: November 24, 2020

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.
P.O. Box 448
Edgemont, SD 57735

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,

Powertech (USA) Inc.
P.O. Box 448
Edgemont, SD 57735

hereinafter referred to as the "Permittee," is authorized to construct and operate wells in accordance with the conditions of this Area Permit.

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 must 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) Class V 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 injecting into 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.

B. Well Location

Approximate location information for the proposed DW No. 1 Class V injection well 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. DW No. 1 Injection Well 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 - 2,355'	Burdock 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, Subpart QQ.

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, § 144.40, or § 144.41. This Permit may be adopted, modified, revoked and reissued, or terminated if the 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 must be directed to the State Program Director or designee.

Issue Date 11/24/2020

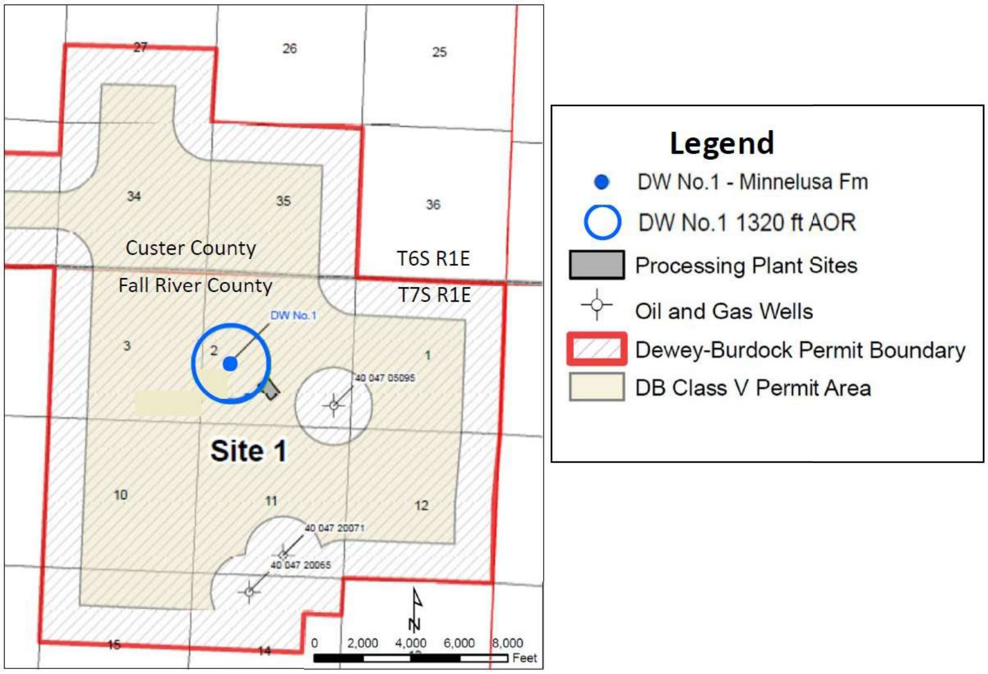
Effective Date 12/24/2020

DARCY OCONNOR Digitally signed by DARCY OCONNOR
Date: 2020.11.24 09:22:02 -07'00'

Darcy O'Connor, Director
Water Division*

*NOTE: Throughout this Permit the term "Director" refers to either the Director of the Water Division (or authorized representative) or the Chief of the Water Enforcement Branch of the Enforcement and Compliance Assurance Division (or authorized representative).

Figure 1. Dewey-Burdock Class V Area Permit Boundary



PART II. REQUIREMENTS FOR AUTHORIZATION TO INJECT

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

A. Information to Submit to the Director to Obtain an Authorization to Inject

For each injection well, the Permittee must provide the following information, further described in Sections B through I, to the Director for evaluation. After evaluating the information, the Director will determine if it is appropriate to issue a written Authorization to Inject.

1. Well logging information, formation testing data and laboratory data from drill hole cores demonstrating that the injection zone is separated from underground sources of drinking water (USDWs) by an overlying confining zone identified in well logs which is demonstrated to have low permeability and low hydraulic conductivity. The Permittee must include annotations on logs, where appropriate, to identify aquifers, injection zones and confining zones.
2. Evaluation of the Minnelusa aquifer injection zone fluids to confirm the injection zone formations are hydraulically isolated from the Madison aquifer at the Dewey-Burdock Project Site.
3. Evaluation of the Madison aquifer fluids at the Madison water supply wells (if constructed), to provide additional confirmation that the injection zone is hydraulically isolated from the Madison aquifer at the Dewey-Burdock Project Site.
4. The Total Dissolved Solids (TDS) concentration of each perforated zone will be determined by two swab

samples. If any swabbed zone contains less than 10,000 mg/L TDS, the injection zone is a USDW. The Director will not authorize injection into an USDW under this Area Permit.

5. Calculations of critical pressures and injection-induced injection zone pressures for the injection zone based on site-specific information and 10 years of injection activity. This information must be used to demonstrate that each injection well is located at a sufficient distance from any feature so that there is not sufficient pressure to move fluids into USDWs.
6. 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.
7. Location of well perforations within the approved injection zone.
8. Demonstration of internal and external mechanical integrity for each injection well.
9. Results of step rate testing to determine the site-specific maximum allowable injection pressure (MAIP) for each well.
10. Results of a temperature survey or radioactive tracer survey for each injection well to establish a baseline assessment of Part II Mechanical Integrity and provide injectivity profile information.
11. The testing procedures, results and interpretation of results for the formation testing required under Part II, Section D must be included in the Injection Authorization Data Package Report.

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

1. The Permittee must 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 Borehole Compensated (BHC) Sonic log.
2. The Permittee must compare geologic logs from the first well with subsequent wells to demonstrate consistency and continuity of the geologic intervals.
3. The information must be included in the Injection Authorization Data Package Report for each Class V injection well.
4. The effective porosity and permeability, and the percentage of flow into each injection zone must 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

CORE INTERVAL	PURPOSE	DUE DATE
While drilling each injection well, core samples must be collected in each Minnelusa injection zone.	For laboratory testing to determine the porosity, effective porosity and permeability of the injection zone	Prior to receiving Authorization to Inject
While drilling the first injection well, core samples must be collected within the Opeche Shale Confining Zone	For laboratory testing to determine the permeability and hydraulic conductivity of the overlying confining zone.	Prior to receiving Authorization to Inject
While drilling each Madison water supply well (if constructed), core samples must be collected from the Lower Minnelusa confining zone.	For laboratory testing to provide additional confirmation that the injection zone is hydraulically isolated from the Madison aquifer at the Dewey-Burdock Project Site.	Within 30 days of core analysis

C. Well Logging Requirements

1. The Permittee must perform the logging operations listed in Tables 3, 4 and 5 on each injection well drill hole and casing.
2. Madison water supply wells (if constructed), the Permittee must conduct a minimum of mud logging, spontaneous potential logging, BHC sonic open-hole logging, and cement bond logs on the well surface and long string casing. Logs must be submitted to EPA within 30 days.
3. 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 adequate cement bond to prevent injected fluids from migrating outside of the authorized injection zone.

Table 3. Surface Casing Logs

TYPE OF LOG	PURPOSE	DUE DATE
Dual Induction Laterolog	Open-hole formation evaluation	Prior to setting surface casing
Gamma Ray	Open-hole formation evaluation	Prior to setting surface casing
BHC Sonic	Open-hole formation evaluation	Prior to setting surface casing
Formation Density	Open-hole formation evaluation	Prior to setting surface casing
Caliper	Open-hole cement estimate	Prior to setting surface casing
Cement Bond Log[1]	Cement quality behind the surface casing	Prior to drilling out surface casing

[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. Long String Casing: Open Hole Logs

TYPE OF LOG	PURPOSE	DUE DATE
Mud Logging	Open-hole formation evaluation	During drilling
Dual Induction Laterolog	Open-hole formation evaluation	Prior to setting long string casing
Spontaneous Potential	Open-hole formation evaluation	Prior to setting long string casing
Gamma Ray	Open-hole formation evaluation	Prior to setting long string casing
BHC Sonic	Open-hole formation evaluation	Prior to setting long string casing
Formation Density	Open-hole formation evaluation	Prior to setting long string casing
Compensated Neutron	Open-hole formation evaluation	Prior to setting long string casing
Fracture Finder (Micro-resistivity)	Open-hole formation evaluation	Prior to setting long string casing
Caliper	Open-hole cement estimate	Prior to setting long string casing

Table 5. Long String Casing Logs

TYPE OF LOG	PURPOSE	DUE DATE
Cement Bond Log[2]	Cement quality behind the long string casing	Prior to receiving Authorization to Inject
Casing Inspection Log	Long string casing quality	Prior to receiving 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 must conduct the formation tests listed in Table 7 for the purposes stated in Table 7.

Table 6. Aquifer to be Tested

Well Drill Hole	**Aquifers to be Tested**
DW No. 1	Each perforated zone in the Minnelusa Formation separated by a confining layer
Madison water supply wells (if constructed).	Stratigraphic intervals correlating to each perforated zone in the Minnelusa Formation separated by a confining layer at the injection wells, Madison aquifer

Table 7. Formation Testing Program

TYPE OF TEST	PURPOSE	DUE DATE
Open-hole fluid samples may be taken at the Permittee's discretion from each aquifer listed in Table 6 according to the requirements under Part II, Section D.2.	To allow Powertech to characterize the water quality from each aquifer specified in Table 6 prior to perforating and swab sampling.	Prior to receiving Authorization to Inject
Cased-hole swab samples must be taken from each Minnelusa perforated zone specified in Table 6 according to the requirements under Part II, Section D.2.	To demonstrate that each injection zone is not an USDW	Prior to receiving Authorization to Inject
Cased-hole potentiometric surface will be measured for each separate perforated zone	To determine potentiometric surface for each injection zone	Prior to receiving Authorization to Inject

Further characterization of each 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 Authorization to Inject
Characterization of the Madison Formation water at the Madison water supply wells (if constructed), 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.	Within 30 days of acquisition of data
Madison water supply wells (if constructed). 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 10 years of pumping.	Within 30 days of acquisition of data.
Initial Temperature Survey Log[3]	To establish baseline temperatures of formations along well bore.	Prior to receiving 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 must include the addition of a fluorescent dye tracer in the drilling fluids. The fluorescent dye tracer used for this purpose must be such that the Permittee is able to analyze for the presence of the tracer in aquifer fluid samples using field testing methods. The tracer must 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. In the event that the dye dissipates in the drilling mud or formation fluid to the extent that it is not detectable during sampling, stabilized values of pH and conductivity during three successive casing volumes may be used to establish the presence of native formation fluids in accordance with Part II, Section 2.d.v.

b. Before aquifer sample collection, each aquifer must be isolated within the well or wellbore to prevent inflow of groundwater from other aquifers.

c. If open-hole samples are collected:

   i. For each isolated injection zone specified in Table 6, potentiometric surface elevations will be allowed to stabilize for 30 minutes. Fluid samples may then be collected.

   ii. A minimum of two fluid samples from each injection zone specified in Table 6 must be collected. The second sample must be collected after one drill stem volume of groundwater has been removed after the collection of the first sample.

iii. The two fluid samples from each injection zone specified in Table 6 must be analyzed for TDS, Specific Gravity, pH, and Conductivity using the analytical methods shown in Table 8. Equivalent analytical methods may be used after prior approval by the Director. Analytical results must be reported in the units listed in Table 8.

iv. One drill stem volume of groundwater must be removed for the collection of each sample.[4]

d. Cased-hole Samples:

i. Potentiometric surface data must be determined for each perforated zone

ii. Swab sampling should take place prior to any formation stimulation or any other procedure where fluids may enter the formation and contaminate the naturally occurring formation water

iii. The sampling procedure should follow immediately after perforating a zone in order to prevent wellbore fluids from contaminating the naturally occurring injection formation water.

iv. From each tubing volume recovered, measure the time, volume of fluid recovered, pH, and conductivity

v. When fluorescent dye is no longer detectable and pH and conductivity have stabilized (0.1 pH units and + 3% µmhos/cm, respectively) during three successive tubing volumes, collect two representative sample (one each, from two successive swab runs) for complete water analysis, measuring for each of the parameters and methods listed in Table 8.

vi. Except as may be required by the analytical method(s) shown in Table 8, samples must be analyzed for dissolved fractions.

vii. Equivalent analytical methods or total recoverable analysis may be used after prior approval by the Director.

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

i. Methods for aquifer isolation;

ii. Methods for sample collection;

iii. Methods for insuring fluid sample is representative of the aquifer conditions; and

iv. Methods for fluorescent dye 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 (as $CaCO_3$)	A2320B	mg/L
2. Arsenic	E200.8	mg/L
3. Barium	E200.8	mg/L
4. Bicarbonate Alkalinity (as $CaCO_3$)	A2320B (as HCO_3)	mg/L
5. Cadmium	E200.8	mg/L
6. Calcium	E200.7	mg/L
7. Carbonate Alkalinity (as $CaCO_3$)	A2320B	mg/L
8. Chloride	A4500-Cl B; E300.0	mg/L
9. Chromium	E200.8	mg/L
10. Specific Conductance	A2510B or E120.1	µmhos/cm at 25°C
11. Fluoride	E300.0	mg/L
12. Lead	E200.8	mg/L
13. Lead-210	E905.0 Mod.	pCi/L
14. Magnesium	E200.7	mg/L
15. Mercury	E200.8	mg/L
16. pH	A4500-H B	pH units
17. Potassium	E200.7	mg/L
18. Radium-226	E903.0	pCi/L
19. Radium-228	E904.0	pCi/L
20. Selenium	E200.8, A3114 B	mg/L
21. Silver	E200.8	mg/L
22. Sodium	E200.7	mg/L
23. Specific Gravity	ASTM D1429-13, SM 2710F	Ratio to density of water
24. Strontium	E200.8	mg/L
25. Sulfate	A4500-SO_4 E; E300.0	mg/L
26. Thorium -230	ASTM D3972-90	pCi/L
27. TDS	A2540C	mg/L
28. Drilling Fluid Tracer		
29. Uranium	E200.7, E200.8	mg/L
30. Uranium (Natural)	ASTM D3972-90	pCi/L

3. Demonstration that the Injection Zone Is Not an 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 Inject, the Permittee must demonstrate the Minnelusa aquifer is not an USDW. This demonstration will be made by individual analysis of swab samples taken from each perforated zone immediately after perforating the zone. If the Permittee is able to demonstrate, based on analytical results from swab samples collected as required under Part II, Sections D.2, that the TDS of the injection zone fluids are 10,000 mg/l or greater, then the injection zone is not an USDW. If the TDS analyses of injection zone fluids are less than 10,000 mg/L, the injection zone is considered an USDW. This permit does not authorize injection into an USDW. If any Minnelusa injection zone is determined to be an USDW based on testing, the Permittee must obtain an aquifer exemption and a major a permit modification as described in Part IV, Section E in order 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. 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	2,355	2,765	410
Minnelusa (Dewey)	Upper: Opeche Shale	1,855	1,950	95
	Lower: Lower Minnelusa Formation	2,704	3,100	396

1. **Determination of Actual Depth and Thickness of Confining Zones**
   - **a.** The Opeche Shale is the upper confining zone immediately overlying the Minnelusa porosity injection zone. Logs from the DW No. 1 Class V injection well must be submitted to the Director for review of the Opeche Shale thickness at the location of each injection well. The Permittee must include annotations on the logs indicating the top and the base of the Opeche Shale.
     - i. The Permittee must also include annotations on the logs indicating the top of the Minnelusa Formation,
     - ii. The permittee must also include annotations on the logs indicating the top of the Red Marker within the Minnelusa porosity injection zone, and the expected depth of the shale markers indicating the top of the Lower Minnelusa confining zone shown in Table 9.
   - **b.** The Permittee must also provide logs of the Opeche Shale and the Minnelusa Formation from the Madison water supply wells (if constructed). The Permittee must include annotations on the logs indicating 1) the top and base of the Opeche Shale, 2) the top of the Minnelusa Formation, 3) the Red Marker within the Minnelusa, 4) the shale markers indicating the top of the Lower Minnelusa confining zone, and 5) the top of the Madison Formation.
2. **Core Sample Collection from Confining Zones**
   - **a.** During the drilling of the first injection well, core samples within the Opeche confining zone must be collected.

b. During the drilling of each Madison water supply well (if constructed), core samples must be collected within the Lower Minnelusa Formation lower confining zone.

c. The core samples must 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 zones and Madison aquifer samples (if Madison water supply wells are constructed) must be provided for the following anions and cations as both mg/L and milliequivalents/L as shown in Table 8. The milliequivalents/L concentrations must 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 must also be plotted in the format of the Stiff Diagram shown in Figure 2.

iii. The Permittee must 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 (if constructed).

A) The Permittee must 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 must include characterization of the Minnelusa injection zone fluids, using the concentrations of the anions and cations listed above and reported in units of milliequivalents/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.

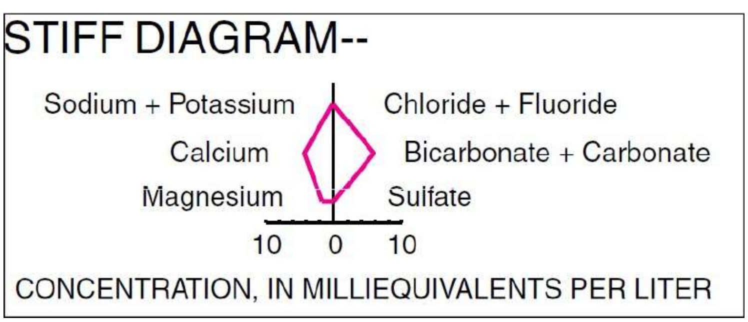


Figure 2. Format of Stiff Diagram for Anion and Cation Concentrations in the Minnelusa Injection Zone and the Madison Aquifer

b. Calculation of Potentiometric Surface Drawdown at the Madison Water Supply Wells (if constructed)

i. After the testing of the Madison aquifer has provided the information on the potentiometric surface and other parameters required, the Permittee must generate a drawdown model of the change in the potentiometric surface of the Madison aquifer that can be expected to result from 10 years of pumping the Madison aquifer at each of the Madison water supply wells.

ii. This information must 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

The Permittee must calculate the critical pressure rise that is needed within each injection zone to move fluids into adjacent USDWs 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 at DW No.1.

2. Calculation of Injection-Induced Injection Zone Pressure

a. For each injection well, the Permittee must calculate the injection zone formation pressures resulting from 10 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 must be considered as applicable.

b. The Permittee must 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 and potentially and into an USDW.

c. The Permittee must 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 potential for movement of fluids into USDWs.

d. The Permittee must use the diffusivity equation included in the Class V permit application as demonstrated by Lee, 1982, using site-specific data for the input values. At the discretion of the Director, the Permittee may use input values from published reports and must 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 10 years of injection activity, the Permittee must calculate a maximum injection rate for each injection well. The maximum injection rate must be determined such that the critical pressure in each injection zone is not exceeded 1,000 feet away from the nearest potential breach 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 must ensure that no injection zone fluids move out of the injection zone through a pathway in the confining zones.

b. The Permittee must 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 Inject 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 Minnelusa 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 must be performed taking into account the pressure effects of having more than two injection wells injecting into the Minnelusa injection zone.

5. Modification to Calculations for Extended Injection Activity

If this Permit is renewed or modified for a period longer than 10 years, calculations of critical pressure rise, injection-induced pressure, and maximum injection rate must be re-evaluated for the revised period of injection, including the effects of drawdown in the Madison aquifer under Section E.3.b and additional Minnelusa injection wells under Section F.4 of this Part.

G. Injection Well Completion Report

1. Each injection well must be constructed according to the requirements in Part III.
2. After well construction has been completed, the Permittee must submit for each Class V injection well the 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 must notify the Director a minimum of 30 days prior to the testing date to give the Director, or an authorized representative, an opportunity to witness the test.

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

The Permittee must 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 Long String Casing

The Permittee must submit the results of the cement bond logs conducted on the surface casing and long string 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 must demonstrate 80% bonding through the confining zones. The Director may require additional logging and testing, or remedial cementing if a Cement Bond Log does not demonstrate External Mechanical Integrity.

I. Formation Testing Involving Injection

1. The Permittee must conduct the formation tests listed in Table 10 for the purposes stated in the table.
2. Limited injection is permissible prior to receiving Authorization to Inject only for the purposes of conducting the formation testing listed in Table 10.
3. The testing procedures, results and interpretation of results must 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 must be measured at the surface and bottom hole to determine friction loss for each well.	Prior to receiving Authorization to Inject
Initial Temperature or Radioactive Tracer Survey	Baseline assessment of Part II Mechanical Integrity, and injectivity profile information.	After MAIP has been determined from the Step Rate Test, but prior to receiving Authorization to Inject

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

a. **Fracture Pressure:** The Permittee must run an injection Step Rate Test for each injection 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 must monitor injection rate, surface injection pressure, and bottom hole injection pressure within 50 ft of the top of the injection zone. The Step Rate Test must be run using the injection tubing and packer. The Step Rate Test results must be submitted to the Director for evaluation.

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

$$fg=FP/d$$

FP = bottom-hole fracture pressure measured in the injection zone interval (from Step Rate Test)
fg = fracture gradient (calculated value)
d = depth to pressure sensor

c. **Maximum Allowable Injection Pressure:** The site specific maximum allowable injection pressure (MAIP) must be set at 90% of the surface pressure causing fracturing in the injection zone. The Area Permit sets a specific gravity limit of 1.0113 and this value must be used for specific gravity in the calculation. The MAIP permit limit for each injection well will be included in the Authorization to Inject approval document issued by the Director.

d. **Loss in Pressure due to Friction**: There may be a pressure loss due to friction between the injectate and the injection tubing. Step Rate Test results will determine this friction loss.

5. Initial Temperature Survey or Radioactive Tracer Survey

a. After the Step Rate Test has been conducted to identify injection zone fracture pressure, the Permittee must conduct an initial temperature survey or 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 must 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 must 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.

J. Evaluation of the Injection Authorization Data Package Reports

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 Inject only after finding:

a. Stratigraphic logs, aquifer potentiometric surface measurements and water quality data for the Minnelusa injection zones that demonstrate adequate confinement is present and provides hydrologic isolation of the injection zone from USDWs;

b. The laboratory analyses core samples from 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. For Madison water supply wells (if drilled): The laboratory analyses of Lower Minnelusa lower confining zone cores demonstrating that confining zone permeability and hydraulic conductivity values are adequate for preventing migration of fluid out of injection zone;

d. The TDS concentration within all Minnelusa injection zones is greater than 10,000 mg/L thus demonstrating that the injection zone is not an 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 an 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 through the confining zones 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;

i. The initial temperature survey or radioactive tracer survey provides baseline conditions for comparison with future logs required under Part V, Section C.6.c;

j. Both internal and external mechanical integrity are demonstrated for the injection well; and
k. Step Rate Test data provide the injection zone fracture pressure for the injection well allowing the Director to set a permit limit for the MAIP for the injection well calculated using the formula in Part II, Section I.4.c.

2. Pond Design Criteria and Cumulative Effects Analysis of Wellfield Operations
Before the Director will issue written Authorization to Inject, 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 must be isolated to prevent intermingling of formation fluids.

B. Approved Well Construction Plans
The details of the approved well construction plan are summarized in Table 11 and Figure 3.

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 constructed), as described under Part II, Section C.

Table 11. Well Casing and Cement Summary

	Burdock
	DW No.1 (Figure 3)
Conductor Casing Size (in)	13-3/8”
Conductor Casing Depth (ft)	~60’
Surface Casing Depth (ft)	50 ft below the base of the Sundance aquifer (~970’)
Surface Casing Size (in)	9-5/8”
Surface Casing Cement Interval (ft)	From base of Surface Casing to surface (0 - ~970’)
Surface Casing Cement volume	120% of calculated volume between exterior of casing and surrounding annulus.
Long string Casing Depth (ft)	328’ below the top of the Red Marker (~2,355’)
Long string Casing Size (in)	7” or 5-1/2”
Long string Cement volume	120% of calculated volume between exterior of casing and surrounding annulus.
Long string Cement Interval (ft)	From base of Long string Casing to surface (0’ - ~2,355’)
Total Depth (ft)	~328’ below the top of the Red Marker (~2,355’)

FIGURE 3

PERMIT REVIEW WORKSHEET

WELL NAME Dewey Burdock DW#1 OPERATOR Powertech

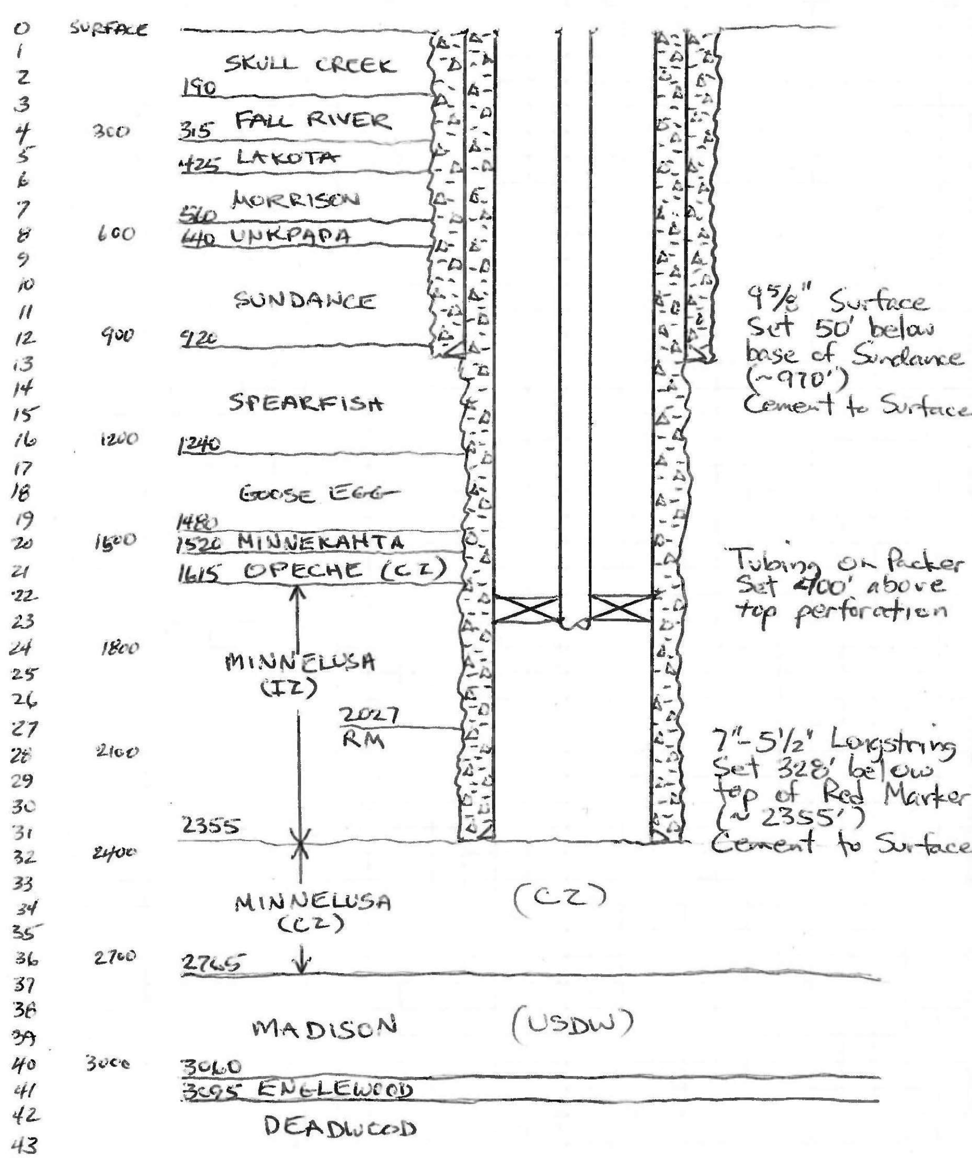
S 2 T 7S R 1E Fall River COUNTY, SD

CATEGORY : ☐ RA ☑ NEW CONSTRUCTION ☐ NEW CONVERSION from ____________

LOCATION : ☐ U/O ☐ WR ☐ SU ☐ UM ☐ MT-IND ☐ MT-NON IND

WELL TYPE : ☐ EOR ☐ NON-COMMERCIAL SWD ☐ COMMERCIAL SWD Class V

DEPTH *GEOLOGY* *SCHEMATIC* *DETAILS*



LOGS
- ☐☐ CBL/VDL/γ-RAY
- ☐☐ OAL
- ☐☐ CASING INSP
- ☐☐ RTS
- ☐☐ TEMP
- ☐☐ DIL
- ☐☐ γ-RAY
- ☐☐ RESISTIVITY
- ☐☐ CONDUCTIVITY
- ☐☐ SP
- ☐☐ SONIC (ϕ)
- ☐☐ N-DENSITY
- ☐☐

TESTS
- ☐☐ PORE PRESSURE
- ☐☐ PERMEABILITY
- ☐☐ IZ SAMPLE
- ☐☐ SOURCE SAMPLE
- ☐☐ SRT
- ☐☐ MIT
- ☐☐

C/A
- ☐☐ PRESSURE LIMIT
- ☐☐ REMEDIAL CMT

WELLHEAD EQUIP
- ☐☐ GAUGES
- ☐☐ STAB GAUGES
- ☐☐ FLOWMETER
- ☐☐ RATE INDICATOR
- ☐☐ SAMPLE TAP
- ☐☐

OPERATION
- ☐☐ COMPLETION RPT
- ☐☐ WORKOVER RPT
- ☐☐ AE ________
- ☐☐ Vmax ________
- ☐☐ Pmax ________
- ☐☐ MON ________
- ☐☐ RPT ________

PERMIT NUMBER SD52173-08764

FIGURE 3 – DW No. 1 Well Construction Schematic

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 that are different from approved specifications described under Part III of this Area Permit will require a modification in accordance with 40 CFR § 144.39, § 144.41, and § 124.5.
3. After well construction has been completed, the Permittee must 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 must be cased and cemented to prevent the movement of fluids into or between underground sources of drinking water.
2. The well casing and cement must be designed for the life expectancy of the well.
3. The Permittee must isolate all USDWs by placing cement between the outermost casing and the well bore;
   a. The Permittee must isolate the injection zone by placing sufficient cement to fill the calculated space between the casing and the well bore from the total depth (TD) to the surface; and
4. The Permittee must 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.
5. A float shoe may be used with a float collar one or two joints up from the bottom of the casing as field conditions dictate.
6. Centralizers must be placed at a minimum of one on every fifth casing joint.
7. The Director may require remedial cementing if it is shown to be inadequate by a cement bond log or other demonstration of external mechanical integrity.

E. Well Casing Perforations

1. Perforation of an injection well must 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 must 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.
3. Additional perforations may be added to an approved injection zone after initial construction is complete in accordance with Part IV, Section F.3.

F. Injection Tubing and Packer

1. All Class V deep wells constructed under this Area Permit must inject fluids through tubing with a packer set immediately above the injection zone. The packer must 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 must be designed for the expected service.
3. The tubing and packer must be chemically compatible with injected fluids.

G. Tubing-Casing Annulus (TCA) Fluid

1. The annulus space between the injection tubing and the well casing must 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 must be included in the well construction report.
3. The Permittee must notify the Director prior to any changes being made to the annulus fluid additives.

H. Sampling and Monitoring Devices

1. The Permittee must 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 or threaded 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 notify the operator in the event that any of the Area Permit conditions related to minimum or maximum permit limits are met. The system must 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 must submit to the Director 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 must 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 DW No. 2, DW No. 3, and DW No. 4 to this Area Permit

1. The Permittee must not construct wells DW No. 2, DW No. 3, and DW No. 4 under this Area Permit until construction has been approved in accordance with the procedures under this Section.

2. Prior to constructing additional wells under this Area Permit, the Permittee must seek authorization to construct by submitting the following materials to the Director:
   a. a cover letter requesting authorization to construct the well and referencing Area UIC Permit **SD52173-00000**;
   b. a completed EPA 7520-6 injection well application form for each well;
   c. a wellbore diagram of the proposed injection wells;
   d. a topographic map showing the location of the additional wells 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 wells including cementing records and cement bond logs for any new wells within the AOR not previously evaluated by the EPA.
   f. Submittal of estimates for well plugging according to the terms in this permit.
   g. Submittal of evidence for Financial Responsibility according to the terms in this permit.
3. Once the EPA has confirmed that the proposed injection well meets permit conditions, the Director 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.

K. Postponement of Construction

1. The Permittee must present an annual Area of Review (AOR) update to the Director until construction of the Class V injection wells commences. The AOR update must include identifying the location, depth, completion interval, and, if applicable, evidence that the Minnelusa injection zone was isolated for any new wells within the permit area. This update will be due and included as part of the Annual Reporting describe in Table 15.
2. In order to obtain authorization for construction and operation of wells DW No. 2, DW No. 3, and DW No. 4, the Permittee must follow the permit requirements under Part II of this Area Permit.
3. If authorization for DW No. 2, DW No. 3, and DW No. 4 is added to this Area Permit, there is no requirement for the Permittee to commence construction of the well within one year of authorization of the additional well(s).

L. Well Stimulation, Workovers and Alterations

1. Well stimulations, workovers, and alterations must meet all conditions of the Permit. Alteration, workover, and well stimulation include any activity that physically changes the well construction (casing, tubing, and packer) or injection formation.
2. Prior to beginning any addition or physical alteration to an injection well's construction or injection formation, the Permittee must give advance notice to the Director. Any modification to well construction that is different from the approved specifications described under Part III of this Area Permit will require a modification of this Area Permit in accordance with 40 CFR § 144.39, § 144.41, and § 124.5.
3. The Permittee must 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 must submit a revised well construction diagram, when the well construction has been modified. The Permittee must provide this and any other records of well workover, logging, or test data to the Director within thirty (30) days of the completion of the activity.

4. 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 must cease until the well has successfully demonstrated mechanical integrity. Documentation of mechanical integrity test results must be included in the next Quarterly Monitoring Report, or sooner if the Permittee chooses. Injection operations must not be resumed until the well has successfully demonstrated mechanical integrity and the Director has provided written approval to resume injection.
5. If an acidizing operation is conducted on well perforations, then a temperature survey log must be conducted to verify that the integrity of cement above the perforations has not been compromised by exposure to the acid. Documentation of temperature survey log results must be included in the next Quarterly Monitoring Report.

PART IV. WELL OPERATION

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

B. The Permittee must 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 an 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 Inject.
2. The Permittee must 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 temperature survey or Radioactive Tracer Survey to the Director for evaluation; and
   d. The Director has issued the written Authorization to Inject.

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 must be made.

E. Requirements if the Injection Zone is an USDW

This Permit does not authorize injection into USDWs. If any Minnelusa injection zone is determined to be an USDW based on testing, the Permittee must obtain an aquifer exemption and a major permit modification according to the requirements of 40 CFR § 144.39 and § 124.5 in order to inject into the Minnelusa formation.

F. Approved Injection Zone and Perforations

1. The Permittee must 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 drill hole logs and only after the Director has issued written Authorization to Inject. The approximate depth to the injection zone for well DW No. 1 is 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 each injection zone must be no less than 50 feet below the base of the lowest USDW intersected by the well bore. The Authorization to Inject will include the actual top and bottom depths of the approved injection zones based on well open hole logs.
3. Additional injection perforations may be added once the following requirements are met:
   a. The Permittee provides notice to the Director in accordance with Part III, Section L for well Workovers and Alterations. The Permittee must also follow the requirements for the Injection Pressure Limit found in Part IV Section H, which may result in a change to the permitted MAIP.
   b. The new perforations must remain within the approved injection zone,
   c. The top perforation is no higher than the approved top of the injection zone,
   d. Fracture gradient data submitted is representative of the portion of the injection zone to be perforated, and
   e. The Permittee has received approval from the Director for the perforations.
4. After the addition of perforations, the Permittee must follow the requirements for well Workovers and Alterations under Part III, Section L.
5. 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 must not exceed 1.0113.

H. Injection Pressure Limit

1. Except during stimulation injection, pressure at the wellhead must not exceed a maximum which must be calculated 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 an USDW.
3. The permitted MAIP, measured at the wellhead, must be established based on site-specific conditions at each injection well location according to Part II, Section I.4. The MAIP for each Class V injection wells will be included in the Authorization to Inject.
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 must not exceed the injection rate limits approved by the Director in the written Authorization to Inject based on calculations under Part II, Section F.3.

K. Approved Injectate

1. Injection fluid is limited to waste fluids from the ISR process generated by the Dewey-Burdock Project. These waste fluids include groundwater produced from well construction, laboratory waste fluids, well field production bleed, concentrated brine generated from the reverse osmosis treatment of groundwater produced from the well field during groundwater restoration, restoration bleed not processed by reverse osmosis, yellowcake wash water, bleed from effluent and precipitation circuits, sumps, membrane cleaning solutions, groundwater sweep solutions, and plant washdown water. 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 injection wells.
2. The injection of fluids with constituent concentrations above the hazardous waste or radioactive waste concentration limits is prohibited. The injectate must meet the permit limits set in Part V, Section D.2.a, Table 14.

L. Tubing-Casing Annulus (TCA) Pressure

The Permittee must ensure that the TCA fluid is maintained under an induced pressure at all times. The tubing-casing annulus pressure must be maintained at a minimum of 100 psi above the injection pressure. If this pressure cannot be maintained, the Permittee must cease injection and inspect the long string 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 must 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 Director 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 the Director prior to conducting the test.
2. The Permittee is required to prepare a plan for running the yearly pressure falloff test. The Permittee must use the EPA guidelines 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 must

be submitted to the Director for review at least 30 days prior to conducting the annual pressure falloff test.

3. The Permittee must 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 must 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 an estimate of the well skin effect and reservoir flow conditions. The report must also compare the test results with the previous year's test data, unless it is the first test performed at that well, and must be prepared by a knowledgeable analyst.

B. Seismicity

The U.S. Geological Survey (USGS) Earthquake Hazards Program operates an email notification service known as the Earthquake Notification Service (ENS), which reports real-time earthquake events for any area specified by the user. Details for the ENS can be found at: **https://earthquake.usgs.gov/ens/.**

The Permittee must subscribe to this service and check daily for notification emails from the service. The Permittee must notify the Director within twenty-four (24) hours of any seismic event measuring 4.5 magnitude (MMI scale) or greater reported within two miles of the permit.

1. If any seismic event of magnitude 4.5 (MMI scale) or greater is reported within two miles of the permit boundary, the Permittee must immediately cease injection.
2. The Director will determine if any structural testing of the facility infrastructure is required before injection resumes.
3. Injection must not resume until the Permittee has obtained approval to recommence injection from the Director.
4. The Permittee must record any seismic event measuring 2.0 magnitude (MMI scale) or greater occurring within fifty miles of the permit boundary and report such events to the Director on a quarterly basis.

C. Ongoing Demonstration of Mechanical Integrity

1. The Permittee must 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 must 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 must 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 must 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 must notify the Director 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 the 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 must be used to demonstrate mechanical integrity. The Permittee must 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 must 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 Director and compatible with the well completion configuration will be used. The pressure to be used will be detailed in proposed procedures supplied with notification of testing.
iv. Install calibrated and 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. For a test to pass, the 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 must conduct a temperature survey or a radioactive tracer survey in accordance with Table 12 to assess the ability of the cement behind the long string casing to prevent movement of injected fluids out of the approved injection formations.

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 must verbally notify the Director within 24 hours (see also Part VII, Section D.11.e of this Permit), and the well must be shut-in within 48 hours unless the Director requires immediate shut-in.

b. Within five days, the Permittee must 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 must 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 must 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 must be representative of the activity or condition being monitored.
b. Injectate samples must be collected at a location between the last treatment process and the injection wellhead.
c. The analytical methods included in Table 14 must be used for injectate sample analysis. Except as may be required by the analytical method(s) shown in Table 14, injectate samples must be analyzed for dissolved fractions. Equivalent methods or total recoverable analysis may be used after prior approval by the Director.
d. Injection pressure, annulus pressure, injection rate, and cumulative injected volumes must be observed and recorded under normal operating conditions, and all parameters must be observed simultaneously to provide a clear depiction of well operation.
e. Pressures are to be measured in pounds per square inch (psi).
f. Fluid volumes are to be measured in standard oilfield barrels (bbl) or gallons (gal).
g. Fluid rates are to be measured in barrels per day (bbl/day) or gallons per minute (gpm).

2. Monitoring Parameters and Frequency

a. Injectate Monitoring

i. The injectate must be monitored as required in Tables 13 and 14.

Table 13. 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 14.	Weekly
Injected Fluid Water Sample Analysis	To determine if the injected fluid meets permit limits in Table 14.	Quarterly and whenever there is a change in the waste stream

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Table 14. Analytes to Monitor in Injectate, Reporting Units, Permit Limits and Analytical Methods

Analyte	Reporting Units	Permit Limit[1]	Analytical Methods
Arsenic	mg/L	5.0	E200.8
Barium	mg/L	100.0	E200.8
Cadmium	mg/L	1.0	E200.8
Chromium	mg/L	5.0	E200.8
pH	pH units	>2 and <12.5	A4500-H B
Lead	mg/L	5.0	E200.8
Lead-210	pCi/L	10	E905.0 Mod.
Mercury	mg/L	0.2	E200.8
Polonium-210	pCi/L	40	RMO-3008
Radium (Total)	pCi/L	60	E903.0/E904.0
Radium-228	pCi/L	60	E904.0
Specific Gravity	Ratio to density of water	1.0113	ASTM D1429-13, SM 2710F
Selenium	mg/L	1.0	E200.8, A3114 B
Silver	mg/L	5.0	E200.8
Sulfate	mg/L	None	A4500-SO4 E; E300.0
TDS	mg/L	None	A2540C
TSS	mg/L	None	EPA 160.2
Thorium-230	pCi/L	100 pCi/L	ATSM D3972-90M
Uranium	mg/L	None	E200.7, E200.8
Uranium (Natural)	pCi/L	300 pCi/L	ATSM D3972-90M

[1] Permit limits for metals and radionuclides are for dissolved fractions.

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 13 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 well field;
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 15 are to be monitored as indicated in Table 15 even during periods when the well is not operating.

3. Monitoring, Recording and Reporting Schedules

The monitoring information listed in Table 15 must be recorded and reported according to the schedules listed below.

Table 15. Monitoring, Recording and Reporting Requirements for Well Operating Parameters

A.	CONTINUOUS MONITORING
MONITOR	Injection Rate (bbl/day or gpm)
	Injection Pressure (psig)
	Cumulative Injected Volume (bbl or gal)
	TCA Pressure (psig)
	Differential Pressure between Injection Pressure and TCA Pressure
	Seismic events greater than or equal to 2.0 (MMI Scale) within a fifty (50) mile radius of the Area Permit boundary, gathered from USGS Earthquake Hazard Program website.
RECORD	Monthly for Cumulative Injected Volume Daily for other parameters Seismic events greater than or equal to 2.0 (MMI Scale) within fifty (50) miles of the project Boundary.
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 active 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 injecting, 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 or gpm)
	Maximum, minimum and average values for Injected Fluid Specific Gravity
	Injected volume for that month (bbl or gal)
	Cumulative volume of injectate for that month (bbl or gal)
	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 14. 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 14. 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 or gpm)
	Monthly average, maximum, and minimum values for Injected Fluid Specific Gravity
	Injected volume for each month during the quarter (bbl or gal)
	Cumulative volume injected since the well began injection operations (bbl or gal)
	Results of injectate fluid analysis in units shown in Table 14.
	Summary of monthly reviews of seismic events greater than or equal to 2.0 (MMI Scale) 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 falloff 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 must 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 must 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 must also compare the test results with previous year's test data, unless it is the first test performed at that well. The Permittee must report any changes to wells within the Area of Review (newly drilled wells, depth changes for existing wells, or alterations to plugged wells) made during the reporting year.

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 must 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 must be due in the following Quarterly Report. A failed MIT must 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 was 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 must 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). The Director may require the Permittee to deliver the records to the Director at the conclusion of the retention period. The Permittee must 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 must notify the Director as to the location where injection well records are maintained. The Permittee must notify the Director within 30 days if this location changes.

F. Quarterly Reports

Following authorization to begin injection, the Permittee must 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 16. 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 16. Reporting Periods and Due Dates for Quarterly Reports

REPORTING QUARTER	REPORTING PERIOD	REPORT DUE TO THE DIRECTOR
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 must be monitored with an automated control system with control switches to notify 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 conditions related to minimum or maximum set points are met, injection operations must cease until the problem is identified and corrected. The system must not be manually restarted by an operator until compliance is verified.
3. The automated control system must operate continuously except in the event of power failure, when all well operation activities must halt.
4. Any alarms, automatic shutdowns due to permit limits and power failures must 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, 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. *Monthly operator inspections*: If fluid injection occurs during the period of any month, a trained operator must physically visit the site to inspect the facility at a minimum frequency of not less than once per month. This inspection must 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.
7. *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 must be required to be observed, recorded and reported when injection takes place.

8. *Annulus tank fluid level measurements*: When the well is not actively being used for injection, one annulus tank fluid level measurement must 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 must be taken, recorded and reported twice per month.
9. When not in use by a trained well operator, offloading connections must be secured and must be locked at the valves leading to wastewater tanks so that access is restricted to trained well operators.
10. 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 must 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.
11. 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 receive 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 must 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:* Automatic shut-downs of the operating well related to Area Permit compliance limits established for well operation must 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 must be automatically shut-in.
    d. *Loss of dial tone:* If the automatic pager cannot get a dial tone for 90 minutes, the well must automatically be shut-in.
    e. *Restart of the well after an automatic shut-in:* Restart of the well after a shut-in related to an 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 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.

PART VI. PLUGGING AND ABANDONMENT

A. Requirement for Director's Approval before Plugging and Abandonment of Class V Deep Injection Wells

The Permittee must not commence plugging and abandonment of a Class V Deep injection well until after receiving written authorization from the Director.

B. Notification of Well Abandonment, Conversion or Closure

The Permittee must 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 must 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 must be plugged in accordance with the Approved Plugging and Abandonment Plan and with 40 CFR § 146.10.
2. Prior to abandonment, the injection well must 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 must 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 must take the following steps prior to abandonment of the Class V wells:

1. Tubing, packer and other downhole apparatus must be removed.
2. A Cement Bond Log test must 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 must be run if it has been more than 6 months since the last test.
5. Each well will be filled with cement from total depth to surface using a minimum of two cementing stages with enough cement to fill calculated volume of inner casing.
6. Within sixty (60) days after plugging, the Permittee must submit a 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 the well being plugged.

F. Plugging and Abandonment Report

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

1. Provide written notice to the Director at the end of 24 months of no injection activity;
2. Demonstrate internal and external mechanical integrity 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 must 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 must 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 must 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; Permit termination, revocation and reissuance, or modification; or 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 must 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 must 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 must 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 must 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 must allow the Director, or an authorized representative, upon the presentation of credentials and other documents as may be required by law, to:

b. Enter 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 must 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 a 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 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 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 must 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 must 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 Inject is issued by the Director for a well, copies of all reports and notifications required by this Permit must be signed and certified in accordance with the requirements under Part VII, D.10 of this permit and must be submitted to the EPA at the following address:

Underground Injection Control Section Chief, 8WD-SDU
1595 Wynkoop Street
Denver, CO 80202-1129

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

UIC Enforcement Coordinator, 8ENF-W-SD
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 must 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 must 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 must 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 must be submitted no later than 30 days following each schedule date.

e. Twenty-four hour reporting. The Permittee must report to the Director within 24 hours 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.

    In addition, a follow up written report must be provided to the Director within five (5) days of the time the Permittee becomes aware of the circumstances. The written submission must 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.

f. Information must 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 the Chief of the Water Enforcement Branch of the Enforcement and Compliance Assurance Division, or by contacting the EPA Region 8 Emergency Operations Center at (303) 293-1788.

g. The written report must 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 must comply with all reporting requirements related to the occurrence of oil spills and chemical releases by contacting the National Response Center at **(800) 424-8802**.

j. Other Noncompliance. The Permittee must 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 must 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 must promptly submit such facts or information to the Director.

PART VIII. FINANCIAL RESPONSIBILITY

A. Method of Providing Financial Responsibility

The permittee, including the transferor of a permit, is required to demonstrate and maintain financial responsibility and resources to close, plug, and abandon the underground injection operation in a manner prescribed by the Director until:

- The well has been plugged and abandoned in accordance with an approved plugging and abandonment plan pursuant to 40 CFR §§ 144.51(o), § 146.10, and § 146.92 of this chapter, and the permittee has submitted a plugging and abandonment report pursuant to 40 CFR § 144.51(p); or
- The well has been converted in compliance with the requirements of 40 CFR §144.51(n); or
- The transferor of a permit has received notice from the Director that the owner or operator receiving transfer of the permit, the new permittee, has demonstrated financial responsibility for the well.

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. a financial test and corporate guarantee.

A surety bond acceptable to the Director must contain wording identical to model language provided to the permittee by the EPA and must 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 must contain wording identical to model language provided to the permittee by the EPA (40 CFR § 144.70) 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 must contain wording identical to model language provided to the permittee by the EPA. Annual reports from the financial institution managing the trust account must be submitted to the Director showing the available account balance.

An independently audited financial test with a corporate guarantee acceptable to the Director must contain wording identical to model language provided to the permittee by the EPA and must demonstrate that the Permittee meets or exceeds certain financial ratios. The permittee must meet the EPA's requirements including, but not limited to, total net worth to be able to use this method. 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. If at any time the permittee does not meet the financial ratios, notice to the EPA must be provided within 90 days and a new demonstration of financial responsibility must be submitted within 120 days.

A standby trust agreement acceptable to the Director must contain wording identical to model language provided to the permittee by the EPA and must accompany any surety bond or letter of credit. Annual reports from the financial institution managing the standby trust account must 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 the Director 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 (1), (2), or (3) 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.

C. Updated Cost Estimate and Timing for Demonstration of Financial Responsibility
An updated cost estimate and a demonstration of financial responsibility must be effective prior to issuance of the Final Permit.

D. 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. COMPLIANCE WITH APPLICABLE FEDERAL LAWS

UIC regulation 40 CFR §144.4, requires the EPA to comply with the following Federal laws when they apply to the issuance of UIC permits. When any of these laws is applicable, its procedures must be followed. When the applicable law requires consideration or adoption of particular permit conditions or requires the denial of a permit, those requirements also must be followed.

A. The National Historic Preservation Act (NHPA) of 1966, 16 U.S.C. 470 et seq.
Section 106 of the NHPA and implementing regulations (36 CFR part 800) require the EPA, before issuing a permit, to adopt measures when feasible to mitigate potential adverse effects of the permitted activity and properties listed or eligible for listing in the National Register of Historic Places. The NHPA's requirements are to be implemented in cooperation with State Historic Preservation Officers and upon notice to, and when appropriate, in consultation with the Advisory Council on Historic Preservation.

The Permittee must comply with the following mitigation measures:

1. The Permittee must abide by the stipulations of the Programmatic Agreement (PA) among U.S. Nuclear Regulatory Commission, U.S. Bureau of Land Managment, South Dakota State Historic Preservation Office, Powertech (USA), Inc. and Advisory Council on Historic Preservation Regarding the Dewey-Burdock In-Situ Recovery Project Located in Custer and Fall River Counties South Dakota (PA) dated March 19, 2014 and adopted by EPA on November 13, 2020.

2. When evaluated properties are NRHP-eligible, avoidance of the properties will be the preferred option. When avoidance is not possible and adverse effects will result, adverse effects will be resolved in accordance with Stipulation 5 of the PA: Resolution of Adverse Effects.

3. The Permittee will ensure employees and/or contractors involved in all phases of the Project are aware of and comply with the requirements of the PA. The Permittee may use measures such as initial orientation training, as well as pre-job briefings to inform employees and contractors of their responsibilities under the PA.

4. In the event a previously unknown cultural resource is discovered during the implementation of the Dewey-Burdock Project, all ground disturbance activities must halt within 150 feet of the area of discovery to avoid or minimize impacts until the property is evaluated for listing on the NRHP by qualified personnel. The Permittee must ensure the steps listed under Stipulation 9 of the PA are followed.

B. The Endangered Species Act, 16 U.S.C. 1531 et seq.

Section 7(a)(2) of the Act and implementing regulations (50 CFR part 402) require the EPA to ensure, in consultation with the Secretary of the Interior or Commerce, that any action authorized by EPA is not likely to jeopardize the continued existence of any endangered or threatened species or result in the destruction or adverse modification of the designated critical habitat of such species.

EPA incorporates the following measures in this UIC permit to avoid, minimize or mitigate any potential impacts to federally-listed species:

1. In the event that construction is planned during the whooping crane and rufa red knot migration seasons or the northern long-eared bat (NLEB) active season, within five days prior to the initiation of any construction activities, a qualified biologist must conduct pre-construction surveys for these species and training for workers to assist with the identification of all listed species during construction and operation.
    a. Whooping crane migration seasons: migrates through South Dakota April 1 to mid-May and mid-September to mid-November.
    b. Rufa red knot migration seasons: migrates through South Dakota mid-April to mid-May and mid-September to October 31.
    c. NLEB active season: mid-April to October 31. The critical pup season is June 1 – July 31.
2. If the whooping crane, the rufa red knot or the northern long-eared bat are sighted within one-half mile of the well sites or associated facilities during construction or operation, the Permittee must contact EPA and the FWS immediately and all construction work within one-half mile of the species' location must cease. Powertech will work with the FWS and a qualified biologist to minimize surface operation activities within one-half mile of the species' location. In coordination with the FWS, work may resume after the species leave the area. For this measure and other ESA-related matters related to this project, the Permittee should contact the FWS and EPA by phone, followed up by an e-mail. The contact points are:
    - The FWS South Dakota Field Office – (605) 224-8693, email: southdakotafieldoffice@fws.gov
    - EPA Region 8 UIC Program – (303) 312-6079, email: minter.douglas@epa.gov
3. Any wells, equipment or buildings associated with the UIC wells authorized under the permit with a fixed location within the project area must be constructed to eliminate openings that look like a small cave or hibernacle to avoid the entrance of any northern long-eared bats.
4. Spills or leaks of chemicals and other pollutants at the UIC well site must be reported to the appropriate regulatory agencies. The procedures of the surface management agency must be followed to contain leaks or spills.
5. If supplemental lighting is used during construction or operation activities, as a protection measure for northern long-eared bat, the lights must be directed and/or sheltered to minimize the amount of light escaping the work or project site.
6. The Permittee must install netting, use bird balls or other acceptable bird deterrent method to prevent birds and bats from accessing all project ponds.
7. Tree removal activities within the project area must be conducted outside of the northern long-eared bat active season (mid-April to October 31). This will minimize impacts to the northern long-eared bat, including to NLEB pups during the critical pup season.

8. During the northern long-eared bat active season (mid-April to October 31), the Permittee must use a motion-activated camera to monitor the Triangle Mine vertical ventilation shaft located at NWNW Section 35, T6S, R1E for 5 days and nights and determine if bats are entering and exiting. If no bats are observed entering or exiting the shaft, the Permittee must investigate the shaft to determine if bats are inside the shaft. If no bats are inside the shaft, the Permittee must cover the entrance to the shaft with finer mesh to prevent bats from entering. If bats are observed in the shaft, the Permittee must work with South Dakota Game, Fish and Parks to evaluate methods for establishing an appropriate buffer zone around the shaft to prevent tree removal or wellfield construction activity. The buffer zone will need to take into account the fact that the shaft is only a few feet away from a road that is used by local residents and may be improved to use as an access road to the Project Site.

C. Record Keeping and Retention Requirements for Endangered Species Act Mitigation

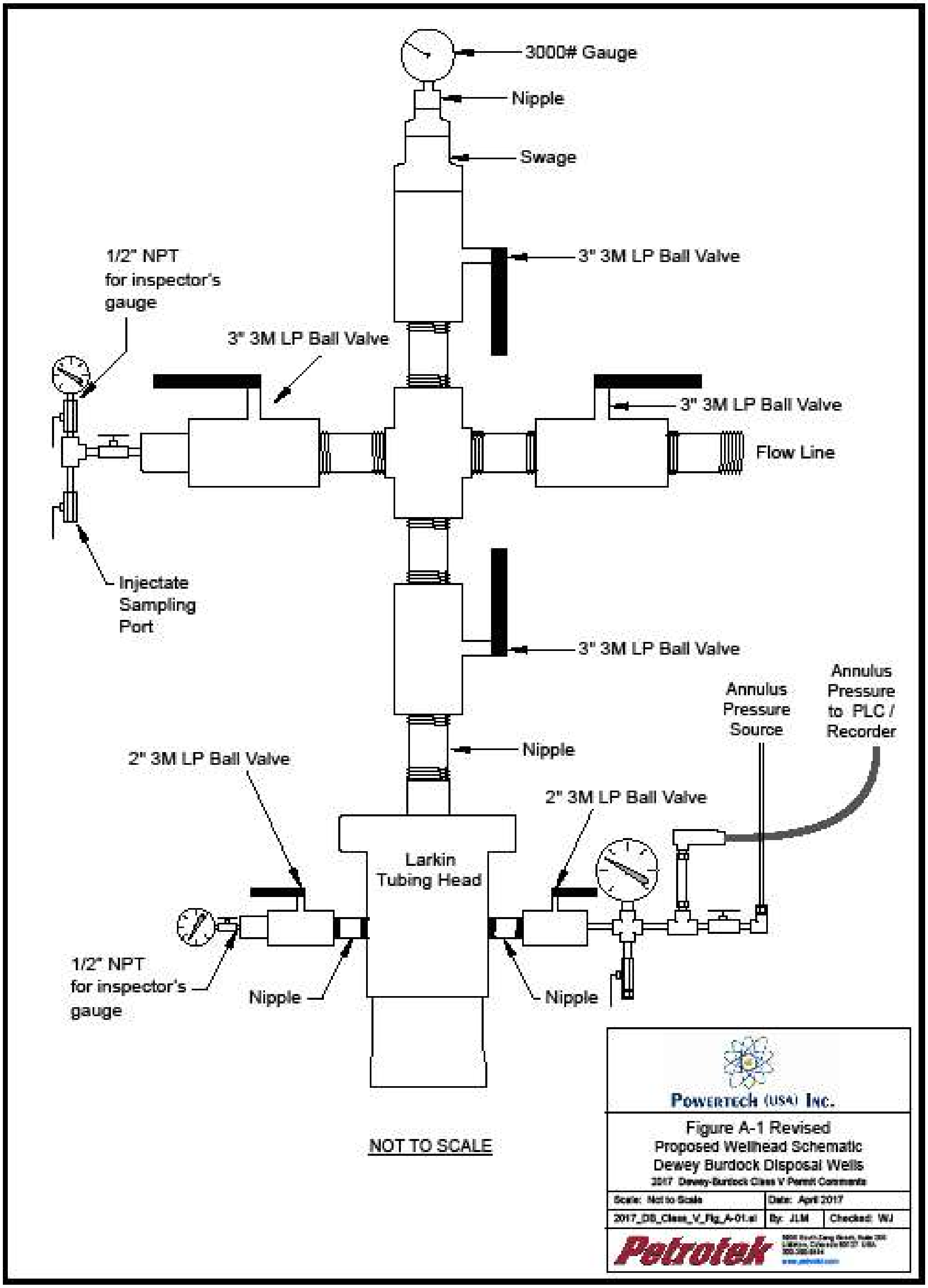
The Permittee must document all activities related to compliance with Part IX, Section B of this Permit. All records of such documentation must be retained and made available for inspection or upon request by the Director. The Permittee must notify the Director as to the location where the records of ESA-related activities are maintained and notify the Director if this location changes. All records must be retained until all wells have been plugged and abandoned after which the owner or operator must deliver the records to the Director or obtain written approval from the Director to discard the records.

PART X. 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

Exhibit 005


3000# Gauge
Nipple
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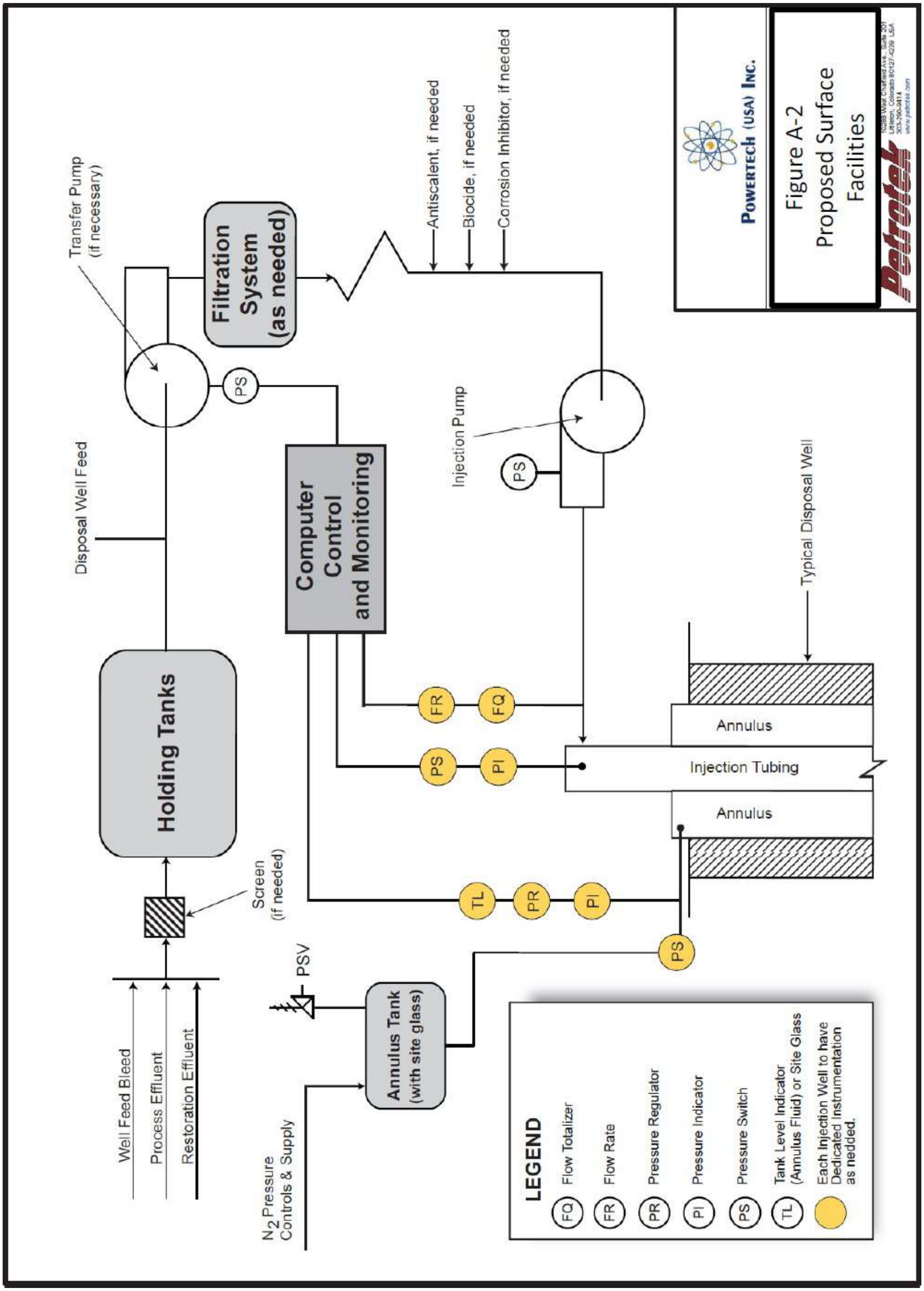
for inspector's
gauge
3" 3M LP Ball Valve
3" 3M LP Ball Valve
Flow Line
Injectate
Sampling
Port
3" 3M LP Ball Valve
Annulus
Pressure
Source
Annulus
Pressure
to PLC /
Recorder
Nipple
2" 3M LP Ball Valve
2" 3M LP Ball Valve
Larkin
Tubing Head
1/2" NPT
for inspector's
gauge
Nipple
Nipple
NOT TO SCALE
POWERTECH (USA) INC.
Figure A-1 Revised
Proposed Wellhead Schematic
Dewey Burdock Disposal Wells
2017 Dewey-Burdock Class V Permit Comments
Scale: Not to Scale
Date: April 2017
2017_DB_Class_V_Fig_A-01.ai
By: JLM
Checked: WJ
Petrotek


Holding Tanks
Screen (if needed)
Well Feed Bleed
Process Effluent
Restoration Effluent
Disposal Well Feed
Transfer Pump (if necessary)
PS
Filtration System (as needed)
Antiscalent, if needed
Biocide, if needed
Corrosion Inhibitor, if needed
Computer Control and Monitoring
Injection Pump
PS
FR
FQ
PS
PI
TL
PR
PI
PS
Annulus
Injection Tubing
Annulus
Typical Disposal Well
PSV
Annulus Tank (with site glass)
N2 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 nedded.
POWERTECH (USA) INC.
Figure A-2
Proposed Surface Facilities
Petrotek