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UNDERGROUND INJECTION CONTROL

Final

CLASS III AREA PERMIT

Area Permit No. SD31231-00000

Class III 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, South Dakota 57735

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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 codified at Title 40 of the Code of Federal Regulations (40 CFR) parts 2, 124, 144, 146, and 147, and according to the terms of this Area Permit,

Powertech (USA) Inc.
P.O. Box 448
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is hereby referred to as the "Permittee."

Because this permit authorizes more than one injection well, it is an Area Permit and subject to the requirements found at 40 CFR § 144.33. The Permittee is allowed to engage in underground injection in accordance with the conditions of this Area Permit. The Permittee 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 law 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.

Issuance of this Area Permit authorizes the construction and operation of the Class III uranium in-situ recovery (ISR) injection wells in the wellfields listed in Table 1 within the Permit Area described below according to the conditions set in this Area Permit.

A. Class III Permit Area Boundary

The Class III injection wells must be located within the Permit Area. As shown in Figure 1, the Class III Permit Area is located in Custer and Fall River Counties, South Dakota. The area included within the Class III Permit Boundary encompasses the portions of Sections 20, 21, 27, 28, 29, 30, 31, 32, 33, 34 and 35 of Township 6 South, Range 1 East in Custer County, South Dakota. The Permit Area also includes the portions of Sections 1, 2, 3, 4, 5, 10, 11, 12, 14 and 15 in Township 7 South, Range 1 East in Fall River County, South Dakota. Figure 2a shows the Dewey Area ore deposit and wellfield locations in Sections 29, 30, 31, 32 and 33 of Township 6 South, Range 1 East. Figure 2b shows the Burdock Area ore deposit and wellfield locations in Sections 34 and 35 of Township 6 South, Range 1 East and Sections 1, 2, 3, 10, 11, 12, 14 and 15 Township 7 South, Range 1 East.

B. Well Locations

This Area Permit authorizes the construction and operation of Class III injection wells in the 14 wellfields located within the Permit Area described above according to the conditions set in this Area Permit. The approximate locations of these fourteen wells fields are listed in Table 1.

Table 1. Wellfields Proposed under the Class III Area Permit

Wellfield Permit Number	Wellfield Name	Section/Township/Range
SD31231-09459	Burdock Wellfield 1	Sections 11 and 12 T7S R1E
SD31231-09460	Burdock Wellfield 2	Sections 10, 11, 14 and 15 T7S R1E
SD31231-09461	Burdock Wellfield 3	Sections 10 and 11 T7S R1E
SD31231-09462	Burdock Wellfield 4	Sections 10 and 11 T7S R1E
SD31231-09463	Burdock Wellfield 5	Sections 3 and 10 T7S R1E
SD31231-09464	Burdock Wellfield 6	Sections 1, 2, 11 and 12 T7S R1E
SD31231-09465	Burdock Wellfield 7	Sections 1 and 2 T7S R1E
SD31231-09466	Burdock Wellfield 8	Section 35 T6S R1E
SD31231-09467	Burdock Wellfield 9	Section 3 T7S R1E
SD31231-09470	Burdock Wellfield 10	Section 34 T6S R1E
SD31231-08351	Dewey Wellfield 1	Sections 29 and 32 T6S R1E
SD31231-09471	Dewey Wellfield 2	Sections 29, 30, 31, 32 and 33 T6S R1E
SD31231-09472	Dewey Wellfield 3	Sections 29, 30, 31 and 32 T6S R1E
SD31231-09473	Dewey Wellfield 4	Sections 29, 30, 31, 32 and 33 T6S R1E

C. Area Permit Information

Permit requirements herein are based on regulations found in 40 CFR parts 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 part 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.

Issue Date 11/24/2020

DARCY OCONNOR Digitally signed by DARCY OCONNOR
Date: 2020.11.24 09:24:30 -07'00'

Effective Date 12/24/2020

Darcy O'Connor, Director*
Water Division

The Area Permit will remain in effect for the life of the facility. The Director must review this Area Permit at least once every 5 years to determine whether it should be modified, revoked and reissued, terminated, or a minor modification made as provided in §§ 144.39, 144.40, and 144.41. This Area Permit may be adopted, modified, revoked and reissued, or terminated if primary enforcement authority for this program is delegated to the State of South Dakota. Upon the effective date of delegation, all reports, notifications, questions and other compliance actions must be directed to the State Program Director or designee.

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).

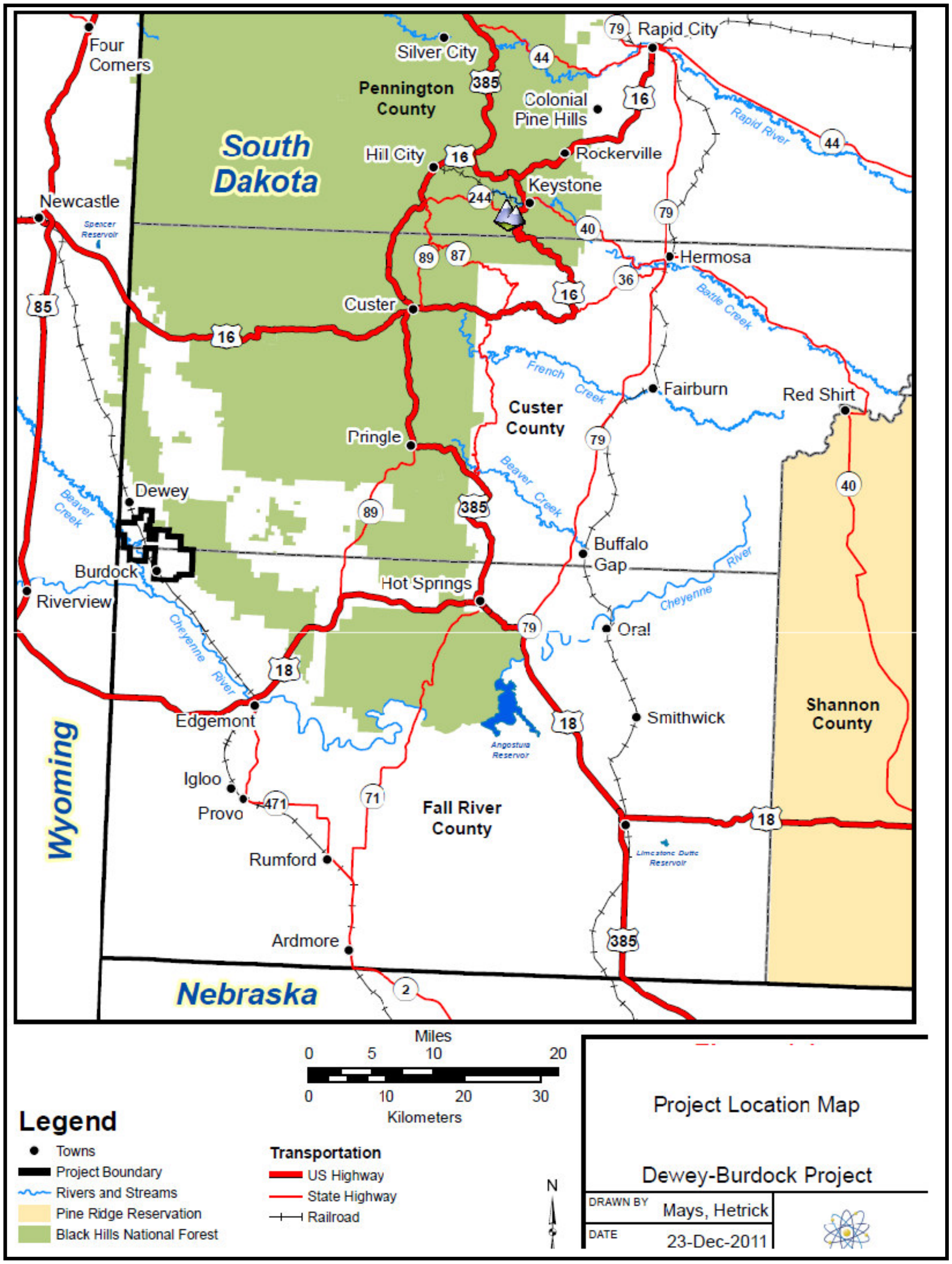


Figure 1. Dewey Burdock Project Location

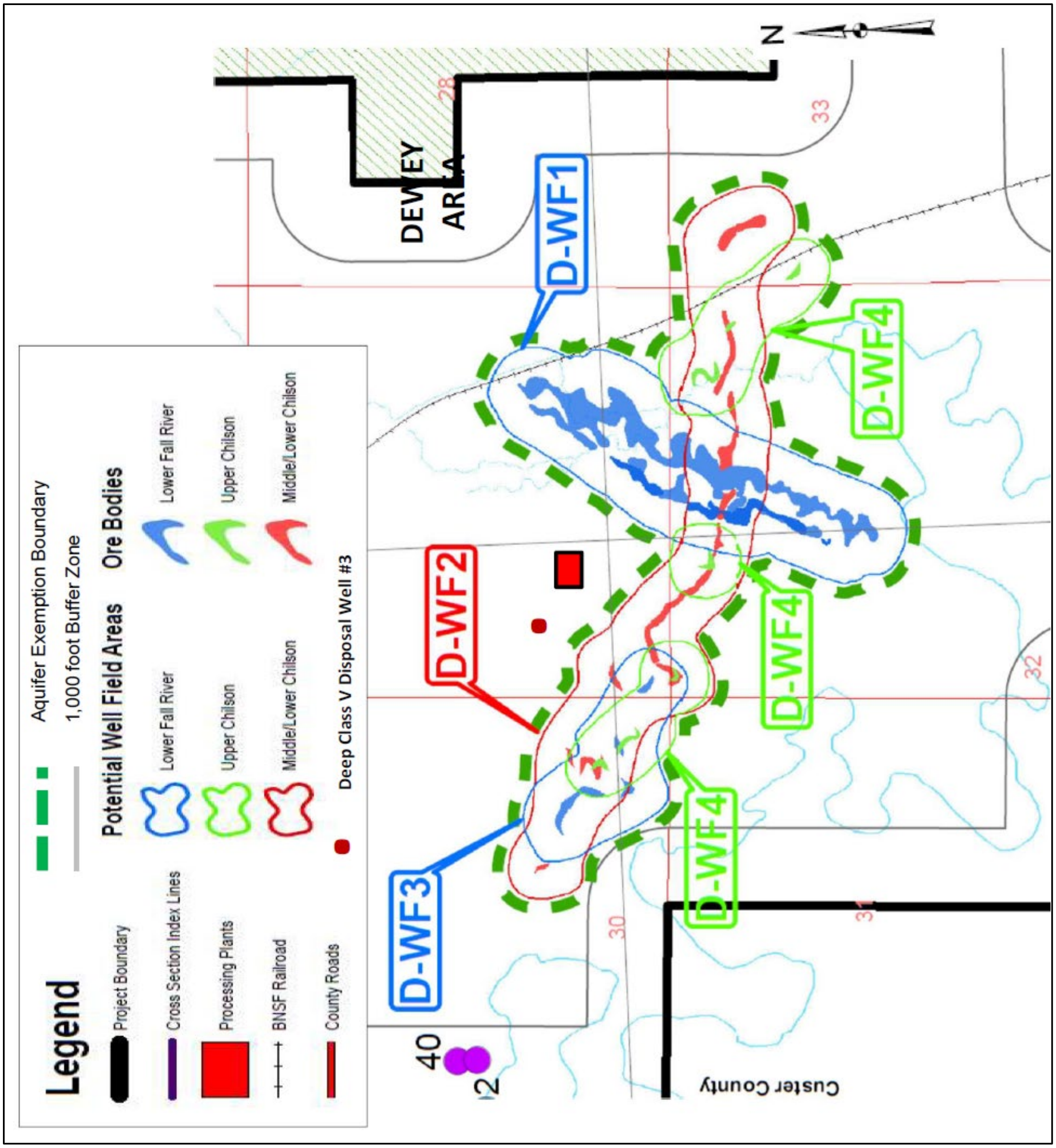


Figure 2a. Locations of the Proposed ISR Wellfields in the Dewey Area.

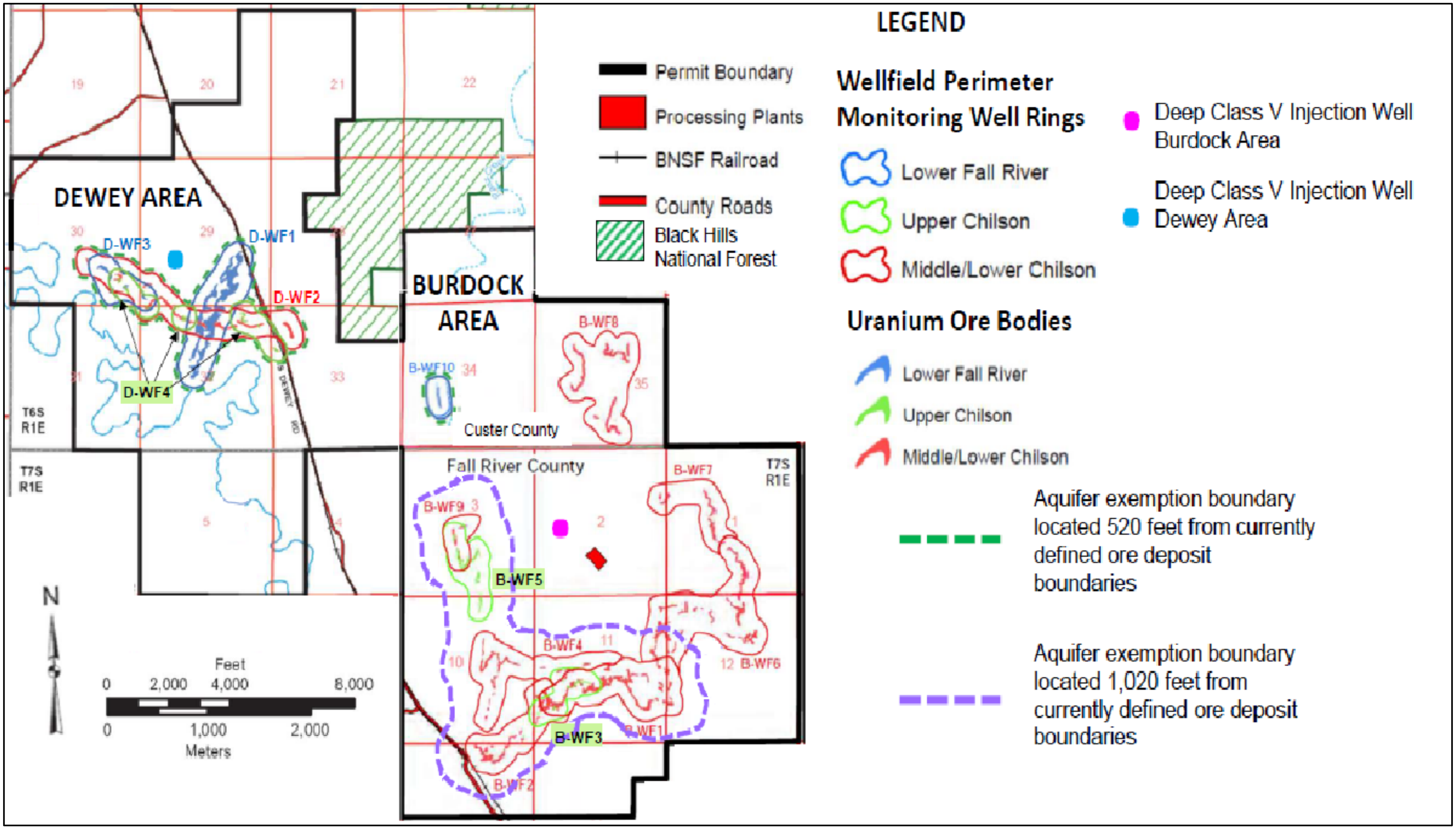


Figure 2b. Locations of the Proposed ISR Wellfields in the Burdock Area.

PART II. WELLFIELD DELINEATION AND PUMP TESTING REQUIREMENTS; AUTHORIZATION TO COMMENCE INJECTION

In order to obtain an Authorization to Commence Injection into wellfield injection wells, wellfield delineation drilling, drillhole logging, and wellfield testing must be performed as described below. A descriptive report interpreting the results of logs and tests must be prepared by a knowledgeable log analyst and submitted to the Director as part of the Injection Authorization Data Package Report described in Section H of this Part.

A. Wellfield Location Restrictions

All wellfields and perimeter monitoring wells must be located within the Permit Area boundary described in Part I. No Class III injection or production wells must be located within the buffer zone located 1,000 feet from the Permit Area boundary in order to establish an operational buffer between the wellfields and the Permit Area boundary. The 1,000-foot buffer zone boundary is shown in Figures 2a and 2b. However, perimeter monitoring wells may be located within the 1,000-foot buffer zone.

B. Drilling and Logging of Wellfield Delineation Drillholes and Pump Testing Wells

The Permittee must conduct the following drilling and logging operations as described below to identify:

(1) the top and bottom depths of the upper and lower confining zones across the wellfield;
(2) the top and bottom depths of the injection interval across the wellfield;
(3) the horizontal extent of injection interval across the wellfield; and
(4) the top and bottom depths of the aquifer units overlying and immediately underlying the confining zones across the wellfield, excluding those below the Morrison Formation.

1. Wellfield Delineation Drilling

a. The Permittee must conduct delineation drilling to delineate the vertical and horizontal extent of the ore deposits targeted for ISR operations within the wellfield and develop a more detailed conceptual hydrogeologic model for wellfield design including:
   i. the horizontal and vertical extent of the proposed injection intervals based on ore deposit locations;
   ii. the presence and thickness of overlying confining zones; and
   iii. the presence and thickness of overlying aquifer units requiring non-injection interval monitoring wells.

b. So as not to compromise the integrity of the Morrison Formation lower confining zone of the Inyan Kara Group, the only delineation drillholes required through and below the Morrison Formation are those for the two new observation wells described in Section C.2.d and Section D.4.c.ii of this Part.

c. If the lower confining zone for the target injection interval is <u>not</u> the Morrison Formation, then delineation drillholes must penetrate below the proposed injection interval through the first underlying aquifer unit to evaluate:
   i. the thickness of the confining zone underlying the target injection interval; and
   ii. the thickness of the first underlying aquifer unit requiring non-injection interval monitoring wells.

d. If the horizontal extent of any uranium ore deposit as determined by wellfield delineation drilling results indicates expansion of the aquifer exemption boundary is needed, beyond the locations shown in Figures 2a and 2b, the Permittee must submit a new aquifer exemption application to the Director for review and approval.

i. If the expanded aquifer exemption boundary encroaches on the capture zone of a private well as calculated by the EPA in the aquifer exemption Record of Decision, the Permittee must perform a new capture zone analysis for potentially impacted private wells using a computer flow model with the capability of simulating the effect of intermittent pumping on the aquifer potentiometric surface.

ii. If the updated capture zone analyses demonstrate the aquifer exemption boundary would encroach on the capture zone of a private well, the Director will not approve exemption of the area that would result in encroachment of the aquifer exemption boundary into a private well capture zone.

iii. The Permittee must obtain the Director's approval of the aquifer exemption before installing any injection and production wells that would result in expansion of the aquifer exemption boundary beyond the locations shown in Figures 2a and 2b.

2. Logging of Wellfield Delineation and Pump Test Well Drillholes

a. The Permittee must log all delineation drillholes and the pump test wells drillholes to determine lithologic horizons and the extent of the ore deposits within the wellfield. The list of logs is included in Table 2.

b. The Permittee must provide this information to the Director in the form of a descriptive narrative containing detailed map(s) and cross sections. The descriptive narrative interpreting the results of logs and tests must be prepared by a knowledgeable log analyst.

c. The Permittee must identify in the report any injection interval perimeter monitoring wells completed in a uranium ore body.

d. The Permittee must submit the report to the Director as part of the Injection Authorization Data Package Report described in Section H of this Part.

Table 2. Delineation and Pump Test Well Drillhole Logging Program

TYPE OF LOG	PURPOSE	DUE DATE
Gamma Ray	To identify ore depth and thickness	Prior to setting well casing
Self Potential	To identify confining zones and aquifer units.	Prior to setting well casing
Resistivity	To identify confining zone depth and thickness	Prior to setting well casing
Physical Geologic Log	To identify lithology and stratigraphy	During drilling

e. The detailed map(s) and cross sections must show:

i. the ore deposit locations color-coded to differentiate the different ore horizons within the injection interval;

ii. the locations of proposed injection/production wells and monitoring wells color-coded to different well type and completion interval;

iii. wellfield cross sections as described in Table 3 with ore deposits, aquifer units and confining zones labeled as applicable;

iv. new delineation drillholes labeled on a separate map and representative drillhole logs included in cross-sections;

v. cross section locations index map; and

vi. a potentiometric surface elevation map for each aquifer intersected by a drillhole or well.

f. If appropriate to better fit the ore deposit configurations, the Permittee may propose alternate wellfield cross section configurations that are different from those described in Table 3 and shown in Appendix A figures, without modification to this Area Permit.

Table 3. Example Cross Section Locations Required for Each Wellfield

Wellfield	Number of Cross Sections
D-WF1	A minimum of 2 cross sections trending NE/SW along trend of Lower Fall River roll fronts delineating Lower Fall River ore deposits and approximately parallel to cross section H – H', as shown in Appendix A, Figure A1. A minimum of 5 cross sections intersecting the first two cross sections, also delineating Lower Fall River ore deposits. The cross sections must clearly identify aquifer units, confining units and Lower Fall River ore deposits.
D-WF2	A minimum of 1 cross section along trend of Middle and/or Lower Chilson roll fronts delineating Middle and/or Lower Chilson ore deposits approximately parallel to cross section J – J' as shown in Appendix A, Figure A1. A minimum of 1 cross section intersecting the first cross section also delineating Middle and/or Lower Chilson ore deposits located in the middle of the west side of D-WF2, as shown in Appendix A, Figure A1. The cross sections must clearly identify aquifer units, confining units and Middle and/or Lower Chilson ore targeted by D-WF2. Also include any intersected ore deposits targeted by D-WF1, D-WF3 and D-WF4 as applicable.
D-WF3	A minimum of 1 cross section along trend of Lower Fall River roll fronts delineating Lower Fall River ore deposits, as shown in Appendix A, Figure A1. The cross section must clearly identify aquifer units, confining units and Lower Fall River ore deposits.
D-WF4	**Western Section:** A minimum of 1 cross section trending approximately NW/SE delineating Upper Chilson ore deposits, as shown in Appendix A, Figure A2. A minimum of 3 approximately NE/SW cross sections intersecting the first cross section also delineating Upper Chilson ore deposits. The cross sections must clearly identify aquifer units, confining units and Upper Chilson ore targeted by the western section of D-WF4. Also include any intersected ore deposits targeted by D-WF3 as applicable.
D-WF4	**Middle Section**: A minimum of 1 cross section trending approximately NW/SE delineating Upper Chilson ore deposits as shown in Appendix A, Figure A2. A minimum of 1 approximately NE/SW cross section intersecting the first cross section also delineating Upper Chilson ore deposits. The cross sections must clearly identify aquifer units, confining units and Upper Chilson ore targeted by the middle section of D-WF4. **Eastern Section:** A minimum of 1 cross section trending approximately NW/SE delineating Upper Chilson ore deposits as shown in Appendix A, Figure A2. A minimum of 2 approximately NE/SW cross sections intersecting the first cross section also delineating Upper Chilson ore deposits. The cross sections must clearly identify aquifer units, confining units and Upper Chilson ore targeted by the eastern section of D-WF4.
B-WF1	A minimum of 1 cross section trending approximately along cross section A – A' in Class III Permit Application Plate 6.12, along trend of and delineating Lower and Middle Chilson ore deposits. A minimum of 4 approximately north/south trending cross sections intersecting cross section A – A' also delineating Lower and Middle Chilson ore deposits. The cross sections must clearly identify aquifer units, confining units and Lower and Middle Chilson ore deposits targeted by B-WF1. Also include any intersected ore deposits targeted by B-WF2, B-WF3, B-WF4 and B-WF6 as applicable.
B-WF2	A minimum of 1 cross section trending approximately along cross section D – D' in Class III Permit Application Plate 6.12, along the trend of and delineating Middle Chilson ore deposits. A minimum of 3 approximately NW/SE trending cross sections intersecting cross section D – D' also delineating Middle Chilson ore deposits. The cross sections must clearly identify aquifer

	units, confining units and Middle Chilson ore deposits targeted by B-WF2. Also include any intersected ore deposits targeted by B-WF1, B-WF3 and B-WF4 as applicable.
B-WF3	A minimum of 1 cross section trending approximately SW/NE along the trend of the Upper Chilson roll fronts and delineating Upper Chilson ore deposits. A minimum of 2 approximately NW/SE trending cross sections intersecting the first cross section. The cross sections must clearly identify aquifer units, confining units and Upper Chilson ore deposits targeted by B-WF3.
B-WF4	A minimum of 1 cross section trending approximately east/west as shown in Appendix A, Figure A3, delineating Middle and/or Lower Chilson ore deposits. A minimum of 5 approximately north-south trending cross sections intersecting the first cross section also delineating Middle and/or Lower Chilson ore deposits. One north-south trending cross section must be approximately parallel to the portion of cross section C – C' in B-WF4. The cross sections must clearly identify aquifer units, confining units and Middle and/or Lower Chilson ore deposits targeted by B-WF4. Also include any intersected ore deposits targeted by B-WF1, B-WF2 and B-WF3 as applicable.
B-WF5	A minimum of the 3 cross sections shown in Appendix A, Figure A4 delineating Upper Chilson ore deposits. The cross sections must clearly identify aquifer units, confining units and Upper Chilson ore deposits targeted by B-WF5.
B-WF6	A minimum of the 7 cross sections in the approximate locations shown in Appendix A, Figure A5 delineating Middle and/or Lower Chilson ore deposits. The cross sections must clearly identify aquifer units, confining units and Middle and/or Lower Chilson ore deposits targeted by B-WF6. Also include any intersected ore deposits targeted by B-WF1 and B-WF7 as applicable.
B-WF7	A minimum of the 1 cross section shown in Appendix A, Figure A5 delineating Middle and/or Lower Chilson ore deposits. The cross sections must clearly identify aquifer units, confining units and Middle and/or Lower Chilson ore deposits targeted by B-WF7.
B-WF8	A minimum of the cross sections shown in Appendix A, Figure A6 delineating Middle and/or Lower Chilson ore deposits. The cross sections must clearly identify aquifer units, confining units and Middle and/or Lower Chilson ore deposits targeted by B-WF8.
B-WF9	A minimum of the 2 cross sections shown in Appendix A, Figure A4 delineating Middle (and Lower, if applicable) Chilson ore deposits. The cross sections must clearly identify aquifer units, confining units and Middle (and Lower, if applicable) Chilson ore deposits targeted by B-WF9. Also include any intersected ore deposits targeted by B-WF5 as applicable.
B-WF10	A minimum of the 2 cross sections shown in Appendix A, Figure A7 delineating Lower Fall River ore deposits. The cross sections must clearly identify aquifer units, confining units and Lower Fall River ore deposits targeted by B-WF10.

3. **Plugging and Abandonment of Wellfield Delineation Drillholes**
   After drilling and logging, all delineation holes that are not used for injection, production or monitoring well construction must be plugged and abandoned in a manner that ensures the integrity of all intersected confining zones remains intact. The integrity of intersected confining zones must be demonstrated by the results of the wellfield pump test required under Part II, Section F.

C. Wellfield Pump Test Design and Pump Test Well Installation

1. The Permittee must design a pump test program for each wellfield to evaluate the hydrogeology and to assess the ability to operate the wellfield and control injection interval fluids.

2. Based on the results of delineation drilling, the Permittee must complete the following wellfield development steps and document each step in the Injection Authorization Data Package Report described in Section H of this Part:

a. Identify the proposed production and injection well locations and approximate screened or open hole intervals.
b. Identify known or suspected locations of exploration drillholes within the wellfield area and adapt pump test design to detect evidence of inter-aquifer communication at the drillhole locations.
c. Design the monitoring well system as required under Part II, Section D below based on production and injection well locations and the refined conceptual geology and hydrogeology provided by the results of wellfield delineation drilling.
d. Install observation wells below the Morrison Formation lower confining zone as described in Table 4. The purpose of the observation wells below the Morrison Formation is to verify that drillholes penetrating the Morrison confining zone have been properly plugged and do not compromise the integrity of the Morrison Formation lower confining zone.
e. Identify all monitoring well locations and screened or open hole intervals.
f. Install all wellfield perimeter monitoring wells.
g. Install all pumping and observation wells to be used during pump testing.
h. Plug and abandon all water supply wells within ¼ mile of the perimeter monitoring well ring or incorporate them into the monitoring system for the wellfield pump test to determine if they have potential to be impacted by ISR operations or to impact ISR operations.

Table 4. Observation Wells for Monitoring the Integrity of the Morrison Formation Lower Confining Zone

Drillholes Penetrating the Morrison Lower Confining Zone within a Wellfield	Location	Wellfield ID	Observation Well Location	Construction of New Well Required?
ELT 14	SESE Section 30 T6S R1E	Dewey WF2	Hydro ID 693 NENW Section 32 T6S R1E	No
DB08-32-11	NENW Section 32 T6S R1E	Dewey WF2		
TRM 38	SENW Section 35 T6S R1E	Burdock WF8	Within Burdock Wellfield 8 between drillholes TRM 38 and DRJ 90.	Yes
DRJ 90	SESE Section 35 T6S R1E	Burdock WF8 Approximately at aquifer exemption boundary		
DB08-1-7	SE Section 1 T7S R1E	Approximately at aquifer exemption boundary of Burdock WF6	Monitor Hydro ID 703 during WF6 pump test, if possible.	No
FBR 31	SESE Section 2 T7S R1E	Burdock WF6 Between aquifer exemption boundary and perimeter monitoring well ring	Between drillholes FBR 31 and DB07-11-31 so it can be used for Burdock WF1 and WF6 pump tests.	Yes
DB07-11-31	NESE Section 11 T7S R1E	Inside Burdock WF1		
DB07-11-18	NESW Section 11 T7S R1E	Inside Burdock WF1	Hydro ID 690 NESW Section 11 T7S R1E	No
DB07-11-16C	NESW Section 11 T7S R1E	Inside Burdock WF1		
RONA 81	SW Section 11 T7S R1E	Inside Burdock WF1		

D. Design and Construction of Wellfield Monitoring Well System

1. Where injection is into an aquifer which contains water with less than 10,000 mg/l Total Dissolved Solids (TDS), monitoring wells must be completed into the injection interval and into any USDWs above the injection interval.

2. Because cementing records for the wellfield injection/production wells must be used to demonstrate the absence of significant fluid movement to fulfill the external mechanical integrity demonstration requirement as described under Part VII, Section D, the monitoring program must be designed to verify the absence of significant fluid movement through the confining zones per 40 CFR § 146.8(c)(4).

3. The monitoring wells must be located in such a fashion as to detect any vertical or horizontal excursion of injection fluids, process by-products, or formation fluids outside the injection interval or wellfield.

4. The wellfield monitoring well system must include:

a. **Wellfield perimeter monitoring well ring:** Monitoring wells must be completed in the injection interval around the wellfield. These wells must be located as specified in Table 5.

b. **Overlying monitoring wells:** Overlying monitoring wells must be completed in all aquifer units overlying the injection interval. These wells must be located as specified in Table 5.

c. **Underlying monitoring wells:**
   i. If the lower confining zone of the injection interval is not the Morrison Formation, then monitoring wells must be completed in the first underlying aquifer unit. These wells must be located as specified in Table 5.
   ii. If the lower confining zone is the Morrison Formation then at least one pump test observation well must be completed in the Unkpapa aquifer below the Morrison Formation near any exploration drillholes penetrating the Morrison Formation to verify that drillholes penetrating the Morrison Formation have not compromised the integrity of the Morrison Formation confining zone. Table 4 lists where the Unkpapa observation wells must be located.

d. **Monitoring wells surrounding possible breaches in confining zones:** If wellfield pump test results indicate a possible breach in a confining unit that cannot be located for corrective action, or corrective action does not completely repair the confining zone breach, then the monitoring well system must be designed to verify that wellfield injection interval fluids will remain within the approved injection interval per 40 CFR § 144.55(b)(4).

e. **Mechanical integrity testing of monitoring wells:** Because the injection interval monitoring wells and any monitoring wells in the first aquifer underlying the injection interval penetrate the injection interval, the Permittee must demonstrate external mechanical integrity for these wells according to Part VII, Section D to verify these wells do not create pathways through the injection interval confining zones for injection interval fluids to move out of the injection interval. The Permittee must plug and abandon any monitoring well for which mechanical integrity cannot be demonstrated. The plugging and abandonment procedures must be conducted according to the requirements under Part XI.

Table 5. Monitoring Well Location Requirements

Type of Monitoring Well	Location Requirements
Injection interval wellfield perimeter monitoring well ring	1) No farther than 400 feet from the outermost wellfield well. 2) Maximum spacing of either 400 feet or spacing that will ensure no greater than a 70 degree angle between adjacent perimeter monitor wells and the nearest wellfield well.
Overlying monitoring wells	1) Monitoring wells completed in first aquifer unit overlying the injection interval: a density of at least one monitoring well per 4 acres of well field area. 2) Monitoring wells completed in subsequent aquifer units overlying the injection interval: a density of at least one well per 8 acres of wellfield area.
Underlying monitoring wells	A density of one well per 4 acres of wellfield area except for aquifers below the Morrison Formation lower confining zone.
Unkpapa Formation observation wells	Unkpapa Formation observation wells are specified in Table 4. Monitoring of Unkpapa Formation observation wells is required only during the wellfield pump tests in order to evaluate the integrity of the Morrison Formation lower confining zone.

E. Formation Testing

1. The Permittee must conduct the formation testing as required in this Section. Table 6 provides a summary of the required testing.

Table 6. Formation Testing Program

Type of Test	Purpose	Timing
Water level measurements in all pump test wells	• To determine potentiometric surfaces of the injection interval and monitored non-injection interval aquifers. • To identify any potential areas of leakage across confining zones due to improperly plugged boreholes or wells, improperly completed wells or naturally occurring features such as fractures.	• After construction of all wellfield pump test wells is completed • The static potentiometric surface for each aquifer has stabilized from well development activities, and • Prior to initiation of pump testing activities.
Sampling and Analysis of Injection Interval and Non-injection Interval Monitoring Wells	• To identify any potential areas of leakage across confining zones due to improperly plugged boreholes or wells or naturally occurring features such as fractures. • To determine concentrations of water quality parameters in Table 8.	Prior to initiation of pump testing activities per Section E.2.b of this Part.
Wellfield pump test	• To demonstrate that control of injectate and injection interval formation fluids is able to be maintained throughout the ISR process and groundwater restoration. • To establish that the production and injection wells are hydraulically connected to the injection interval perimeter monitoring wells. • To evaluate whether the production and injection wells are hydraulically isolated from non-injection interval monitoring wells. • To identify any potential areas of leakage across confining zones due to improperly plugged boreholes or wells, improperly completed wells or naturally occurring features such as fractures.	Prior to receiving written Authorization to Commence Injection from the Director

2. The Permittee must follow these procedures while conducting the formation testing described in Table 6:
   a. **Determination of Aquifer Potentiometric Surfaces**
      i. Once the potentiometric surface has stabilized within each aquifer after well development, static potentiometric surface water levels must be measured in every perimeter and non-injection interval monitoring well and the injection or production wells installed in the wellfield for the wellfield pump test.
      ii. Based on these data points, the Permittee must provide pre-pump test potentiometric surface elevation maps for the injection interval and each non-injection interval aquifer being monitored in order to identify drawdown resulting from the wellfield pump test.
      iii. These water levels must be considered in the determination of the baseline water levels to be

used to evaluate the presence of a wellfield cone of depression signifying hydraulic control of wellfield groundwater during the wellfield pump test and to identify breaches in confining zones for non-injection interval monitoring wells.

iv. Once the potentiometric surface has stabilized within each aquifer after the pump test, static potentiometric water levels must be measured in every perimeter and non-injection interval monitoring well and the injection or production wells installed in the wellfield for the wellfield pump test, prior to the initiation of injection into the wellfield to determine if there have been any changes in water levels not attributable to changes in barometric pressure.

b. Sampling and Analysis of Injection Interval and Non-injection Interval Monitoring Wells

Sampling and analysis of groundwater from all wellfield injection interval and non-injection interval monitoring wells is required to obtain background concentration data for each aquifer. This data is needed to provide pre-operational groundwater quality data for the Conceptual Site Model as required under Part IV, Section A and to provide groundwater quality data in the injection zone downgradient from the wellfield for comparison with the Table B-1 permit limits.

i. After the construction and development of the wellfield perimeter monitoring wells, the wellfield injection interval wells used to determine Commission-approved background and the monitoring wells completed in aquifers above and below (where applicable) the injection interval, the Permittee must collect groundwater samples from each of these wells according to the following procedures:

A) The Permittee shall purge at least three casing volumes prior to sample collection and measure the field parameters listed in Table 7 at the surface as fluid is pumped out of the well to determine when collection of a representative sample is possible.

B) The Permittee must collect a sample only after the field parameters meet the stabilization criteria in Table 7, indicating that the water quality indicator parameters have stabilized.

C) If stabilization is not occurring and the procedure has been strictly followed, then sample collection can take place once three (minimum) to six (maximum) casing volumes have been removed.

D) The Permittee must include stabilization information in the Injection Authorization Data Package Report described in Section H of this Part.[1]

Table 7. Field Parameters to be Monitored and Stabilization Criteria to Meet before Sample Collection

Parameter	Stabilization Criteria
pH	$\pm$ 0.1 pH units
Specific conductance	$\pm$ 3% μmhos/cm at 25 °C
Temperature	$\pm$ 0.5 °C
Dissolved oxygen	$\pm$ 0.3 mg/L

ii. After following the procedures in Part II, Section E.2.b.i above, the Permittee must collect and handle groundwater samples according to the requirements found in 40 CFR part 136 Table II – *Required Containers, Preservation Techniques, and Holding Times*.

[1] The EPA recommends capturing and storing the groundwater pumped from each perimeter monitoring well (except for any completed in an ore deposit) to use as the injectate for the Step Rate Tests described in Part II, Section J.

iii. The samples must be analyzed for the water quality parameters listed in Table 8 using the analytical methods shown. Equivalent analytical methods may be used after prior approval by the Director.

iv. The Permittee must compare analytical results from samples collected from the downgradient wellfield perimeter monitoring-ring wells for ISR constituents listed in Table B-1 in Appendix B of this Permit. If naturally occurring background concentrations for any constituent exceed the permit limit listed in Table B-1, the Permittee must determine the background concentration to use as the alternate permit limit based on analytical results from the perimeter monitoring wells on the downgradient side of the wellfield.

v. The Permittee must develop a brief report that includes the analytical results and a description of statistical methods used for computing the background concentration for each constituent for which a background concentration is required and include the report in the Injection Authorization Data Package Reports per Part II, Section H.3.x for review and approval.

vi. Requirements related to groundwater sample analysis for radium-228: If radium 228 is not detected in the initial sample from each well radium-228 may be removed from the analyte list for remaining sampling and analysis events. However, if radium-228 is detected in the first sample, it must remain on the analyte list for future samples collected from that well.

Table 8. Water Quality Parameter List

Test Analyte/Parameter	Units	Analytical Method
Physical Properties		
pH*	pH Units	A4500-H B
Total Dissolved Solids (TDS)	mg/L	A2540C
Specific Conductance*	μmhos/cm at 25°C	A2510B or E120.1
Turbidity	nephelometric turbidity units (NTU)	EPA-NERL: 180.1
Field-Measured Parameters		
Temperature**	°C	2014 EPA Region 4 SOP (Temperature)
Dissolved Oxygen**	mg/L	2017 EPA Region 4 SOP (DO)
Common Elements and Ions		
Carbon Dioxide	Convert mg/L to atm	A4500-CO2
Total Organic Carbon	mg/L	415.3, 9060A
Dissolved Organic Carbon	mg/L	415.3, 9060A
Total Alkalinity (as $CaCO_3$)*	mg/L	A2320B
Bicarbonate Alkalinity (as $CaCO_3$)*	mg/L	A2320B (as HCO_3)
Calcium	mg/L	E200.7
Carbonate Alkalinity (as $CaCO_3$)*	mg/L	A2320B
Chloride, Cl	mg/L	A4500-Cl B; E300.0
Magnesium, Mg	mg/L	E200.7
Nitrate, NO_3 (as Nitrogen)	mg/L	E300.0
Potassium, K	mg/L	E200.7
Silica, as SiO_2	mg/L	E200.7
Sodium, Na	mg/L	E200.7
Sulfate, SO_4	mg/L	A4500-SO_4 E; E300.0
Dissolved Metals		

Aluminum, Al	mg/L	E200.7, E200.8, E200.9
Antimony, Sb	mg/L	E200.8
Arsenic, As	mg/L	E200.8
Barium, Ba	mg/L	E200.8
Beryllium, Be	mg/L	E200.8
Boron, B	mg/L	E200.7
Cadmium, Cd	mg/L	E200.8
Chromium, Cr	mg/L	E200.8
Copper, Cu	mg/L	E200.8
Fluoride, F	mg/L	E300.0
Total Iron, Fe	mg/L	E200.7
Ferrous Iron, (Fe^{2+})	mg/L	Titration with Dichromate
Lead, Pb	mg/L	E200.8
Manganese, Mn	mg/L	E200.8
Mercury, Hg	mg/L	E200.8
Molybdenum, Mo	mg/L	E200.8
Nickel, Ni	mg/L	E200.8
Selenium, Se	mg/L	E200.8, A3114 B
Silver, Ag	mg/L	E200.8
Strontium, Sr	mg/L	E200.8
Uranium, U	mg/L	E200.7, E200.8
Thallium, Tl	mg/L	E200.8
Vanadium, V	mg/L	E200.7, E200.8
Zinc, Zn	mg/L	E200.8
Radiological Parameters		
Adjusted Gross Alpha***	pCi/L	E900.0
Gross Beta	mRem/Year	E900.0
Radium, Ra-226	pCi/L	E903.0
Radium, Ra-228	pCi/L	E904.0

All water quality parameters determined by laboratory analysis only, except where indicated.
*Field and Laboratory
**Field only
***Excluding radon and uranium.

F. Wellfield Pump Test Requirements

1. The Permittee must monitor the following wells during the pump test to evaluate the hydrogeology and assess the ability to operate the wellfield and control injection interval fluids:
   a. The wells being pumped,
   b. Monitoring wells within the injection interval,
   c. Injection interval perimeter monitoring wells,
   d. Monitoring wells in the immediately overlying non-injection interval aquifer unit,
   e. Monitoring wells in each subsequently overlying non-injection interval aquifer unit,
   f. Monitoring wells in the alluvium, if present,
   g. Monitoring wells in the immediately underlying non-injection interval aquifer unit,
   h. Any additional wells installed for investigating other hydrogeologic features,
   i. Any other wells within ¼ mile of the wellfield perimeter monitoring well ring, and
   j. Any other wells determined to be necessary by the Director or the Permittee.

2. During each pump test the Permittee must measure and record the following parameters:
   a. instantaneous (gallons per minute) and totalized flow (gallons),
   b. periodic pressure transducer measurements (pounds per square inch),
   c. periodic manual water level depth measurements (inches or tenths of feet and feet),
   d. barometric pressure (millibars) (unless using a gauge transducer that is vented to the atmosphere), and
   e. time (scaled as appropriate).

3. The Permittee must conduct the wellfield pump tests with sufficient iterations and using pumping wells in as many locations within the wellfield as necessary to create drawdown in each injection interval perimeter monitoring well.

4. If any injection interval perimeter monitoring well does not show any water level drawdown (decrease in water level not due to barometric pressure fluctuation), the Permittee must recomplete or replace the well and verify that the recompleted or new well is in hydraulic communication with the wellfield injection interval.

5. The wellfield pump test for Burdock Wellfield 10 must be designed in such a manner as to provide data in order to evaluate the impacts from Triangle Pit water on the operation and groundwater restoration of Burdock Wellfield 10.

G. Additional Requirements to Obtain Approval of Exemption of Inyan Kara Aquifers and Authorization to Commence Injection for Burdock Wellfields 6, 7 and 8

1. Because the Chilson Sandstone downgradient from Burdock Wellfields 6, 7 and 8 has been partially oxidized by native groundwater, the Permittee must evaluate the capacity of the downgradient exempted portion of the Chilson Sandstone to attenuate residual ISR contaminants (Appendix B, Table B-1) in restored wellfield groundwater as they travel downgradient toward the aquifer exemption boundary.

2. To fulfill this requirement the Permittee must:
   a. Develop preliminary Conceptual Site Models for wellfields 6, 7 and 8 by conducting all the sampling and testing required for all wellfields as described under this Part.

   b. In addition, the Permittee must expand the Conceptual Site Model for wellfields 6, 7 and 8 by characterizing the geology, hydrologic properties, and geochemical characteristics and processes as described under Part IV, Section A.

   c. In addition, the Permittee must further expand the Conceptual Site Model for wellfields 6, 7 and 8 by conducting batch sorption testing or other appropriate laboratory and field testing methods to provide site-specific sorption parameters for input into the geochemical model, as specified in Part IV, Section C.

   d. Because preliminary Conceptual Site Models for wellfields 6, 7 and 8 must be developed prior to obtaining approval of the exemption of Inyan Kara aquifers and authorization to commence injection, geochemical conditions representing the restored wellfield may be estimated based on data from similar restored wellfields.

   e. On the basis of data collected under this Part, develop preliminary reactive-transport geochemical models for wellfields 6, 7 and 8 as specified in Part IV, Section B to evaluate the potential for ISR contaminants to cross the aquifer exemption boundary. The Permittee must calibrate the geochemical models using analytical data from field and laboratory testing as specified in Part IV, Section B.5 and conduct uncertainty analysis as specified in Part IV, Section B.6.

f. Submit the Conceptual Site Model and geochemical modeling results to the Director as part of the Injection Authorization Data Package Report for each wellfield, evaluating the potential for ISR contaminants to cross the downgradient aquifer exemption boundary.

3. If, during the wellfield pump tests using a pumping rate simulating production and restoration in Burdock Wellfields 6, 7 or 8, the Chilson aquifer potentiometric surface is drawn down to the point where the proposed injection interval becomes less than fully saturated, the Permittee must develop a 3-D unsaturated groundwater flow model for the area where less than fully saturated conditions are anticipated.
   a. The model must be calibrated to site-specific hydrologic conditions and verified by use of wellfield-specific pump test data.

   b. The model must assess the ability to maintain hydraulic control in the partially saturated injection interval and demonstrate the ability to detect and reverse excursions in the partially saturated injection interval and in the first overlying non-injection interval aquifer.

   c. The model must incorporate the effects of concurrent production and restoration activities in other Burdock wellfields on the Chilson aquifer potentiometric surface in the areas where partially saturated injection intervals are anticipated.

4. The results from the additional requirements for Burdock Wellfields 6, 7 and 8 must be included in the Injection Authorization Data Package Report for each of these respective wellfields.

5. The results from these additional requirements for Burdock Wellfield 6, 7 and 8 must be submitted to the Director as part of the aquifer exemption request.

6. After review of groundwater flow model results, if the Director determines that additional hydrologic testing using pumping and injection is required to verify the groundwater flow model, the Director may issue a Limited Authorization to Inject in order to allow reinjection of groundwater pumped from the field test site pumping well(s) for the purposes of hydrologic testing only.

7. The Director will issue a Limited Authorization to Inject into Burdock Wellfields 6 and 7 only after the aquifer exemption for those two wellfields have been approved according to Section I.3 of this Part.

H. Injection Authorization Data Package Reports

1. An Injection Authorization Data Package Report must be prepared for each wellfield and submitted to the Director for review in order to obtain written Limited Authorization to Inject for each wellfield.

2. The information in this report must become part of the Conceptual Site Model required under Part IV, Section A.

3. Each Injection Authorization Data Package Report must contain a description of all logging and testing procedures required under Part II, Sections B through F (Sections B through G for Burdock Wellfields 6, 7 and 8) and the results of such logs and tests. In summary, each Injection Authorization Data Package Report must contain the following:

a. A descriptive report interpreting the results of logs and tests prepared by a knowledgeable log analyst.

b. A description of the proposed wellfield, including a map delineating the ore deposits, color-coded to differentiate each ore level within the wellfield injection interval.

c. Map(s) showing the proposed production and injection well patterns and locations of all monitoring wells.

d. Map showing all plugged and abandoned exploration drillholes within the wellfield perimeter monitoring ring. Identify any exploration drillholes that had to be replugged.

e. Characterization of faults, fractures, and lithologic variability that might provide preferential flow paths or otherwise affect groundwater flow.

f. Copies of any new or historic drillhole logs annotated to indicate presence of fault, fracture or joint for any drillholes located inside the perimeter monitoring wells ring.

g. Map showing all plugged and abandoned wellfield delineation drillholes within the wellfield perimeter monitoring ring.

h. Wellfield geologic cross section location map and geologic cross sections showing:
   i. the top and bottom depths of the upper and lower confining zones across the wellfield;
   ii. the top and bottom depths of the injection interval across the wellfield; and
   iii. the top and bottom depths of the aquifer units overlying and immediately underlying the confining zones across the wellfield, excluding those below the Morrison Formation.

i. Isopach maps showing the thickness of the injection interval and the first confining zones overlying and underlying the wellfield injection interval.

j. Descriptions of wellfield monitoring wells, including screened or open hole intervals, that will be used to demonstrate control of injectate and injection interval formation fluids throughout the ISR process and groundwater restoration.

k. Description of well construction activities, including well completion reports and mechanical integrity test dates and results. Include the locations and plugging reports for any wells that had to be plugged and abandoned because mechanical integrity could not be demonstrated.

l. The results from the formation testing required under Section E of this Part.

m. Discussion of how pump testing was performed. Include results and conclusions. Include pump testing raw data, drawdown match curves, potentiometric surface maps, water level graphs, drawdown maps and, when appropriate, directional transmissivity data and graphs.

n. Water level drawdown data demonstrating that each well in the injection interval perimeter monitoring well ring is in communication with the wellfield injection and production wells.

o. The report For Burdock Wellfield 10 must include an analysis of impacts from Triangle Pit water on the operation and groundwater restoration of Burdock Wellfield 10.

p. Estimation of wellfield maximum injection pressure calculated using an estimated fracture gradient value in the fracture pressure equation under Part V, Section F.3 of this Permit and depth measurements of the injection interval top from wellfield delineation drilling and logging for the purpose of selecting well casing and piping that meet requirements under Part V, Sections E.2.c and E.3.c.

q. The results of the evaluation of all nearby water supply wells with the potential to be impacted by ISR operations or the potential to interfere with ISR operations and the plan for replacing all wells removed from service.

r. A corrective action plan (as required under Part III) identifying areas where breaches in the overlying or underlying confining zones were detected and describing mitigation measures to prevent the migration of injectate and formation fluids out of the injection interval through identified breaches.

s. A description of any wellfield operational controls designed to contain injectate and injection interval fluids within the injection interval to address breaches in confining zones that cannot be precisely located or for which other types of corrective action cannot be performed successfully and operational controls are the method of corrective action. Include a narrative demonstration that the number and placement of non-injection interval monitoring wells are capable of detecting any loss of hydraulic control in that area per 40 CFR § 144.55(b)(4).

t. Schedule for completing mechanical integrity tests, preparing well completion reports and submitting financial responsibility for all injection and production wells prior to bringing the wells online.

u. Groundwater quality data for wellfield and injection interval perimeter monitoring ring wells. Identify any injection interval perimeter monitoring ring wells located in an ore deposit.

v. Proposed locations for Step Rate Test.

w. Proposed source of fluid that will be injected during the Step Rate Test described in Part II, Section J.1 below.

x. The report required under Part II, Section E.2.b.v that includes the analytical results from Part II, Section E.2.b.iii and a description of statistical methods used for computing the background concentration for each constituent for which a background concentration is required.

4. The Permittee must also include information about wellfield level monitoring locations for collection of injection fluid samples and continuous monitoring of injection and production flow rates and volumes required under Part V, Section J.

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

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

a. In order for the Director to issue a Limited Authorization to Inject only for the purpose of injection to conduct a Step Rate Test for a wellfield, the Injection Authorization Data Package Reports must demonstrate the following:

   i. All requirements under Part II, Section B through F (and Section G for Burdock Wellfields 6, 7 and 8) have been met;

   ii. Hydraulic connection between the production and injection wells and all injection interval perimeter monitoring wells and downgradient compliance wells;

iii. The overlying and underlying confining zones provide vertical confinement of the injection interval;
iv. Calculation of the hydraulic conductivity, storativity, and transmissivity of the injection interval aquifer unit;
v. Evaluation of anisotropy within the injection interval aquifer unit has been conducted;
vi. Corrective action has been performed to the extent that hydraulic control of injection interval fluids will be maintained during ISR activities until the completion of groundwater restoration;
vii. The number and location of monitoring wells meet permit requirements, provide indication of hydraulic control of injection interval fluids and will detect potential excursions;
viii. Wellfield injection and production wells have mechanical integrity, as required under Part VII, Section B.2; and
ix. Analytical results for the proposed injectate to be used for the Step Rate Test for all constituents listed in Table 8.

b. If:
   i. well pump test results indicate the presence of a breach in confinement that the Permittee cannot precisely locate in order to perform corrective action or cannot eliminate through the application of best available technology; and
   ii. the Permittee proposes operational controls and monitoring as the corrective action plan, the Director may require the Permittee to perform groundwater modeling or additional pump testing to demonstrate that the wellfield design and monitoring systems are sufficient to control and detect any potential excursions before issuing any Authorization to Commence Injection.

2. Limited Authorization to Inject

a. The Limited Authorization to Inject document will include specification of the approved fluid that will be injected during the Step Rate Test described in Part II, Section J.1.

b. No injection into Burdock Wellfields 6, 7 and 8 will be authorized until after the Aquifer Exemption of Inyan Kara groundwater in that area has been approved by the Director.

3. Information on Well 16 to Submit to the Director to Obtain Approval of the Exemption of Inyan Kara Aquifers for Burdock Wellfields 6 and 7.

The Permittee must submit documentation to the South Dakota Water Rights Program to reclassify well 16 located in NWSE Section 1, T7S, R1E as a monitoring well. Documentation must include a statement that: 1) well 16 should not be used for human consumption because the groundwater produced from the well exceeds the primary drinking water standards for radium and gross alpha and 2) groundwater radon levels are high enough that indoor use of that groundwater should be avoided.

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

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

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

b. Step Rate Test Results

i. After obtaining the Limited Authorization to Inject for a wellfield, the Permittee must inject only for the purpose of conducting the Step Rate Tests indicated in Table 9.

ii. The Permittee must select a location for conducting the Step Rate Tests that will provide representative fracture gradients for each area and injection interval indicated in Table 9.

iii. The Permittee must use the Step Rate Test guidance document found on the EPA Region 8 UIC Program website: https://www.epa.gov/uic/underground-injection-control-epa-region-8-co-mt-nd-sd-ut-and-wy#guidance

iv. The Permittee must provide information on results from the Step Rate Tests to the Director for evaluation as required under Part II, Section J.

Table 9. Step Rate Tests to be Performed to Determine Fracture Gradient for the Determination of Maximum Allowable Injection Pressure (MAIP)

Area	Injection Interval Formation
Dewey Area	Lower Fall River
Dewey Area	Lower or Middle Chilson Sandstone
Burdock Area	Lower or Middle Chilson Sandstone

J. Step Rate Test and Determination of Fracture Gradient

1. Fracture Pressure Determination

a. The Permittee must run an injection Step Rate Test at a perimeter monitoring well ring well at the locations indicated in Table 9 to determine the site-specific pressure at which fractures form in the injection interval at each testing location.

b. During the Step Rate Test the Permittee must monitor pressure within the injection interval, as well as surface injection pressure.

c. The Step Rate Test results must be submitted to the Director for evaluation.

2. Fracture Gradient Calculation

After the site-specific fracture pressure for the injection interval has been determined based on the Step Rate Test results, the fracture gradient must be calculated according to the following formula:

$$fg=FP/d$$

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

3. Loss in Pressure due to Friction

a. There may be a pressure loss due to friction between the injectate and the injection tubing.

b. During the Step Rate Test, if the pressure measured at the injection interval sensor is less than the pressure measured at the surface gauge plus the pressure from the weight of the injectate in the injection tubing, this is the pressure loss due to friction.

c. This pressure loss due to friction may be calculated and added back into the MAIP calculated under Part V, Section F.4.

K. Plugging and Abandonment of Wellfield Wells

If evaluation of the Injection Authorization Data Package Reports as described under Section I of this Part indicate the hydrogeologic conditions are not conducive to the in-situ recovery of uranium, the Director will not issue Authorization to Commence Injection and the Permittee must plug and abandon all wellfield wells according to the requirements under Part XI of this Area Permit.

PART III. CORRECTIVE ACTION

Corrective action requirements are as follows.

A. Water Supply Wells near Wellfields

1. All water supply wells located within the wellfield and within ¼ mile of the wellfield must either be plugged and abandoned or monitored during the wellfield pump test to determine if they have potential to be impacted by ISR operations or to impact ISR operations.

2. If wellfield pump test results demonstrate that a water supply well causes no breach in a confining zone, the Permittee may continue to use the well for monitoring.

3. The Permittee must notify the well owner in writing prior to removing any well from private use and work with the well owner to determine whether a replacement well or alternate water supply is more appropriate.

4. The Permittee must install locking wellhead covers on private wells under the Permittee's control within the Project Area to ensure that only the Permittee and authorized representatives have access to these wells.

B. Wellfield Delineation Drilling and Pump Testing

If the more detailed hydrogeologic evaluation during the delineation drilling or wellfield-scale pump testing prior to the development of each wellfield indicates a breach in a confining zone that could serve as a potential pathway for groundwater movement through an unplugged or improperly plugged drillhole, a well or a natural geologic structure:

1. The Permittee must attempt to determine the location of the feature causing the breach using best available technology and best professional practices.

2. If the feature can be located and is man-made, then corrective action must be performed to repair the breach in confinement.

3. If the feature is a naturally occurring geologic structure or if the feature cannot be located precisely enough to conduct corrective action or cannot be repaired, then wellfield operational controls must be designed to contain injection interval fluids to the injection interval.

4. When features causing a breach cannot be precisely located or corrective action cannot be successfully performed and operational controls are the method of corrective action, the Permittee must demonstrate that the number and placement of non-injection interval monitoring wells are capable of detecting any loss of hydraulic control in that area per 40 CFR § 144.55(b)(4).

5. Demonstration of the effectiveness of the monitoring system may include additional pump testing or groundwater modeling as determined by the Director after the evaluation of the wellfield Injection Authorization Data Package Report.

C. ISR Operations

1. If vertical excursion cannot be controlled in the area around a breach that cannot be located or remediated with corrective action because operational controls are not effective, the Permittee must be prohibited from injection activity in this location.
2. The Permittee must remediate any vertical excursions that have occurred in the area around a breach that cannot be located or remediated.
3. Excursion monitoring must continue in the area where around a breach that cannot be located or remediated with corrective action even though there is no longer any injection activity occurring.

D. Documentation of Corrective Action

1. The Permittee must document all corrective action activities performed according to the requirements under Part III Sections A and B and include the information in the Injection Authorization Data Package Report for each wellfield as described in Part II, Section H.3.r.
2. The Injection Authorization Data Package Report must also include a description of corrective action implementation and completion status.

PART IV. REQUIREMENTS FOR DEVELOPMENT OF A CONCEPTUAL SITE MODEL AND REACTIVE TRANSPORT GEOCHEMICAL MODELING

A. Development of a Conceptual Site Model

The Permittee must develop a Conceptual Site Model (CSM) for the purpose of supporting reactive transport geochemical modeling to evaluate the potential for ISR contaminants to cross the aquifer exemption boundary. The constituents considered to be ISR contaminants under this Area Permit are listed in Appendix B, Table B-1. Development of the CSM will include the information already available in the Class III Permit Application, the information required under Part II, Section H for each wellfield as part of the Injection Authorization Data Package Reports, and additional information required for geochemical modeling described in this Part. A complete representation of the geology, hydrologic properties, and geochemical characteristics and processes for each wellfield is necessary to minimize uncertainty of model predictions concerning the potential for ISR contaminants to cross the aquifer exemption boundary.

This information will become part of the Wellfield Closure Plan for all ISR wellfields. With the exception of the preliminary CSMs developed for Burdock wellfields 6, 7, and 8 under Part II Section G, a CSM is not required as part of the Injection Authorization Data Package Report unless site-specific data indicate oxidizing conditions downgradient from the wellfield.

1. **The extent of the CSM for geochemical modeling must encompass an area sufficient to characterize flow paths across each wellfield injection interval, including:**
   a. Upgradient of wellfields,
   b. Within wellfields,
   c. Downgradient of wellfields within the aquifer exemption boundary, and

d. Margin beyond the downgradient aquifer-exemption boundary sufficient to protect USDWs.

2. The Permittee must include the following information in the CSM:

a. Geology

i. Maps indicating the locations of ore bodies.
ii. Contour maps indicating the structure of each injection interval across the Dewey and Burdock Areas.
iii. A wellfield geologic cross section location map and geologic cross sections showing:
   A) Locations of ore bodies;
   B) Top and bottom depths of the injection interval across the wellfield, including localized confining layers within the interval;
   C) Top and bottom depths of the upper and lower confining zones across the wellfield; and
   D) Top and bottom depths of the aquifer units overlying and immediately underlying the confining zones across the wellfield, excluding those below the Morrison Formation.
iv. Isopach maps showing the thickness of each injection interval and the first confining zones overlying and underlying the wellfield injection interval.
v. Characterization of localized confining layers that could affect groundwater flow paths and transport of ISR contaminants toward the aquifer exemption boundary.
vi. Characterization of faults, fractures, and lithologic variability that might provide pathways for preferential flow or otherwise affect groundwater flow.

b. Hydrologic Properties

For each injection interval, the CSM must include site-specific data to assess:

i. Aquifer hydraulic conductivity, transmissivity, and storativity;
ii. Aquifer porosity;
iii. Aquifer heterogeneity and anisotropy;
iv. Potentiometric surface representing static conditions prior to injection activities;
v. Potentiometric surface representing stabilized post-restoration conditions;
vi. Groundwater velocities; and
vii. Aquifer confinement and hydraulic connection to overlying and underlying aquifers.

c. Geochemical Characteristics

Because results of reactive transport modeling are sensitive to geochemical input parameters, site-specific characterization of aquifer geochemistry is required.

i. Characterization of aqueous geochemistry for the CSM must include analysis of the following:
   A) Groundwater representing background conditions within, upgradient, and downgradient of each wellfield for water-quality parameters listed in Table 8;
   B) Injection fluids for analytes listed in Table 15; and
   C) Groundwater representing post-restoration stability conditions within each wellfield for parameters listed in Table 8.

ii. Characterization of solid-phase geochemistry must include evaluation of the following:

   A) Quantitative mineralogy representative of lithologic variations within injection intervals, particularly with respect to minerals that can have a substantial effect on uranium mobility, including but not limited to calcite, clay minerals, hematite, iron oxyhydroxides, and pyrite/marcasite.

B) Petrologic and mineralogic characteristics that can affect geochemical properties, such as bulk density, grain size, cementation, overgrowths, and nodules.

C) Presence of metals listed in Appendix B, Table B-1 for which solubility and transport may be affected by geochemical conditions of the background aquifer or restored wellfield; and

D) Content of organic carbon.

iii. Areas where groundwater geochemistry and mineralogical characteristics of the aquifer solids indicate reduced or oxidized conditions must be delineated.

d. Geochemical Processes

i. To ensure important geochemical processes at the Dewey-Burdock site are represented, the CSM must include evaluation of the following interactions between fluids and solids in each injection interval:

A) Interactions between native groundwater and aquifer solids under background pre-mining conditions.

B) Interactions between upgradient groundwater and the aquifer in the wellfield after restoration is completed.

C) Interactions between restored groundwater in the wellfield and the aquifer downgradient of the wellfield.

D) Interactions between upgradient groundwater and the aquifer downgradient of the wellfield after the groundwater has passed through the restored zone.

ii. The following geochemical processes must also be evaluated in the CSM:

A) Effect of aqueous uranyl-carbonate complexes and calcium-carbonate-uranyl complexes on uranium mobility.

B) Desorption of uranium and other metals due to pH and other changes in groundwater geochemistry.

C) Dissolution or precipitation of calcite due to changes in pH, alkalinity, and calcium content.

D) The immobilization of uranium by reduction of U(VI) to U(IV) and formation of low solubility uranium minerals (uraninite, pitchblende, and coffinite).

E) Stagnant groundwater zones and dual-domain porosity.

F) Potential effects of residual lixiviant.

G) The possibility that ore-zone uranium was hydraulically bypassed by lixiviant during ISR activities because of lithologic variability and could be mobilized by post-restoration groundwater.

iii. In addition, the following geochemical processes must be evaluated in the CSM for Burdock Wellfields 6, 7, and 8 and any other wellfield found to have downgradient oxidized aquifer conditions:

A) Adsorption of uranium and other metals onto iron and manganese oxyhydroxides or clay minerals.

B) Release of uranium and other metals from iron and manganese oxyhydroxides under reductive dissolution.

C) The role of competition for sorption sites from other cations and metals in controlling the retardation of uranium and other metals.

D) The effect of cation exchange processes.

iv. The following conditions and geochemical processes also must be included in the CSM for a wellfield if the Director determines that, based on site conditions, they are important to accurately simulate the transport of ISR contaminants toward the aquifer exemption boundary:

A) Redox changes driven by localized heterogeneity in organic carbon;

B) Kinetic rates and rate-limited sorption;

C) Hydrodynamic dispersion;

D) Potential for uranium and other metals to be sorbed onto and transported by colloid-size particles;

E) Potential for microbial populations to affect geochemical conditions after restoration;

F) Residual effects of excursions; and

G) Other important geochemical processes identified during data collection and site characterization.

3. The Conceptual Site Model must meet the following criteria:

a. The CSM is based on data collected from wellfield characterization activities as well as data collected specifically to evaluate geochemical conditions and processes that will affect uranium mobility.

b. Data representing background groundwater chemistry and aquifer solid phases are collected from within the proposed wellfield as well as upgradient and downgradient of the wellfield as specified in Part IV, Sections C.1.a and C.2 and Part II, Section E.2.b.i.

c. Data representing groundwater chemistry and aquifer solid phases within the restored wellfield, including areas having high residual ISR contaminant concentrations, are collected as specified in Part IV, Sections C.1.b and C.2 and Part IX, Section B.4.

d. The CSM incorporates hydrogeologic characteristics representative of the injection interval aquifer.

e. The CSM is based on site-specific data from groundwater samples, core analyses, laboratory batch and/or column tests, well logs, and other appropriate laboratory and field tests, as specified in Part IV, Section C.

f. The areal extent of the CSM encompasses areas upgradient of wellfields, within wellfields, and downgradient of wellfields, including a margin beyond the aquifer exemption boundary sufficient to protect USDWs. The vertical extent of the CSM includes all injection intervals, the first overlying and underlying confining zones and aquifer units overlying and immediately underlying the confining zones, excluding those below the Morrison Formation.

g. Sufficient data were collected to characterize heterogeneity and statistically represent variations in geologic, hydrologic, and geochemical conditions of each injection interval.

h. Geochemical data spatially represent the sites necessary to identify and characterize geochemical processes at the site.

i. Groundwater geochemical data are collected according to applicable procedures described in Part II, Section E.2.b and Part IX, Section A.

j. Groundwater samples are analyzed for the analytes and parameters listed in Table 8 using the specified analytical method or equivalent method with Director's approval. Water-quality analyses have a charge imbalance less than 10 percent.
k. Mineral assemblages and solid phases are quantitatively evaluated and laboratory tests to determine sorption properties are conducted in accordance with Part IV, Section C.3.
l. Data gaps, inconsistencies, and limitations are identified and their potential impact on model results are assessed.

4. The Permittee must update the CSM when any of the following occur:

a. The Permittee identifies data gaps or uncertainty concerning geology, hydrologic properties, geochemical characteristics, and/or geochemical processes that could affect mobility and transport of uranium and other metals at the Dewey-Burdock site. When this occurs, the Director may require the Permittee to collect additional data or develop alternative CSMs to accommodate and characterize the areas of uncertainty as they relate to evaluating the potential for ISR contaminants to cross the aquifer exemption boundary. This could include, but is not limited to, characterizing geochemical processes listed under Section A.2.d.iv of this Part.
b. Upon the identification of an expanding excursion plume as required under Part IX, Section C.5.d.
c. Burdock Wellfields 6, 7, and 8 are developed. If the Director approves the exemption of Inyan Kara aquifers in these wellfield areas and authorizes injection into these wellfields, the preliminary CSMs developed under Part II, Section G must be updated with site-specific groundwater and solid-phase data collected from the restored wellfield prior to conducting final geochemical modeling for the Wellfield Closure Plan.

B. Reactive Transport Geochemical Modeling

The Permittee must conduct reactive transport geochemical modeling for each wellfield to evaluate the potential for ISR contaminants to cross the aquifer exemption boundary. Constituents considered to be ISR contaminants under this Area Permit are listed in Appendix B, Table B-1. The objective of the modeling is to demonstrate that the concentration of each ISR contaminant will not exceed the permit limit (or alternate permit limit, if applicable) at the aquifer exemption boundary within the injection-interval aquifer. Modeling results will become part of the Wellfield Closure Plan for all ISR wellfields.

1. The Permittee must incorporate the following scenarios into the geochemical modeling:

a. Evaluation of the restored wellfield's capacity to maintain long-term geochemical stability as upgradient groundwater flows across the wellfield.
b. Assessment of the downgradient portion of the exempted aquifer to attenuate residual contamination as restored groundwater flows out of the wellfield.
c. Where another wellfield is located upgradient adjacent to the wellfield, chemistry of the post-restoration groundwater within the upgradient wellfield must be included in the modeling scenarios.

2. Predictive modeling of contaminant transport for each wellfield closure

The Permittee must conduct predictive modeling of contaminant transport for each wellfield closure. The preliminary modeling conducted under Part II Section G as part of the Injection Authorization Data Package for wellfields 6, 7, and 8 must be updated on the basis of data collected for the full CSM developed under Part IV.A, including characterization of the restored wellfield, if the Director approves the exemption of Inyan Kara aquifers in these wellfield areas and authorizes injection into these wellfields.

Predictive modeling for each wellfield must include the following:

a. Reactive transport of post-restoration fluids in the wellfield flowing downgradient toward the aquifer exemption boundary;
b. Reactive transport of upgradient groundwater, including from any adjacent wellfields, into the restored wellfield and subsequently farther downgradient toward the aquifer exemption boundary.

3. Model Specifications

a. The models must be constructed based on the CSM described in Part IV, Section A of this permit and requirements specified in Part IV, Section C.
b. The areal extent of the model domain may vary by wellfield, but must incorporate an area that enables simulation of groundwater flow and geochemical processes from upgradient, through the wellfield, and into the area downgradient from the wellfield, including a margin beyond the aquifer exemption boundary sufficient to demonstrate protection of USDWs.
c. The vertical model extent must represent the full injection interval aquifer. In the event that a vertical excursion out of the injection interval is indicated, the model must also include the excursion interval and confining zones.
d. Cell size and spacing in the model domain must be based on groundwater flow velocity and allow for adequate resolution when simulating geochemical processes along flow paths.
e. Reactive transport models may be 3-D, 2-D, or 1-D as needed to represent conditions across the site. If 2-D or 1-D modeling is used, enough simulations must be used to represent site heterogeneity, including areas of high residual concentrations, within each injection interval and flow-path variations through each wellfield based on site-specific data.
f. Geochemical boundary conditions of the model must:
    i. Accurately represent mineral phases, gas partial pressures, and concentrations of constituents in groundwater;
    ii. Be based on site-specific field and laboratory data;
    iii. Represent the oxidation states of the mineral assemblages and saturation indices of the groundwater; and
    iv. Not overly constrain model results to produce unrealistic modeling predictions.
g. Model runs must cover a sufficient timeframe to reestablish natural groundwater flow conditions and simulate the transport of ISR contaminants to the aquifer exemption boundary, including the potential rebound of uranium and other metals.
h. Modeling must include ISR contaminants listed in Appendix B, Table B-1. Modeling is not required for ISR contaminants that have been shown by monitoring under Part IX, Section B.3.a to have concentrations at or below the permit limit or the groundwater background concentration at all injection interval wells within the wellfield after completing ISR operations and prior to initiating wellfield restoration.

4. Equilibrium, Kinetic, and Sorption Data

a. The thermodynamic data used by the modeling program must contain up-to-date information available on uranium and other constituents of concern at the site, such as, but not limited to, those presented by Guillaumont et al. (2003), Dong and Brooks (2006), Mahoney et al. (2009), and Mühr-Ebert et al. (2019).
b. Where important reactions or kinetics (if simulated) are not included in the model's thermodynamic database, the databases must be augmented with site-specific data from laboratory and field studies as described in Part IV, Section C.

c. The activity-coefficient model used to simulate reactions must be chosen based on the range of ionic strengths and constituents measured in background groundwater and the post-restoration groundwater within the wellfield.

5. Model calibration

To reduce model prediction uncertainty concerning the long-term fate and transport of ISR contamination, the model must be calibrated as follows:

a. The model must be calibrated by using site-specific field and laboratory data as described by Part IV, Section C.
b. Prior to conducting predictive simulations, the model must be calibrated to background hydrogeologic and geochemical conditions at the site to verify conditions at the field scale.
    i. The model must have the same domain (2-D or 3-D model) or flow path (1-D model) to be subsequently used for predictive simulations.
    ii. Model calibration must consist of adjusting model input parameters over a representative range of values based on site-specific data to match the distribution of groundwater chemistry observed from upgradient to downgradient across the area where the wellfield will be located.
c. Other calibration approaches may be used with Director's approval.

d. Where the Director finds that model calibration indicates an unsatisfactory match to observed site-specific hydrologic or geochemical conditions, the Director may require that additional data be collected, and/or the model be revised to provide a better match to the observations. This could include, but is not limited to, simulating geochemical processes listed under Part IV, Section A.2.d.iv.

6. Uncertainty Analysis

Uncertainty analysis must attempt to quantify prediction uncertainty concerning the long-term fate and transport of ISR contamination at the Dewey-Burdock site. This may include techniques such as forward Monte Carlo simulations, inverse modeling, or other methods but at a minimum must include the following:

a. Sensitivity analyses for pH, pE, alkalinity, and the quantity or concentration of calcite, pyrite, dissolved oxygen, carbon-dioxide, and organic-carbon, as well as other parameters found to have a substantial effect on simulation results. In addition, for Burdock Wellfields 6, 7, and 8 and any other wellfield found to have downgradient oxidized aquifer conditions, sensitivity analyses must be conducted for sorption parameters based on results of laboratory testing described under Part IV, Section C.3.d.
b. Quantitative evaluation of prediction uncertainty by conducting multiple simulations using a range of hydrologic and geochemical values representative of observed conditions across the site to indicate the potential range of outcomes.
    i. Predictive ranges must include measurement and analytical uncertainties, system heterogeneity, and calibration uncertainty.
    ii. Predictions must be reported with a confidence interval of 90 percent or greater based on the statistical distribution (probability density function) of observed model input parameter values.
c. For model assumptions having high uncertainty, the Director may require that alternative CSMs be generated to explore the effects on reactive transport geochemical model output.

C. Groundwater Sampling, Core Collection, Laboratory Testing, and Field Investigations to Support the Conceptual Site Model and Geochemical Modeling

The Permittee must develop the CSM under Part IV, Section A and conduct geochemical modeling specified under Part IV, Section B based on site-specific data from groundwater sampling, core collection, laboratory testing, and/or other field investigations to minimize uncertainty concerning the potential for ISR contaminants to cross the aquifer exemption boundary. Data collected under this Part must be used in the development of the CSM described under Part IV.A and will become part of the Wellfield Closure Plan for all ISR wellfields.

1. Groundwater Sampling

a. Groundwater samples must be collected from wellfield perimeter monitoring wells, the wellfield injection interval wells used to determine Commission-approved background, and the monitoring wells completed in aquifers above and below (where applicable) the injection interval in accordance with Part II, Section E.2.b.i.
b. Once post-restoration stability monitoring begins, the Permittee must conduct quarterly water quality monitoring for parameters listed in Table 8 in accordance with Part IX, Section B.4, including additional evaluations of any areas with high contaminant concentrations. Final constituent concentrations at the end of the stability-monitoring phase may be used to represent the groundwater chemistry of the restored wellfield.
c. Upon the identification and verification of an expanding excursion plume as described under Part IX, Sections C.4.e and C.4.f, the Permittee must collect a groundwater sample from the impacted well(s) and analyze the sample(s) for the water quality parameters in Table 8 in accordance with Part IX, Section C.4.g.

2. Core Collection

Core samples must be collected at representative locations within each wellfield and from areas upgradient and downgradient from each wellfield to characterize aquifer solids for the CSM based on site-specific data. Core collected to support the CSM must meet the following requirements:

a. Core must include a sufficient number of samples to adequately characterize both horizontal and vertical heterogeneity with respect to hydrogeology and geochemical conditions within the injection interval but at a minimum must include the following:
    i. Wellfield Core
        A) To characterize background aquifer solid phases, core must be collected from one corehole location per 40 acres of wellfield area or 2 corehole locations, whichever is greater, prior to initiating ISR operations. Core collected for the purpose of meeting this minimum requirement must be collected at or near wells used to determine background groundwater quality.
        B) To characterize aquifer solid phases within the restored wellfield, core must be collected from one corehole location per 40 acres of wellfield area or 2 corehole locations, whichever is greater, after completing the wellfield restoration process. Core collected for the purpose of meeting this minimum requirement must be collected near locations where background core was collected according to Section C.2.a.i.A) above.

ii. Upgradient Core

Core must be collected from the area upgradient of the wellfield based on one corehole location per 2,400 linear feet of wellfield perimeter representing the upgradient side of the wellfield, or 2 corehole locations, whichever is greater. Core collected for the purpose of meeting this minimum requirement must be collected at or near wells used to determine background groundwater quality and must be from locations distributed across the upgradient area.

iii. Downgradient Core

Core must be collected from the area downgradient of the wellfield based on one corehole location per 1,200 linear feet of wellfield perimeter representing the downgradient side of the wellfield, or 4 corehole locations, whichever is greater. Core collected for the purpose of meeting this minimum requirement must be collected at or near wells used to determine background groundwater quality and must be from locations distributed across the downgradient area.

iv. Core Representing Vertical Heterogeneity

A minimum of 3 cores must be collected from the injection interval at each corehole location in the wellfield and in areas upgradient and downgradient from each wellfield. Core intervals should be selected to represent lithologic variability within the injection interval. Lithologic logs, geophysical logs, or other methods may be used to identify lithologic variability and target intervals for coring.

b. Core must have sufficient length to accurately identify mineral assemblages and solid phases in quantities representative of the injection interval.

c. Core must be recovered and preserved in a manner to prevent further oxidation so as to be representative of in-situ geochemical conditions for use in laboratory testing.

d. Core collected as part of site-wide characterization activities prior to wellfield development may be used to represent solid phases for individual wellfields provided it meets location, length, and preservation requirements described in Sections C.2.a. through C.2.c. of this Part.

e. Core may be collected as part of well-drilling operations or collected from independent coreholes as needed to characterize the site.

f. All independent coreholes must, upon completion of coring operations at each corehole, be plugged with bentonite or cement grout in a manner which prevents the movement of fluids into or between USDWs in accordance with 40 CFR § 146.10 and applicable portions of the approved plugging and abandonment plan described under Part XI, Section C.

3. Laboratory Testing

Laboratory testing is needed to constrain geochemical parameters and processes controlling uranium mobility and attenuation and to determine sorption parameters and possible mineral dissolution or precipitation reactions.

a. Laboratory testing must be conducted with site-specific solids from the Dewey-Burdock site and fluids representative of geochemical conditions for the background aquifer and the restored wellfield.

b. Core collected under Part IV, Section C.2 must be quantitatively evaluated to determine mineral assemblages and solid phases present that may affect the transport of ISR contaminants toward the aquifer exemption boundary. At a minimum, core must be analyzed to determine quantities of calcite, clay minerals, hematite, iron oxyhydroxides, pyrite/marcasite, and organic carbon.

c. Analytical methods may include:
   i. Mineral and texture evaluation by thin section, transmitted light microscopy and scanning electron microscopy (SEM), and X-ray diffraction;
   ii. Determination of chemical composition by scanning electron microscope, X-ray spectroscopy, and solids analyses for sulfur and organic carbon; and/or
   iii. Other methods as approved by the Director.

d. For wellfields 6, 7, and 8 and any other wellfield determined to have oxidizing downgradient groundwater conditions, geochemical reduction likely will not be the primary process controlling attenuation of ISR contaminants. Therefore, laboratory testing to determine sorption parameters for uranium and metals listed in Appendix B, Table B-1 is required to provide site-specific data for geochemical modeling.

   i. Batch-sorption tests or column studies may be used as needed to provide data for this purpose.
   ii. Laboratory testing must be conducted using standard methods to be determined by the Permittee and approved by the Director.
   iii. Laboratory testing must include analysis of interactions between:
      A) Restored groundwater and core downgradient from the wellfield;
      B) Background upgradient groundwater and core from the restored wellfield;
      C) Downgradient core and the upgradient groundwater after it has passed through and reacted with the restored wellfield. This can be accomplished by using leachate resulting from interactions between background upgradient groundwater and restored wellfield core in a subsequent batch or column test with core from downgradient of the wellfield.
   iv. Water used for testing purposes must represent the geochemistry of restored wellfield groundwater, background upgradient groundwater, and upgradient groundwater after it has passed through and reacted with the restored wellfield, as applicable to assess interactions described in Part IV, Section C.3.d.iii.
   v. A sufficient number of tests must be conducted to represent the range of solid-phase compositions observed within and downgradient from the wellfield, particularly with respect to iron oxyhydroxides, clay minerals, and organic carbon.
   vi. Laboratory tests must be conducted using a range of concentrations for uranium and metals listed in Table B-1 that bracket potential groundwater concentrations to determine how sorption varies with concentration.
   vii. Batch tests must allow sufficient time for effective equilibrium between water and solid phases to occur. Flow in any column tests must be temporarily halted to evaluate concentration rebound and evaluate whether the column is in equilibrium with the injection fluid.
   viii. Laboratory testing for sorption is not required for ISR contaminants shown by monitoring under Part IX, Section B.3.a to have concentrations at or below the permit limit or the

groundwater background concentration at all injection interval wells within the wellfield after completing ISR operations and prior to initiating wellfield restoration.

4. Field investigations

In addition to monitoring and laboratory testing, other investigations to determine geochemical conditions at the Dewey-Burdock site may need to be conducted with the approval of the Director. These could include:

a. Well logging with specialized equipment;
b. Tracer tests or age dating;
c. Geophysics;
d. Field injection and recovery tests; or
e. Cross-hole testing.

D. Wellfield Closure Plan

The Permittee must submit a Wellfield Closure Plan to the Director for review and approval. The Wellfield Closure Plan must demonstrate that the wellfield closure, including plugging and abandonment of all wellfield injection and production wells, will result in adequate protection of USDWs as required under 40 CFR § 146.10(a)(4). If the Wellfield Closure Plan does not demonstrate adequate protection of USDWs, the Director must prescribe aquifer cleanup and monitoring where deemed necessary and feasible to ensure adequate protection of USDWs to fulfill the requirements under 40 CFR § 146.10(a)(4).

1. Process for Wellfield Closure.

a. After the post-restoration stability phase is completed and the geochemical model has been calibrated, the Permittee must conduct reactive transport modeling to evaluate the long-term geochemical stability of the restored wellfield and the potential for ISR contaminants to cross the aquifer exemption boundary according to Section B of this Part. This must include reactive transport of post-restoration fluids in the wellfield downgradient toward the aquifer exemption boundary and reactive transport of upgradient groundwater into the restored wellfield and subsequently farther downgradient toward the aquifer exemption boundary.
b. Once modeling has been completed, the Permittee must submit the Wellfield Closure Plan to the Director for review and approval prior to wellfield closure.
c. The Permittee must not remove wellfield infrastructure necessary for aquifer remediation until the Director has approved the Wellfield Closure Plan and has determined no additional aquifer cleanup and monitoring is necessary and feasible to ensure adequate protection of USDWs per 40 CFR § 146.10(a)(4).

2. Documentation for the Wellfield Closure Plan must include discussion of the following:

a. Geology, hydrologic properties, and geochemical characterization of the CSM.
b. Components of the CSM that are not well defined.
c. Results of data collected from monitoring, laboratory testing, and field investigations.
d. Analysis and uncertainty of data from monitoring, laboratory testing, or other investigations.
e. Geochemical model structure, domain, and discretization.
f. Geochemical inputs to the model.
g. Processes and reactions represented by the model, including the model's thermodynamic database and any updates or modifications to the database. The Permittee must identify any species or phases

that were not able to be represented well in the geochemical model due either to data gaps in sampling or to limitations in the databases for the geochemical modeling program.

h. Results of reactive transport simulations, including an assessment of the potential for ISR contamination to cross the aquifer exemption boundary. Model results must demonstrate that the concentration of each ISR contaminant listed in Appendix B, Table B-1 will at no time exceed the permit limit (or alternate permit limit, if applicable) at the aquifer exemption boundary within the injection interval aquifer.

i. Description of model calibration, including results of monitoring, laboratory and field testing, and modeling performed to match observed hydrologic and geochemical conditions.

j. Uncertainty of model results, including sensitivity analyses and evaluation of predictions over a range of potential site conditions. Predictions must be reported with a confidence interval of 90 percent or greater based on the statistical distribution of observed model input parameter values.

PART V. WELL AND WELLFIELD CONSTRUCTION REQUIREMENTS

The following requirements represent the approved minimum construction standards for well casing and cement for injection and production wells.

A. Approved Well Construction Plan

Details of the approved well construction plan required by 40 CFR § 144.52(a)(1) are incorporated into this Permit in the following sections and Figures 3 through 5.

B. Requirements for Changes to Approved Well Construction Plan

1. Changes in construction plans during construction may be approved by the Director as minor modifications under 40 CFR § 144.41.
2. 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).
3. After initial well construction is complete, any subsequent changes in well construction must be done by modification in accordance with 40 CFR § 144.39 and § 144.41.

Figure 3. Options for Well Construction Designs

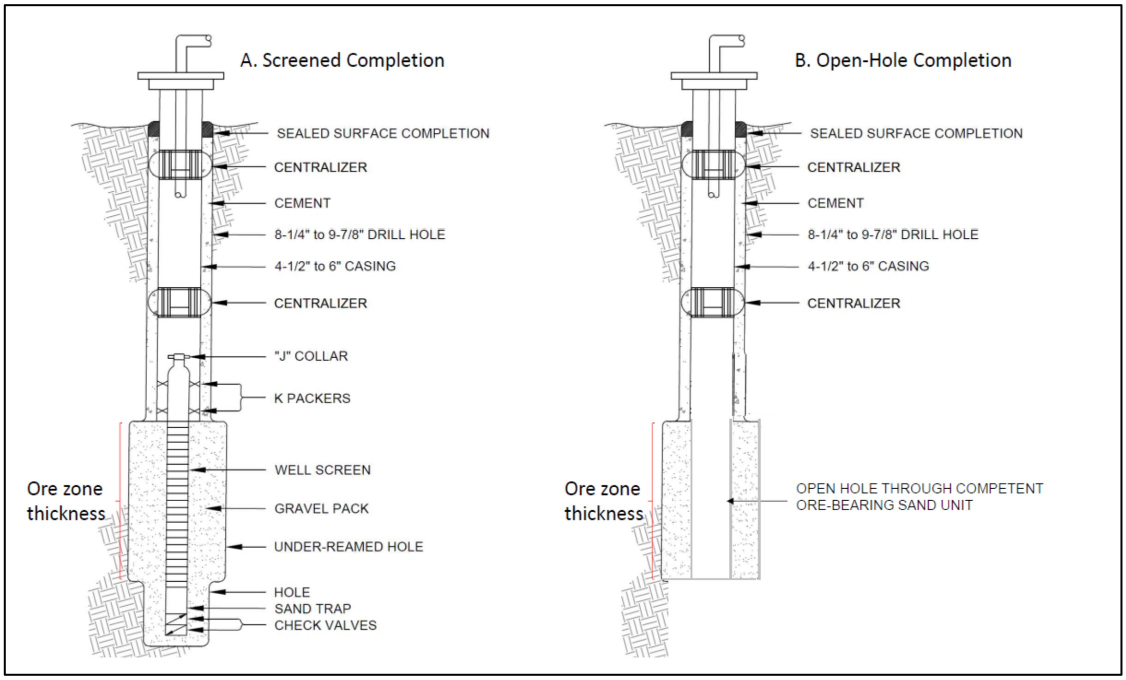


Figure 4. Injection Wellhead Design

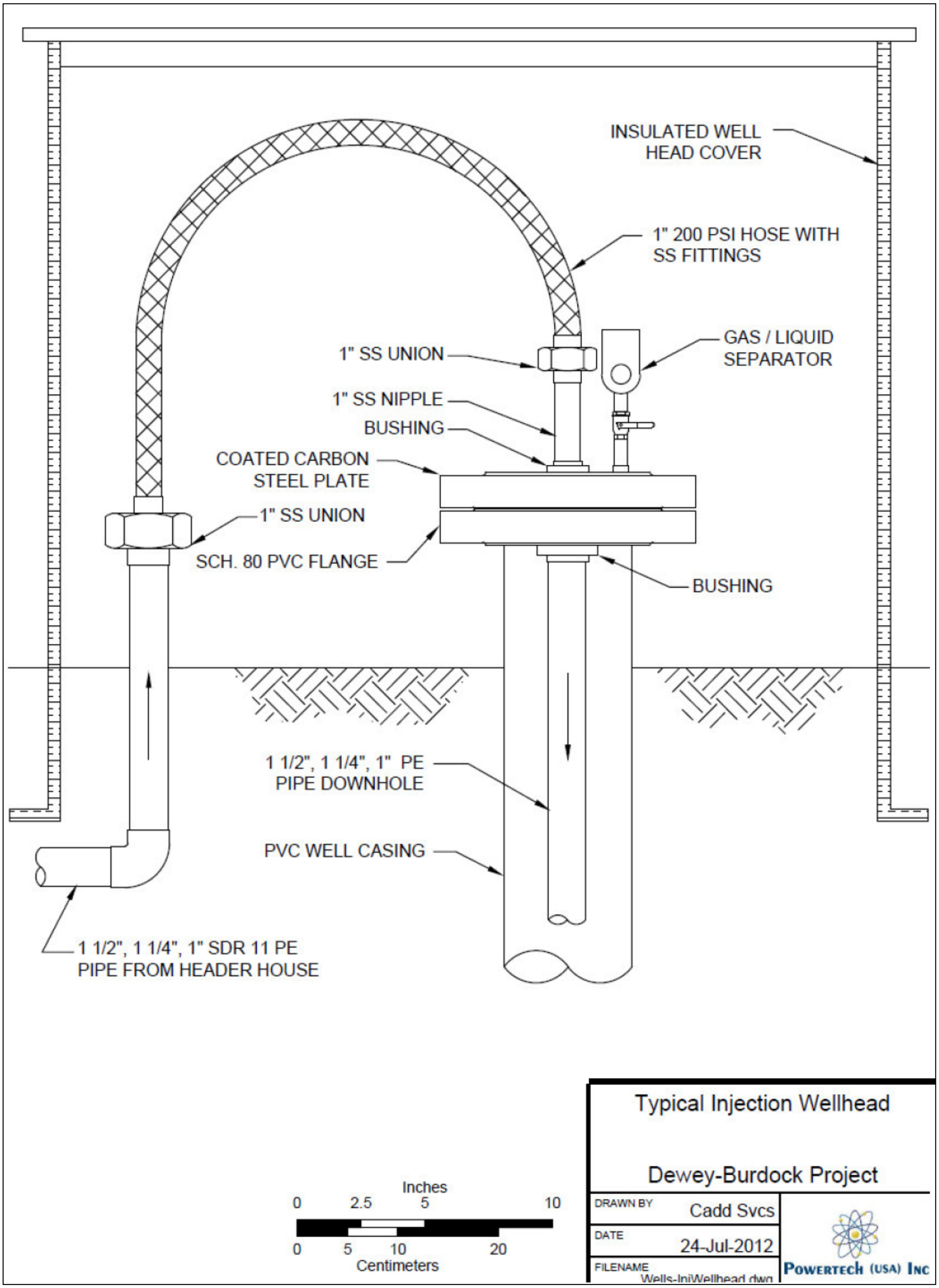
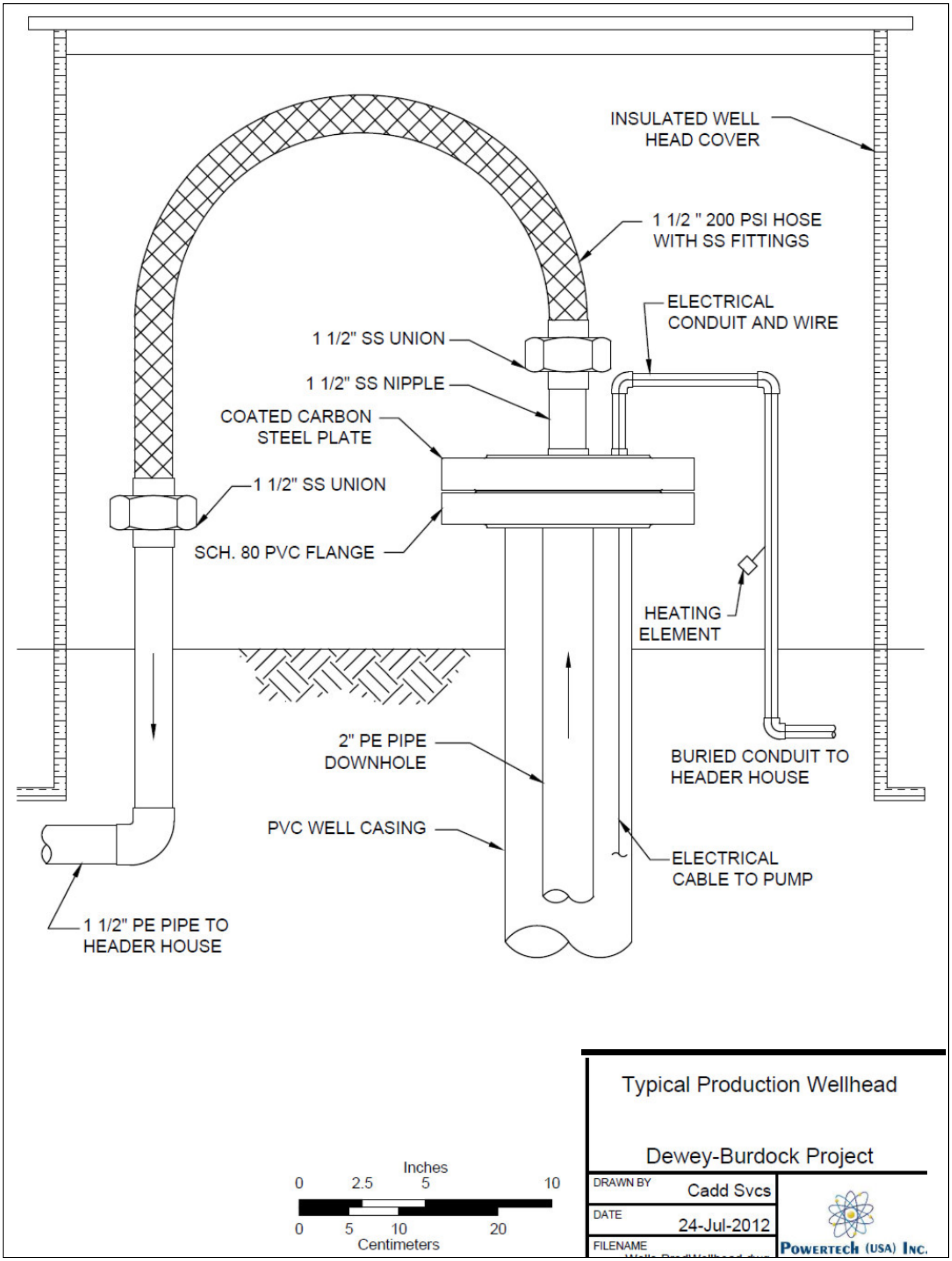


Figure 5. Production Wellhead Design



C. Well Logging

1. The logs listed in Table 10 must be conducted during or after the drilling of all wellfield injection and production wells. A descriptive report interpreting the results of such logs must be prepared by a knowledgeable log analyst and submitted to the Director as part of the well construction report required in Section G of this Part.
2. Deviation checks must be conducted on all holes where pilot holes and reaming are used, unless the hole will be cased and cemented by circulating cement to the surface. Where deviation checks are necessary they must be conducted to assure that vertical avenues for fluid migration in the form of diverging holes are not created during drillings.
3. The Permittee must ensure the log requirements are performed on each injection and production well within the time frames specified in Table 10. Well logs must be performed according to current EPA-approved procedures, where applicable.

Table 10. Well Drillhole Logging Program

TYPE OF LOG	PURPOSE	DUE DATE
Physical Geologic Log	To identify lithology and stratigraphy	During drilling
Gamma Ray	To identify ore depth and thickness	Prior to reaming hole to set casing
Self Potential	To identify depth and thickness of confining zones and aquifer units.	Prior to reaming hole to set casing
Resistivity	To identify depth and thickness of confining zones and aquifer units.	Prior to reaming hole to set casing

D. Well Construction Procedures

1. In order to provide an adequate annular seal, the drillhole diameter must be at least 2 inches larger than the outside diameter of the well casing.
2. A continuous string of joined casing must be placed into the reamed borehole.
3. Casing centralizers must be installed as needed, a minimum of two, along the casing string to ensure that annulus space surrounding the casing is consistent.
4. When designing and installing injection, production and monitoring wells, the Permittee must adhere to the requirements of ASTM F480 and manufacturer's criteria to ensure that the installation does not exceed the well casing hydraulic collapse resistance.

E. Well Casing and Cement

1. General Requirements

a. All injection, production and monitoring wells must be cased and cemented to prevent the migration of fluids into or between USDWs.
b. When a well intersects alluvium at the ground surface, surface casing must be set 50 feet below the base of the alluvium and cemented to the surface.
c. The well casing and cement used in the construction of each injection and production well must be designed for the life expectancy of the well.
d. The well casing, injection pipe and cement must be chemically compatible with the injectate and formation fluids.
e. The piping connecting the wellfield injection and production wells to the header houses must have a pressure rating greater than the highest maximum injection pressure within the wellfield.
f. Remedial cementing may be required if well cement is shown to be inadequate as a demonstration of

external mechanical integrity as discussed in Part VII, Section D.

2. Well Casing Requirements

Injection and production well casing must:

a. Meet or exceed the specifications of ASTM Standard F480 and NSF Standard 14 for thermoplastic pipe, including PVC;
b. Have a Standard Dimension Ratio no greater than SDR 17;
c. Have a pressure rating that exceeds the highest maximum allowable injection pressure for the wellfield and
d. Casing joints must be joined using methods recommended by the casing manufacturer to ensure a water tight seal between joints. The details of the joining methods must be included in the well completion report.

Table 11. Well Casing Dimensions for SDR 17

Proposed Casing Pipe Diameter (inches)	Minimum Casing Pipe Wall Thickness (inches)	Minimum drillhole Diameter (inches)
4.5	0.265	6.5
6.0	0.353	8.0

3. Injection Piping Requirements

The injection pipe must:

a. meet or exceed the specifications of ASTM Standard D3350 for polyethylene pipe,
b. have no greater than SDR 11, and
c. have a pressure rating that exceeds the highest maximum allowable injection pressure for the wellfield.

Table 12. Injection Pipe Dimensions for SDR 11

Proposed Injection Pipe Diameter (inches)	Minimum Casing Pipe Wall Thickness (inches)
1.0	0.09
1.5	0.136

4. Well Cementing Requirements

a. The Permittee must isolate all USDWs by placing cement/bentonite grout between the well casing and the well bore from top of well to top of well screen or open hole interval.
b. The Permittee must use cement/bentonite grout:
    i. Of a quantity and quality to withstand the maximum operating pressure; and
    ii. Which is resistant to deterioration from formation and injection fluids; and
    iii. In a quantity no less than 120% of the calculated volume necessary to fill the borehole-casing annulus from the top of the injection interval to the ground surface.
c. With the casing in place, a cement/bentonite grout must be pumped under pressure into the casing allowing the grout to circulate out the bottom of the casing and back up the borehole-casing annulus to the ground surface.
d. The volume of grout necessary to cement the borehole-casing annulus must be calculated from the bore hole diameter, the outer diameter of the casing, and the depth from the ground surface to the

top of injection interval with a minimum of 20% additional allowance to achieve grout returning to surface.

e. Grout remaining inside the well casing must be displaced by water to minimize the column of the grout plug remaining inside the casing. A bottom hole grout plug must remain inside casing at completion.
f. The casing and grout then must be allowed to set undisturbed for a minimum of 24 hours. When the grout has set, if the annular seal observed from ground surface has settled below ground surface, additional grout must be placed into the annular space to bring the grout seal to ground surface and allowed to set for an additional 24 hours.

5. Well Screen or Open Hole Intervals

a. After the 24-hour (minimum) grout setup period, well construction must be completed by drilling through the grout plug and through the target completion zone to the specified total well depth.
b. The open borehole must then be under-reamed to a larger diameter.
c. Injection intervals and well screen or open hole intervals must be authorized only within the vertical interval of the aquifer exemption.
d. Screened or open hole injection intervals must be determined based on results of wellfield delineation drilling and logging and well borehole logging to determine the vertical thickness of the ore deposit.
e. Information about the well screen or open hole interval must be included in the well completion report.

F. Calculation of Fracture Pressure and Determination of MAIP

1. The fracture pressure must be calculated for each well using the depth to the top of the wellfield injection interval as determined from the well logging results required under Section C of this Part.
2. The calculated fracture pressure for each injection and production well must be included in the well construction report required under Section G of this Part.
3. The fracture pressure must be calculated according to the following formula:

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

FP = formation fracture pressure
fg = fracture gradient (determined from nearest Step Rate Test under Part II, Section J.2)
sg = specific gravity = 1.009 (based on maximum estimated TDS of injectate = 12,000 mg/L)
d = depth to top of well screen or open hole

4. The MAIP Based on Calculated Fracture Pressure

The MAIP measured at each header house pressure gauge must not exceed 90% of the injection formation fracture pressure calculated for each well as required above, plus any pressure loss due to calculated according to Part II, Section J.3. The MAIP at each header house must be set at 90% of the lowest fracture pressure of all the wells connected to the header house (plus any pressure loss due to friction) to assure that the pressure in the injection interval during injection does not initiate new fractures or propagate existing fractures within the injection interval. In no case must injection pressure initiate fractures in the confining zone or cause the migration of injectate or formation fluids into an underground source of drinking water. Any exceedance of MAIP is a violation of this permit and may result in an enforcement action.

5. **Alternative MAIP Set at Well Casing or Injection Pipe Operating Pressure**
   The Permittee has the option to use well casing pipe or injection pipe within the well casing that has a pressure rating below the MAIP set at 90% of the calculated fracture pressure based on the depth to the top of the injection interval plus any pressure loss due to friction calculated according to Part II, Section J.3. In those cases, the MAIP must be set at the well casing or injection pipe operating pressure.

6. **The permit limit MAIP must be no greater than the lowest value of the following:**
   a. The lowest value of MAIP for all injection wells connected to the header house based on 90% of the calculated fracture pressure under Section F of this Part plus any pressure loss due to friction calculated according to Part II, Section J.3.
   b. The manufacturer-specified maximum operating pressure for the well casing.
   c. The manufacturer-specified maximum operating pressure of the injection pipe.
   d. The manufacturer-specified maximum operating pressure of the casing and injection pipe fittings.

7. **The well construction report must contain:**
   a. The manufacturer-specified maximum operating pressure for all components of the injection or production well as required under Section G.6 of this Part and
   b. The MAIP determined for the injection well based on requirement 6 above.

G. Well Construction Report

1. After well construction is completed, the Permittee must prepare a well construction report to submit to the Director as required in Part IX, Section E.4.
2. The well construction information must be submitted for each well in electronic format containing the data fields from EPA 7520-9 *Completion Form for Injection Wells* and a narrative description of the procedure for the cementing of well casing as required under Section E.4 of this Part and logs and tests performed as required under Section C of this Part. EPA form 7520-9 found at http://water.epa.gov/type/groundwater/uic/reportingforms.cfm.
3. The well construction report must document the adequacy of casing and cementing to prevent USDW contamination through vertical movement of fluids through the borehole-casing annulus.
4. The report must contain information as to how the Permittee met the cementing requirements in Section E.4 of this Part.
5. Remedial cementing may be required if documentation of cementing requirements is inadequate as a demonstration of external mechanical integrity.
6. The well construction report must also contain the manufacturer-specified maximum operating pressure for all components of the injection or production well.
7. The Permittee must indicate the MAIP determined for the injection well in the construction report in accordance with Section F.7 of this Part.

H. Postponement of Construction

1. If the Permittee does not begin construction of at least one of the proposed wellfields within one year of the Effective Date of the Permit, the Permittee must submit an annual Area of Review (AOR) update to the Director until construction commences. The AOR update must include:
   a. Identifying the location and screened interval of any new wells within 2 kilometers (1.2 miles) of the potential wellfield areas, as measured from the perimeter monitoring well rings;
   b. Performing a capture zone analysis for each new drinking water well constructed within the AOR and

c. Adding the new well to the list of operational monitoring wells discussed in Part IX, Section B.2.

2. Prior to commencing wellfield construction, the Permittee must send notification to the Director which includes the approximate date construction will begin and provides an updated AOR.
3. The Permittee must not commence wellfield construction until after receiving written notice from the Director that the AOR update is adequate for the protection of USDWs.

I. Additional Requirements for Manifold Monitoring

Under UIC regulation 40 CFR § 146.33(b)(6), Class III wells may be monitored on a field or project basis rather than an individual well basis by manifold monitoring. Manifold monitoring may be used in cases of facilities consisting of more than one injection well, operating with a common manifold.

1. Demonstration that Manifold Monitoring Is Equivalent to Individual Well Monitoring

a. In order for the Permittee to use manifold monitoring rather than individual well monitoring and use the header house pressure gauge as the point of compliance for monitoring injection pressure, the Permittee must demonstrate that manifold monitoring is comparable to individual well monitoring.
b. The Permittee must conduct a bounding analysis which will demonstrate for each header house that manifold monitoring is comparable to individual well monitoring using the maximum anticipated carbon dioxide and oxygen injection rates.
c. A demonstration is valid as long as adjustments to the carbon dioxide and oxygen injection rates stay within the range of the bounding analysis.
d. The bounding analysis must be provided to the Director with the next Quarterly Monitoring Report required under Part IX, Section E.8, as described under Part IX, Section E.5.e.

2. The installation of following additional equipment is required for manifold monitoring:

At each wellfield header house the Permittee must install and maintain in good operating condition the following sampling and monitoring devices for manifold monitoring (as shown in Figure 6):

a. a pressure gauge on the injection manifold line for continuous monitoring of injection pressure and daily recording of the injection pressure for the header house;
b. a pressure switch, as an operational control to prevent exceeding designated maximum injection pressure;
c. designated maximum injection pressure for the header house posted in a visible location near the injection manifold line pressure gauge;
d. a flow meter on the injection manifold line for continuous monitoring of injection flow rate; and
e. injection manifolds (as shown in Figures 6 and 7) equipped with:
   i. flow meters labeled with designated well identification numbers;
   ii. flow control valves to regulate the flow to each well and balance individual well patterns; and
   iii. a block valve between the header and the flow meter so that the injection well may be blocked off to service the meter and the well.
f. The Permittee must install a female port (1/2 inch), protected by a valve, to accept a UIC inspector pressure gauge, located in such a way that the inspector can inspect the pressure to compare it to the MAIP.
g. The 1/2 inch female port must be installed at wellheads, in those cases where the MAIP compliance points is located at the wellhead instead of the header manifold.

Figure 6. Injection Header Instrumentation

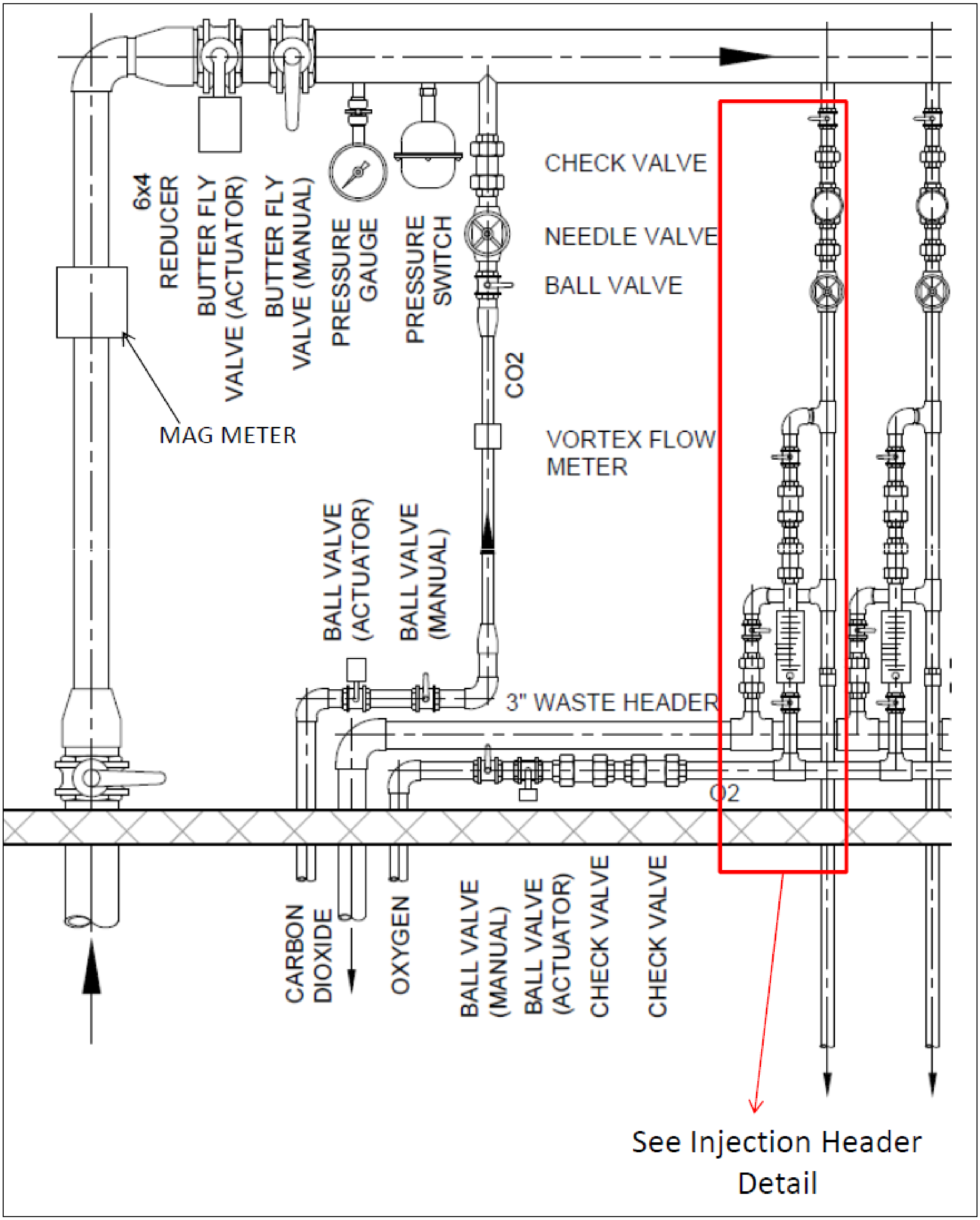
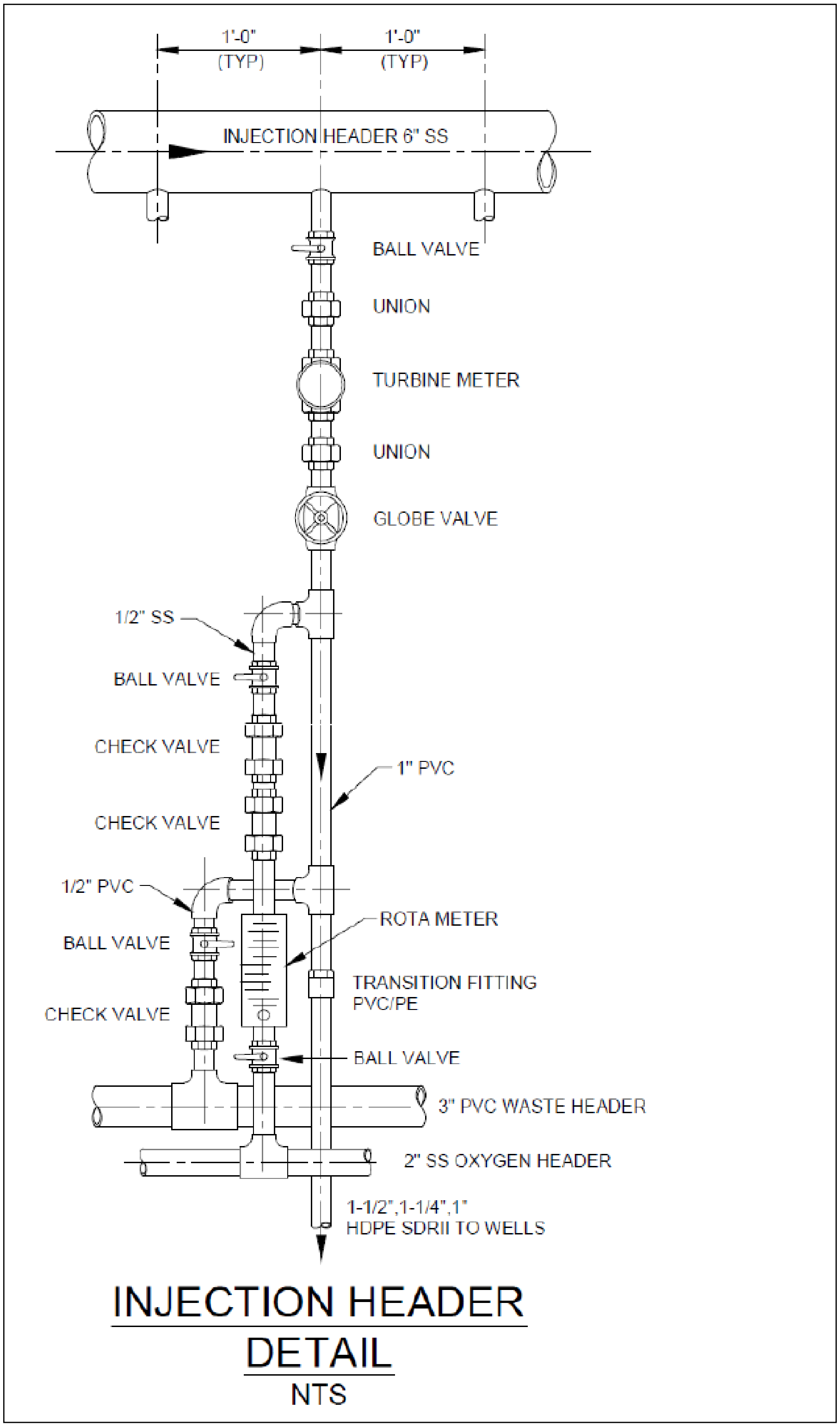


Figure7. Injection Well Header Detail



J. Wellfield Monitoring

Samples and measurements taken for the purpose of monitoring must be representative of the monitored activity per 40 CFR § 144.51(j)(1). The following equipment must be installed in the Burdock Central Processing Plant, the Dewey Satellite Facility or another representative sampling or measurement location:

1. a sampling port in the injectate trunkline to collect representative samples of the injectate for each wellfield;
2. instrumentation to continuously monitor and measure injectate and production flow rates for the daily recording of the injection and production flow rates for each wellfield; and
3. instrumentation to continuously monitor and measure injectate and production volumes for the monthly recording of the injection and production volumes for each wellfield.

K. Protective Automated Monitoring and Shut-off Devices

1. An instrumentation and control system must be installed to monitor pressure and flow and immediately detect and correct any anomalous condition.
2. The instrumentation and control system must meet the following requirements:
   a. Pressure and flow sensors must be installed for the purpose of leak detection on the main trunk lines connecting the Burdock Central Processing Plant and the Dewey Satellite Facility to the wellfields.
   b. Injection pressures and flow must be monitored through automated control and data recording systems that will include alarms and automatic controls to detect and control a potential release.
   c. Measurements must be collected and transmitted to both the Burdock Central Processing Plant and the Dewey Satellite Facility control systems.
   d. Alarms must be installed to provide immediate warning to operators should pressures or flows fluctuate outside of normal operating ranges to enable a timely response and implementation of appropriate action.
   e. Both external and internal shutdown controls must be installed at each header house to provide for operator safety and spill control. The external and internal shutdown controls must be designed for automatic and remote shutdown of each header house. In the event of an automatic header house shutdown, an alarm will occur and the flows of all injection and production wells in that header house will be automatically stopped. The alarm will activate a blinking light on the outside of the header house and will cause an alarm signal to be sent to the Burdock Central Processing Plant and the Dewey Satellite Facility control rooms.
   f. A control valve that will close when power is turned off or lost as a result of power failure must be used on the injection header to stop the flow to all injection wells.
   g. A pressure switch will be installed on each injection header to ensure that fluid pressure does not exceed the maximum designated injection pressure for the injection wells served by that header house. If the injection pressure reaches the maximum set value in the pressure switch, an automatic header house shutdown will occur.

PART VI. WELL WORKOVERS AND ALTERATION

A. Requirements for Well Stimulation, Workovers and Alterations

1. Well stimulations, workovers, and alterations must meet all conditions of the Permit.

2. Alteration, workover, and well stimulation include any activity that physically changes the well construction (casing, tubing, and packer) or injection formation.

3. 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 well construction plan must be done by modification in accordance with 40 CFR § 144.39 and § 144.41.

4. 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 record of well workover, logging, or test data to the Director within thirty (30) days of the completion of the activity.

5. A successful demonstration of internal mechanical integrity is required following the completion of any well workover or alteration which affects the integrity of the casing, packer or tubing. 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.

6. If the activities were conducted within 45 days of the next Quarterly Monitoring Report, then the information must be submitted with the next Quarterly Monitoring Report.

B. Demonstration of Well Mechanical Integrity after Well Workover or Alteration

1. Following the completion of any well workover or alteration which affects the integrity of the casing or cement, the Permittee must submit to the Director a successful demonstration of internal mechanical integrity according to Part VII, Section C before recommencing injection activities into the well.
2. Injection operations must not be resumed until the Permittee has successfully demonstrated the well has mechanical integrity.
3. Documentation of mechanical integrity test results must be included in the next Quarterly Monitoring Report, or if the Permittee would like to recommence injection into the well sooner, the documentation of mechanical integrity test results may be submitted immediately to the Director.
4. If the workover is being conducted because of mechanical integrity loss, the Permittee must not resume injection until the Director has provided written approval.
5. If mechanical integrity cannot be successfully demonstrated following a workover, the well must be plugged and abandoned according to the approved plugging and abandonment plan in Part XI, Section C.

PART VII. MECHANICAL INTEGRITY

A. Definition of Mechanical Integrity

An injection well has mechanical integrity if:

1. There is no significant leak in the casing, tubing or packer; and
2. There is no significant fluid movement into an underground source of drinking water through vertical channels adjacent to the injection well bore.

B. Requirement to Demonstrate and Maintain Mechanical Integrity

1. The Permittee is required to ensure each injection well and production well maintains mechanical integrity at all times. Injection into a well that lacks mechanical integrity is prohibited.
2. Before the Authorization to Commence Injection is issued by the Director for each wellfield, the Permittee

must demonstrate that each wellfield injection and production well installed during development of the Injection Authorization Data Package Report has mechanical integrity according to 40 CFR § 146.8.

3. For injection and production wells constructed after the Director issues the initial Authorization to Commence Injection, the Permittee must send documentation to the Director demonstrating that each well has mechanical integrity.
4. The Permittee must receive written authorization from the Director prior to commencing operation of additional wells.
5. The Permittee must ensure the mechanical integrity tests in Table 13 are performed within the time frames specified. The internal mechanical integrity test must be performed according to the requirements in Section C of this Part. External mechanical integrity must be demonstrated according to Section D of this Part.
6. The Director, by written notice, may require the Permittee to comply with a schedule describing when mechanical integrity demonstrations must be made.

Table 13. Well Testing Program

TYPE OF TEST	PURPOSE	DUE DATE
Pressure-Packer Test	To assess Internal Mechanical Integrity	Before Authorization to Commence Injection is issued for wells constructed before the wellfield pump test is conducted. For wells constructed after initial Authorization to Commence Injection, demonstration of mechanical integrity must be submitted to the Director for written approval before commencing operation. For all wellfield wells, periodically thereafter according to Part VII, Section G.
Well cementing records	To assess External Mechanical Integrity	At the completion of well construction

C. Internal Mechanical Integrity Test

1. Prior to initiation of injection activities in a wellfield, all injection, production, and monitoring wells must be field tested to demonstrate the mechanical integrity of the well casing.
2. The mechanical integrity of the well casing must be demonstrated using a pressure-packer test.
3. If the testing pressure drops less than 10 percent during the 10-minute test, the well casing has demonstrated acceptable mechanical integrity.
4. The Permittee must conduct the pressure-packer test procedure as follows:
   a. Seal bottom of the casing with a plug, downhole inflatable packer, or other suitable device.
   b. Fill the casing with water.
   c. Seal the top of the casing with a threaded cap, mechanical seal or downhole inflatable packer.
   d. Apply an induced pressure on the water column within the well casing using water or compressed gas.
   e. Monitor induced pressure with a calibrated pressure gauge.
   f. Increase induced pressure to 125% of the maximum operating pressure of the well field or 125% of the maximum operating pressure rating of the well casing, whichever pressure value is lower.

5. A well must maintain at least 90 percent of this pressure for a minimum of 10 minutes to pass the test.
6. If there are obvious leaks, or the pressure drops by more than 10 percent during the 10-minute period, the Permittee must check and/or reset the seals and fittings on the packer system and conduct another test.

D. Demonstration of External Mechanical Integrity

1. The well construction report must include detailed cementing records documenting that the requirements under Part V, Section E were met to demonstrate the absence of significant fluid movement through the well borehole-casing annulus.
2. Because this Area Permit is allowing cementing records to demonstrate external mechanical integrity, the monitoring program requirements in Part IX must be designed to verify the absence of significant fluid movement outside the injection interval through confining zones as required under 40 CFR § 146.8(c)(4).
3. The Director may require the Permittee to conduct remedial cementing between the well casing and the borehole wall if the well construction report cannot verify that the requirements under Part V, Section E were met.

E. Reporting Results of Initial Mechanical Integrity Demonstrations

The results of initial mechanical integrity tests must be submitted to the Director as required in Part IX, Section E.6.

F. Requirement to Plug and Abandon any Injection, Production or Monitoring Well for which Mechanical Integrity Cannot Be Demonstrated

1. If mechanical integrity cannot be demonstrated for any injection, production, or monitoring well after workovers and remedial actions have been performed, the Permittee must plug and abandon those wells according to the requirements under Part XI.
2. The Permittee must include these activities in the report on initial mechanical integrity demonstrations.

G. Ongoing Demonstration of Mechanical Integrity

1. After initial demonstration of mechanical integrity required in Sections B.2 and B.3 of this Part, the Permittee must demonstrate internal mechanical integrity of each injection well within five (5) years of the last successful mechanical integrity test even if the well is not active. The procedure and criteria for demonstrating internal mechanical integrity are found in Section C.4 of this Part.
2. Results of mechanical integrity tests must be submitted to the Director with the next scheduled Quarterly Monitoring Report, unless the mechanical integrity test occurred within 45 days before the due date of the Quarterly Monitoring Report. In that case, the mechanical integrity test results must be submitted with the following Quarterly Monitoring Report.
3. Failing to provide the Director with a successful demonstration of mechanical integrity in a timely manner will be a violation of this permit.
4. **Demonstration of External Mechanical Integrity**
   Because the well cementing record in the well construction report must be used to demonstrate external mechanical integrity as required under Section D of this Part, no repeat test is required.
5. **Demonstration of Mechanical Integrity after Well Workovers**
   In addition to these regularly scheduled demonstrations of mechanical integrity, the Permittee must demonstrate internal mechanical integrity following any workover that affects the integrity of the casing or cement of any injection or production wells within a wellfield as required under Part VI, Section B. The

Permittee must not resume injection after a well workover until the Director has issued writing approval to resume injection.

6. Additional or Alternative Mechanical Integrity Tests

The Director may require additional or alternative tests if the results presented by the Permittee are not satisfactory to the Director for demonstrating there is no movement of fluid into or between USDWs resulting from injection activity.

H. Notification Prior to Testing

Except for the initial mechanical integrity test required before injection or production well operation, the Permittee must notify the Director at least seven calendar days prior to any regularly scheduled mechanical integrity test. When the mechanical integrity test is conducted after well construction, well conversion, or a well rework, any prior notice is sufficient. The Director may allow a shorter notification period if it would be sufficient to enable EPA to witness the mechanical integrity test. 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.

I. Loss of Mechanical Integrity

1. If an active well fails to demonstrate mechanical integrity during a test, or a loss of mechanical integrity becomes evident during operation (such as increase in flow rate measured at injection well header or water flowing at the surface, etc.), the Permittee must notify the Director within 24 hours (see Part XII, Section D.10.e of this Permit), and the well must be shut-in within 48 hours unless the Director requires immediate shut-in.
2. Upon discovering that an active well fails to demonstrate mechanical integrity during a test, or a loss of mechanical integrity becomes evident during operation, as soon as practically possible, the Permittee must collect water level measurements from the nearest monitoring wells in overlying aquifers and compare them to the previously collected water level data. If an increase in water level is observed, then the Permittee must collect fluid samples from the nearest monitoring wells in overlying aquifers, analyze the samples for excursion parameters and compare the data to previous analyses for these wells. If an excursion is confirmed according to Part IX, Section C.3, then the Permittee must follow the monitoring requirements under Part IX, Section C.4.
3. Within five days of when the loss of mechanical integrity became evident, the Permittee must submit a follow-up written report that documents test results, repairs undertaken or a proposed remedial action plan and the results of the recent monitoring well data required under 2 above that are available at the time of the five-day report.
4. Injection operations must not be resumed until after the Permittee has:
    i. has successfully repaired the well,
    ii. demonstrated the well has mechanical integrity,
    iii. demonstrated that monitoring for an excursion has occurred as required under Section I.2 under this Part and any excursion confirmed according to Part IX, Section C.3 resulting from the mechanical integrity loss is being addressed according to Part IX, Section C.4, and
    iv. received written approval to resume injection from the Director.

PART VIII. WELL OPERATION

The Permittee must adhere to the following requirements prior to and during injection and production well operation.

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

B. The migration of ISR contaminants across the aquifer exemption boundary into USDWs is prohibited.
The constituents considered to be ISR contaminants under this Area Permit are listed in Appendix B, Table B-1. The permit limit for each constituent is either the permit limit listed in Appendix B, Table B-1 or the or the aquifer background concentration as determined according to Part II, Section E.2.b.iv, whichever value is higher.

C. Requirements Prior to Commencing Injection in a Wellfield

1. General Requirements

The Permittee must not commence injection until:

a. Well construction is complete;
b. The well construction report is complete;
c. The Permittee has submitted the Injection Authorization Data Package Report described in Part II, Section H;
d. Initial demonstration of mechanical integrity pursuant to 40 CFR § 146.8 and Part VII, Sections B.2 and B.3 has been successful and documented; and
e. The Director has issued the written Authorization to Commence Injection.

2. Confirmation of Aquifer Baseline Potentiometric Surface

a. After the wellfield pump test has been completed and the static potentiometric surface for each aquifer has stabilized from the wellfield pump test, the static potentiometric water levels must be measured in every well in the monitoring system prior to the initiation of injection into the wellfield to determine the degree to which the injection interval potentiometric surface has recovered after the wellfield pump tests.
b. At that time the baseline static potentiometric surface for each aquifer must be established, along with a range of water level variance to be expected due to barometric pressure change, for comparison against operational water level measurements.

D. Injection Interval

1. Injection is authorized only within the approved vertical interval of the Inyan Kara aquifers.
2. Injection intervals and well screen or open hole intervals will be authorized only within the exempted portion of the Inyan Kara aquifer.
3. Well screen or open hole injection intervals must be determined based on results of wellfield delineation drilling and logging and injection and production well logging to determine the vertical thickness of the ore deposits.

E. Injection Pressure Limitation and MAIP Compliance Point

1. The Permittee must use a pressure gauge located either at each wellhead or at the injection manifold at each header house as the compliance point at which the MAIP is demonstrated not to exceed the permit limit set according to Part V, Section F.6.

2. The Permittee may use pressure gauges at the injection manifold only after verification that the injection pressure measured at the header house pressure gauge is greater than or equal to the injection pressure measured at the wellhead of each injection well connected to the header house as described under Part V, Section I.1.

F. Hydraulic Control of Wellfield

1. The Permittee must maintain hydraulic control of each wellfield from the initiation of injection through the end of groundwater restoration.
2. During ISR operation in each wellfield, the production wells must pump a larger volume of fluids out of the wellfield than the injection wells are injecting to maintain a hydraulic gradient directed inward toward the wellfield.
3. During post-ISR groundwater restoration, pumping wells must extract a greater volume of groundwater than the injection wells are pumping into the wellfield to maintain the inward hydraulic gradient.

4. Hydraulic Control of Wellfield during ISR Operation

a. During uranium recovery, the groundwater removal rate in each wellfield must exceed the lixiviant injection rate, creating a cone of depression within each wellfield.
b. This condition must be verified by:
   i. monitoring water levels in the injection interval perimeter monitoring wells that are below the baseline water levels established under Section C.2 of this Part the majority of the time;
   ii. continuous monitoring of injection and production flow rate and volume and
   iii. daily recording of flow rate of injection and production fluids for each wellfield.

5. Hydraulic Control of Wellfield during Groundwater Restoration

a. The Permittee must maintain hydraulic control of each wellfield until groundwater restoration has been completed through intermittent or continuous pumping of groundwater from the wellfield.
b. Hydraulic control must be verified by monitoring water levels in the injection interval perimeter monitoring wells that are consistently below the baseline water levels established under Section C.2 of this Part.
c. The Permittee must monitor the water levels in the wellfield perimeter monitoring well ring in accordance with the requirements in Part IX, Section B.1.e, Table 14.F and Part IX, Section C.

6. Notification of Completion of Groundwater Restoration

a. The Permittee must notify EPA in the next Quarterly Monitoring Report once groundwater restoration is completed for a wellfield.
b. At that time the requirement to maintain hydraulic wellfield control for the wellfield is no longer applicable.
c. However, the monitoring requirement for measuring water levels in all perimeter wellfield monitoring wells must be continued in order to verify the return of the natural groundwater gradient in the wellfield area.
d. Monitoring the water levels in the non-injection interval monitoring wells in overlying aquifer units must be conducted as required in Part IX, Section C until wellfield post-restoration stability monitoring is completed.

G. Injection Flow Rate and Injectate Volume

Because of the net extraction of groundwater within the wellfield during injection activities, there is no injection volume limit requirement in this Area Permit.

H. Injection Fluid Limitation

1. During the ISR process, the injection fluid is limited to ISR lixiviant consisting of wellfield groundwater with carbon dioxide and oxygen added.
2. During the groundwater restoration phase, the injectate will be limited to permeate from reverse osmosis (RO) treatment of groundwater extracted from the post-ISR wellfields, clean makeup water or groundwater recirculated within the wellfield.
3. Chemical reductant may be injected for the purposes of aquifer remediation after written authorization by rule from the Director.
4. If the Permittee determines that injection is required for groundwater restoration either within the wellfield or outside the wellfield due to an excursion or to inject a groundwater tracer, the Permittee must submit an authorization by rule proposal to the Director.

I. Tubing-Casing Annulus

The approved well construction design does not include requirements for a packer to seal off the annulus between the tubing and casing. There are no permit requirements under this section for the annulus between the well casing and the injection tubing. (The injection tubing is called the injection piping under Part V, Section E.3.)

PART IX. MONITORING, RECORDING AND REPORTING OF RESULTS

A. General Monitoring Requirements

1. Because this Area Permit allows cementing records to be used to demonstrate the absence of significant fluid movement to fulfill the external mechanical integrity demonstration requirement as described under Part VII, Section D, the monitoring program required under Section B of this Part must be designed to verify the absence of significant fluid movement through the confining zones per 40 CFR § 146.8(c)(4).
2. Monitoring observations, measurements, fluid samples, etc. taken for the purpose of complying with these requirements must be representative of the activity or condition being monitored.
3. Fluid samples collected for the purpose of compliance with the conditions of this Area Permit must be tracked and controlled using a Chain of Custody to verify the analytical results are applicable to the identified fluid sample.
4. To ensure that groundwater samples are representative of ambient groundwater conditions surrounding the well, groundwater samples must be collected according to the procedures in Part II, Sections E.2.b.
5. Fluid samples collected for the purpose of compliance with this Area Permit must be handled according to the requirements found in 40 CFR part 136 Table II – *Required Containers, Preservation Techniques, and Holding Times*.
6. Operating parameters must be observed and recorded under normal operating conditions, and all parameters must be observed simultaneously to provide a clear depiction of well operation.
7. All monitoring equipment to be installed, maintained and used according to manufacturer's directions and any applicable operating manuals.
8. Any equipment calibration must be conducted as specified by the manufacturer at the frequency specified by the manufacturer. Documentation of calibration must include the name of the person performing the

calibration and the date of calibration.

9. Required monitoring including type, intervals, and frequency must be sufficient to yield data which are representative of the monitored activity including when appropriate, continuous monitoring.
10. Pressures are to be measured in pounds per square inch (psi).
11. Fluid volumes are to be measured in gallons.
12. Fluid rates are to be measured in gallons per minute (gpm).

B. Monitoring Parameters, Frequency, Records and Reports

Monitoring parameters and frequency are specified in Section 1 below.

1. Monitoring Parameters and Frequency

a. Monitoring information is to be collected, recorded and reported for all parameters at the frequency indicated, even during periods when the well is not operating.
b. Injection pressure must be continuously monitored at the pressure gauges installed on each header house injection manifold and manually recorded at least daily for each header house.
c. The injection and production flow rates must be continuously monitored for each wellfield and must be recorded daily from monitoring devices at the Burdock Central Processing Plant, the Dewey Satellite Facility or another representative location compliant with 40 CFR § 144.51(j)(1) requirement that samples and measurements taken for the purpose of monitoring must be representative of the monitored activity.
d. Monthly injection and production volumes must be continuously monitored and recorded for each wellfield from monitoring performed at the Burdock Central Processing Plant, the Dewey Satellite Facility or another representative location compliant with 40 CFR § 144.51(j)(1) requirement that samples and measurements taken for the purpose of monitoring must be representative of the monitored activity.
e. Parameters must be monitored and recorded as indicated in Table 14.
f. Monitoring information and results must be included in the Quarterly Monitoring Report.
g. Representative samples of the injectate for each wellfield must be collected and analyzed monthly for the analytes listed in Table 15.
h. The analytical methods included in Table 15 must be used for injectate sample analysis. Equivalent methods may be used after prior approval by the Director.

Table 14. Monitoring Parameters and Frequency

A. CONTINUOUSLY	
MONITOR	Injection Pressure (psig) at each header house
	Injection Rate (gpm) for each wellfield at injection trunkline at the Burdock Central Processing Plant, the Dewey Satellite Facility or another representative location compliant with 40 CFR § 144.51(j)(1). Production rate (gpm) for each wellfield at production trunkline at the Burdock Central Processing Plant, the Dewey Satellite Facility or at another representative location compliant with 40 CFR § 144.51(j)(1).
	Injection volume (gallons) for each wellfield at injection trunkline at the Burdock Central Processing Plant, the Dewey Satellite Facility or at another representative location compliant with 40 CFR § 144.51(j)(1). Production volume (gallons) for each wellfield at production trunkline at the Burdock

	Central Processing Plant, the Dewey Satellite Facility or at another representative location compliant with 40 CFR § 144.51(j)(1).
B. DAILY	
OBSERVE AND RECORD	Injection Pressure (psig) at each header house (or each wellhead if Part V, Section I.2.g is used) Injection Flow Rate for each wellfield Production Flow Rate for each wellfield
C. WEEKLY EXCURSION MONITORING OF WELLS WHEN EXCURSION IS CONFIRMED	
OBSERVE AND RECORD	Wellfield perimeter monitoring well water levels for impacted wells and the two adjacent non-impacted wells Impacted wellfield non-injection interval monitoring well water levels
ANALYZE	Water samples from monitoring wells described above for chloride, total alkalinity, and specific conductance values
REPORT	Next scheduled Quarterly Report
D. 14-DAY INTERVAL EXCURSION MONITORING DURING ISR OPERATION	
OBSERVE AND RECORD	Wellfield perimeter monitoring well water levels Wellfield non-injection interval monitoring well water levels
ANALYZE	Water samples from each well listed above for chloride, total alkalinity, and specific conductance values
REPORT	Next scheduled Quarterly Report
E. MONTHLY	
RECORD	Monthly Average, Maximum, and Minimum values for Injection Pressure (psig)
	Maximum, minimum and average values for Daily Injection Rate (gpm) for each wellfield
	Maximum, minimum and average values for Daily Production Rate (gpm) for each wellfield
	Injected volume for that month (gallons) for each wellfield
	Produced volume for that month (gallons) for each wellfield
ANALYZE	Injectate flowing to each wellfield for parameters in Table 15 Expanding excursion monitoring well samples for water quality constituents in Table 8 per Part IX, Section C.4.g.
REPORT	Next scheduled Quarterly Report
F. 60 DAY INTERVAL EXCURSION MONITORING DURING GROUNDWATER RESTORATION AND POST-RESTORATION STABILITY MONITORING	
OBSERVE AND RECORD	Wellfield perimeter monitoring well water levels Wellfield non-injection interval monitoring well water levels
ANALYZE	Water samples from each well listed above for chloride, total alkalinity, and specific conductance values
REPORT	Next scheduled Quarterly Report
G. QUARTERLY	
ANALYZE	Samples from operational monitoring stock wells within permit area for chloride, total alkalinity, and specific conductance Samples from operational monitoring of domestic wells for excursion parameters, except for

	the annual sampling event that coincides with the NRC License requirement.
REPORT	Monthly Average, Maximum, and Minimum values for Daily Injection Pressure (psig)
	Monthly Average, Maximum, and Minimum values for Daily Injection Rate (gpm)
	Monthly Average, Maximum, and Minimum values for Daily Production Rate (gpm)
	14-day interval excursion monitoring results during ISR operation
	Injection volume for each wellfield for each month during the quarter (gallons)
	Production volume for each wellfield for each month during the quarter (gallons)
	Monthly Results of injectate fluid analysis in units listed in Table 15
	Summary of seismic events measuring 2.0 magnitude on the Modified Mercalli Intensity (MMI) scale or greater occurring within a fifty (50) mile radius of the Area Permit boundary.
	Well construction reports and initial mechanical integrity test results for new injection, production and monitoring wells
	Initial header house injection pressure verification reports
	60-day interval excursion monitoring results during groundwater restoration and post-restoration stability monitoring
	Quarterly sampling results from Operational Monitoring Wells
	Quarterly Operational Groundwater Monitoring sample results from domestic wells.
	Results from Post-operational groundwater samples per Part IX, Section B.3 as applicable.
	Results from Post-restoration stability monitoring samples per Part IX, Section B.4 as applicable.
	Weekly excursion monitoring of wells when excursion is confirmed
H. 24-HOUR REPORTING	
REPORT	Upon discovery that an active well fails to demonstrate mechanical integrity during a test, or a loss of mechanical integrity becomes evident during operation as described under Part VII, Section I.
	Injection pressure measured above the MAIP for a header house.
	If any seismic event measuring 4.5 magnitude (MMI scale) or greater is reported within two miles of the permit boundary per Part IX, Section D.
	Any noncompliance which may endanger human health or the environment, including: • Any monitoring or other information which indicates that any contaminant may cause endangerment to a USDW; or • Any noncompliance with a permit condition or malfunction of the injection system which may cause fluid migration into or between USDWs.
	Initial excursions as described in Part IX, Section E.9.a.
	An expanding excursion plume as described in Part IX, Section E.9.d
	Discovery that excursion indicator concentrations are increasing in excursion-impacted monitoring wells as described in Part IX, Section E.9.d.
	Upon discovery of any other noncompliance as described in Part XII, Section D.10.e.

I. ANNUALLY	
ANALYZE	Operational Monitoring samples from domestic wells for NRC list of analytes.
REPORT	Analytical results for Operational Monitoring samples from domestic wells.
	AOR update per Part V, Section H for each year construction is delayed at the Project Site

Table 15. Injection Fluid Characterization Parameters

Analyte	Reporting Units	Analytical Methods
Physical Properties		
pH	pH units	A4500-H B
Total Dissolved Solids	mg/L	A2540 C
Specific conductance	μmhos/cm	A2510B or E120.1
Specific Gravity	Ratio to density of water	ASTM D1429-13, SM 2710F
Commons Elements and Ions		
Alkalinity (as $CaCO_3$)	mg/L	A2320 B
Chloride	mg/L	A4500-Cl B; E300.0
Sulfate	mg/L	A4500-SO4 E; E300.0
Dissolved Metals		
Arsenic	mg/L	E200.8
Iron	mg/L	E200.7
Lead	mg/L	E200.8
Manganese	mg/L	E200.8
Selenium	mg/L	E200.8
Strontium	mg/L	E200.8
Uranium	mg/L	E200.7; E200.8
Vanadium	mg/L	E200.7; E200.8
Radionuclides		
Gross Alpha	pCi/L	E900.0
Gross Beta	pCi/L	E900.0
Radium -226	pCi/L	E903.0
Radium -228	pCi/L	E903.0

2. Operational Groundwater Monitoring

a. Domestic Wells

i. During operations, the Permittee must monitor all downgradient domestic wells within 1.2 miles of the boundary of each wellfield (as measured from the perimeter monitoring well ring), unless the well owners do not consent to sampling or the condition of the wells renders a well unsuitable for sampling.

ii. Wells to be monitored under this requirement are shown in Figure 8.

iii. Samples must be collected quarterly and analyzed for the three excursion parameters, except for the sample collected at the time of the annual monitoring sample required under the NRC license. The annual sample must be analyzed for the analytes in Table 5.7-2: *List of Baseline* Parameters in the NRC Safety Evaluation Report.

b. Stock Wells

i. During the design of each wellfield, all stock wells within ¼ mile of the perimeter monitoring well ring must be evaluated for the potential to be adversely affected by ISR operations or to adversely affect ISR operations.
ii. During operation, the Permittee must monitor all stock wells located within the project boundary (Figure 9) that were not plugged and abandoned due to impact on ISR operations.
iii. Samples must be collected quarterly and analyzed for water level and the three excursion indicators: chloride, total alkalinity, and specific conductance.

c. Monitoring Wells

i. The Permittee must monitor wells located hydrologically up-gradient and downgradient of ISR operations as part of the operational groundwater monitoring program.
ii. Monitoring wells included in the operational monitoring program must include wells completed in the alluvium, Fall River, Chilson, and Unkpapa aquifers.
iii. The proposed wells indicated in Table 16 (Well ID is TBD) and in Figures 10 and 11 must be installed before the first wellfield pump test is conducted in the Burdock Area.
iv. The monitoring wells must be monitored quarterly and analyzed for the water quality parameters listed in Table 8.

d. The operational monitoring well locations are shown in Figures 8 through 12 and are listed in Table 16.

Table 16. Monitoring Wells Included in Operational Monitoring Program

Well ID	Qrt- Qrt		Section	Township	Range	Relative Position
	Alluvium					
676	SESW		34	6S	1E	Burdock/Downgradient of land application
677	SWSW		4	7S	1E	Dewey/Downgradient near Beaver Creek
678	SWNE		9	7S	1E	Downgradient of Site Boundary
679	NWSE		27	6S	1E	Burdock/Up-gradient
707	SWNE		34	6S	1E	Burdock/Downgradient of Triangle Pit
708	SESW		3	7S	1E	Burdock/Downgradient of land application
709	SENW		15	7S	1E	Burdock/Downgradient of wellfields
DC-1	NWSW		30	6S	1E	Dewey/Up-gradient
DC-2	SESW		30	6S	1E	Dewey/Downgradient of land application
DC-3	NWNE		31	6S	1E	Dewey/Downgradient of wellfield
DC-4	NWNW		32	6S	1E	Dewey/Downgradient of wellfield
	Fall River					
631	SWSW		23	6S	1E	North of Site Boundary/Up-gradient
681	NENW		32	6S	1E	Dewey/Production Zone
688	NESW		11	7S	1E	Burdock/Overlying Production Zone
694	NWNW		15	7S	1E	Burdock/Downgradient
695	SESE		32	6S	1E	Dewey/Downgradient
698	NESW		2	7S	1E	Burdock/Downgradient
706	NENE		21	6S	1E	North of Project Site/Up-gradient
TBD	SWNE		34	6S	1E	Burdock/Downgradient of Triangle Pit
TBD	NWSE		2	7S	1E	Burdock/Downgradient of Darrow Pit
	Chilson					
43	SWSE		34	6S	1E	Burdock/Downgradient of Triangle Pit
680	NESW		11	7S	1E	Burdock/Production Zone
689	NENW		32	6S	1E	Dewey/Production Zone
696	NWNW		15	7S	1E	Burdock/Downgradient
697	SESE		32	6S	1E	Dewey/Downgradient
705	NENE		21	6S	1E	North of Project Site/Up-gradient
3026	SESE		1	7S	1E	Burdock/Up-gradient
TBD	SWSE		2	7S	1E	Burdock/Downgradient of Darrow Pit
	Unkpapa					
690	NESW		11	7S	1E	Burdock/Underlying Production Zone
693	NENW		32	6S	1E	Dewey /Underlying Production Zone
703	SWSE		1	7S	1E	Burdock/At Up-gradient Edge of Wellfield

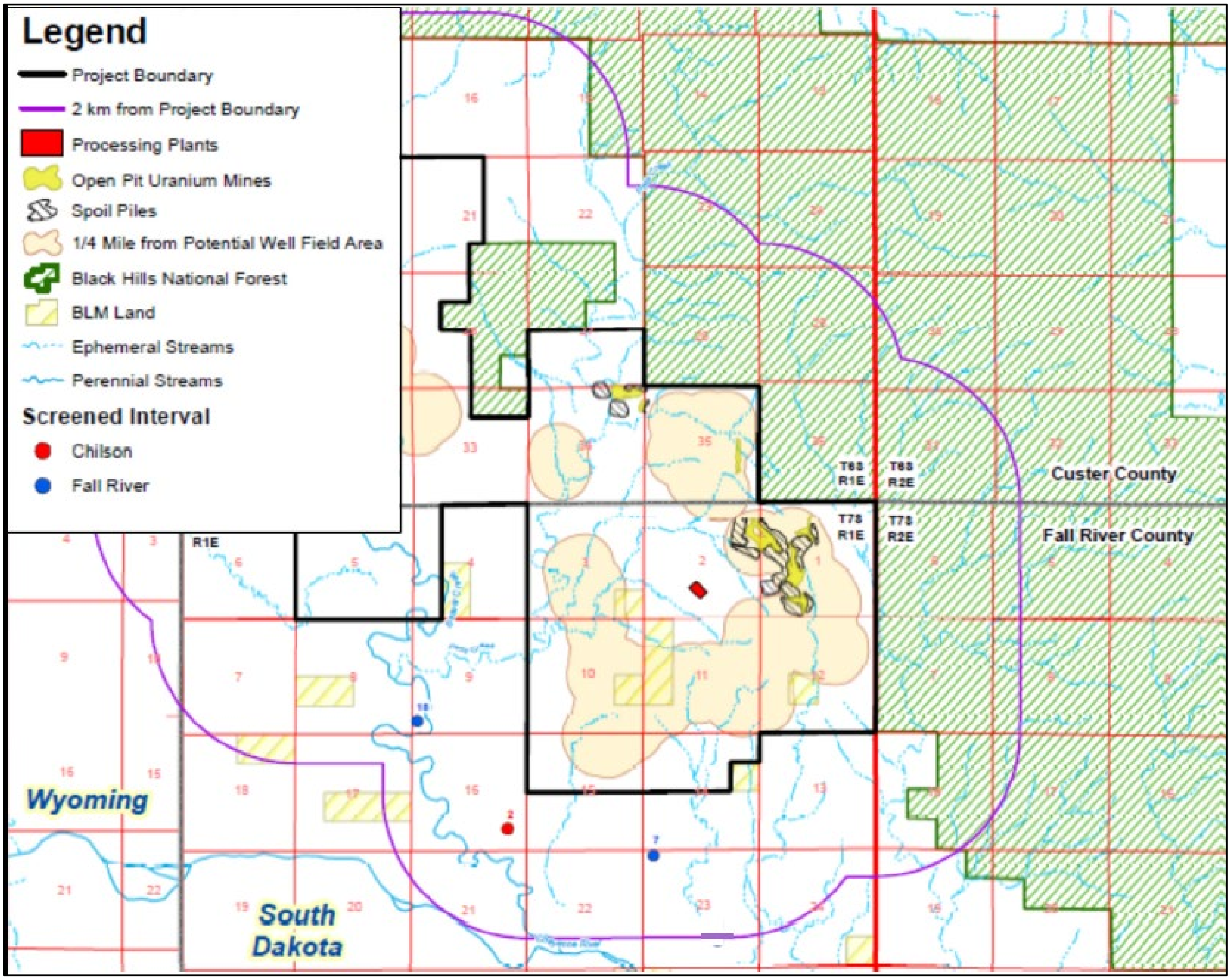


Figure 8. Operational Monitoring Wells – Three Domestic Wells: Hydro IDs 2, 7 and 18

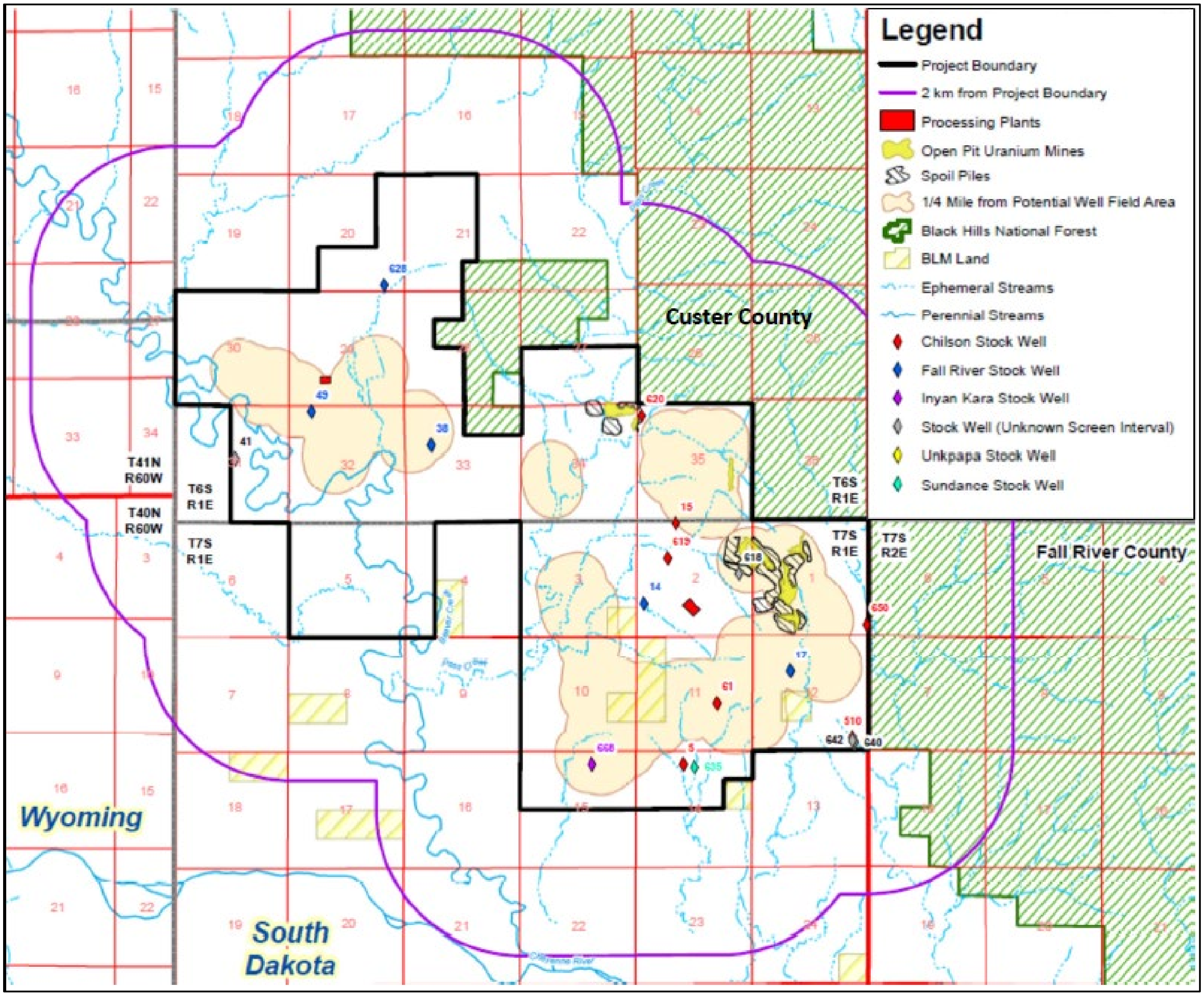


Figure 9. Operational Monitoring Wells - Stock Wells

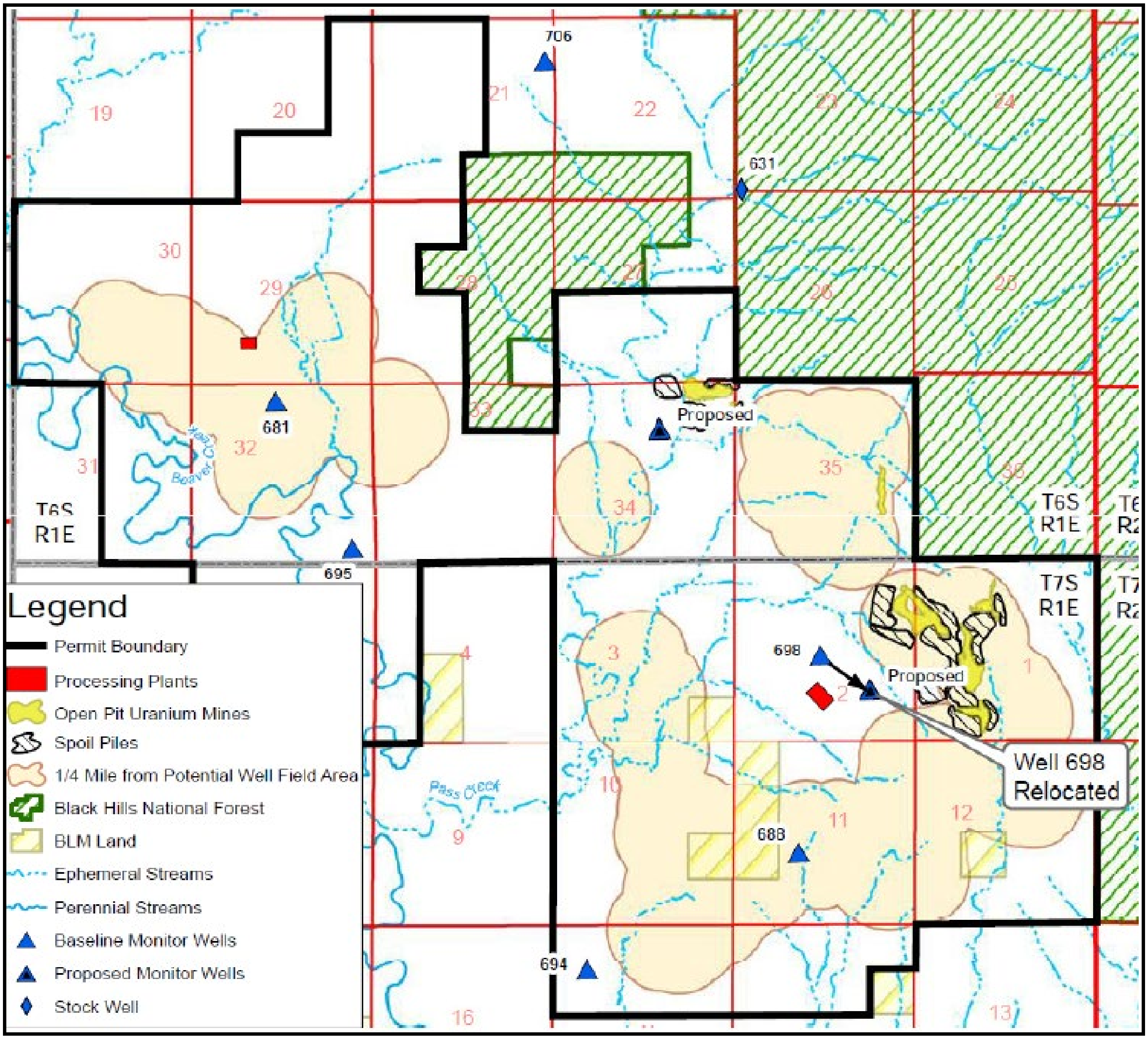


Figure 10. Fall River Operational Monitoring Wells

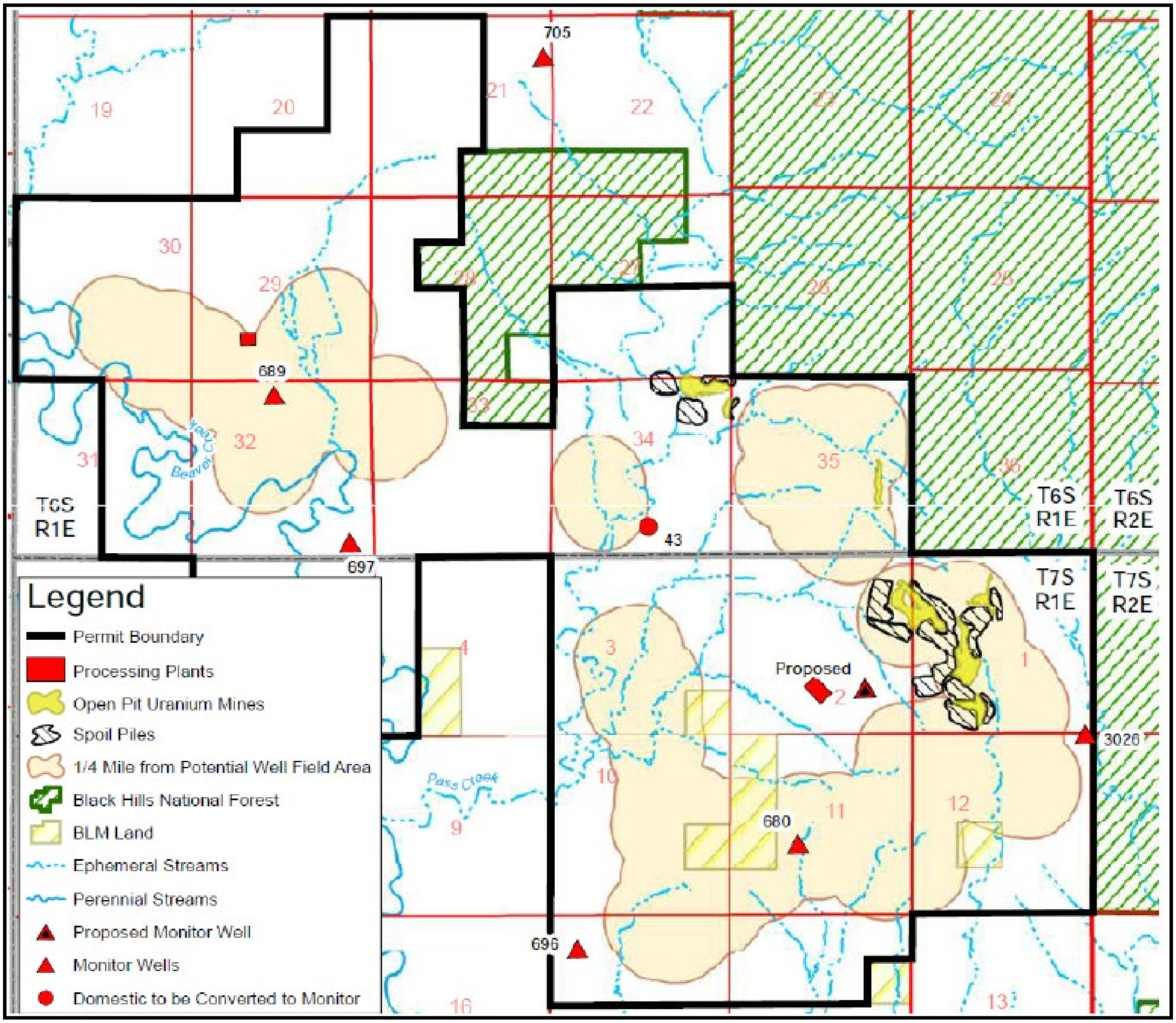


Figure 11. Chilson Operational Monitoring Wells

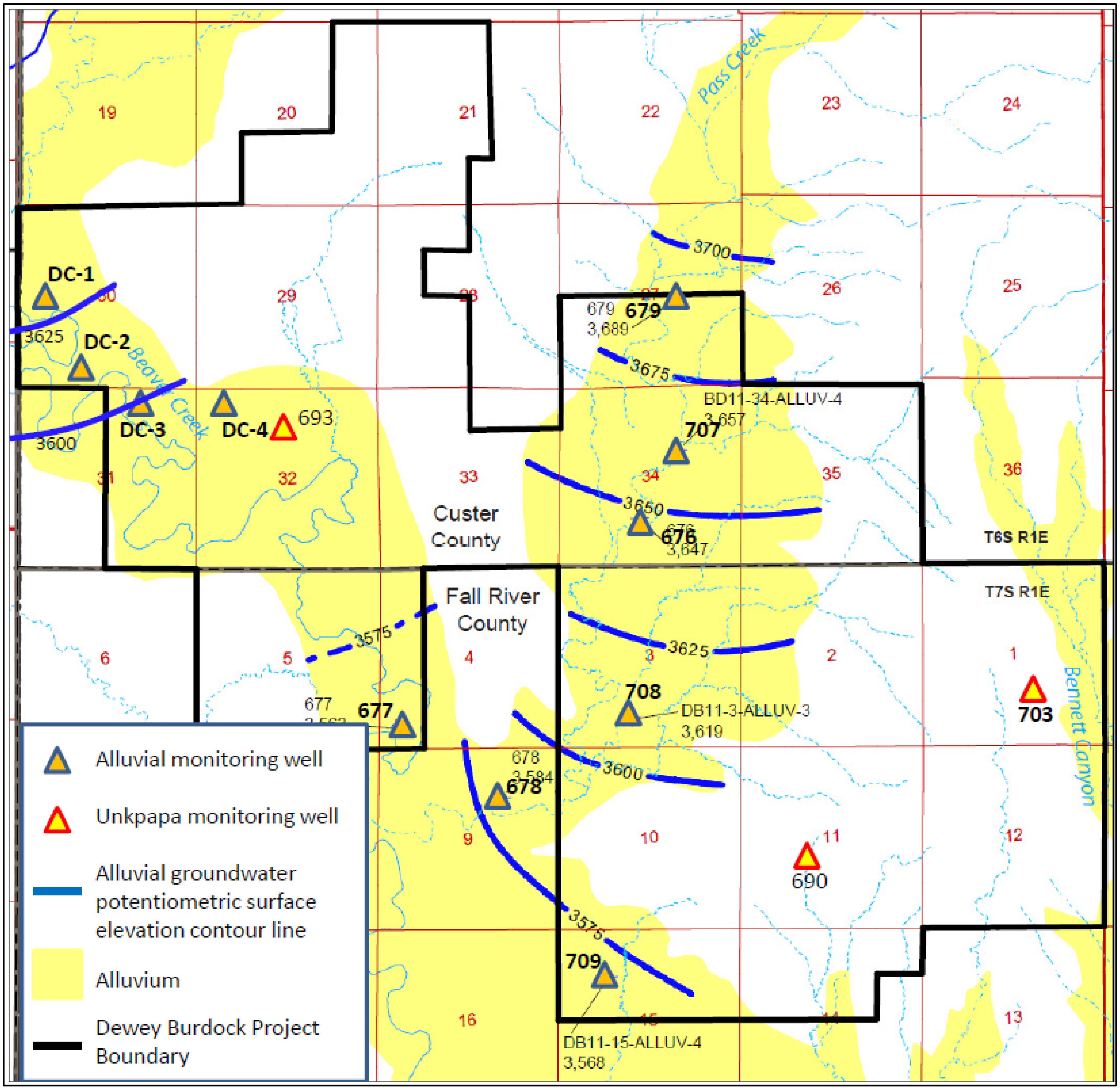


Figure 12. Unkpapa and Alluvial Operational Monitoring Wells

3. **Post-Operational Groundwater Monitoring**
   a. After completing ISR operations and prior to initiating the wellfield restoration process, groundwater samples may be collected at the Permittee's discretion from the wellfield injection interval wells used to determine Commission-approved background concentrations as discussed under condition 11.3 of the NRC license and analyzed for parameters listed in Table 8, including radium-228.
   b. Any ISR contaminant listed in Appendix B, Table B-1 having a concentration at or below the permit limit or the groundwater background concentration at all injection interval wells within the wellfield may be excluded from geochemical modeling described under Part IV, Section B of this Permit.
   c. If radium-228 is not detected in a well, then this parameter may be omitted from the analyte list for analysis of subsequent samples from that well.

4. **Post-Restoration Stability Monitoring**
   a. Groundwater samples must be collected quarterly from injection interval wells used to determine Commission Approved Background concentrations as discussed under condition 11.3 of the NRC license and analyzed for parameters listed in Table 8.
   b. Additional samples must be collected as necessary for evaluation of any areas with high contaminant concentrations.

5. **Monitoring records must Include:**
   a. Chain of Custody for fluids samples
   b. The date, exact place, and time of sampling or measurements;
   c. The individual(s) who performed the sampling or measurements;
   d. The date(s) analyses were performed;
   e. The individual(s) who performed the analyses;
   f. The analytical techniques or methods used; and
   g. The results of such analyses.

C. Excursion Monitoring

1. **During ISR Operations**
   a. **Groundwater Level Measurements:** Monitoring for excursions during ISR operations must consist of measuring water levels in injection interval wellfield perimeter monitoring wells and non-injection interval monitoring wells twice a month and no more than 14 days apart in any given month.
   b. **Groundwater Sampling and Analysis:** Groundwater samples must be collected from injection interval wellfield perimeter monitoring well and non-injection interval monitoring wells and analyzed for chloride, total alkalinity and specific conductance twice a month and no more than 14 days apart in any given month.
2. **During Groundwater Restoration and Post-Restoration Stability Monitoring**
   a. **Groundwater Level Measurements:** Monitoring for excursions during groundwater restoration and post-restoration stability monitoring must consist of measuring water levels in injection interval wellfield perimeter monitoring wells and non-injection interval monitoring wells every 60 days.
   b. **Groundwater Sampling and Analysis:** Groundwater samples must be collected from injection interval wellfield perimeter monitoring well and non-injection interval monitoring wells and analyzed for the excursion parameters: chloride, total alkalinity and specific conductance every 60 days.

3. **Criteria for Confirmation of an Excursion**

   If the concentrations of any two excursion indicator parameters exceed their respective Upper Control Limit (UCL) , as established under the NRC License, or any one excursion indicator parameter exceeds its UCL by 20 percent, the excursion criterion is exceeded and a verification sample must be taken from that well within 48 hours after results of the first analyses are received. If the verification sample confirms that the excursion criterion is exceeded, the well must be placed on excursion status. If the verification sample does not confirm that the excursion criterion is exceeded, a third sample must be taken within 48 hours after the results of the verification sample are received. If the third sample shows that the excursion criterion is exceeded, the well must be placed on excursion status. If the third sample does not show that the excursion criterion is exceeded, the first sample will be considered an error and routine excursion monitoring will be resumed (the well is not placed on excursion status).

4. **During a Confirmed Excursion Event**
   a. **Notify the Director within 24 hours:** If an excursion has been confirmed under Section C.3 of this Part, the Permittee must notify the Director within 24 hours of receiving the confirmation sampling results.
   b. **Groundwater Level Measurements:** For an excursion event that has been confirmed according Section C.3 above, monitoring must consist of measuring the water levels every seven (7) days in injection interval wellfield perimeter monitoring wells and non-injection interval monitoring wells impacted by the excursion.
   c. **Groundwater Sampling and Analysis:** Groundwater samples must be collected every seven (7) days from all impacted wellfield monitoring wells and analyzed for the excursion parameters: chloride, total alkalinity and specific conductance.
   d. **Monitoring Nearest Unimpacted Wellfield Perimeter Monitoring Wells:** For injection interval excursions impacting wellfield perimeter monitoring wells, the nearest injection interval wellfield perimeter monitoring wells on each side of the impacted well(s) that have not been impacted by the excursion must also be monitored weekly according to Sections C.4.**a** and C.4.**b** above to verify that the excursion plume is not expanding.
   e. **Criteria for Expanding Excursion Plume:**
      i. If excursion monitoring shows that an adjacent unimpacted wellfield perimeter monitoring well or an adjacent unimpacted non-injection interval monitoring well becomes impacted by an existing excursion, the excursion is now considered to be an expanding excursion plume.
      ii. Even if no adjacent monitoring wells are impacted by an existing excursion as described in Section 4.e.***i*** above, if excursion monitoring shows increasing concentrations in excursion parameters over four consecutive sampling periods, the excursion is now considered to be an expanding excursion plume.
   f. **Verification Actions for Expanding Excursion Plume:**
      i. A verification sample must be taken from the newly impacted adjacent well(s) within 48 hours after results of the first analyses are received.
      ii. If the verification sample confirms that the excursion criterion is exceeded, the well must be placed on excursion status and the excursion is considered to be an expanding plume. The Permittee must conduct the activities required under Section C.5 of this Part below.
      iii. If the verification sample does not confirm that the excursion criterion is exceeded, a third sample must be taken within 48 hours after the results of the verification sample are received. If

the third sample shows that the excursion criterion is exceeded, the well must be placed on excursion status and the excursion is considered to be an expanding plume.

iv. If the third sample does not show that the excursion criterion is exceeded, the first sample will be considered an error. Routine weekly excursion monitoring must continue but the well is not placed on excursion status and the excursion is not considered to be an expanding excursion plume.

g. Additional Requirements for Expanding Excursion Plumes

i. For monitoring wells impacted by expanding excursion plumes, in addition to the monitoring required under Sections C.4.b and C.4.c of this Part above, the Permittee shall collect a groundwater sample from the impacted well(s) and analyze the sample(s) for the water quality parameters in Table 8.

ii. The Permittee must continue to analyze groundwater samples from impacted monitoring wells described under Section C.g.i above for the water quality parameters in Table 8 on a monthly basis until **excursion parameter concentrations** show decreasing concentrations for three consecutive weekly sampling periods required under Section C.4.c of this Part above. Table 8 water quality parameter analytical results must be used to calibrate the geochemical model required under Section C.5 of this Part below.

iii. After the excursion is corrected, the Permittee must collect a final sample from each impacted non-injection interval monitoring well and analyze it for the water quality parameters in Table 8 to determine if additional aquifer remediation is required in the excursion-impacted area.

5. Geochemical Modeling for Expanding Excursion Plumes

a. If monitoring under Section C.4.f of this Part shows that concentrations of ISR contaminants included in Appendix B, Table B-1 are detected above background in a monitoring well impacted by an expanding excursion plume, the Permittee must notify the Director within 24 hours as required by Section E.9.d.i of this Part.

b. The background concentration for an ISR contaminant is the Commission-approved background concentration for that monitoring well determined according to NRC License condition 11.3.

c. The Permittee must conduct the following verification steps to determine if ISR contaminant concentrations exceed background concentrations:

i. If one ISR contaminant exceeds its background concentration by 20% or two or more ISR contaminants exceed background concentrations by 10%, within 48 hours the Permittee must collect a follow-up confirmation groundwater sample from the monitoring well and analyze it for the ISR contaminants with concentrations above background.

ii. If the second sample confirms elevated concentrations of ISR contaminants meeting criteria in Section C.5.***c.i*** above, then the Permittee must initiate the activities under Section C.5.***d*** below. If not, within 48 hours the Permittee must collect a third groundwater sample from the monitoring well and analyze it for the ISR contaminants with concentrations above background.

iii. If the third sample does not show ISR contaminant concentrations above background, then the Permittee does not need to initiate the activities under Section C.5.***d*** below.

d. Upon verification that ISR contaminants have increased in concentrations above background concentrations, the Permittee must conduct the following activities:

i. As required by Section E.9.d.ii of this Part, the Permittee must notify the Director within 24 hours of receiving the verification sampling results and follow-up in 5 days with a brief written report providing a schedule for the following activities.
ii. The Conceptual Site Model must be updated with all available information list in Part IV, Section A.1 for the non-injection interval aquifer impacted by the expanding plume.
iii. The Permittee must initiate the geochemical modeling process.

e. The geochemical model must:
i. Be calibrated to flow and geochemical conditions present at the excursion site and excursion parameter concentrations measured in the monitoring well(s);
ii. Evaluate the extent of the excursion plume;
iii. Determine the potential for the excursion plume to reach the aquifer exemption boundary at the current rate of expansion; and
iv. Estimate the concentrations of ISR contaminants at the aquifer exemption boundary, taking into account the effects of dispersion and natural attenuation based on the geochemistry of the aquifer unit.

f. After reviewing the model results, the Director will determine what actions the Permittee should take to protect USDWs, including the installation of additional monitoring wells and aquifer remediation, if needed.

6. Requirement to Remediate Excursions

The Permittee must take appropriate action to recover an excursion and continue excursion monitoring at all impacted monitoring wells until the excursion parameter concentrations meet non-excursion levels for four consecutive monitoring periods in all impacted monitoring wells. Non-excursion levels means no single excursion parameter exceeds 20% of its UCL and no two excursion parameters exceed their respective UCLs in any monitoring well.

D. Seismic Activity Monitoring

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/

1. The Permittee must subscribe to this service and check daily for notification emails from the service.

2. 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 boundary.

3. 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.

4. The Director will determine if any structural testing of the facility infrastructure is required before injection resumes.

5. Injection must not resume until the Permittee has obtained approval to recommence injection from EPA.

6. 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 EPA on a quarterly basis.

E. Reporting Requirements

Monitoring may be reported on a project or field basis rather than individual well basis where manifold monitoring is used.

1. Reporting requirements must, at a minimum, include:

a. Quarterly reporting to the Director on required monitoring required by this Permit;
b. Results of mechanical integrity demonstrations as required under Sections 6 and 7 below and any other periodic test required by the Director.
c. Updates to the Conceptual Site Model required under Part IV, Section A.3.

2. Following authorization to begin injection into a wellfield, the Permittee must submit Quarterly Monitoring Reports to the Director containing the monitoring information required in Section B of this Part whether the wellfield is operating or not.

a. Reporting periods and due dates for Quarterly Monitoring Reports are shown in Section E.8.b, Table 17 of this Part.
b. An electronic format may be used to submit monitoring information using the data fields included on EPA Form 7520-8 *Injection Well Monitoring Report* found at http://water.epa.gov/type/groundwater/uic/reportingforms.cfm as a guide.
c. However, the monitoring requirements specified in this Permit are mandatory even if EPA Form 7520-8 indicates otherwise.

3. Injection Authorization Data Package Reports

Injection Authorization Data Package Reports must be prepared and submitted to the Director for each wellfield in order to obtain written Authorization to Commence Injection in that wellfield. These data packages may be submitted when completed and do not have to be submitted on the Quarterly Monitoring Report schedule shown below. The Injection Authorization Data Package Reports must be signed according to Part XII, Section D.9 and certified using the paragraph included under Part XII, Section D.9.d. The information may be submitted in a standardly available electronic format but must be accompanied by a letter containing the required certification.

4. Injection, Production and Monitoring Well Completion Reports

a. After an injection, production or monitoring well has been completed, the Permittee must submit a well completion report including the information in EPA Form 7520-9 *Completion Form for Injection Wells* with attachments.
b. The report may be in electronic format including the completion information for a number of wells. The EPA Form 7520-9 can be found at http://water.epa.gov/type/groundwater/uic/reportingforms.cfm.
c. The well construction report must also contain the manufacturer-specified maximum operating pressure for all components of the injection or production well.
d. The cementing procedure must be documented in detail in each well completion report.
e. Remedial cementing may be required if the Director determines the well cementing record is not adequate for demonstration of external mechanical integrity.
f. Injection well completion reports must be submitted to the Director with the next scheduled Quarterly Monitoring Report, unless well construction was completed within 45 days of the next Quarterly Monitoring Report due date.

g. If well construction was completed within 45 days of the next Quarterly Monitoring Report due date, the well completion report must be submitted with the following Quarterly Monitoring Report.

5. Demonstration that Manifold Monitoring of Injection Pressure is Comparable to Wellhead Monitoring

a. Demonstration must consist of a list of injection pressures measured at each wellfield injection wellhead compared to the injection pressure measured at the pressure gauge at each header house and the time and date each injection pressure measurement was collected.
b. The Permittee must conduct a bounding analysis demonstration for each header house that manifold monitoring is comparable to individual well monitoring using the maximum anticipated carbon dioxide and oxygen injection rates.
c. The Permittee must make an effort to record the measurements at the same time from wellhead pressure gauge and the header house pressure gauge.
d. The report must consist of
    i. injection well identification numbers,
    ii. injection pressure measured at each wellhead,
    iii. time and date of measurement,
    iv. header house identification number for the injection well,
    v. header house injection pressure measured,
    vi. time and date of measurement,
    vii. maximum anticipated flow rate of carbon dioxide for the header house and
    viii. maximum anticipated flow rate of oxygen for each injection well.
e. This information must be included in the next Quarterly Report after the information is compiled.
f. After the initial demonstration for a wellfield, if adjustments are made to the oxygen flow rate or carbon dioxide flow rates outside the range of the bounding analysis, then a new demonstration is required.

6. Initial Internal Mechanical Integrity Reports

The initial mechanical integrity test results required under Part VII, Sections B.2 and B.3 must be submitted to the Director in order to obtain written Authorization to Commence Injection. The mechanical integrity test results may be submitted when completed and do not have to be submitted on the Quarterly Monitoring Report schedule shown below. The mechanical integrity test results must be signed according to Part XII, Section D.9 and certified using the paragraph included under Part XII, Section D.9.d. The information may be submitted in electronic format but must be accompanied by a letter containing the required certification.

7. Ongoing Demonstrations of Mechanical Integrity

The results from ongoing mechanical integrity tests must be submitted to the Director with the next scheduled Quarterly Monitoring Report, unless the mechanical integrity test was completed within 45 days of the next Quarterly Monitoring Report due date. In that case, the information must be submitted with the following Quarterly Monitoring Report.

8. Quarterly Monitoring Reports

a. The Permittee must include the monitoring parameters listed under Section B of this Part in the Quarterly Monitoring Report as specified here.

b. The Permittee must submit the Quarterly Monitoring Reports to Director according to the schedule included in Table 17.
c. At minimum, the Permittee must include in the Quarterly Monitoring Reports the following information:
    i. Monthly physical, chemical and other relevant analytical results of injection fluids.
    ii. Monthly average, maximum and minimum values for injection pressure, flow rate and volume.
    iii. Quarterly mechanical integrity test results, a list of any wells failing mechanical integrity test and remedial actions taken, and a list of wells anticipated to undergo mechanical integrity testing during the next quarter.
    iv. Operational monitoring results.
    v. Excursion monitoring results.
    vi. Post-restoration wellfield post-restoration stability monitoring results.
    vii. Any seismic events measuring 2.0 magnitude (MMI scale) or greater within a 2-mile radius of the Area Permit boundary, gathered from USGS Earthquake Hazard Program website.
    viii. Any well maintenance activities.
    ix. Updates to the Conceptual Site Model required under Part IV, Sections A.3 and A.4.

d. The Permittee must sign and certify the monitoring reports according to the Draft Area Permit Part XII, Sections D.9 and D.9.d.
e. The Permittee may submit quarterly Monitoring Reports in electronic format, but the electronic data must be accompanied by a letter containing the required certification.

U.S. Environmental Protection Agency – Region 8
Chief, SDW Enforcement Branch, Mailcode: 8ENF-W-SDW
Enforcement and Compliance Assurance Division
1595 Wynkoop Street
Denver, CO 80202-1129

f. The Permittee must include in the monitoring reports raw data and graphical analysis for the current reporting period to date.
g. The Permittee must tabulate each calendar quarter, the maximum, minimum, and average monthly values for each continuously monitored parameter specified for the injection wells.
h. The Permittee must include a narrative description of any deviations from permit limitations that occurred during the reporting period.
i. The Permittee must describe any maintenance activities, mechanical integrity test activities, and other significant events that took place during the reporting period.

Table 17. Schedule for Submitting Quarterly Monitoring Reports

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

9. Excursion Reporting

a. Initial Excursion Reporting

If an excursion has been confirmed under Section C.3 of this Part, the Permittee must notify the Director within 24 hours per Part XI, Section C.4.a and, within 5 days, follow up with a written report that provides the following information:

i. Location of excursion,
ii. Monitoring wells impacted,
iii. Date of previous excursion monitoring activities in the area, and
iv. Actions to correct the excursion.

b. 60 Day Excursion Reporting

i. Within 60 days of the excursion confirmation, the Permittee must submit a written report describing the excursion event, recovery actions taken and the recovery action results.
ii. If monitoring wells are still on excursion status when the report is submitted, the report will also contain a schedule for submittal of future reports describing the excursion event, recovery actions taken, and results obtained.

c. Reporting an Expanding Excursion Plume

i. If an expanding excursion is verified as described in Section C.4.f of this Part, the Permittee must notify the Director of an expanding excursion plume within 24 hours per Part XI, Section C.4.a and follow up with a written report within 5 days.
ii. The written report must contain an estimation of how far excursion plume may have traveled, including a map showing estimated extent of the expanding excursion plume.

d. Reporting Increase in Concentration of ISR Contaminants in Impacted Monitoring Wells

i. The Permittee must notify the Director within 24 hours as required by Section C.5.a of this Part if monitoring under Section C.4.g of this Part shows that concentrations of ISR contaminants included in Appendix B, Table B-1 are detected above background in a monitoring well impacted by an expanding excursion plume.
ii. As required by Section C.5.d.i of this Part, the Permittee must notify the Director within 24 hours of receiving the verification sampling results and follow-up in 5 days with a brief written report providing a schedule for the following activities:
   A) The Conceptual Site Model must be updated with all available information list in Part IV, Section A.1 for the non-injection interval aquifer impacted by the expanding plume.
   B) The Permittee must initiate the geochemical modeling process.

PART X. RECORDKEEPING REQUIREMENTS

A. Records of Permit Application Data

The Permittee must keep records of all data used to complete permit applications and any supplemental information submitted under 40 CFR § 144.31 for a period of at least 3 years from the date the application is signed.

B. Records of Monitoring Data

The Permittee must retain records of all monitoring information, including the following:

1. Calibration and maintenance records and data from continuous monitoring instrumentation, copies of all reports required by this permit, for a period of at least 3 years from the date all wells have been plugged and abandoned.
2. Well completion reports.
3. The nature and composition of all injected fluids until three years after the completion of any plugging and abandonment procedures specified under § 144.52(a)(6), or under part 146 subpart G as appropriate.
4. Mechanical integrity test results, description and results of any other tests required by EPA, and any well workovers completed.
5. System failures and follow-up actions.
6. The Permittee must also maintain an electronic database containing well completion and mechanical integrity test records for all injection wells and provide it for EPA use upon request.
7. Records of all monitoring activities must be retained and made available for inspection. The Permittee must notify the Director as to the location where the records of monitoring activities are maintained and notify the Director if this location changes.
8. At the end of the retention period, the owner or operator must deliver the records to the EPA Regional Administrator or obtain written approval from the Regional Administrator to discard the records.

C. Retention Schedule for Well Plugging and Abandonment Reports

1. The Plugging and Abandonment Reports required under Part XI, Section D must be retained for at least 3 years from the date of the submission unless the Director requests an extension.
2. At the conclusion of the retention period, the reports will be delivered to the Director upon request.

PART XI. PLUGGING AND ABANDONMENT

A. Notification of Well Abandonment, Conversion or Closure

1. Except for the plugging and abandonment of a well that cannot demonstrate mechanical integrity under Part VII and will be replaced by a newly constructed well meeting the requirements in Part V, the Permittee must notify the Director in writing at least forty-five (45) days prior to:
   a. plugging and abandoning an injection well;
   b. converting to a non-injection well, other than a wellfield production well; and
   c. closure of the project.
2. Notification must include demonstration that the NRC considers the wellfield groundwater to be restored before the Director will authorize the closure of wellfield injection and production wells.
3. In accordance with 40 CFR § 146.10(a)(4), the plugging and abandonment plan required in 40 CFR §§ 144.51(o) and 144.52(a)(6) must demonstrate adequate protection of USDWs per 40 CFR § 146.10(a)(4).
4. Before approving well closure, the Director may prescribe aquifer cleanup and monitoring where he deems it necessary and feasible to ensure adequate protection of USDWs per 40 CFR § 146.10(a)(4).

B. Well Plugging Requirements

1. Prior to abandonment, each Class III injection well must be plugged with bentonite or cement grout in a manner which prevents the movement of fluids into or between USDWs.
2. Each well must be plugged in accordance with the approved plugging and abandonment plan and with 40 CFR § 146.10.

C. Approved Plugging and Abandonment Plan

1. Wells must be plugged with bentonite grout if the weight of the bentonite grout column is greater than the bottom hole pressure or must be plugged with cement grout placed from the bottom of the well or hole to within eight feet of the ground surface. Cement grout must be placed from eight feet below ground surface to within three feet of the ground surface. The top three feet may be filled with native material. If a pipe cannot be lowered inside the well casing to place grout from the bottom to the top, the well may be plugged by making a tight connection to the top of the casing and pumping a volume of cement grout, sufficient to fill the well, under pressure into the well. Bentonite grout must not be used if the well is being plugged by making a tight connection to the top of the casing and pumping the grout in under pressure. If it cannot be verified that a well's casing was grouted in accordance with this chapter, an effort must be made to plug the annulus between the casing and the borehole wall from the bottom of the annulus up to the ground surface with the same type of material or materials required for plugging inside the casing.
2. Records must be kept of each well cemented including at a minimum the following information:
   a. well ID, total depth, and location
   b. driller, company, or person doing the cementing work
   c. total volume of grout placed down hole
   d. viscosity and density of the grout
3. The Permittee must remove any surface casing or cut off surface casing below ground and set a cement surface plug on each well plugged and abandoned.
4. Changes to the approved plugging and abandonment plan must be approved by the Director prior to beginning plugging operations. The Director also may require revision of the approved plugging and abandonment plan at any time prior to plugging the well.

D. Plugging and Abandonment Report

1. Within 60 days after plugging a well or at the time of the next quarterly report (whichever is less) the owner or operator must submit a report to the Director. If the quarterly report is due less than 15 days before completion of plugging, then the report must be submitted within 60 days. In accordance with this requirement, a Plugging and Abandonment Report (EPA Form 7520-13) must be submitted to the Director.
2. The plugging report must be certified as accurate by the person who performed the plugging operation. Such report must consist of either:
   a. A statement that the well was plugged in accordance with the approved plugging and abandonment plan in Section C of this Part; or
   b. Where actual plugging differed from the approved plugging and abandonment plan, an updated version of the plan specifying the differences.
3. Documentation must be provided to verify that the quantity of sealing material placed in the well is at least equal to the volume of the empty hole.

4. The Plugging and Abandonment Reports will be retained for at least 3 years from the date of the submission unless the Director requests an extension. If requested, at the conclusion of the retention period, the reports will be delivered to the Director.

PART XII. CONDITIONS APPLICABLE TO ALL UIC 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 non-injection well. Conversion may not proceed until the Permittee receives written approval from the Director. 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.

5. Construction Changes, Workovers, Logging and Testing Data

The Permittee must give advance notice to the Director, and must obtain the Director's written approval prior to any physical alterations or additions to the permitted facility. Alterations or workovers must meet all conditions as set forth in this permit. The Permittee must record any changes to the well construction on a Well Rework Record (EPA Form 7520-12), and must provide this and any other record of well workovers, logging, or test data to EPA with the next quarterly report. If the quarterly report is due within 30 of the activity, then the Permittee must include the information in the subsequent quarterly report.

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

Claims of confidentiality for the following information will be denied:

- The name and address of the Permittee, and
- information which deals with the existence, absence or level of contaminants in drinking water.

D. GENERAL PERMIT REQUIREMENTS

1. Duty to Comply

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

2. Need to Halt or Reduce Activity Not a Defense

It must 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.

3. 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.

4. 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.

5. 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.

6. Property Rights

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

7. 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.

8. Inspection and Entry

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:

a. Enter upon the Permittee's premises where a regulated facility or activity is located or conducted, or where records must be kept under the conditions of this Permit;
b. Have access to and copy, at reasonable times, any records that must be kept under the conditions of this Permit;
c. Inspect at reasonable times any facilities, equipment (including monitoring and control equipment), practices, or operations regulated or required under this Permit; and,
d. 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.

9. Signatory Requirements

All reports or other information requested by the Director must be signed and certified as follows:

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 general partner or the proprietor, respectively; or
    iii. for municipality, state, federal, or other public agency—by either a principal executive or a ranking elected official.
b. A duly authorized representative of the official designated in paragraph (a) above also may sign only if:
    i. the authorization is made in writing by a person described in paragraph (a) above;
    ii. the authorization specifies either an individual or a position having responsibility for the overall operation of the regulated facility or activity, such as the position of plant manager, operator of a well or a wellfield, 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.*

10. Reporting Requirements

Before written Authorization to Commence Injection is issued by the Director for a well, copies of all reports and notifications required by this Permit must be signed and certified in accordance with the requirements under Part XII, Sections D.9 and D.9.b of this permit and must be submitted to the EPA at the following address:

U.S. Environmental Protection Agency – Region 8
Chief, Underground Injection Control Section, 8WD-SDU
1595 Wynkoop Street
Denver, Colorado 80202-1129

After written Authorization to Commence Injection is issued by the Director for a well, copies of all reports and notifications required by this Permit must be signed and certified in accordance with the requirements under D.9 and D.9.b of this Part and must be submitted to the EPA at the following address:

U.S. Environmental Protection Agency – Region 8
Chief, Water Enforcement Branch, Mailcode: 8ENF-W-SD
Enforcement and Compliance Assurance Division
1595 Wynkoop Street
Denver, CO 80202-1129

All correspondence must reference the well name or wellfield 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 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 EPA Region VIII UIC Program Compliance and Technical Enforcement Director, 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.
h. 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.**
i. Other Noncompliance. The Permittee must report all instances of noncompliance not reported under paragraphs Section D.10.b, Section D.10.e or Section D.10.h of this Part at the time the monitoring reports are submitted. The reports must contain the information listed in Section D.10.g of this Part and be provided to the Director in electronic format as required in Part XII, Section D.10.h.
j. 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 XIII. 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 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 must become effective until the Permittee receives written notification from the Director that the alternative demonstration of financial responsibility is acceptable. The Director may, on a periodic basis, require the holder of a permit to revise the estimate of the resources needed to plug and abandon the well to reflect changes in such costs and may require the Permittee to provide a revised demonstration of financial responsibility.

1. Types of Adequate Financial Responsibility

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

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

A surety bond acceptable to the Director must contain wording identical to EPA's model language 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 EPA's model language (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 EPA's model language (40 CFR § 144.70). 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 statement with a Chief Financial Officer's letter acceptable to the Director must contain wording identical to EPA's model language (40 CFR § 144.70) and must demonstrate the Permittee meets or exceeds certain financial ratios. If this financial instrument is used, it must be resubmitted annually, within 90 days after the close of the Permittee's fiscal year, using the financial data available from the most recent fiscal year.

A standby trust agreement acceptable to the Director must contain wording identical to EPA's model language (40 CFR § 144.70). 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), U.S. Code naming 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. Timing for Updated Cost Estimate and Demonstration of Financial Responsibility

1. The Permittee must provide annual updates by providing the Director with a list of wells planned for construction in the upcoming year and the demonstration of adequate Financial Responsibility for the new wells.
2. This information must be provided to the Director by December 1 every year, to provide time for the Director to review and approve the updated demonstration of Financial Responsibility by Jan 1 of the following year.

D. This surety fulfills 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 XIV. COMPLIANCE WITH APPLICABLE FEDERAL LAWS

UIC regulation 40 CFR § 144.4, Considerations under Federal law, specifies federal laws that the EPA must comply in issuing 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 at 36 CFR part 800 require federal agencies to take into account the effects of their undertakings on historic properties.

In accordance with section 106 and the regulations at 36 CFR part 800, the Permittee must comply with the following measures:

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

2. When evaluated properties are eligible for the National Register of Historic Places, 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 that its employees and contractors involved in the Project are aware of and comply with the requirements of the PA. The Permittee may use measures such as initial orientation training and pre-job briefings to inform employees and contractors of their responsibilities under the PA in accordance with Stipulation 13a of the PA.

4. If a previously unknown cultural resource is discovered during the implementation of the Project, all ground-disturbing activities within 150 feet of the area of discovery must halt so as 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 (ESA), 16 U.S.C. 1531 et seq.

Section 7(a)(2) of the ESA and its 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.

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

a. 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.
   i. Whooping crane migration seasons: migrates through South Dakota April 1 to mid-May and mid-September to mid-November.
   ii. Rufa red knot migration seasons: migrates through South Dakota mid-April to mid-May and mid-September to October 31.
   iii. NLEB active season: mid-April to October 31. The critical pup season is June 1 – July 31.

b. 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

c. 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.

d. 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.

e. 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.

f. The Permittee must install netting, use bird balls or other acceptable bird deterrent method to prevent birds and bats from accessing all project ponds.

g. 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.

h. 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.

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

The Permittee must document all activities related to compliance with Part XIV, 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 mitigation 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

APPENDIX A
WELLFIELD CROSS SECTIONS

Figure A1. Cross Sections through Dewey Wellfields 1, 2 and 3

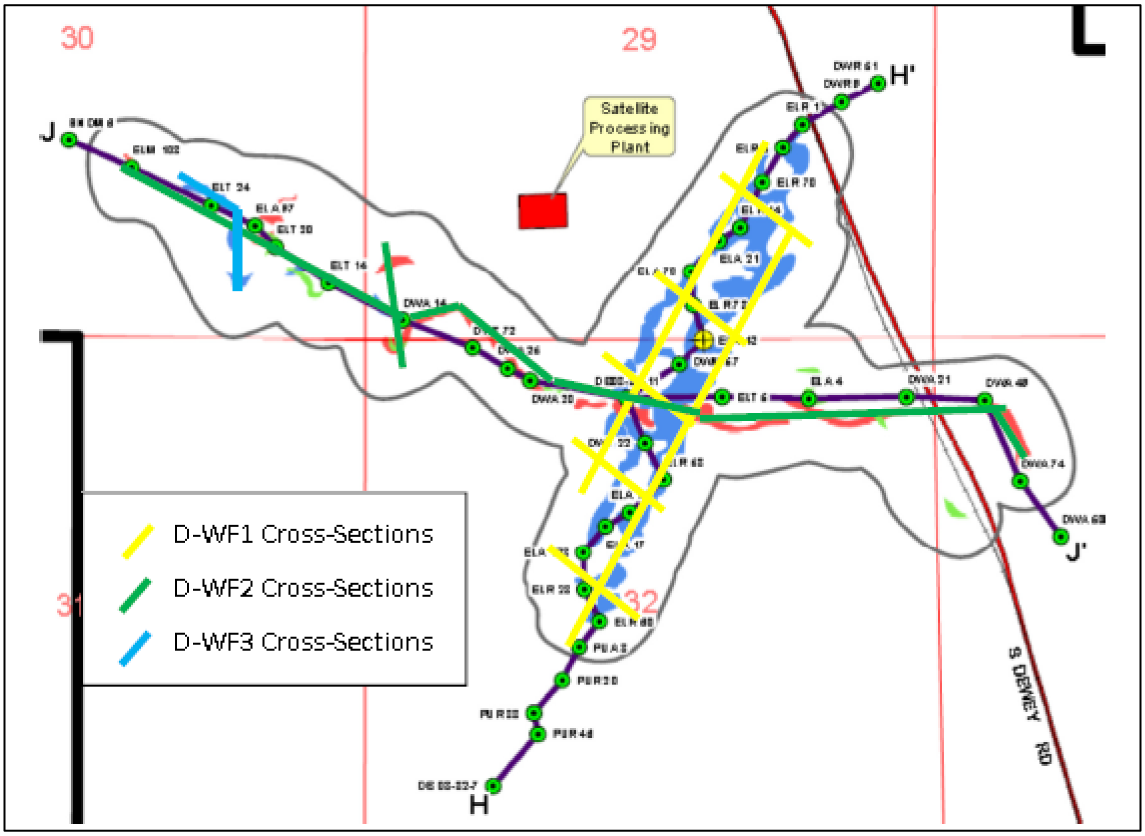


Figure A2. Cross Sections through Dewey Wellfield 4

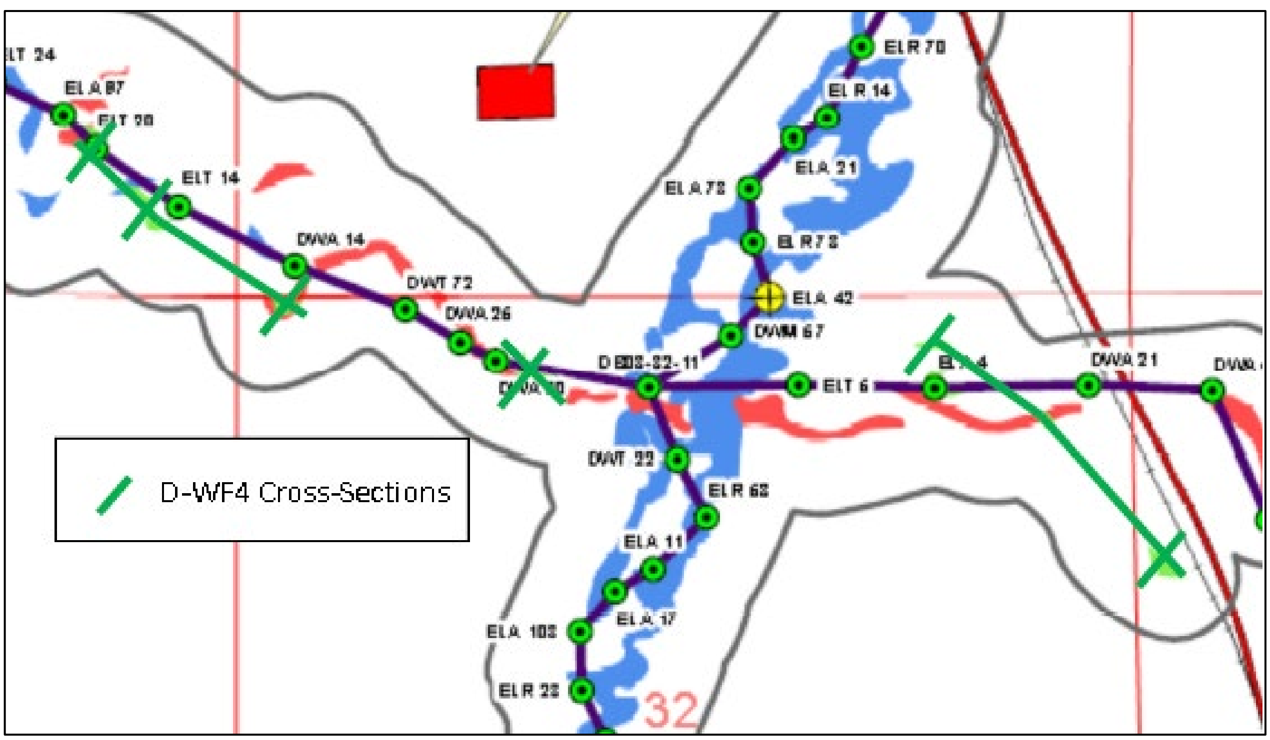


Figure A3. Cross Sections through Burdock Wellfield 4

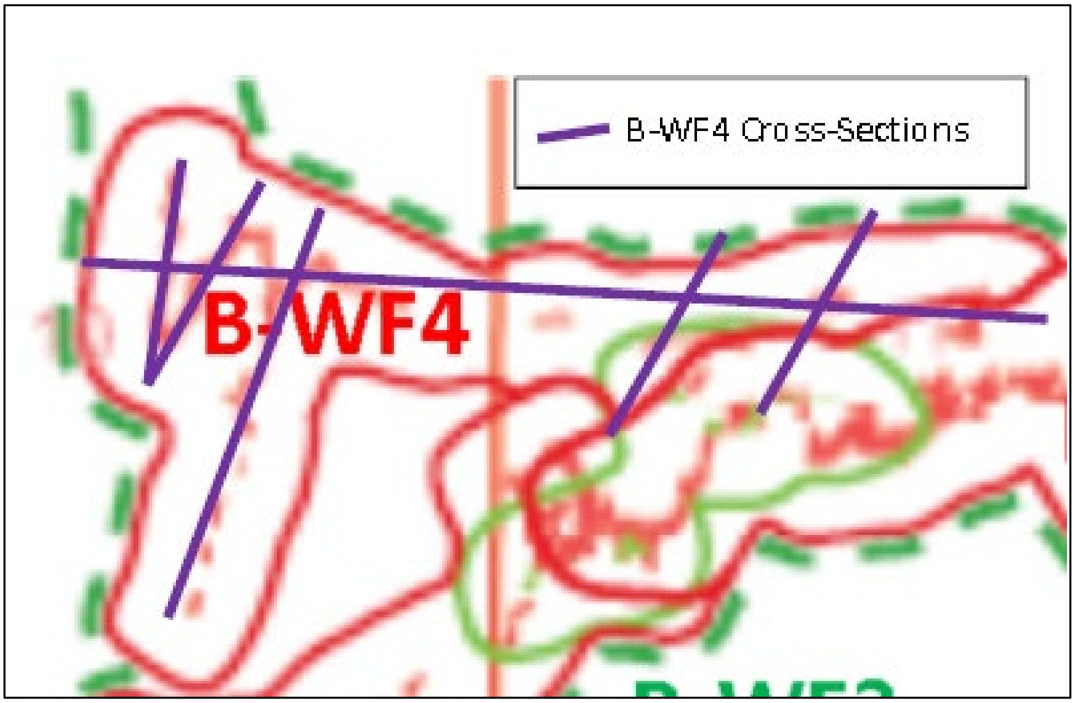


Figure A4. Cross Sections through Burdock Wellfields 5 and 9

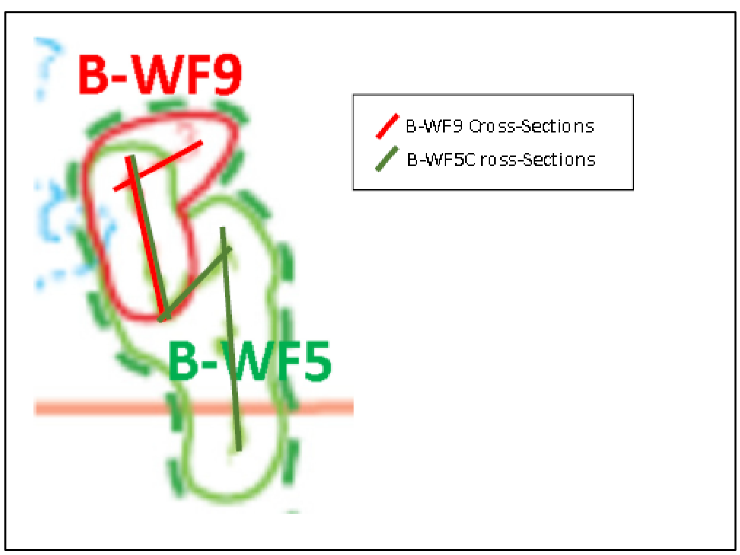


Figure A5. Cross Sections through Burdock Wellfields 6 and 7

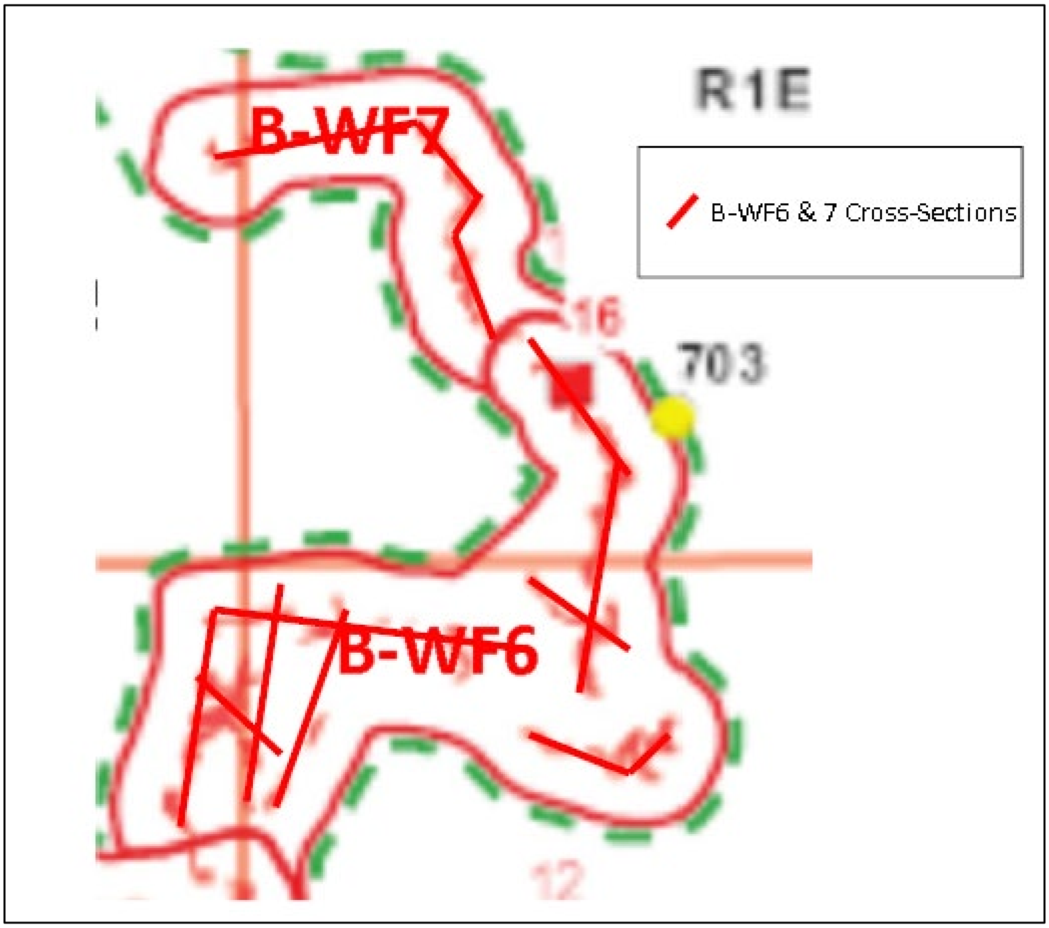


Figure A6. Cross Sections through Burdock Wellfield 8

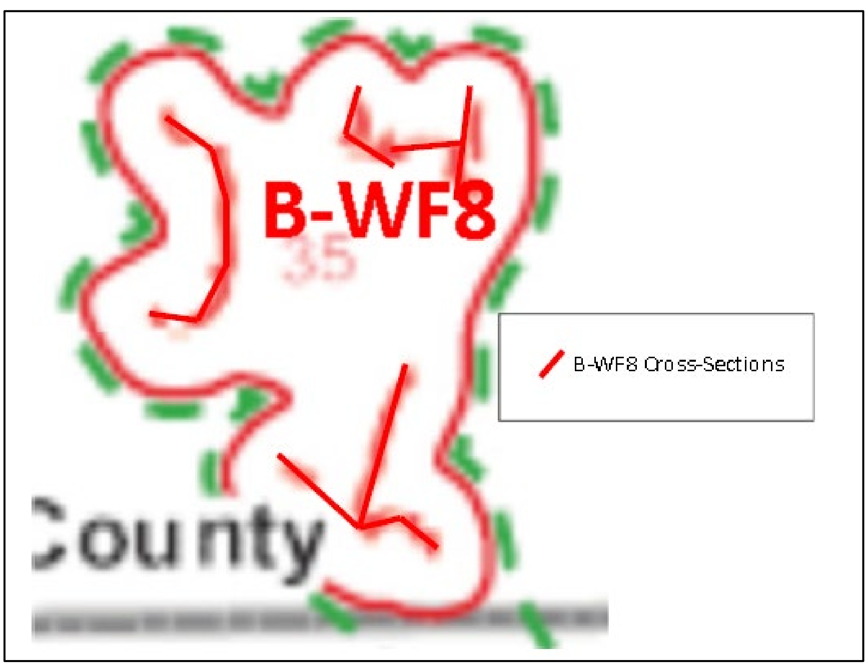
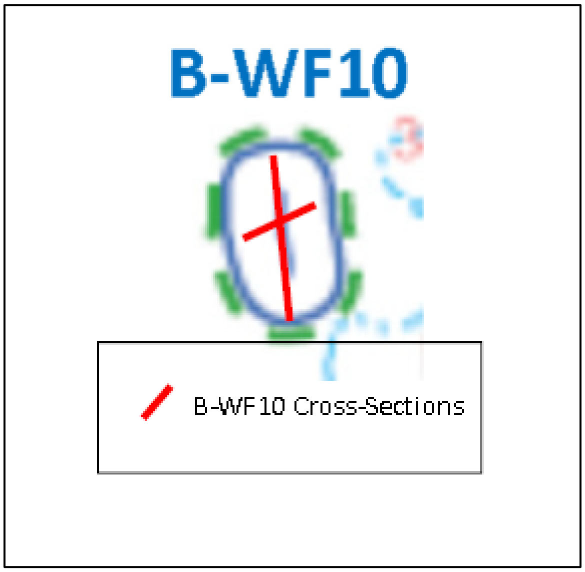


Figure A7. Cross Sections through Burdock Wellfield 10



APPENDIX B
ISR CONTAMINANT PERMIT LIMITS AT AE BOUNDARY

Table B-1. List of ISR Contaminants, Permit Limits, Standards Type and Required Analytical Method Minimum Detection Limit

Test Analyte/Parameter*	Permit Limit (mg/L)	Standard Type	Required Analytical Method Minimum Detection Limit (mg/L)
Antimony, Sb	0.006	MCL[1]	0.003
Arsenic, As	0.01	MCL	0.005
Barium, Ba	2	MCL	1
Beryllium, Be	0.004	MCL	0.002
Boron, B	6	HA-L[2]	3
Cadmium, Cd	0.005	MCL	0.0025
Chromium, Cr	0.1	MCL	0.05
Copper, Cu	1.3	LCR-Action Level[3]	0.65
Fluoride, F	4	MCL	2
Iron, Fe	5	R8-HBS[4]	2.5
Lead, Pb	0.015	LCR-Action Level[3]	0.0075
Manganese, Mn	0.3	HA-L	0.15
Mercury, Hg	0.002	MCL	0.001
Molybdenum, Mo	0.04	HA-L	0.02
Nickel, Ni	0.1	HA-L	0.05
Nitrate, NO_3^- (as Nitrogen)	10	MCL	5
pH	6.5-8.5 (pH units)	SMCL[5]	0.5 pH units resolution
Radium-226 + Radium-228	5 pCi/L (converted to mg/L)	MCL	2.5 pCi/L (converted to mg/L)
Selenium, Se	0.05	MCL	0.025
Silver, Ag	0.1	HA-L	0.05
Sodium, Na	20	HBS[6]	10
Strontium, Sr	4	HA-L	2
Sulfate, SO_4	500	HBS[7]	250
TDS	500	SMCL[5]	250
Thallium, Tl	0.002	MCL	0.001
Uranium, U	0.03	MCL	0.015
Vanadium, V	0.3	ATSDR MRL[8]	0.15
Zinc, Zn	2	HA-L	1

[1]MCL – Maximum Contaminant Level or Primary Drinking Water Standard
[2]HA-L – Health Advisory – Lifetime
[3]LCR-Action Level – Lead and Copper Rule action level
[4]R8-HBS – EPA Region 8 Health-Based Standard

[5]Secondary MCL
[6]EPA, 2003, Drinking Water Advisory: Consumer Acceptability Advice and Health Effects Analysis on Sodium, EPA 822-R-03-006, 29 p.
[7]EPA, 2003, Drinking Water Advisory: Consumer Acceptability Advice and Health Effects Analysis on Sulfate, EPA 822-R-03-007, 29 p.
[8]Based on Agency for Toxic Substances and Disease Registry oral intermediate Minimum Risk Level of 0.01 mg/kg-day using 80 kg and 2.4 L/day