EPA REGION 8'S RESPONSE TO PETITION FOR REVIEW

ATTACHMENT V

Fact Sheet for the second Dewey-Burdock Draft Class III Area Permit, August 26, 2019

Administrative Record Document No. 171

FACT SHEET
Powertech (USA) Inc.
Dewey-Burdock Class III Injection Wells
Custer and Fall River Counties, South Dakota
EPA PERMIT NO. SD31231-00000

CONTACT:
Valois Robinson
U. S. Environmental Protection Agency
Underground Injection Control Program, Mail Code: 8WD-SDU
1595 Wynkoop Street
Denver, Colorado 80202-1129
Telephone: 1-800-227-8917 ext. 312-6276 or 1-303-312-6276
Email: robinson.valois@epa.gov

TABLE OF CONTENTS

1.0 INTRODUCTION

This FACT SHEET presents the derivation of site-specific Underground Injection Control (UIC) Permit conditions and reasons for them.

UIC Permits specify the conditions and requirements for construction, operation, monitoring and reporting and plugging of injection wells to prevent the movement of fluids into underground sources of drinking water (USDWs). Under Title 40 Code of Federal Regulations (CFR) 144 subpart D, certain conditions apply to all UIC Permits and may be incorporated either expressly or by reference. Certain general permit conditions, for which content is mandatory and not subject to site-specific differences (40 CFR parts 144, 146 and 147), are not discussed in this document. UIC regulations specific to injection wells in South Dakota are found at 40 CFR part 147 subpart QQ.

Powertech (USA) Inc. (the Permittee) submitted a UIC Class III Permit Application. The EPA has reviewed the information provided and has determined the required information and data was complete and in accordance with 40 CFR parts 124, 144, 146 and 147.

This Permit is proposed as an Area Permit, which means that it authorizes more than one injection well. The injection wells authorized by the Area Permit will be used for the injection of fluids associated with in-situ recovery (ISR) of uranium; therefore, per 40 CFR § 144.6(c)(2), they are classified as Class III injection wells. Upon the Effective Date, the Class III Area Permit will authorize the construction of a new injection well project governed by the conditions specified in the Area Permit. The use of an injection well for any injection activities before the Permittee obtains a written authorization from the EPA is prohibited. The Permittee must submit the information specified in Part II of the Class III Area Permit for the EPA review to obtain authorization from the EPA for injection activities as specified in the Class III Area permit.

The Class III Area Permit will be in effect for a period up to the operating life of the facility. The EPA will review the Class III 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 40 CFR §§ 144.39, 144.40, and 144.41.

1.1 The Public Review Process for UIC Permits

1.1.1 The 2017 Public Review Process

On March 6, 2017, the EPA Region 8 UIC Program published a public notice on the EPA Region 8 UIC website: https://www.epa.gov/uic/uic-epa-region-8 announcing the proposal of two UIC Area Permits to Powertech for injection activities related to uranium recovery and an accompanying aquifer exemption. One is a UIC Class III Area Permit for injection wells related to the In-situ Recovery (ISR) of uranium; the second is a UIC Class V Area Permit for deep injection wells that will be used to dispose of ISR process waste fluids into the Minnelusa Formation after treatment to meet radioactive waste and hazardous waste standards. The proposed aquifer exemption is associated with the Class III permit. The public comment period was originally scheduled to end on May 19, 2017. However, the EPA granted an extension to the public comment period through June 19, 2017. The EPA solicited comments on the two UIC Area Permits and the aquifer exemption record of decision (ROD). The EPA also issued a draft Environmental Justice Analysis, a draft document outlining the EPA National Historic Preservation Act (NHPA) section 106 consultation process, and a Cumulative Effects Analysis document. In addition to the public notice on the EPA Region 8 UIC Program website, the EPA published notice of the issuance of the draft UIC permits in the *Lakota Country Times,* the *Edgemont Herald Tribune,* the *Rapid City Journal,* and the *Custer County Chronicle*. A notice was also posted on http://www.indianz.com. All of these notices directed readers to the EPA Region 8 UIC Program website, which contained links to the Administrative Record for the proposed actions.

The EPA received comments from the public through testimony given during the public hearings listed below, email and written correspondence. The EPA held the following public hearings:

<u>Thursday, April 27, 2017</u> from 4:00 to 8:30 p.m. (with a break from 6:00 to 6:30 p.m.)
Niobrara Lodge
803 US Highway 20
Valentine, Nebraska 69201

<u>Monday-Tuesday, May 8-9, 2017</u>, from 1:00 to 8:00 p.m. (with a break from 5:00 to 6:00 p.m.)
The Best Western Ramkota Hotel
2111 N. LaCrosse Street
Rapid City, South Dakota 57701

Wednesday, May 10, 2017, from 1:00 to 8:00 pm (with a break from 5:00 to 6:00 p.m.)
The Mueller Center
801 S 6th Street
Hot Springs, South Dakota 57747

Thursday, May 11, 2017, from 1:00 to 8:00 pm (with a break from 5:00 to 6:00 pm)
St. James Catholic Church
310 3rd Avenue
Edgemont, South Dakota 57735

The EPA reviewed the comments received during the public comment period and updated the Class III and Class V draft area permits and associated documents.

1.1.2 The 2019 Public Review Process

On August 26, 2019, the EPA Region 8 UIC Program published a public notice on the EPA Region 8 UIC website: https://www.epa.gov/uic/uic-epa-region-8 announcing the updated UIC draft Class III and V Area Permits to Powertech for injection activities related to uranium recovery and an accompanying aquifer exemption. In addition to the updated draft permits, the EPA has issued an updated draft Aquifer Exemption Record of Decision, an updated draft Environmental Justice Analysis and an updated NHPA process document for public review and comment.

The EPA also published notice of the issuance of the updated UIC draft Class III and V permits and associated documents in the *Lakota Country Times,* the Fall River County *Herald,* the *Rapid City Journal,* and the *Custer County Chronicle*. A notice was also posted on http://www.indianz.com. All of these notices direct readers to the EPA Region 8 UIC Program website, which contains links to the Administrative Record for these proposed actions.

The EPA has set up Docket EPA-R08-OW-2019-0512 on the Regulations.gov website to receive comments. For instructions on how to submit comments to the Regulations.gov website see *How to Use Regulations.gov* and *Frequently Asked Questions*.

The EPA will hold a public hearing on Saturday, October 5, 2019, from 9:00 am to 1:00 pm and from 2:00 to 6:00 pm at:
The Mueller Center
801 S 6th Street
Hot Springs, South Dakota 57747

At the public hearing, any person may submit oral or written statements and data concerning the updated draft permits and associated documents. Reasonable limits may be set upon the time allowed for oral statements, and the submission of statements in writing are required for the public record. As stated under 40 CFR § 124.13, "[a]ll persons, including applicants, who believe any condition of a draft permit is inappropriate or that the EPA's tentative decision…to prepare a draft permit is inappropriate, must raise all reasonably ascertainable issues and submit all reasonably available arguments supporting their position by the close of the public comment period (including the public hearings)." Any supporting materials which are submitted shall be included in full and may not be incorporated by reference, unless they are already part of the Draft Area Permit Administrative Record, or consist of State or Federal statutes and regulations, are EPA documents of general applicability, or are other generally available reference materials. Commenters shall make supporting materials not included in the list above available to the EPA by presenting a printed copy at a public hearing, submitting the file to Docket EPA-R08-OW-2019-0512 on the Regulations.gov website or mailing the information to Valois Robinson at the mailing address on the first page of this Fact Sheet. A written transcript of the hearing shall be made available to the public as part of the Administrative Record for the Final Area Permit decision.

At the close of the public comment period, the EPA will review all comments received during both the 2017 and 2019 public comment periods and during all the public hearings and prepare a written statement addressing all the comments received that are relevant to the UIC Class III and V Draft Area Permits. The EPA will issue a final permit decision and notify the applicant and each person who has submitted comments or requested notice of the final permit decision. A final permit decision means a final decision to issue or deny the permit. The written statement addressing all relevant comments received will be included in the notification of the final permit decision. The notice will also include reference to the procedures for appealing a decision on a UIC permit under 40 CFR § 124.19.

If the EPA receives comments on the UIC Class III and V Draft Area Permits from the public during the public review process, the Final Area Permit decisions will not be effective until 30 days after the final permit issue date as required by 40 CFR § 124.15. The purpose of this 30-day period is to allow time for those who submitted comments or participated in a public hearing to appeal the final permit decision as described under 40 CFR § 124.19, which is paraphrased below.

Within 30 days after the UIC final permit decisions have been issued, any person who filed comments on the draft permits or participated in a public hearing may petition the Environmental Appeals Board to review any condition of the permit decisions. Any person who failed to file comments or failed to participate in a public hearing on the draft permits may petition for administrative review only to the extent of the changes from the draft to the final permit decisions. The 30-day period within which a person may request review under this section begins with the service of notice of the EPA's final permit decisions unless a later date is specified in that notice. The petition shall include a statement of the reasons supporting that review, including a demonstration that any issues being raised were raised during the public comment period (including any public hearing) to the extent required by these regulations and when appropriate, a showing that the condition in question is based on:

(1) A finding of fact or conclusion of law which is clearly erroneous, or
(2) An exercise of discretion or an important policy consideration which the Environmental Appeals Board should, in its discretion, review.

Within a reasonable time following the filing of the petition for review, the Environmental Appeals Board will issue an order granting or denying the petition for review. To the extent review is denied, the conditions of the final permit decisions become a final agency action.

1.2 Contact Information

For any additional information about this Draft Class III Area Permit or the public review process, please contact Valois Robinson at the email address shown at the beginning of this Fact Sheet.

2.0. GENERAL INFORMATION AND DESCRIPTION OF FACILITY

Powertech (USA) Inc.
5575 DTC Parkway, Suite 140,

Greenwood Village, Colorado 80111

submitted an application for a UIC Program Area Permit to construct and operate up to 14 Class III injection wellfields within the Dewey-Burdock Project Area, which is the area within the Project Boundary shown in Figures 1 and 2. The 14 wellfields will be used for the ISR of uranium from ore deposits in the Fall River Formation and Chilson Sandstone of the Lakota Formation of the Inyan Kara Group. The Class III Area Permit establishes requirements for the 14 proposed injection wellfields listed in Table 1:

Table 1. Injection Wellfields Proposed under the Class III Area Permit

Wellfield Permit Number	Wellfield Name	Proposed Injection Interval
SD31231-09459	Burdock Wellfield 1	Middle Chilson Sandstone – west end Lower Chilson Sandstone – east end
SD31231-09460	Burdock Wellfield 2	Middle Chilson Sandstone
SD31231-09461	Burdock Wellfield 3	Upper Chilson Sandstone
SD31231-09462	Burdock Wellfield 4	Middle Chilson Sandstone
SD31231-09463	Burdock Wellfield 5	Upper Chilson Sandstone
SD31231-09464	Burdock Wellfield 6	Lower Chilson Sandstone – northeast end Middle Chilson Sandstone – middle section Lower Chilson Sandstone – southwest end
SD31231-09465	Burdock Wellfield 7	Lower Chilson Sandstone
SD31231-09466	Burdock Wellfield 8	Middle Chilson Sandstone
SD31231-09467	Burdock Wellfield 9	Middle Chilson Sandstone
SD31231-09470	Burdock Wellfield 10	Lower Fall River Formation
SD31231-08351	Dewey Wellfield 1	Lower Fall River Formation
SD31231-09471	Dewey Wellfield 2	Middle and/or Lower Chilson Sandstone
SD31231-09472	Dewey Wellfield 3	Lower Fall River Formation
SD31231-09473	Dewey Wellfield 4	Upper Chilson Sandstone

2.1 Project Description

The proposed Dewey-Burdock uranium ISR Project Area is located in the southern Black Hills region in South Dakota on the South Dakota-Wyoming state line in southwest Custer and northwest Fall River Counties as shown in Figure 1. The site is located approximately 13 miles northwest of Edgemont, SD and 46 miles west of the western border of the Pine Ridge Reservation. The Dewey-Burdock Project Area is divided into two areas: the Dewey Area, comprising the western portion of the Project Area and the Burdock Area, comprising the eastern portion of the Project Area, as shown in Figure 2.

The Permittee proposes recovering uranium from ore deposits in the Fall River Formation and Lakota Formation Chilson Sandstone of the Inyan Kara Group using the ISR process. The sub-units of the Inyan Kara Group geologic units are shown in the stratigraphic column in Figure 3, which shows the geologic formations present at the surface and in the subsurface at the Dewey-Burdock Project Area.

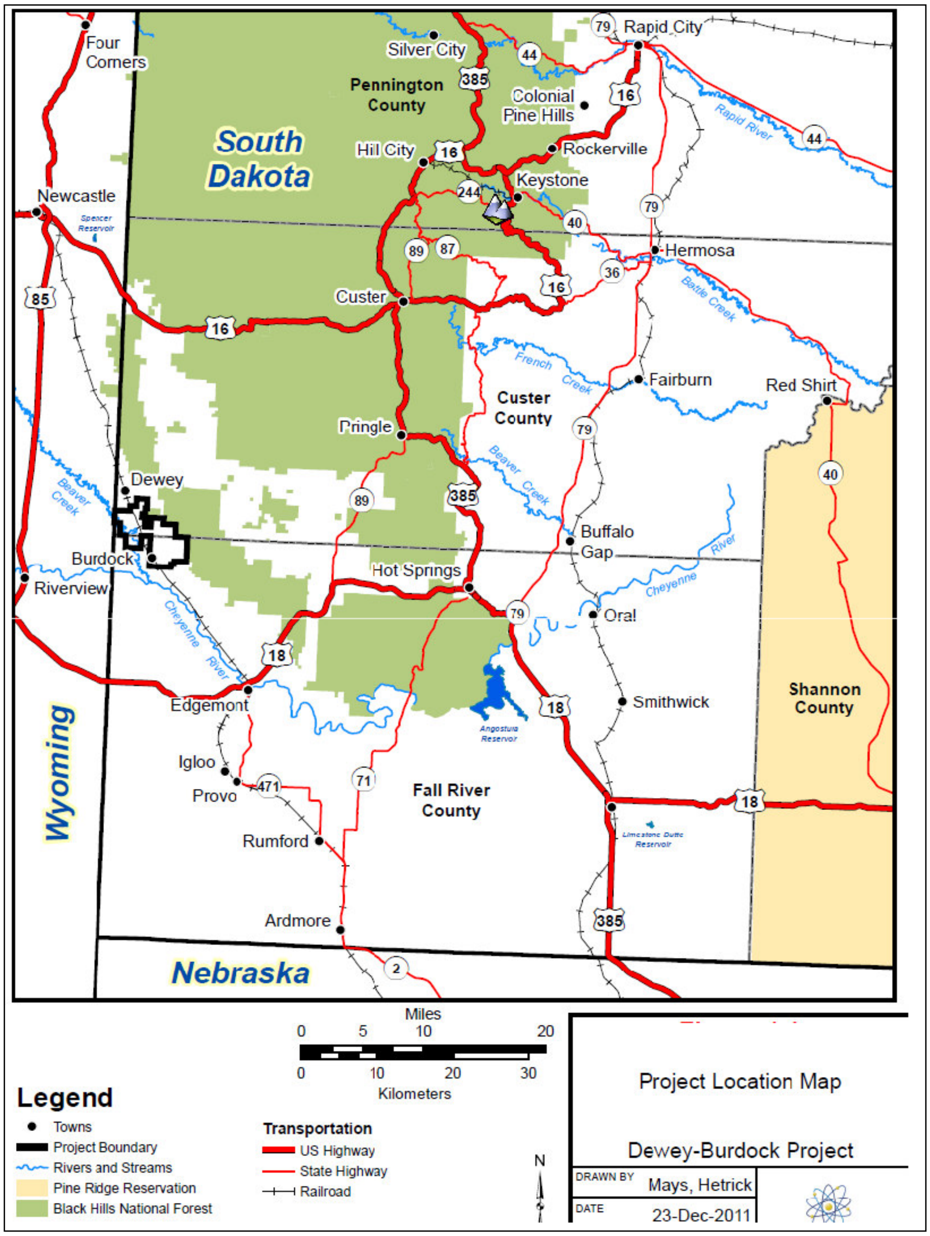


Figure 1. Dewey-Burdock Project Area Location

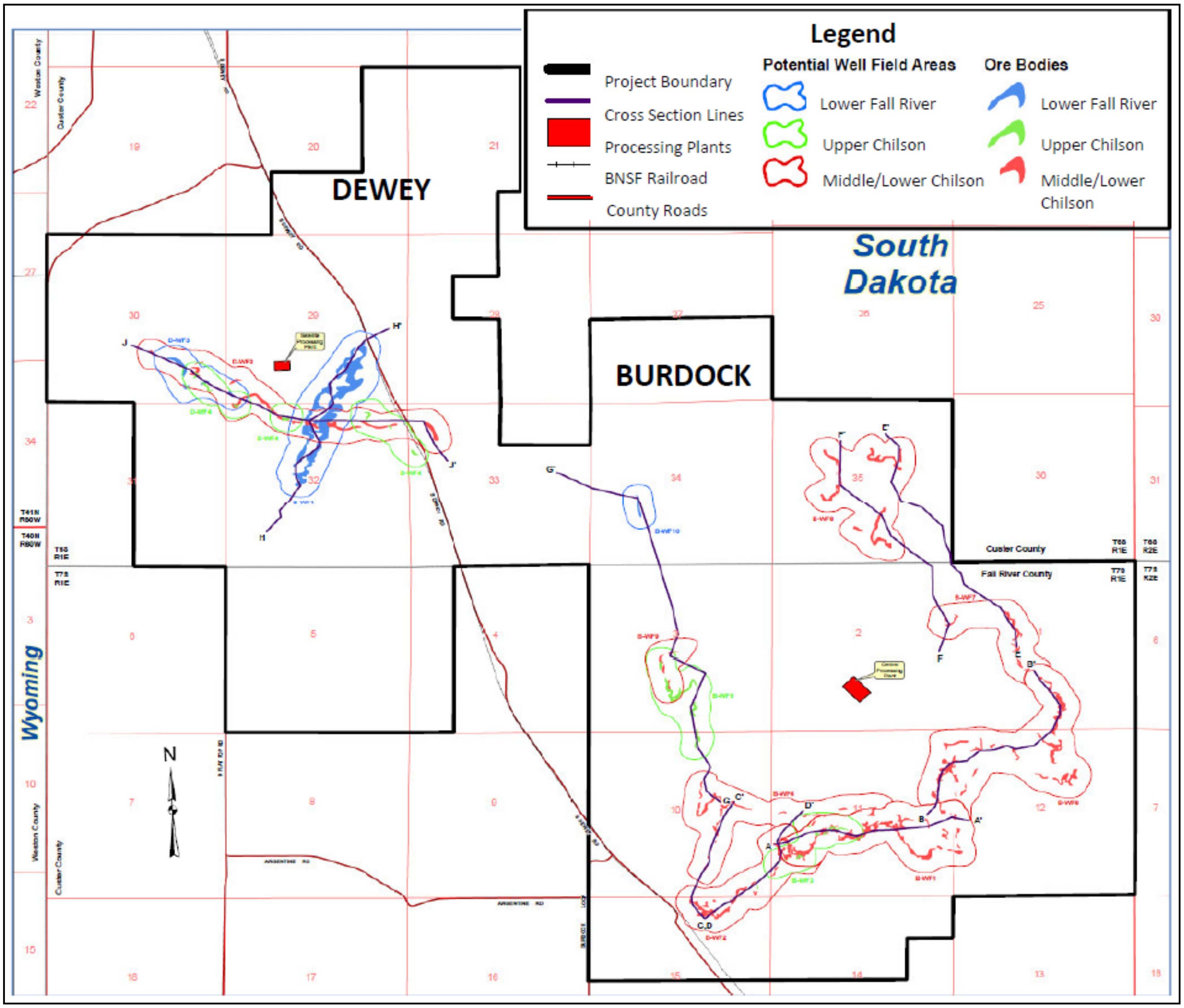


Figure 2. The Dewey-Burdock Class III Area Permit Boundary (Project Boundary)

ERATHEM	SYSTEM	ABBREVIATION FOR STRATIGRAPHIC INTERVAL	STRATIGRAPHIC UNIT		THICKNESS IN FEET	DESCRIPTION
CENOZOIC	QUATERNARY & TERTIARY (?)	QTac	UNDIFFERENTIATED SANDS AND GRAVELS		0-50	Alluvial and colluvial materials.
		Tw	WHITE RIVER GROUP		0-300	Light colored clays with sandstone channel fillings and local limestone lenses.
	TERTIARY	Tui	INTRUSIVE IGNEOUS ROCKS		--	Includes rhyolite, latite, trachyte, and phonolite.
MESOZOIC	CRETACEOUS	Kps	PIERRE SHALE		1,200-2,700	Principal horizon of limestone lenses giving teepee buttes. Dark-gray shale containing scattered concretions. Widely scattered limestone masses, giving small teepee buttes. Black fissile shale with concretions.
			NIOBRARA FORMATION		[1]80-300	Impure chalk and calcareous shale.
			CARLILE SHALE	Turner Sandy Member Wall Creek Member	[1]350-750	Light-gray shale with numerous large concretions and sandy layers. Dark-gray shale.
			GREENHORN FORMATION		225-380	Impure slabby limestone. Weathers buff. Dark-gray calcareous shale, with thin Orman Lake limestone at base.
			GRANEROS GROUP: BELLE FOURCHE SHALE		150-850	Gray shale with scattered limestone concretions. Clay spur bentonite at base.
			GRANEROS GROUP: MOWRY SHALE		125-230	Light-gray siliceous shale. Fish scales and thin layers of bentonite.
			GRANEROS GROUP: MUDDY SANDSTONE	NEWCASTLE SANDSTONE	0-150	Brown to light-yellow and white sandstone.
			GRANEROS GROUP: SKULL CREEK SHALE		150-270	Dark-gray to black siliceous shale.
		Kik	INYAN KARA GROUP: FALL RIVER FORMATION		10-200	Massive to slabby sandstone.
			INYAN KARA GROUP: LAKOTA FM	Fuson Shale Minnewaste Limestone Chilson Member	10-190 0-25 25-485	Coarse gray to buff cross-bedded conglomeratic sandstone, interbedded with buff, red, and gray clay, especially toward top. Local fine-grained limestone.
	JURASSIC	Ju	MORRISON FORMATION		0-220	Green to maroon shale. Thin sandstone.
			UNKPAPA SS		0-225	Massive fine-grained sandstone.
			SUNDANCE FORMATION	Redwater Member Lak Member Hulett Member Stockade Beaver Mem. Canyon Spr Member	250-450	Greenish-gray shale, thin limestone lenses. Glauconitic sandstone; red sandstone near middle.
			GYPSUM SPRING FORMATION		0-45	Red siltstone, gypsum, and limestone.
	TRIASSIC	TRPs	SPEARFISH FORMATION	Goose Egg Equivalent	375-800	Red sandy shale, soft red sandstone and siltstone with gypsum and thin limestone layers. Gypsum locally near the base.
PALEOZOIC	PERMIAN	Pmk	MINNEKAHTA LIMESTONE		[1]25-65	Thin to medium-bedded fine-grained, purplish-gray laminated limestone.
		Po	OPECHE SHALE		[1]25-150	Red shale and sandstone.
	PENNSYLVANIAN	PIPm	MINNELUSA FORMATION		[1]375-1,175	Yellow to red cross-bedded sandstone, limestone, and anhydrite locally at top. Interbedded sandstone, limestone, dolomite, shale, and anhydrite. Red shale with interbedded limestone and sandstone at base.
	MISSISSIPPIAN	MDm	MADISON (PAHASAPA) LIMESTONE		[1]250-1,000	Massive light-colored limestone. Dolomite in part. Cavernous in upper part.
	DEVONIAN		ENGLEWOOD FORMATION		30-60	Pink to buff limestone. Shale locally at base.
	ORDOVICIAN	Ou	WHITEWOOD (RED RIVER) FORMATION		[1]0-235	Buff dolomite and limestone.
			WINNIPEG FORMATION		[1]0-150	Green shale with siltstone.
	CAMBRIAN	O€d	DEADWOOD FORMATION		[1]0-500	Massive to thin-bedded buff to purple sandstone. Greenish glauconitic shale, flaggy dolomite, and flat-pebble limestone conglomerate. Sandstone, with conglomerate locally at the base.
PRECAMBRIAN		p€u	UNDIFFERENTIATED METAMORPHIC AND IGNEOUS ROCKS			Schist, slate, quartzite, and arkosic grit. Intruded by diorite, metamorphosed to amphibolite, and by granite and pegmatite.

Figure 3. Stratigraphic Column Showing the Geologic Formations Present at the Dewey-Burdock Project Area Site

[1] Modified based on drillhole data.

[2] The Gypsum Springs Formation is identified in only one of the oil & gas test well logs near the Dewey-Burdock site. The other logs include it with the Spearfish Formation because of similar lithology. The Gypsum Springs is not included as a separate formation in Table 3.

The ISR process involves using Class III injection wells to introduce a lixiviant into subsurface uranium ore deposits to leach the uranium from the ore deposits. The Permittee proposes using a lixiviant consisting of groundwater from the uranium-bearing aquifer, adding gaseous oxygen to mobilize uranium into solution and gaseous carbon dioxide to hold the uranium in solution while it is transported to production wells.

The uranium-bearing lixiviant will be pumped from the production wells to a processing plant, where the dissolved uranium will be removed from solution using an ion-exchange resin. After uranium removal, the groundwater will be re-fortified with oxygen and carbon dioxide, recirculated and reinjected back into the wellfield via injection wells.

Once the ion-exchange resin is loaded with uranium, the loaded resin will be stripped using a saltwater solution. The resulting barren resin then will be used again to recover more uranium. The uranium-bearing solution will be pumped through a precipitation process, where the uranium will be precipitated as a yellow, solid uranium oxide yellowcake. The precipitated uranium oxide then will be filtered, washed, dried and packaged in sealed containers for shipment to a processing site where it will be further processed until it can be used as uranium fuel.

After treatment to meet radioactive waste and hazardous waste thresholds, the waste fluids from this process will be injected into the proposed UIC Class V deep injection wells or by land application under a Groundwater Discharge Permit issued by the South Dakota Department of Environment and Natural Resources (DENR). Part VIII, Section F of the Class III Area Permit requires that the Permittee maintain hydraulic control of each wellfield by injecting a lower volume of fluids into the wellfield than the production wells are pumping out of the wellfield. The difference between the fluid volume being pumped out of the wellfield and the fluid volume being injected is the wellfield *bleed*. *Bleed* is defined as excess ISR operation or restoration solution withdrawn to maintain a cone of depression so native groundwater continually flows toward the center of the wellfield. The wellfield *bleed* is an additional waste fluid from the ISR operation as described in the Fact Sheet for the UIC Class V Area Permit Fact Sheets under Section 7.8 *Approved Injectate and Injectate Permit Limits*.

Liquid waste generated by the Dewey-Burdock Project will be treated and disposed of by injection into Class V deep injection wells or by land application. Figures 4a and 4b show the proposed locations for the Class V deep injection wells. For more information about the Class V deep injection wells, see the Fact Sheet for the Class V Draft Area Permit. For a discussion of the land application disposal methods refer to the South Dakota DENR Groundwater Discharge Permit found at https://denr.sd.gov/des/gw/Powertech/Powertech_GW_Discharge_Permit.aspx or Sections 2.1.1.1.2.4.2 and 2.1.1.1.4.1.2 of the NRC Final *Environmental Impact Statement for the Dewey-Burdock Project in Custer and Fall River Counties, South Dakota* found at http://pbadupws.nrc.gov/docs/ML1402/ML14024A477.pdf.

The Permittee plans to operate each ISR wellfield until uranium recovery is no longer economical. The Permittee estimates that individual wellfields will operate for about 2 years. After the uranium recovery process has been completed in a wellfield, the groundwater restoration process begins for that wellfield. The contaminated groundwater is pumped from the wellfield and treated using reverse osmosis. The restoration process also produces *bleed* fluids. The restoration *bleed* and the reject water from the reverse osmosis treatment are injected into the Class V deep injection wells as described in the Fact Sheet for the Class V Draft Area Permit under Section 7.8 *Approved Injectate and Injectate Permit Limits*.

The Burdock Area (the eastern portion of the Project Area) will contain ten ISR wellfields and a central processing plant, which will be used to recover uranium from the Burdock wellfields. The Dewey Area (the western portion of the Project Area) will contain four ISR wellfields and a satellite facility, which will be used to recover uranium from the Dewey wellfields. The uranium-loaded ion exchange resin will be transported by tanker truck from the Dewey satellite facility to the Burdock central processing plant or to another licensed central processing plant for processing.

Three types of wells will be installed in each wellfield to conduct ISR operations within the proposed Dewey-Burdock ISR Project Area: injection wells, production wells and monitoring wells. During ISR operation, injection wells will be used to introduce lixiviant into the uranium ore bodies and production wells will be used to extract uranium-bearing lixiviant. The monitoring wells will be used to identify and assess impacts of ongoing uranium recovery operations and detect fluid movement out of the approved injection interval, should such an event occur. As discussed in Section 11.0, during the groundwater restoration phase, the injection wells will be used to inject clean water, and the production wells will be used to pump groundwater out of the wellfields. If a groundwater sweep phase is used during restoration, then no fluids will be pumped into the wellfield. Instead, production wells will pump groundwater out of the wellfield causing groundwater to flow in toward the wellfield from outside the wellfield boundary.

The Class III Area Permit includes requirements for all injection and production wells in the 14 proposed ISR wellfields. Because the functions of injection and production wells may be interchanged frequently during uranium recovery operations and during wellfield restoration, both well types are regulated under the Class III Area Permit. The construction of all injection and production wells are subject to the requirements in Part V of the Class III Area Permit; the mechanical integrity testing of all injection and production wells must follow the requirements described in the Part VII of the Class III Area Permit.

2.2 Area Permit Boundary

The fact that the Class III Area Permit is an area permit means that it authorizes multiple injection wells within the designated wellfield areas. There is no limit in the Class III Area Permit as to how many injection and production wells the Permittee may construct. The injection wells may be located only in the designated wellfield areas shown in Figure 2. The area included within the Area 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 shown in Figure 2. It 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 shown in Figure 2.

2.3 Well Locations

This Area Permit authorizes the construction and operation of up to 14 Class III ISR wellfields within the Permit Area shown in Figure 2. The proposed locations for these 14 wellfields are listed in Table 2 and shown in Figures 4a and 4b.

Table 2. Approximate Locations of the Proposed ISR Wellfields

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

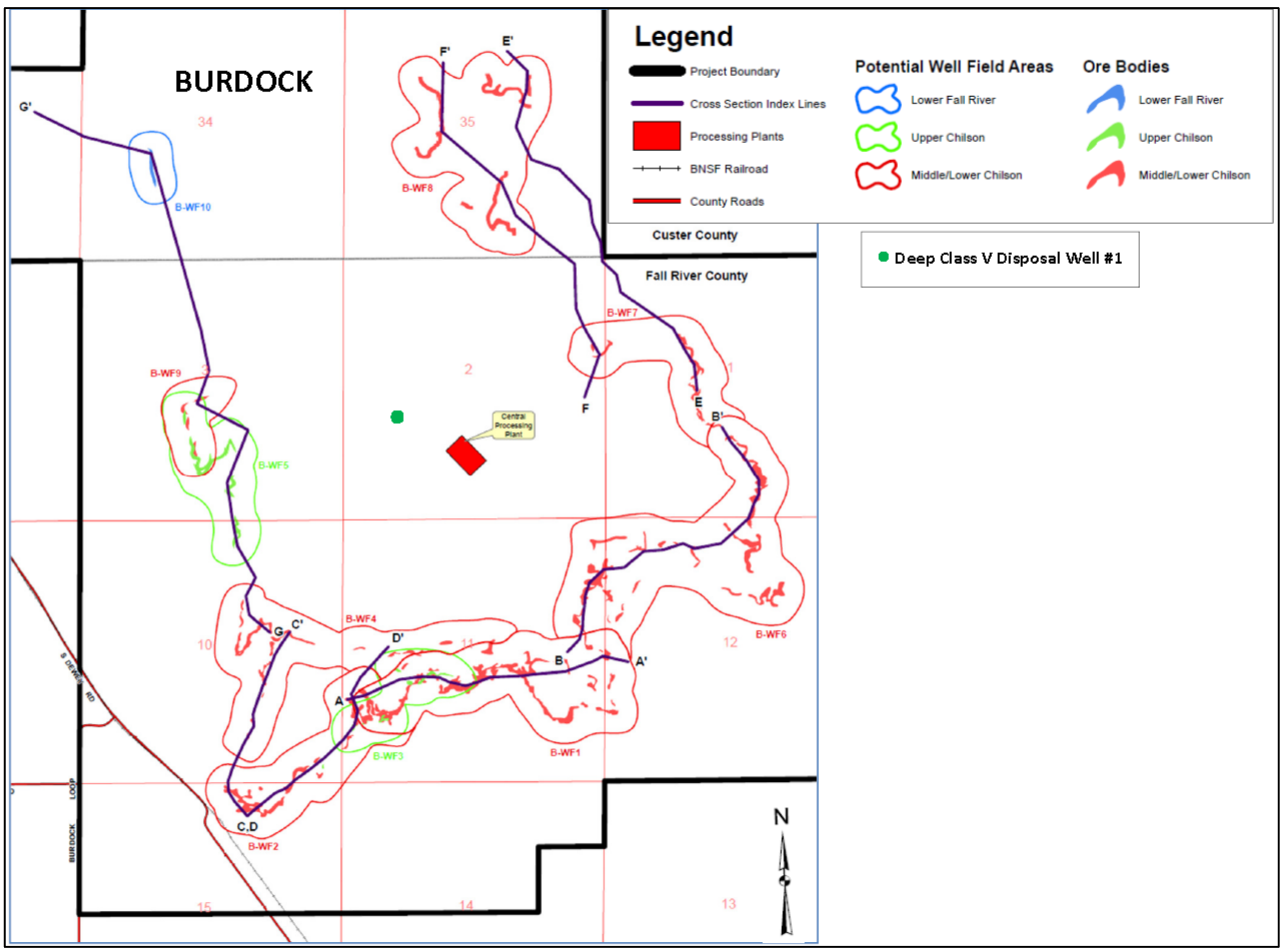


Figure 4a. Locations of the Proposed ISR Wellfields in the Burdock Area

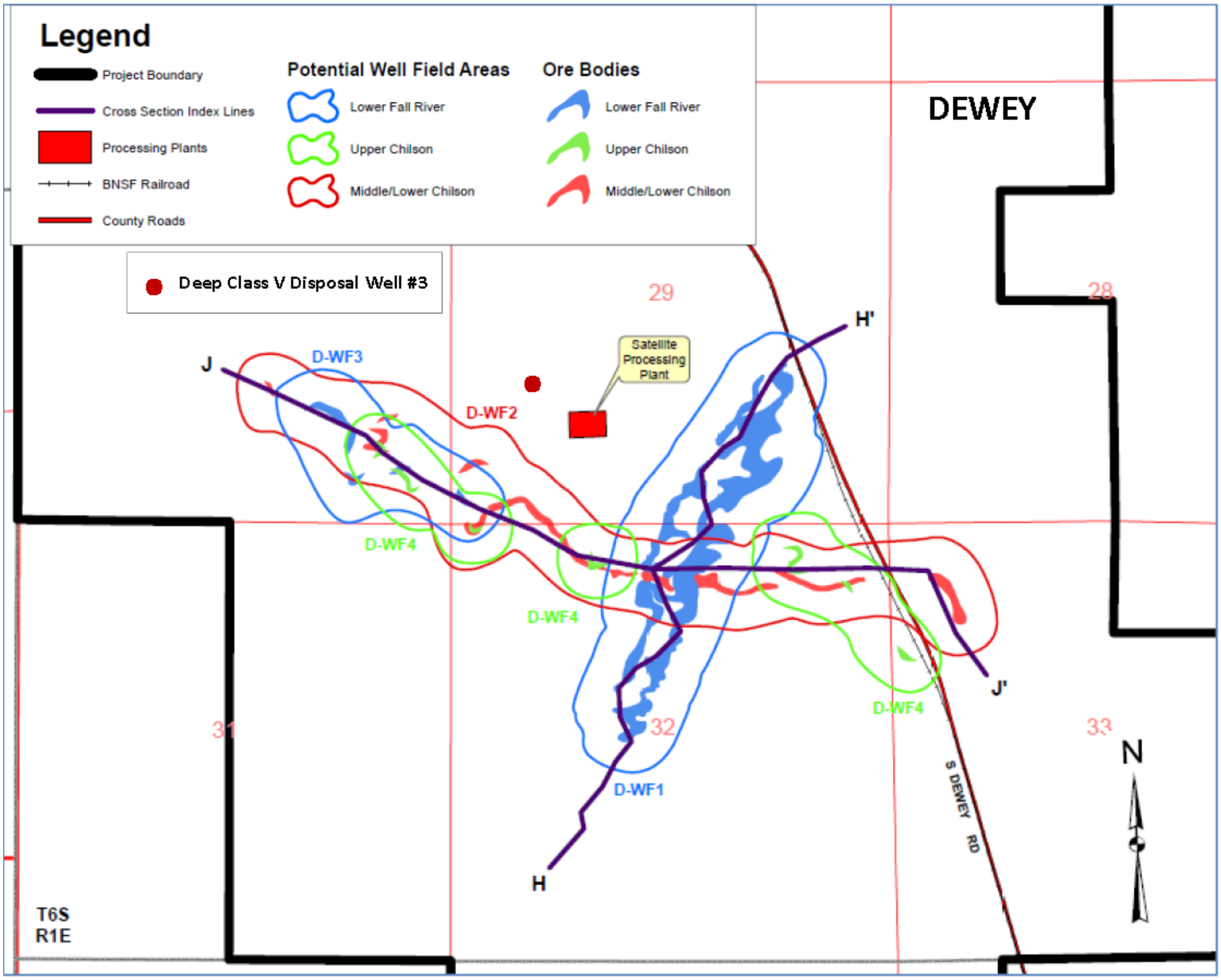


Figure 4b. Locations of the Proposed ISR Wellfields in the Dewey Area

3.0. PERMIT CONSIDERATIONS

3.1 Hydrogeologic Setting

The geological information within the Dewey-Burdock Project Area was compiled from the interpretation of data gathered from thousands of exploration drillholes (5,932 exploration drillholes are included in Appendix C of the Class III Permit Application) located throughout the Dewey-Burdock Project Area. For each drillhole, a suite of down-hole electric logs was run to characterize natural radioactivity and the lithology (type of rock) in the subsurface. Logs run to measure the resistivity of the lithologic unit to the flow of electrical current and self-potential (the electrical potential difference occurring naturally within the earth) were used to identify the rock types encountered in the subsurface (e.g. sandstone or shale).

3.2 Geologic Setting

The geologic formations present at the Dewey-Burdock site are listed in Table 3.

Table 3. Geologic Setting

Formation Name	Burdock Area		Dewey Area		Lithology (Rock Type Description)
	Top[3] (ft)	Base (ft)	Top (ft)	Base (ft)	
Graneros Group	0	190	0	525	
Belle Fourche Shale					Gray shale with scattered limestone concretions and basal clay bentonite.
Mowry Shale					Light-gray shale with thin layers of bentonite
Skull Creek Shale					Dark-gray shale
Inyan Kara Group					
Fall River Formation	190	315	525	650	Interbedded fluvial sandstones and shale
Lakota Formation	315	425	650	760	Interbedded fluvial sandstones and shale
Fuson Shale	315	355	650	690	Shale
Chilson Sandstone	355	425	690	760	Interbedded fluvial sandstones and shale
Morrison Formation	425	560	760	895	Variegated shales
Unkpapa Sandstone	560	640	895	975	Sandstone
Sundance Formation	640	920	975	1255	Sandstone and shale Basal sandstone
Spearfish Formation	920	1240	1255	1575	Red shales and siltstones with white gypsum beds and limestone layers.
Goose Egg Formation	1240	1480	1575	1815	Forells Lime Member (limestone) Glendo Shale Member(shale)
Minnekahta Limestone	1480	1520	1815	1855	Thin to medium-bedded fine-grained, purplish-gray laminated limestone
Opeche Shale	1520	1615	1855	1950	Red sandy shale, soft red sandstone and siltstone with gypsum and thin limestone layers. Gypsum locally near the base.
Minnelusa Formation					
Minnelusa Injection interval	1615	2205	1950	2540	Porous eolian sandstones with interbedded shale and anhydrite (porosity zone)
Minnelusa Lower Confining Zone	2205	2765	2540	3100	Cemented sandstones with interbedded shale and anhydrite
Madison Formation	2765	3060	3100	3395	Limestone and dolomite
Englewood Formation	3060	3095	3395	3430	Pink to buff limestone. Shale locally at base.
Deadwood Formation	3095	3195	3430	3530	Sandstone with beds of shale and limestone; basal conglomerate
Granite wash					Granitic pebbles formed by weathering of Precambrian basement locally present between the Deadwood Formation and the Precambrian basement
Precambrian basement	3195		3530		Undifferentiated metamorphic and igneous rocks

[3] Formation tops shown in this table are based on extrapolations from exploratory drillhole logs and are representative of formation depths at the approximate center of the Burdock and Dewey Areas respectively. Top elevations for formations deeper than the Sundance Formation are based on the Type Logs in Class V Permit Application.

3.3 Proposed Injection Zone

An injection zone is a geological formation, group of formations, or part of a formation that receives fluids through an injection well. The proposed Class III injection zones at the Dewey-Burdock Project Area are the aquifers within the Inyan Kara Group: the Fall River Formation and the Chilson Sandstone of the Lakota Formation. The uranium ore deposits targeted by the 14 proposed wellfields occur within sandstone units contained within either the Fall River aquifer or the Chilson aquifer. Injection wells in each wellfield will be designed to inject only into the sandstone unit containing the ore deposit targeted by that wellfield. The term "injection interval" will be used in this document and in the Class III Area Permit to refer to the sandstone unit within the Inyan Kara Group that is receiving the injected lixiviant in each wellfield. Table 4 lists the proposed injection intervals at each proposed wellfield, the depth to the top of the injection interval and the drillhole at which the depth to the injection interval top was determined. The drillholes in Table 4 are shown in Plates 6.12 through 6.21 from the Class III Permit Application.

Table 4. Proposed Injection Intervals

Wellfield	Injection Interval Formation	Depth to Injection Interval Top (ft below ground surface)	Drillhole at Which Depth to Injection Interval Top Was Determined
Burdock #1	Lower Chilson east end Middle Chilson west end and middle	West-322' East-385'	FBS 192 FBM 75
Burdock #2	Middle Chilson	435'	PS 43
Burdock #3	Upper Chilson	290'	FBM 75
Burdock #4	Middle Chilson	327'	FBM 105
Burdock #5	Upper Chilson	455'	DB07-3-4
Burdock #6	Lower Chilson NE section Middle Chilson middle section Lower Chilson SW section	NE-271' Middle-290' SW-345'	DRA 15 IHA 13 FBJ 16
Burdock #7	Lower Chilson	308'	DRM 48
Burdock #8	Middle Chilson	205'	TRT 70
Burdock #9	Middle Chilson	535'	KLA 9
Burdock #10	Lower Fall River	328'	SNF 17
Dewey #1	Lower Fall River	516'	ELR 60
Dewey #2	Middle and/or Lower Chilson	663'	DWA 74
Dewey#3	Lower Fall River	530'	LM 103
Dewey #4	Upper Chilson	West-707' Middle-670'1 East-567'	DWT 72 DB08-32-11 DWA 50

Appendix N of the Class III Permit Application includes a summary of the water quality information from monitoring wells located within the Dewey-Burdock Project Area. Total dissolved solids (TDS) concentrations of the Fall River Formation aquifer measured in samples collected from wells completed in the Fall River Formation within the Area Permit Boundary range from 773.85 mg/L to 2,250.00 mg/L. The mean TDS concentration for the Fall River injection interval is 1,275.01 mg/L. The TDS concentrations of the Chilson Sandstone aquifer measured in samples collected from wells completed in the Chilson Sandstone within the Dewey-Burdock Project Area range from 708.33 mg/L to 2,358.33 mg/L. The mean TDS concentration for the Chilson injection interval is 1,263.38 mg/L.

Because the TDS of the Fall River aquifer fluids and Chilson Sandstone aquifer fluids are less than 10,000 mg/L in concentration, both aquifers are USDWs. The definition of a USDW is found at 40 CFR § 144.3: *Underground source of drinking water (USDW)* means an aquifer or its portion:

(a)(1) Which supplies any public water system; or
(2) Which contains a sufficient quantity of ground water to supply a public water system; and
(i) Currently supplies drinking water for human consumption; or
(ii) Contains fewer than 10,000 mg/L TDS; and
(b) Which is not an exempted aquifer.

The injection of lixiviant into the Fall River and Chilson Sandstone uranium ore bodies will result in an increase in uranium concentrations in the groundwater within these USDWs. Under UIC regulations, an aquifer exemption is needed in order to inject fluids into the wellfield injection intervals. Because the Fall River Formation and the Chilson Sandstone Member of the Lakota Formation occur within the Inyan Kara Group and are the only USDWs within the Inyan Kara, the Permittee has requested the exemption of all USDWs within the Inyan Kara Group. The aquifer exemption process is discussed in Section 10.0.

3.4 Confining Zones

A confining zone is a geological formation, part of a formation, or a group of formations that limits vertical fluid movement above and below the injection interval. Table 5 lists the major confining zones and their minimum and maximum thicknesses at wellfield locations within the Dewey-Burdock Project Area. The thickness values for the upper and lower confining zones for each injection formation are based on logs from drillholes located throughout the Dewey-Burdock Project Area.

Table 5. Major Confining Zones with Minimum and Maximum Thickness at Wellfield Locations

Injection Formation	Formation Name	Minimum Thickness (ft)	Maximum Thickness (ft)
Fall River Sandstone	Upper Confining Zone: Graneros Group	280	550
	Lower Confining Zone: Fuson Shale	20	80
Chilson Sandstone	Upper Confining Zone: Fuson Shale	20	80
	Lower Confining Zone: Morrison Formation	60	140

Permeability is the ability of a geologic unit to transmit fluid through its pore space. Shales tend to be less permeable than sandstones. The air intrinsic permeability and water hydraulic conductivity values provide an indication of how permeable a geologic unit is. The values listed in Table 6 demonstrate the relative vertical permeability values of the sandstone injection intervals and the shale confining zones. These measurements were obtained from core samples tested in a laboratory. Low values indicate the shales provide good confinement to the injection intervals demonstrated by how slowly air and water were measured to move through them.

Table 6. The Vertical Air Intrinsic Permeability and Water Hydraulic Conductivity Values

Formation/Area	Air Intrinsic Permeability (milliDarcys)	Water Hydraulic Conductivity (cm/s)
Fuson Shale Burdock Area	0.228	1.7555×10^{-7}
Fuson Shale Burdock Area	0.015	1.1549×10^{-8}
Fuson Shale Dewey Area	0.008	6.1595×10^{-9}
Skull Creek Shale Dewey Area	0.007	5.3896×10^{-9}
Morrison Shale in the Burdock Area	0.043	3.3107×10^{-8}
Morrison Shale in the Burdock Area	0.012	9.2392×10^{-9}
Chilson Sandstone in the Burdock Area	1,464	1.1272×10^{-3}
Chilson Sandstone in the Burdock Area	939	7.2297×10^{-4}
Chilson Sandstone in the Burdock Area	1,750	1.3474×10^{-3}
Fall River Sandstone in the Dewey Area	619	4.7659×10^{-4}

Source: Class III Permit Application Table 8.2

3.4.1 Fall River Overlying Confining Zone

The Graneros Shale serves as the overlying confining zone for the Fall River Formation and consists of three members: the Skull Creek Shale, the Mowry Shale and the Belle Fourche Shale. The Skull Creek Shale directly overlies the Fall River Formation. The Skull Creek Shale has a thickness of approximately 200 feet and together with the overlying shales of the Graneros Group is the uppermost confining zone for the proposed ISR operations. Analyses of core samples of the Skull Creek Shale within the Project Area indicate low vertical permeability allowing water to travel vertically though the Skull Creek Formation at 5.3896×10^{-9} cm/s as shown in Table 6. The Belle Fourche Shale is present at the surface in the Dewey Area; the Skull Creek and Mowry Shales are present at the surface in the Burdock Area.

The Graneros Shale has been eroded away along the eastern portion of the Burdock Area where the Fall River Formation outcrop is shown in the geologic map in Figure 5. No wellfields will be constructed targeting Fall River Formation ore in the area where the Graneros Group has been eroded away. As shown in Figure 4b, the wellfields located in the eastern portion of the Burdock Area are targeting ore in the Chilson Sandstone. The easternmost Fall River wellfield is located in the southwest quarter of Section 34 in Township 6 South, Range 1 East, as shown in Figure 4a. Permit Application Plate 6.19, Cross section G-G' shows the Graneros Group to be approximately 280 feet thick in this location (at drillhole SNJ-10). In the Dewey Area, Permit Application Plate 6.20, Cross section H-H' shows the Graneros confining zone to be over 400 feet thick in wellfields targeting the Fall River Formation. Actual Graneros confining zone thicknesses will be determined through the wellfield delineation drilling performed during the initial stages of the wellfield pump test design as discussed in Section 5.1.

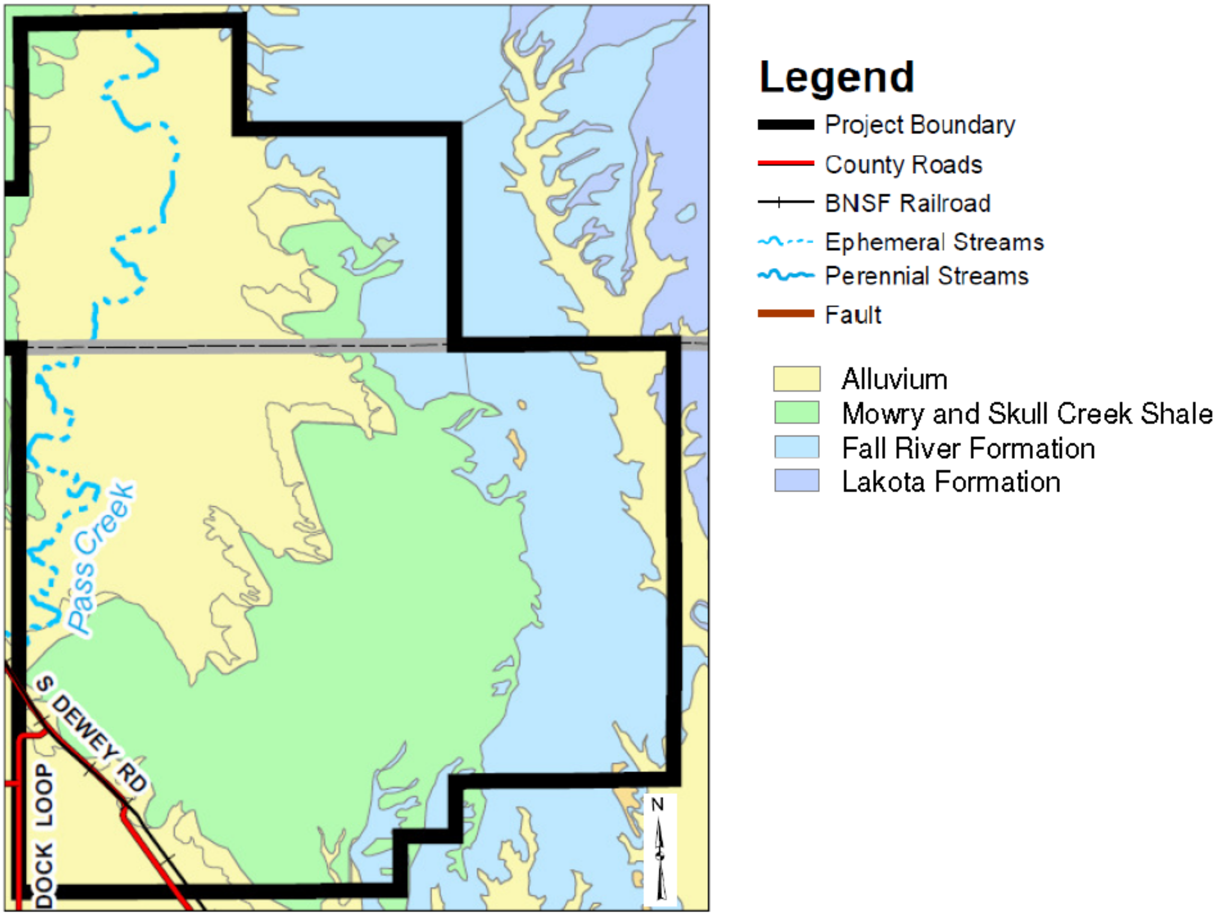


Figure 5. Geologic Map Showing the Surface Formations at the Dewey-Burdock Project Site

3.4.2 Fall River Underlying Confining Zone and Chilson Overlying Confining Zone

The Fuson Shale of the Lakota Formation serves as the confining zone between the Fall River Formation injection interval and the underlying Chilson Sandstone of the Lakota Formation. In the northeast corner of Section 1, Township 7 South, Range 1 East, the Chilson Sandstone outcrops at the surface with no overlying Fuson confining zone. This area is more than 0.5 miles away from the nearest Chilson wellfield and is located up-gradient with respect to groundwater flow from the Chilson wellfield areas. Groundwater would have to flow up-dip (essentially up hill) to reach this area where the Chilson Sandstone outcrops. That fact, along with the Class III Area Permit requirement to contain wellfield injection interval fluids by maintaining an inwardly directed hydraulic gradient (Part VIII, Section F), provides assurance that uranium-bearing injection interval fluids will not flow to the surface at the Chilson Sandstone outcrop in the northeast corner of Section 1.

In the Burdock Area wellfields targeting Chilson Sandstone ore zones, the Fuson Shale overlies the Chilson Sandstone and ranges in thickness from 20 feet to 80 feet across the Permit Area. An isopach map showing the thickness of the Fuson Shale is shown in Plate 6.8 of the Class III Permit Application. Plate 6.4 of the Permit Application is a contour map of the top surface of the Fuson Shale. Analyses of core samples from the Fuson Shale within the Project Area indicate low vertical permeability allowing water to travel vertically though the Fuson Formation between 6.1595×10^{-9} cm/s and 1.7555×10^{-7} cm/s as shown in Table 6.

Included in the Class III Permit Application are a number of cross sections (Plates 6.13 through 6.21) based on drillhole log information. These cross sections and logs indicate that the Fuson is continuous throughout the

Dewey-Burdock Project Area. The EPA has reviewed the information that the Permittee provided in the Permit Application and has determined that evidence indicates that except for the northeast corner of Section 1, T7S, R1E, the Fuson member of the Lakota formation is a continuous confining zone underlying the Fall River injection interval and overlying the Chilson Sandstone injection interval throughout the Dewey-Burdock Permit Area. Wellfield delineation drilling performed during the initial stages of the wellfield and pump test design as discussed in Section 5.1, and required under Part II, Section B.1 of the Class III Area Permit, will provide more detailed information about the thickness and continuity of the Fuson confining zone.

There may be points where the Fuson confining zone has been compromised by improperly plugged exploration drillholes or wells that penetrate the Fuson confining zone. Evidence that suggests at least one breach in the Fuson confining zone is included in the reports on the pump tests conducted by the Tennessee Valley Authority (TVA) and the Permittee in the Chilson aquifer in the Burdock Area.

During both Burdock Area pump tests a water level decrease was measured in observation wells completed in the Fall River Formation while pumping was conducted in the Chilson aquifer. This issue is discussed in greater detail in Section 4.6 of the Area of Review Requirements. The wellfield-scale pump tests will help pinpoint the areas where these breaches occur. Part III of the Area Permit describes the corrective action requirements the Permittee must comply with when any breaches in well-field confining zones are identified during the wellfield-scale pump tests.

During the Dewey Area TVA pump test in the Chilson Sandstone, a response was observed in the Fall River Formation after 3,000 minutes or 50 hours. The Permittee also conducted a pump test in the Dewey Area, but completed the pumping well in the Fall River Formation. No response was measured in the Chilson observation wells during the 4,440 minute or 74-hour the Powertech pump test. The pumping rate during the TVA test averaged 495 gpm, while the pumping rate during the Powertech test averaged 30.3 gpm. The much higher pumping rate used by TVA induced greater stress on the aquifer, which created a greater hydraulic gradient through the Fuson confining zone. The TVA report stated that a possible explanation for the late response in the Fall River aquifer during the Dewey pump test may be that "the direct avenues of hydraulic communication (e.g., numerous open pre-TVA exploration boreholes) believed to exist at Burdock, are not present in the Dewey area." If the response observed in the Fall River during the TVA pump test was the result of a breach in the Fuson confining zone, the breach should have been detected during the Powertech Dewey pump test. The Permittee will conduct additional pump tests in the Chilson in the Dewey Area for Dewey Wellfields 2 and 4. The results of those pump tests will provide additional information about the integrity of the Fuson confining zone in the Dewey Area.

3.4.3 Chilson Underlying Confining Zone

The Morrison Formation is the underlying confining zone for the Chilson Sandstone injection interval. The Morrison Formation is intersected by 26 exploration drillholes throughout the Dewey-Burdock Project Area. Table 6.1 of the Permit Application lists the drillholes penetrating the Morrison Formation. Permit Application Plate 6.22 is a cross section showing 10 of the drillholes that penetrate the Morrison Formation. The thickness of the Morrison Formation ranges from 60 feet to 140 feet across the Project Area. Plate 6.6 of the Permit Application is an isopach map showing the thickness of the Morrison Formation across the Dewey-Burdock Project Area and the locations of the 26 drillholes. Plate 6.2 of the Permit Application is a contour map of the top surface of the Morrison Formation. Analyses of Morrison Formation core samples within the Project Area demonstrate the vertical permeability of the Morrison shales to be very low as shown in Table 6.

In the Project Area, results from recent pump tests demonstrate that the Morrison effectively confines the underlying Unkpapa USDW since no measurable drawdown in the Unkpapa was observed while pumping in the Inyan Kara. The EPA reviewed the information the Permittee provided in the Permit Application in Sections 5.2.1.1, 6.2.2 and 14.2.1.2, along with other references describing the geology of the area, and has determined that the Morrison formation is a continuous confining zone across the Dewey-Burdock Permit Area. The EPA concurs with the Permittee's assertion that the Unkpapa USDW underlying the Morrison Formation does not need to be monitored during the injection activities.

In addition, the Unkpapa USDW shows a substantially higher potentiometric surface than the Fall River and Chilson throughout the permit area. An aquifer's potentiometric surface is the level to which water in a well will naturally rise (i.e., to an elevation above the top of the aquifer it penetrates). The potentiometric surface reflects the water pressure of a confined aquifer. In addition, the Part VIII, Section F of the Class III Area Permit requires that the Permittee maintain hydraulic control of each wellfield during ISR operations and groundwater restoration by maintaining a hydraulic gradient that ensures groundwater flow is directed toward the wellfield. In each ISR wellfield, the production wells will pump a larger volume of fluids out of the wellfield than the injection wells are injecting so as to maintain a hydraulic gradient directed inward toward the wellfield. During post-ISR restoration pumping wells will be extracting a greater volume of groundwater than the injection wells are pumping into the wellfield to maintain the inward hydraulic gradient. As a result, during ISR operations the potentiometric surface will be depressed in the Fall River and Chilson Sandstone aquifers, creating a cone of depression in the potentiometric surface and lowering the aquifer pressures in the wellfield area. Therefore, the injection intervals in the Fall River and Chilson wellfields will be operating with a substantially lower potentiometric surface than that of the Unkpapa USDW. This situation precludes the movement of Fall River or Chilson formation fluids moving into the Unkpapa USDW.

Where drillholes penetrating the Morrison Formation occur within a wellfield targeting ore within an injection interval that has the Morrison Formation as the lower confining zone, Part II, Section D.4.c.ii of the Class III Area permit requires that at least one Unkpapa Formation observation well be included in the wellfield pump test design. This requirement will verify that the drillholes penetrating the Morrison Formation within wellfields of concern do not cause a breach in the Morrison Formation lower confining zone. Table 4 of the Class III Area Permit lists the observation wells required for monitoring the integrity of the Morrison Formation lower confining zone. Three of the five wells already exist. The Class III Draft Area Permit requires the Permittee to install two additional wells completed below the Morrison Formation: one in Burdock Wellfield 8 and one for the east end of Burdock Wellfield 1 that can also be used for the Burdock Wellfield 6 pump test.

3.4.4 Operational Wellfield Confining Zones

In addition to the major confining zones, the wellfields will have operational confining zones consisting of confining zones that are present either above and/or below the injection interval of a wellfield, but are not continuous throughout the Project Area. These local confining zones will serve to direct horizontal flow within the injection interval aquifer between the injection and production wells. Wellfield pump tests will verify that these local confining zones are continuous enough to allow a cone of depression to form in the injection interval around the wellfield demonstrating control of injection interval fluids within the wellfield. Examples of these local confining zones are shown in Figure 6 which shows portions of cross section A-A' (Plate 6.13 of the Class III Permit Application) in Burdock Wellfield 1. The cross section shows the uranium ore in the Middle and Lower Chilson (see the blue arrows). The local confining zone between the Middle and Lower Chilson pinches out in the blue circle demonstrating the discontinuous nature of the local confining zones. The presence of the local confining zone isolating the Lower/Middle Chilson injection interval from the overlying Upper Chilson will provide a vertical permeability barrier to direct the flow of lixiviant through the ore zone. The horizontal control of lixiviant within the injection interval will be verified by monitoring wells placed in the Middle/Lower Chilson in a perimeter monitoring well ring surrounding the wellfield as discussed under the monitoring requirements in Section 12.5.5 of this Fact Sheet. There will also be monitoring wells above and below the injection interval to monitor vertical control of injection interval fluids. However, there are no monitoring wells required below the Morrison Formation lower confining zone as discussed above in Section 3.4.3.

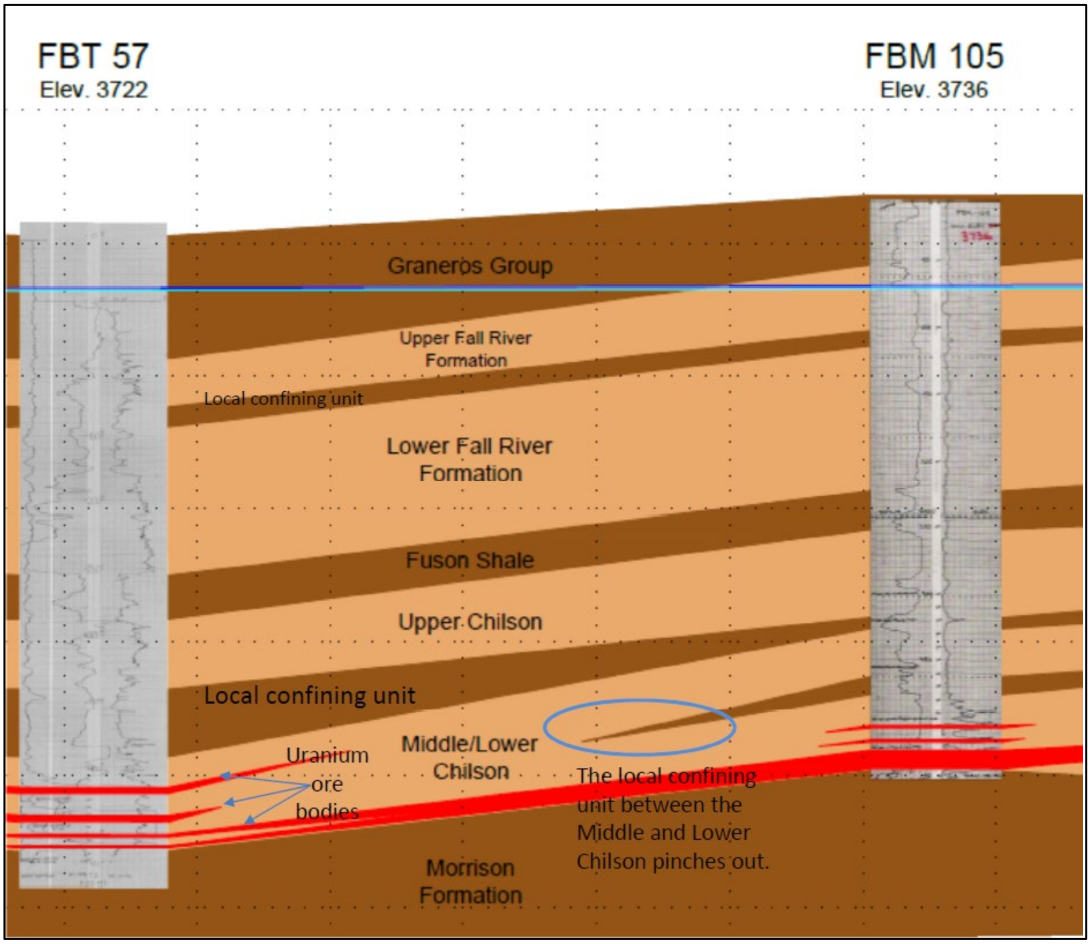


Figure 6. Cross Section through Burdock Wellfield 1 Showing Local Confining Zones for the Wellfield Injection Intervals

3.5 Underground Sources of Drinking Water (USDWs)

As discussed earlier, the definition of a USDW is found at 40 CFR § 144.3: *Underground source of drinking water (USDW)* means an aquifer or its portion:

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

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

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

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

(b) Which is not an exempted aquifer.

Table 7 lists the USDWs in the Dewey-Burdock Project Area with average depths in the Burdock and Dewey areas, lithologic descriptions and mean TDS concentrations.

Table 7. Underground Sources of Drinking Water

Formation Name	Burdock Area		Dewey Area		Lithology	TDS (mg/L)
	Top (feet)	Base (feet)	Top (feet)	Base (feet)		
Alluvial Deposits	0	50	0	30	Alluvium (poorly sorted, unconsolidated silt, clay, sand and gravels)	5285
Inyan Kara Group Fall River Formation Lakota Formation Chilson Sandstone	 140 350	 300 425	 440 625	 580 705	Interbedded fluvial sandstones and shale	 1275 1263
Unkpapa Sandstone	560	640	825	900	Sandstone	1375
Sundance Formation	640	920	900	1180	Shale, sandstone, thin beds of limestone Basal sandstone	1375
Madison Formation	2765	3060	3100	3395	Limestone and dolomite The Madison aquifer occurs within the top 100 to 200 feet[4]	690 - 1333

3.6 Structural Geology

The geologic structure across the Project Area consists of flat-lying, sedimentary layers that dip gently 2 to 6 degrees to the southwest. Stratigraphic mapping based on the numerous drillholes at the site reveals no abrupt vertical offset in sedimentary layers that would indicate the presence of faults within the project area. Stratigraphic continuity is illustrated by structure contour maps showing the elevation of the tops of the Unkpapa Sandstone (Plate 6.1), the Morrison Formation (Plate 6.2), the Chilson Member of the Lakota Formation (Plate 6.3), the Fuson Shale (Plate 6.4), and the Fall River Formation (Plate 6.5). These maps indicate no vertical discontinuities in formation top elevations that would be observed if a fault causing vertical displacement intersected the Project Area. The cross sections shown in Plates 6.13 through 6.21 show no vertical offsets or discontinuities in the horizontal continuities of the formations present that would be observed if a fault were present.

The Dewey Fault, a northeast to southwest trending fault zone, lies approximately 1,500 feet northwest of the Dewey-Burdock Area Permit Boundary. The fault lies more than 6,000 feet to the northwest of the nearest wellfield boundary in the Dewey Area as shown on Class III Permit Application Plate 3.1. The Dewey Fault is a steeply dipping to vertical normal fault with the north side uplifted approximately 500 feet by a combination of displacement and drag. Two springs are present along the Dewey Fault near the town of Dewey approximately 1.2 miles northwest of the Area Permit Boundary and cross-gradient and slightly up-gradient of the Class III and Class V injection wells. These two springs are shown in Class III Permit Application Figure 4.6. The southwestern dip of the geologic units will prevent any fluids injected into the Class III injection intervals from traveling up dip to the Dewey Fault, because the injected fluids would have to travel uphill to reach the Dewey Fault. In addition, the inward hydraulic gradient discussed in Section 9.2 will direct all injection interval fluid flow inward toward the wellfield center.

The Long Mountain Structural Zone is located seven (7) miles southeast of the Project Area. This northeast-southwest trend contains several small, shallow surface faults in the Inyan Kara Group. No faults were identified

[4] Hydraulic properties of the Madison aquifer system in the western Rapid City area, South Dakota.

along this trend on subsurface structure maps of the underlying Madison Limestone, Minnelusa Formation or the Deadwood Formation.

In addition to these major fault zones located northwest and southeast of the Project Area, the Dewey[5] and Burdock[6] geologic quadrangles show the locations of faults in areas outside the Dewey-Burdock Project Site.

The Dewey Geologic Quadrangle covers only the northern portions of the Dewey Area as shown in Figure 7. The Dewey Geologic Quadrangle shows a subsurface fault zone 1.5 miles long and about 400 feet wide that was identified by seismic methods. The fault zone is located in Sections 16 and 21, T5S, R1E. The fault location is shown by the red rectangle in Figure 7. The fault has a NE-SW trend and separates into two faults to the south in Triangle Park where it dies out. The fault is located 5.5 miles north of the Dewey Burdock Project Boundary. Many smaller faults occur north of the Dewey Fault. These faults appear to be nearly vertical and most show displacement of less than 20 feet. These faults were identified by offset in distinctive marker beds occurring within the Belle Fourche and Mowry shales. The map legend indicates that these marker beds were not mapped in detail south of the Dewey Fault Zone. The report states that many other small faults are probably present but not discernable because of poor exposures. As far as the EPA is aware, there is no map available showing detailed geologic structural features in the portion of the Dewey Area where the Class III wellfields are located.

The Burdock Geologic Quadrangle includes all of the Burdock Area as shown in Figure 8. Small vertical faults are mapped in SE Section 28, T6S, R2E located a little over 3 miles east of the Dewey-Burdock Project Boundary, NENW Section 4, T7S, R2E located about 2.5 miles east of the Project Boundary and SWSE Section 4, T7S, R2E located a little over 2.5 miles east of the Project Boundary. No faults are shown within the Burdock Area.

There is some folding of geologic strata in the areas surrounding the Project Area. East of the Project Area is a northwest-southeast trending anticline that ends in a closed structure called the Barker Dome. To the west is the Fanny Peak Monocline. This monocline is the structural boundary between the Black Hills and the Powder River Basin.

If there are any faults and fractures occurring within a wellfield area that cause a breach in a confining zone, they will be detected during the wellfield delineation drilling and pump testing. If found, the placement of injection and production wells can be modified from the regular pattern to control lixiviant flow around the factures or faults to keep it flowing through the uranium ore bodies rather than along these paths of lower hydraulic resistance. Part II, Section D.4.d of the Class III Area permit requires additional monitoring wells in any areas where faults or vertical fractures are found to verify that lixiviant does not migrate vertically out of the intended injection interval along the faults or fractures as discussed in Section 12.4.2.

[5] Geology of the Burdock Quadrangle Fall River and Custer Counties, South Dakota.

[6] Geology of the Dewey Quadrangle Wyoming-South Dakota.

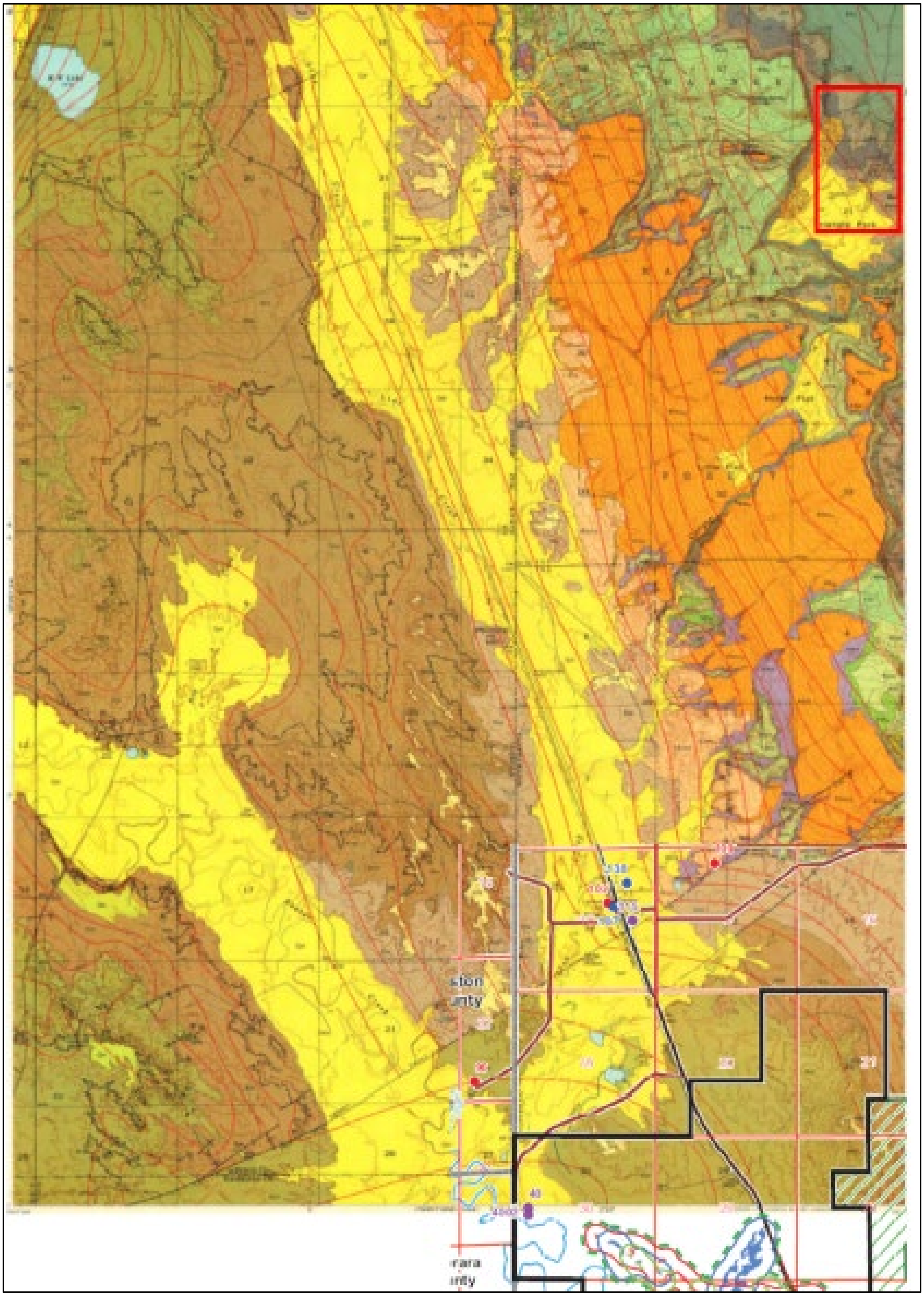


Figure 7. The Dewey Geologic Quadrangle and the Dewey Area

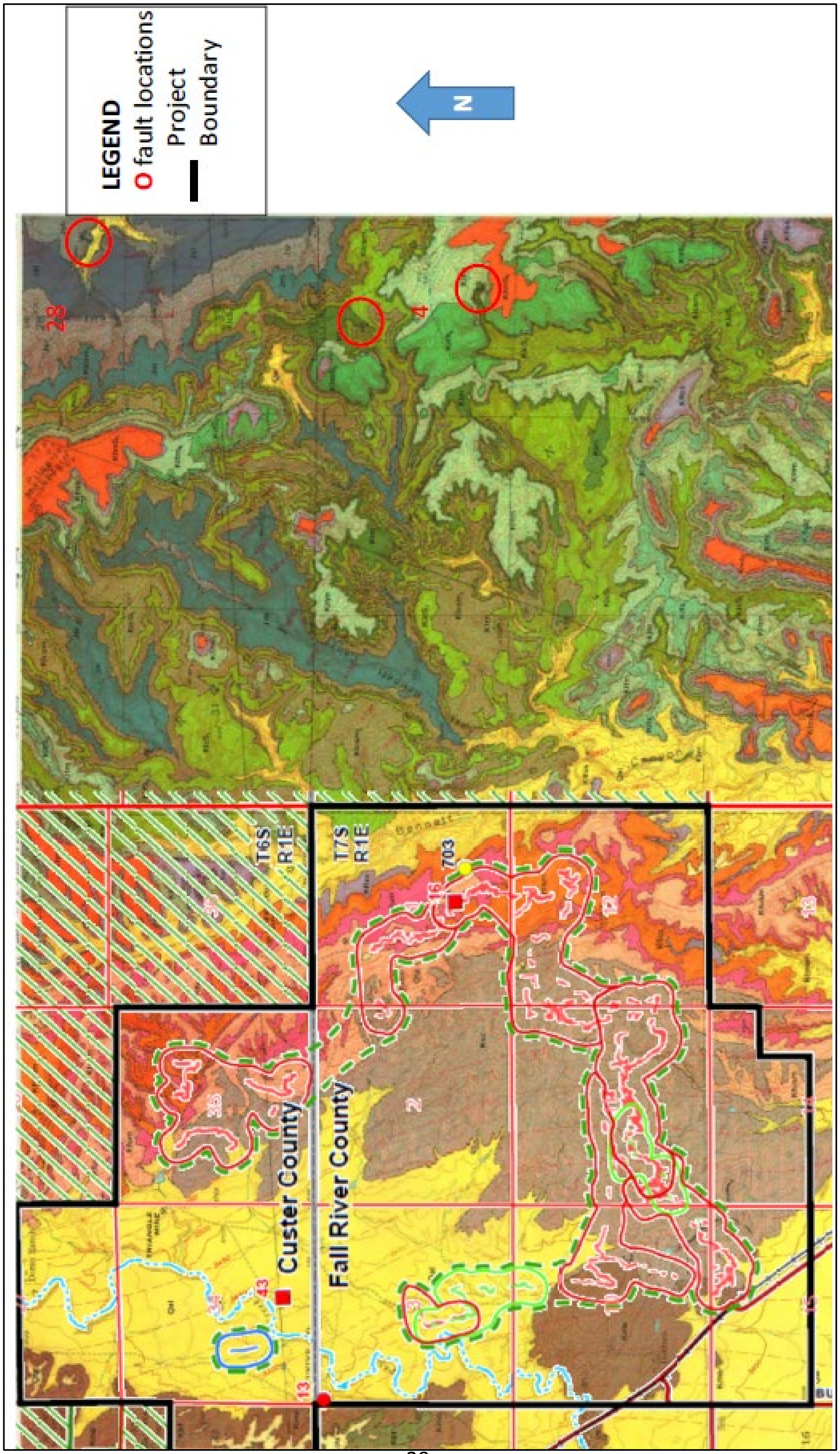


Figure 8. The Burdock Geologic Quadrangle and the Burdock Area

4.0 AREA OF REVIEW REQUIREMENTS

4.1 Area of Review Definition and Purpose

The UIC Regulatory Program Statement of Basis states:

> One of the common ways by which fluids can enter an underground source of drinking water is by migration through improperly abandoned and improperly completed wells. This would occur if fluids moving laterally within an injection interval encountered an improperly abandoned or completed well, and, following the path of least resistance, flowed upward within the well until entering an overlying underground source of drinking water or overflowing onto the land surface.
>
> To prevent this contamination, the regulations require the EPA to determine an "area of review" for injection wells. This is the area around the injection well through which the incremental pressure of injection can cause vertical migration. Operators of Class I, III, and new Class II wells (operators of existing and converted Class II wells are treated differently…) must locate other wells within the "area of review" and correct any problems related to improperly abandoned or improperly completed wells before beginning injection. Under this approach, well injectors would have the affirmative responsibility to demonstrate that the proposed injection operation would not cause contamination by this route.

Area of review (AOR) means the area surrounding an injection well described according to the criteria set forth in 40 CFR § 146.06, or in the case of an area permit, the Project Area plus a circumscribing area the width of which is either 1/4 of a mile or a number calculated according to the criteria set forth in the regulation. The calculated value, called the Zone of Endangering Influence in 40 CFR § 146.6(a), is based on a well that is continually injecting, resulting in an injectate volume that moves away from the injection well over time. This model is not appropriate for Class III injection wellfields because of the inward hydraulic gradient generated at each wellfield by pumping out a greater volume of injection interval fluid than is injected by the injection wells. Therefore, the fixed radius method described under 40 CFR § 146.6(b) is a more appropriate method for designating the Area of Review for the Dewey-Burdock Project Site. For an area permit, this regulation allows a fixed width of not less than one-fourth (1/4) mile for the circumscribing area. The Permittee used a more extensive AOR to satisfy the NRC review area guidance for groundwater resources. For the purposes of this Permit, the AOR will include the area within 1.2 miles from the Dewey-Burdock Area Permit Boundary. The Dewey-Burdock Project Area of Review has been investigated for any features that would compromise the confining zones that are necessary to contain the injected fluids within the authorized injection interval.

4.2 Evaluation of Wells and Drillholes

To fulfill the Area of Review requirements, the Permittee conducted a search of historical records and performed field investigations to develop an inventory of all wells within the 2-km (1.2-mile) AOR. The Permittee identified a total of 159 wells within the AOR summarized in Table 8.

Table 8. Wells Located within the Dewey-Burdock Class III Area of Review

Type of Wells	Number
Active wells	122
Wells found in historical records for which no surface expression was able to be located	20
Wells with historical records that have been visually confirmed as plugged and abandoned	17
total	159

The field investigations involved locating each well and verifying or determining the use and condition of each well. Appendix A of the Class III Permit Application contains summary tables of all wells in the inventory; Appendix B contains the detailed well investigation field notes, well completion records and associated documentation from the South Dakota Department of Natural Resources databases. There are 122 currently active within the AOR; these existing wells are listed in the Permit Application Appendix A, Table 1. The locations of these wells are shown on Plate 3.1 of the Permit Application. Permit Application Appendix A, Table 2 lists 27 well records found in historical records but have no surface expression that the Permittee could identify in the field. The approximate locations for these wells are shown in Permit Application Figure 4.1. Note that seven of the "wells" listed in Appendix A, Table 2 represent either duplicate records or are not actually a well; therefore, there are only twenty actual wells in the list in Appendix A, Table 2. There are 17 wells with historical records that the Permittee visually confirmed as plugged and abandoned. These wells are listed in Permit Application Appendix A, Table 3 and their locations are shown in Permit Application Figure 4.1. Of these 17 plugged and abandoned wells, nine are oil and gas test wells discussed in Section 4.2.2. More information about these nine plugged and abandoned oil and gas test wells is included in Table 10 and their locations are included on Plate 3.1 of the Permit Application. Note that four of the oil and gas test wells included in Table 10 have been recompleted as water supply wells and are included in Permit Application Appendix A, Table 1 as currently active wells. Their locations are shown on Plate 3.1 of the Permit Application.

4.2.1 Water Well Inventory

Table 1 in Appendix A of the Permit Application identifies type of use for each well. Well use types include:

Domestic: There are 18 private domestic water wells located within the Area of Review and one well located just outside the Area of Review boundary that are either currently being used for drinking water or have been used for drinking water in the past. Table 9 shows the list of these 19 wells, and Figure 9 shows the locations.

Nine of these wells are located within the Dewey-Burdock Project Boundary. Only one well, well 16, is located within the proposed aquifer exemption boundary. Three of the nine wells are no longer being used for drinking water:

- Well 16 has been physically disconnected from the residence, and a cistern has been installed to hold drinking water;
- Well 41 is now a stock watering well located at a residence that the Permittee has reported as uninhabitable;
- Well 43 is an abandoned drinking water well located at an uninhabitable house.

Well 703 is located within the Project Boundary and is completed in the Unkpapa Sandstone, which is hydrologically isolated from the Inyan Kara aquifers by the Morrison Formation. Because it is hydrologically isolated from the Inyan Kara aquifers, well 703 can remain active and not be affected by, nor will it affect, ISR operations. The Permittee has agreements in place with owners of the five active drinking water wells located within the project boundary (Well IDs 13, 40, 42, 704, 4002) stipulating that these wells will no longer be used as drinking water wells once project operations begin.

Table 9. Nineteen Domestic Wells Located in and near the Dewey-Burdock Project Area of Review

Well ID	Aquifer of Completion	Well Location	Inside Project Boundary	Currently Being Used for Drinking Water
2	Chilson	SESE Sec 16 T7S R1E	No	Yes
7	Fall River	NWNW Sec 23 T7S R1E	No	Yes
8	Fall River	SWSE Sec 23 T7S R1E	No	Yes
13	Chilson	NWNW Sec 3 T7S R1E	Yes	Yes
16	Chilson	NWSE Sec 1 T7S R1E	Yes	No
18	Fall River	SWSW Sec 9 T7S R1E	No	Yes
40	Inyan Kara	SWNW Sec 30 T6S R1E	Yes	Yes
41	Unknown	SWNE Sec 31 T6S R1E	Yes	No
42	Chilson	SWNE Sec 5 T7S R1E	Yes	Yes
43	Chilson	SWSE Sec 34 T6S R1E	Yes	Nof
65	Chilson	SWSW Sec 22 T41N R60W	No	Yes
102	Chilson	SWNE Sec 18 T6S R1E	No	Yes
107	Fall River	SWNE Sec 18 T6S R1E	No	Yes
109	Chilson	NENW Sec 17 T6S R1E	No	Yes
115	Inyan Kara	SENE Sec 18 T6S R1E	No	Yes
138	Fall River	NENE Sec 18 T6S R1E	No	Yes
703	Unkpapa	SWSE Sec 1 T7S R1E	Yes	Yes
704	Chilson	SWNE Sec 5 T7S R1E	Yes	Yes
4002	Inyan Kara	NWSW Sec 30 T6S R1E	Yes	Yes

The remaining ten wells are located outside the area permit boundary. Four of the domestic wells (Well IDs 2, 7, 8 and 18) are located down-gradient (south) of the Area Permit Boundary. Wells 2, 7 and 18 are located within the Area of Review boundary, the purple line located 2 km or 1.2 miles from the Project Boundary in Figure 9. Well 8 is located just outside the Area of Review boundary. Well 8 is not included in the 122 active wells within the Area of Review counted in Table 8. Well 96 is located in Wyoming and is northwest of, and cross-gradient from, the Project Area. Five wells (Well IDs 102, 107, 109, 115 and 138) are located north or northwest of, and up-gradient or cross-gradient from, the Project Area. All wells outside of the Project Area Boundary will remain active during ISR operations. The three down-gradient wells (Hydro IDs 2, 7 and 18) located within the Area of Review will be monitored as part of the operational monitoring requirement under Part IX, Section B.3.a of the Class III Area Permit.

Stock: Watering of livestock is sole use (44 wells, including Well 41 discussed above)

Irrigation: Permitted to be used for irrigation (1 well)

Monitor: Sole use is for monitoring (60 wells)

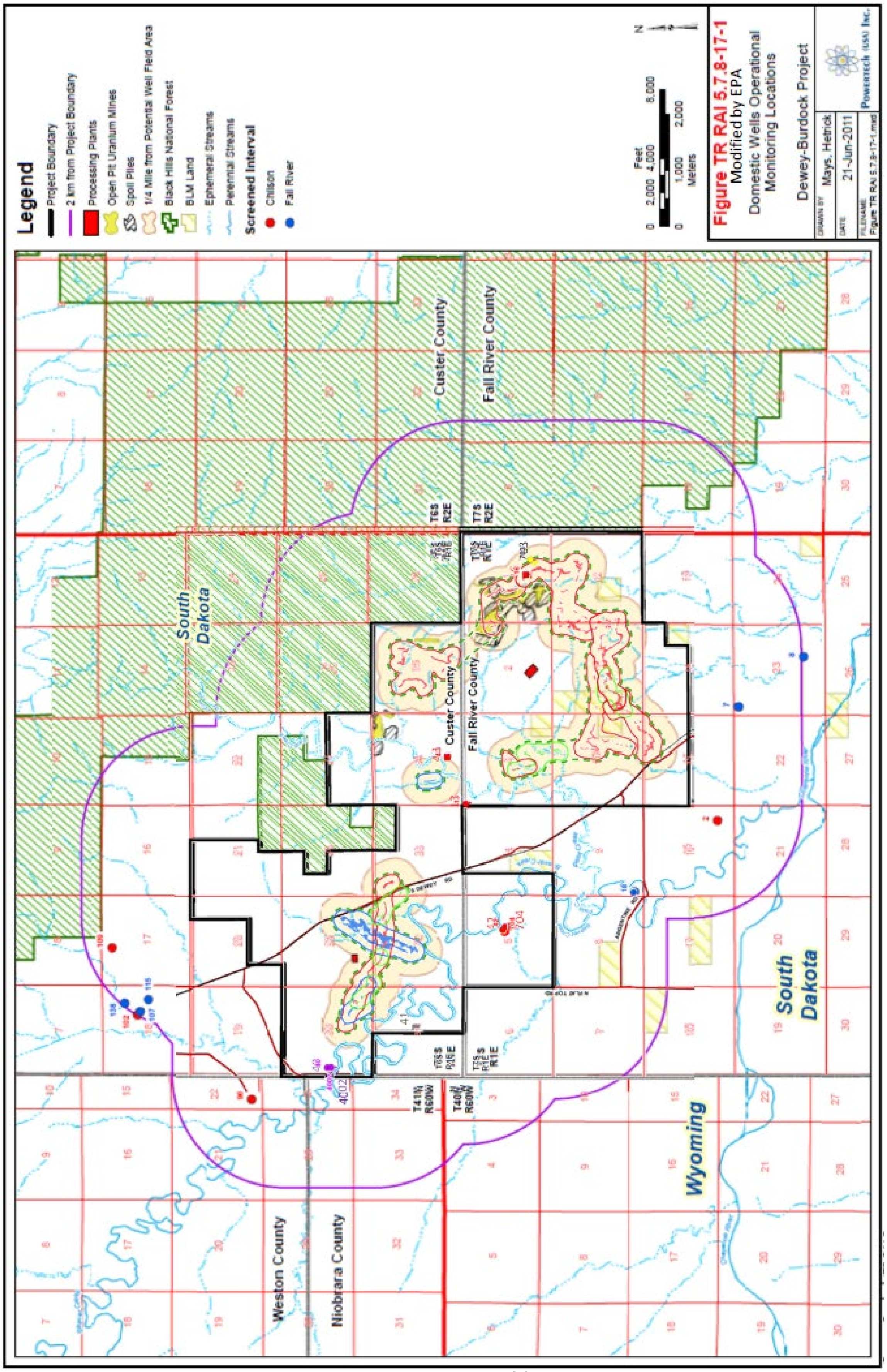


Figure 9. Locations of Drinking Water Wells in and near the Dewey-Burdock Area of Review

Table 2 in Class III Permit Application Appendix A lists the wells identified in historical records that were not evident at the surface during the field investigations. The locations of these wells as documented in historic records are shown on Permit Application Figure 4.1. Several of these wells are suspected of being plugged and abandoned. The Permittee has stated that they will continue to search for these wells. Construction operations and wellfield delineation drilling provides opportunity for further site evaluation. The wellfield pump tests must be designed to locate any such wells and to detect any potential impacts from such wells on the ISR operations. Table 3 in Permit Application Appendix A lists all the wells within the AOR that have been confirmed by the Permittee to have been plugged and abandoned. The Permittee visually inspected each well to verify that cement was placed within the well bores to isolate the aquifers intersected.

4.2.2. Oil and Gas Test Well Inventory

No formerly producing or actively producing oil and gas wells were found within the Dewey-Burdock Project Area Boundary or within the AOR. Within the AOR, the locations of 13 plugged and abandoned oil test wells have been identified, three of which are within the Project Area. Four of these plugged and abandoned oil test wells were recompleted so the land owner could use them as stock watering wells. These recompleted wells are Hydro IDs 3, 4, 5 and 11. The locations of the abandoned test wells are depicted on Permit Application, Plate 3.1. The plugging information for these former oil and gas test wells is included in Table 10.

Table 10. Plugging Information Available for Former Oil and Gas Test wells within the Dewey-Burdock AOR

Well Name	Location Information	API #	Plugging information available	Target formation & depth to top (ft bgs)	Total Depth of Well (ft bgs)
1. Carter 1	SWSE Sec 19 T6S R1E Fall River County Lat: 43.508820 Long: -104.042397	4003305219	No info available on P&A	Fall River Top of Fall River at 395’	TD=405’ or 420’
2. Carter 2	SWSE Sec 19 T6S R1E Fall River County Lat: 43.508820 Long: -104.042397	4003305221	No info available on P&A	Fall River Top of Fall River at 300’	TD=420’ or 405’
3. Dolezal 1 Darrow	SESE Sec 2 T7S R1E Lat: 43.4660620 Long: -103.958032 (inside Project Area Boundary)	4004705095	<u>Depth of Plugs/cement volume</u>: 2435-2360 Leo Sand 25 sx 1650-1575 Minnelusa 25 sx 600-525 top Sundance 25 sx 400-325 top Lakota 25 sx 156-90 base surface casing 10 sx surface plug <u>Formation Tops</u>: Fuson 300’ Lakota 350’ Morrison 425’ (Plug #4 intersects bottom 25 feet of Fuson confining zone) <u>Surface casing:</u> Depth: 142' diam: 8 5/8”	Minnelusa Top of Minnelusa at 1616’	TD=2450’ at 3rd Leo SS

			Cemented with 60 sx		
4. Consolidated Royalty 1 Peterson	NWSE Sec 22 T7S R1E Lat: 43.429674 Long: -103.983142	4004705147	<u>Depth of plugs/cement volume</u>: 1925' to 1850' – 25 sx 1195' to 1125' – 25 sx <u>Formation Tops</u>: Dakota 260' Lakota 460' Morrison 560' Sundance 750' Spearfish 1122' <u>Surface casing:</u> Depth: 1136 diam: 8 5/8"	Minnelusa Top of Minnelusa at 1690'	TD=2440'
5. ARC 34-11 Peterson	SWSE Sec 11 T7S R1E Lat: 43.963826 Long: -103.963826 (inside Project Area Boundary)	4004720071	<u>Depth of plugs/cement volume</u>: 1900'-2000' across Red Shale Marker 35 sx 750'-900' across Basal Sundance sandstone 50 sx 105'-190' across casing shoe 30 sx Set regulation marker in top of surface casing w/ 10 sx <u>Formation Tops</u>: Morrison 406' <u>Surface casing:</u> Depth: 163' Diam: 8-5/8" Cemented with 135 sx	Minnelusa Top of Minnelusa at 1552'	TD=2250'
6. Wulf 1 Peterson	NENE Sec 21 T7S R1E Lat: 43.433117 Long: -103.997735	4004720074	<u>Depth of plugs/cement volume</u>: 2424-2274' 16 sx 290-210' 8 sx *(this plug was missing when DENR checked for cement plugs in well casing)* 15'-0' 5 sx surface casing annulus 10 sx <u>Surface casing:</u> Depth: 253' Annulus cemented with 250 sx *Replug of leaking well on 8/31/95:* total of 105 sx cmt were pumped down the 5 ½" csg, which calculates to a plug from 736' to surface.	Minnelusa Top of Minnelusa at 1840'	TD=2500'
7. Wulf 2 Peterson	SWSW Sec 15 T7S R1E Lat: 43.435870 Long: -103.991563	4004720077	<u>Depth of plugs/cement volume</u>: 0' – surface 10 sx 682' - Top Morrison – Sundance Basal Sand 60 sx 1922' – Minnelusa 25 sx 2232' - Red Marker 25 sx <u>Formation Tops</u>: Sundance 822' <u>Surface casing:</u> Depth: 600' Diam: 8 5/8"	Minnelusa Top of Minnelusa at 1922'	TD=2462'
8. Wulf 1-A Peterson	NENE Sec 21 T7S R1E Lat: 43.433064 Long: -103.996978	4004720085	<u>Depth of plugs/cement volume</u>: 2200 to 2300 40 sx 1800 to 1900 25 sx 1050 to 1150 30 sx 750 to 850 40 sx surface no/marker 10 sx	Minnelusa Top of Minnelusa at 1840'	TD=2460'

			Formation Tops: Lakota probably at 500’ Surface casing: Depth: 250' Diam: 8 5/8" Cemented with: 200 sx		
9. Sun 1 Lance Nelson	NESE Sec 21 T7S R1E Lat: 43.425795 Long: -103.997224	4004705089	Depth of plugs/cement volume: 2977-3057 Madison 25 sx 2360-2440 2nd Leo Sand 25 sx 1800-1880 Minnelusa 25 sx 820- 900 Top Sundance 25 sx 330- 460 Top Dakota 40 sx 220- 290 Bottom Surface Casing 25 sx Surface Plug 10 sx Formation Tops: Dakota 368’ Lakota 562’ Surface casing: Depth: 269' Diam: 8 5/8" Cemented with: 175 sx	Madison Top of Madison at 2990’	TD=3057’
10. PRC 21-14 Peterson (Hydro ID 5)	NENW Sec 14 T7S R1E Lat: 43.447765 Long: -103.968121 (inside Project Area Boundary)	4004720065	Depth of plugs/cement volume: 2020-1900 across Red Marker 40sx 1600-1500 across top of 1st Converse Sand 30sx 950-850 across Sundance basal sand 30sx (no plug in surface pipe because left as water well.) Powertech field notes (Source E) in Appendix B Part 6 of 7 p. 94 Down-hole camera shows well is screened within lower Fall River. Well has 4" casing to a depth of 155 ft bgs and is open hole from 155 to 175 feet. Formation Tops: Top of Fuson picked at 178 in well log. Surface casing: Depth: 152' Diam: 8 5/8" Cemented with: 125 sx	Minnelusa Top of Minnelusa at 1571’	TD = 2269’
11. Superior 1 Peterson 44-15 (Hydro ID 4)	SESE Sec 15 T7S R1E Lat: 43.436899 Long: -103.447765	4004705093	Depth of plugs/cement volume: 1970-1920 3rd Converse sand 25 sx 1715-1645 Top Minnelusa 35 sx 1020-950 Base surface casing 30 sx Formation Tops: Dakota Mud 185’ Lakota 371’ Morrison 471’ Surface casing: Depth: 971' Diam: 8 5/8 Cemented with: 575 sx The base of the casing is just above the lowest Sundance sand. Immediately below the sand is a cement plug (1020 to 950 ft). Additional plugs were placed so as to isolate the Minnelusa sands in the hole.	Minnelusa Top of Minnelusa at 1652’	TD=2264’

12. Consolidated Royalty 1 State (Hydro ID 11)	NWSW Sec 24 T7S R1E Lat: 43.425719 Long: -103.952837	4004705090	Depth of plugs/cement volume: 2135-2060 2nd Leo Sand 25 sx 1715-1640 3rd Converse Sand 25 sx 1525-1460 Top 2nd Converse Sand 25 sx 910- 835 Base Sundance 40 sx 600-420 Base surface casing & top Sundance 60 sx surface plug 10 sx Formation Tops: Dakota 50' Lakota 237' Sundance 540' Basal Sand Sundance 860' Surface casing: Depth: 498' Diam: 8-5/8" Cemented with: 275 sx	Minnelusa Top of Minnelusa at 1530'	TD=2467'
13. Petro-Lewis #5-22 Peterson (Hydro ID 3)	SWNW Sec 22 T7S R1E Lat: 43.429484 Long: -103.992869	4004720045	Depth of plugs/cement volume: 2420-2300 across Red Marker 40 sx 1850-1750 across top of Converse 30 sx 1130-1030 across Basal Sand of Sundance 30 sx Plugged back to Morrison, 4 1/2" casing run to 367' and completed as water well. Formation Tops: Fall River 324' Fuson 452' Chilson 469' Morrison 700' Sundance 848' Basal Sundance Sand 1061' Surface casing: Depth: 167' Diam: 8 5/8" Cemented with: 100 sx	Minnelusa Top of Minnelusa at 1815'	TD=2545'

bgs = below ground surface

4.2.3 Exploration Drillhole Inventory

It is typical for a proposed uranium ISR site to have many exploratory drillholes across the site. Class III Permit Application Appendix C summarizes the available information for historical drillholes and the newer Powertech drillholes located within one mile of the Area Permit Boundary. Exploration drillhole locations are shown in Figure 10. Although the drillhole inventory map does not extend the full distance of 1.2 miles beyond the Project Boundary to the Area of Review boundary, the drillhole inventory area sufficiently covers the area of concern around the Class III wellfields. The EPA used this information to analyze the potential lixiviant flare zone[7] and potential breaches in confining zones within the wellfields discussed in Section 4.6 of this document. In this area, the lixiviant mobilizes uranium into the groundwater, so the evaluation of confining zone integrity is important to verify the containment of uranium-bearing wellfield groundwater within the injection interval. Part VIII, Section B of the Class III Area Permit prohibits the movement of ISR contaminants across the aquifer exemption boundary into USDWs. The drillhole inventory map shows drillhole locations extending beyond the aquifer

[7] *Flare* is lixiviant that might have migrated beyond the extraction zone, but not as far as the wellfield perimeter monitoring wells. (NRC Safety Evaluation Report, Section 6.1.3.2 Restoration Methods)

exemption boundary for each proposed wellfields and also extends beyond the project boundary, therefore, it satisfies the EPA requirements for the purposes of this review.

State regulations require these holes to be plugged after the holes have been logged. The newer Powertech drillholes were plugged and abandoned according to current protective South Dakota regulatory requirements. The historical drillholes have been plugged; however, records are not available to show how they were plugged. It is possible that some historical drillholes may not have been plugged in a manner that would prevent communication between subsurface aquifers. Part II of the Class III Area Permit requires the Permittee to take steps to identify leaky historic drillholes near the wellfield areas during the design and implementation of the wellfield pump tests (Section C), during the design of the wellfield monitoring system (Section D), during the implementation of formation testing (Section E), and during the implementation of the corrective action requirements in Part III. The Permittee must complete these actions prior to receiving authorization to inject, to prevent these drillholes, or any other type of confining zone breach, from acting as pathways for contamination of USDWs.

There are three strategies that the Permittee has used or will use to locate improperly plugged historic drillholes:

1) There are areas within the Dewey-Burdock Project Area where the potentiometric surface of the groundwater is above ground level. Where this is the case, leaky historic drillholes can be identified by groundwater discharges at the ground surface. In attempt to identify where leaky historic drillholes may exist, the Permittee performed extensive investigation into all surface water features within the Project Area. This includes field investigations during the initial baseline monitoring period performed for the NRC license and the use of color infrared (CIR) imagery. The Permittee appears to have identified all surface water features and sources of groundwater flow to the surface within the Project Area. The areas where the Fall River and Chilson aquifer potentiometric surfaces are not above ground level will be investigated for leaky historic drillholes during the wellfield pump tests.
2) The Permittee performed a detailed investigation of the Pass Creek and Beaver Creek alluvium to identify where groundwater is present in the alluvium as described in Section 4.3. Alluvial groundwater samples were collected to characterize the alluvial water quality. If there were leaky historic drillholes in the areas where the potentiometric surfaces of the Fall River and Chilson aquifers are above ground surface, there would be groundwater present in the alluvium with water quality similar to Fall River or Chilson groundwater. Areas where alluvium occurs within the Dewey-Burdock Project Boundary are shown in Figure 11, Figure 12a and Figure 12b. Water quality analyses of alluvial groundwater show it to be distinctly different from the water quality of the Fall River and Chilson aquifers. This information is included in Permit Application Appendix N, Groundwater Quality Summary Tables. The areas where alluvium occurs and the Fall River and Chilson aquifer potentiometric surfaces are not above ground level will be investigated for leaky historic drillholes during the wellfield pump tests.
3) One of the purposes of the wellfield pump tests is to locate improperly plugged historic drillholes so they can be mitigated before the commencement of injection activities. There will be two methods for detecting leaky historic drillholes during the wellfield pump tests. The first is detailed mapping of the aquifer potentiometric surfaces. With the high density of delineation drillholes and pump test wells, any leakage across confining zones due to improperly plugged drillholes will become apparent while preparing potentiometric surface maps based on water levels measured in the delineation drillholes and the wellfield pump test wells. However, in the areas where the potentiometric surfaces of the Fall River

and Chilson aquifers are at nearly the same elevation, this method will not be useful. The second is the detection of any water level responses in the pump test monitoring wells completed in overlying or underlying aquifers during the aquifer pump test.

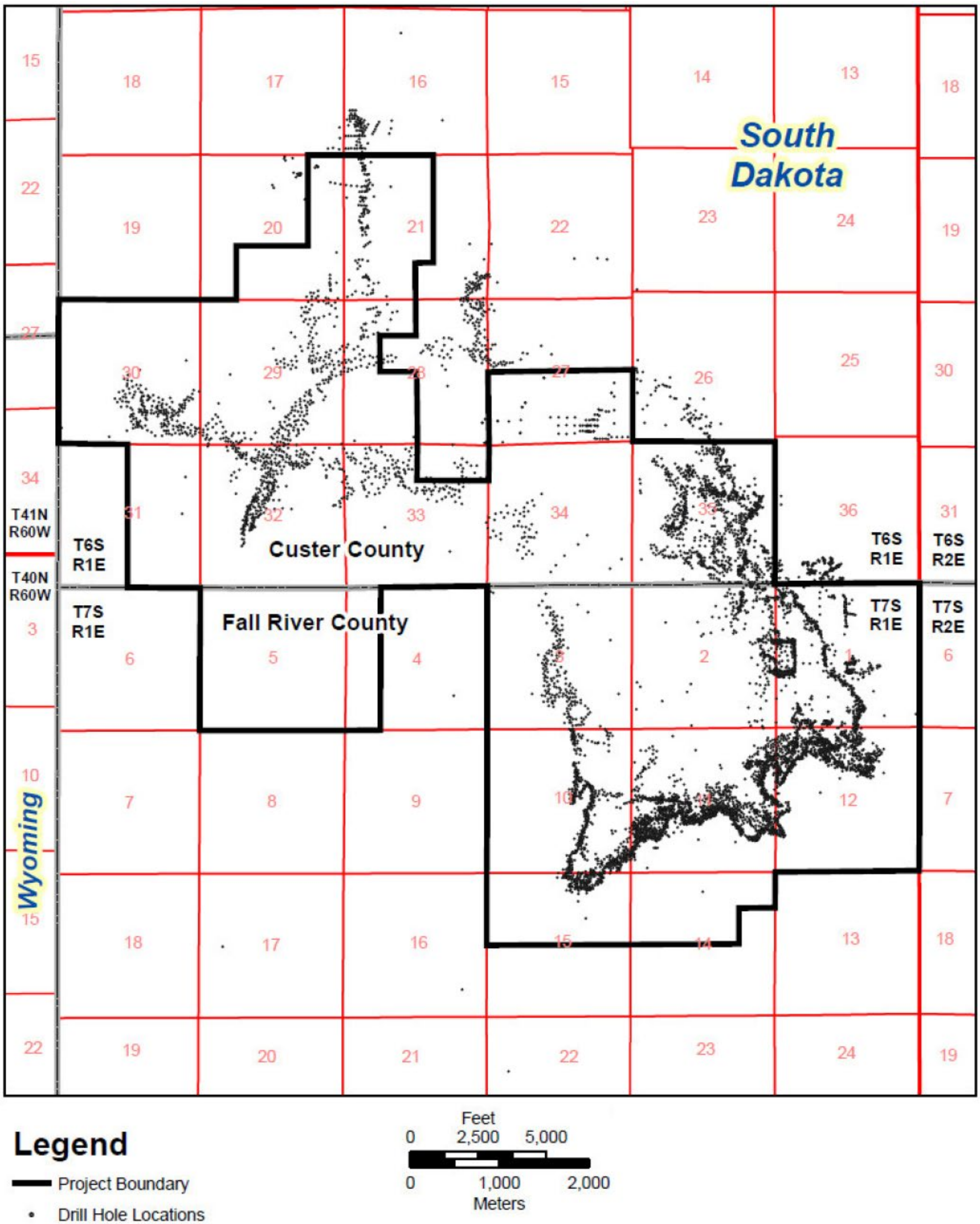


Figure 10. Map of Exploration Drillhole Locations at the Dewey-Burdock Site

4.3 Alluvial Drilling Program

Alluvium is an unconsolidated geologic unit consisting of sediments ranging in particle size from silt and clay to cobbles deposited by Beaver and Pass Creeks as they have changed surface location throughout the history of their existence. The unconsolidated nature of alluvium would mask the occurrence of any upwelling groundwater flow from a deeper aquifer through a breach in the confining zone separating the alluvium from underlying aquifers. For this reason, it is important to map the depth and areal extent of the alluvium and characterize the alluvial groundwater within the Dewey-Burdock Project Area. Characterization work was performed on alluvium associated with the Beaver Creek and Pass Creek surface drainage systems within the Dewey-Burdock Project Boundary. There is also alluvium associated with the Bennett Canyon drainage system along the eastern edge of the site, but because there will be no wellfields located in that area, the Bennett Canyon alluvium was not characterized.

The Permittee conducted an alluvial drilling program to characterize the thickness, extent and saturated thickness of the alluvium along Beaver Creek and Pass Creek. The program was designed to identify any potential discharge to alluvium from underlying aquifers through breaches in the Graneros Group confining zone and to acquire baseline alluvial groundwater quality for the Groundwater Discharge Permit application submitted to the South Dakota DENR. Several borings were drilled into the alluvium along Beaver Creek and Pass Creek, many of which were dry. Figure 11 shows the extent of alluvium within the Dewey-Burdock Project Area and the alluvial wells used to determine the potentiometric surface of alluvial groundwater. Figure 11 also shows the potentiometric surface elevation of the alluvial groundwater. The thickness of the saturated alluvium at these wells ranged from 10 to 12 feet. The alluvium in the Pass Creek drainage ranges from zero to 50 feet thick. In the Beaver Creek drainage, the alluvium ranges from zero to 30 feet thick. An alluvial isopach map, which shows the thickness of the alluvium, is shown in Figure 12b.

In addition to characterizing the thickness, extent and saturated thickness of the alluvium along Beaver Creek and Pass Creek, the alluvial drilling program included evaluating the water quality of the alluvial groundwater. The alluvial groundwater has higher TDS, sulfate, and specific conductance values than the underlying Fall River aquifer groundwater. Appendix N of the Class III Permit Application shows summary water quality information for the alluvium and other aquifers investigated during the AOR process. If any Fall River groundwater were currently moving upward into the alluvial groundwater, these areas would manifest as groundwater plumes with lower values of specific conductance measurements.

Information from the alluvial drilling program regarding the occurrence or absence of groundwater, saturated thickness and water quality data did not indicate any areas of discharge to the alluvium from underlying aquifers but were consistent with limited recharge occurring from surface waters in the upland portions of the Project Area.

The alluvial deposits and alluvial groundwater will be further assessed during wellfield delineation drilling discussed in Section 5.1 and formation testing in Section 5.3. Figure 12a is a map that shows the wellfields that will have overlying alluvium. Figure 12b is a map that shows the thickness of alluvium and the locations of the proposed wellfields. These wellfields will have non-injection interval monitoring wells completed in all overlying aquifers as discussed in Section 12.4.2.1 and shown in Figure 29 and Figure 30. Water quality and water level data will be collected after the drilling and completion of the wellfield pump testing wells. Therefore, these areas will be further characterized in the future to provide additional data for the Conceptual Site Model discussed in Section 15.2 and to design the wellfield non-injection interval monitoring wells layout.

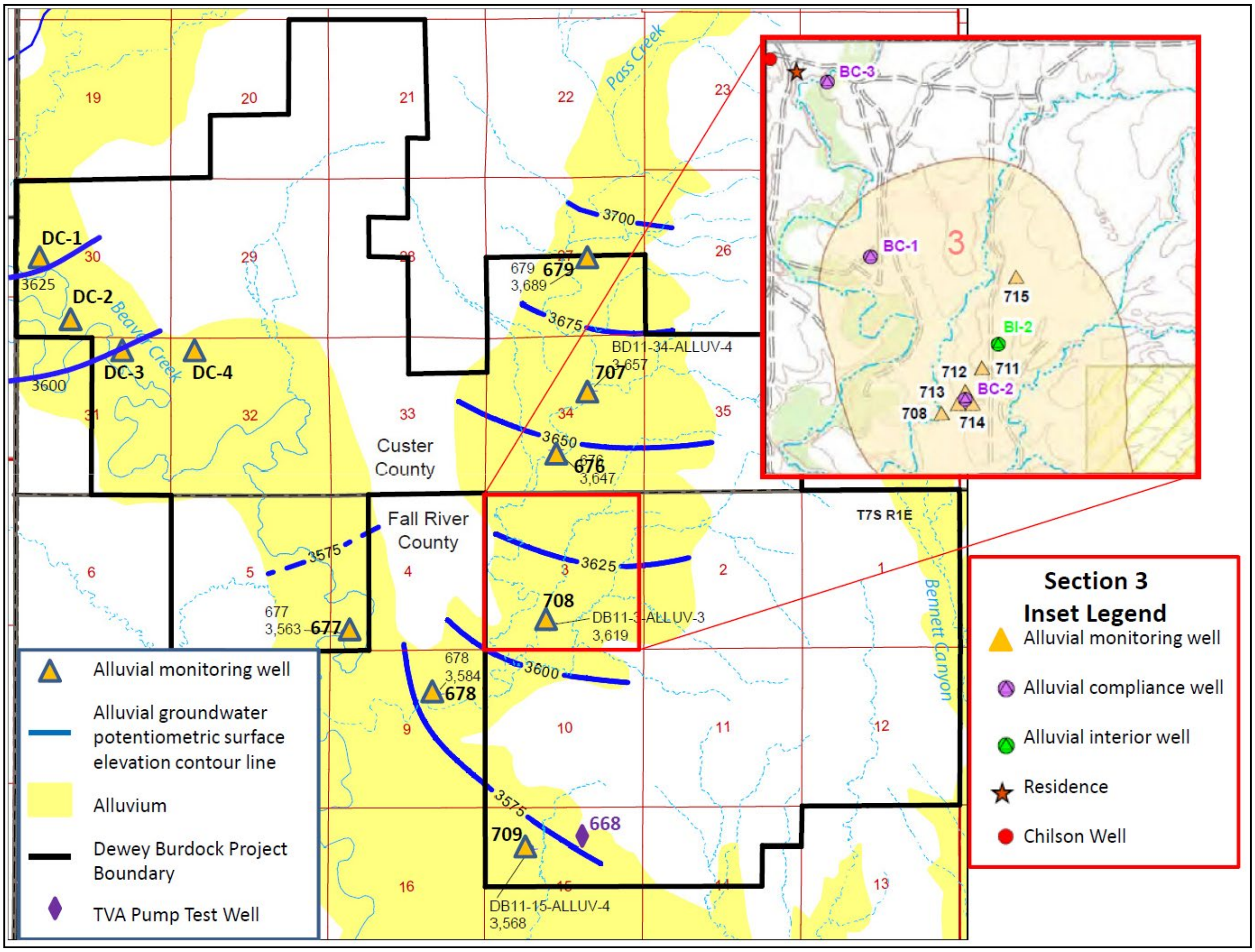


Figure 11. Extent of Alluvium in the Dewey-Burdock Project Area and the Potentiometric Surface Elevation of Alluvial Groundwater

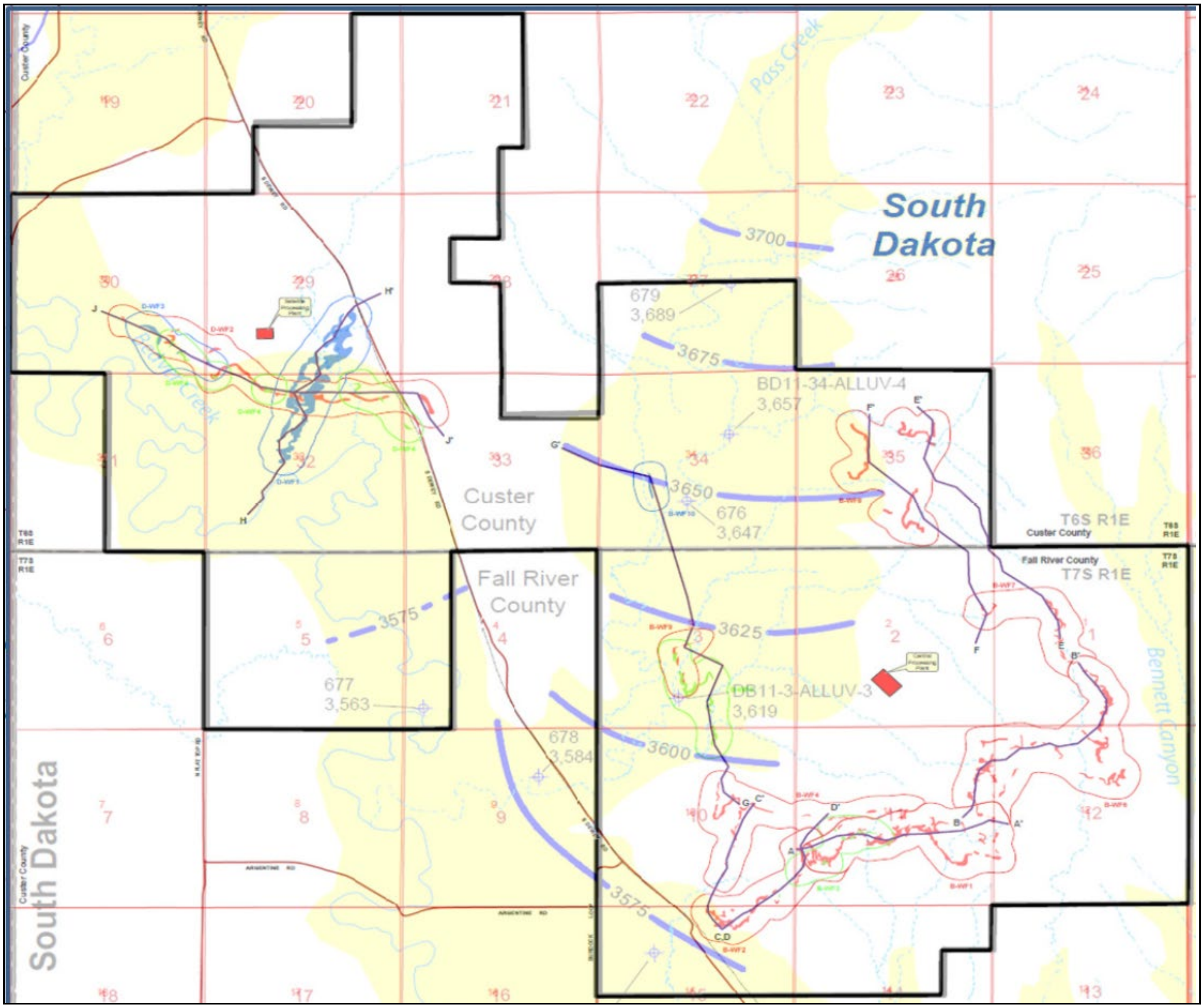
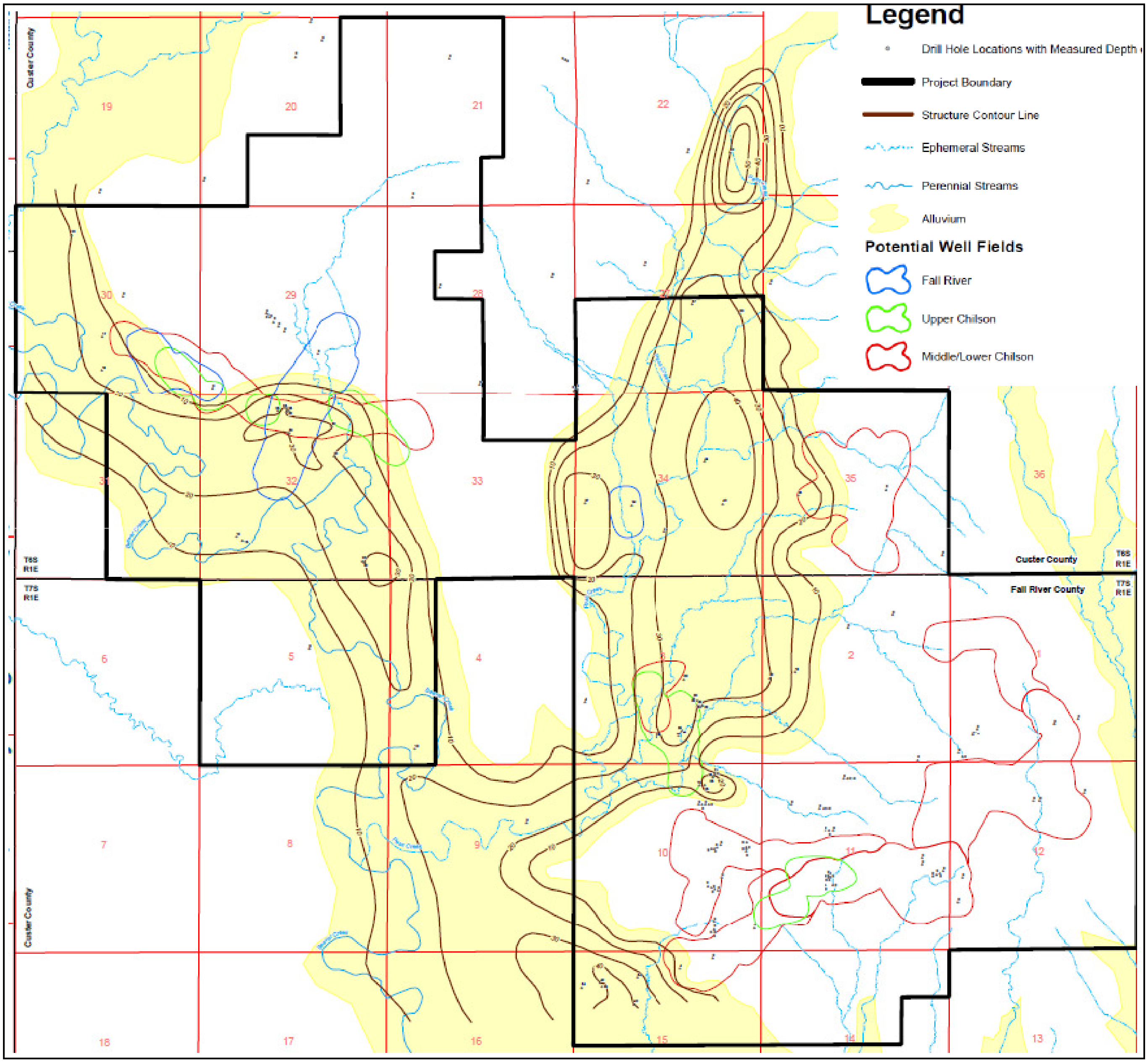


Figure 12a. Extent of Alluvium in the Dewey-Burdock Project Area and Proposed Wellfield Locations



(Plate 3.6-4 Alluvium Isopach in the Groundwater Discharge Permit Application prepared for the SD DENR)

Figure 12b. Alluvium Isopach Map Showing Thickness of Alluvium and Proposed Wellfield Locations

4.4 Chilson and Fall River Potentiometric Surface Evaluation

The Permittee also evaluated areas where the potentiometric surfaces of the Fall River and Chilson are above ground surface as an indicator of the potential for groundwater upwelling into the alluvium. Those areas within the Beaver Creek and Pass Creek drainages where the potentiometric surfaces of the Fall River and Chilson are above the ground surface are depicted on Permit Application Figures 4.7 and 4.8, respectively. Note that the potentiometric surfaces are anticipated to be above ground surface to the west and southwest of the areas depicted on Figures 4.7 and 4.8 as well; the boundaries shown in these directions are due to lack of data. The potential for groundwater discharge to alluvium from an operating wellfield is limited to those areas where the wellfield overlaps alluvium and the potentiometric surface of the Fall River or Chilson is above the base of the alluvium. Figure 13 and Figure 14 show the overlay of the areas where the potentiometric surfaces of the Fall

River and Chilson aquifers, respectively, are above the ground surface on the map of the alluvium to illustrate the areas where the potential for Fall River and Chilson groundwater has the potential to flow upward into the alluvium through any breach in confining zones if proper wellfield control is not maintained during uranium recovery and restoration and after wellfield restoration is complete and pre-ISR hydrologic conditions are regained. This area will be further characterized as the wellfield delineation, formation testing and pump testing work is performed as discussed in Section 5.0 and required under Part II of the Class III Area Permit.

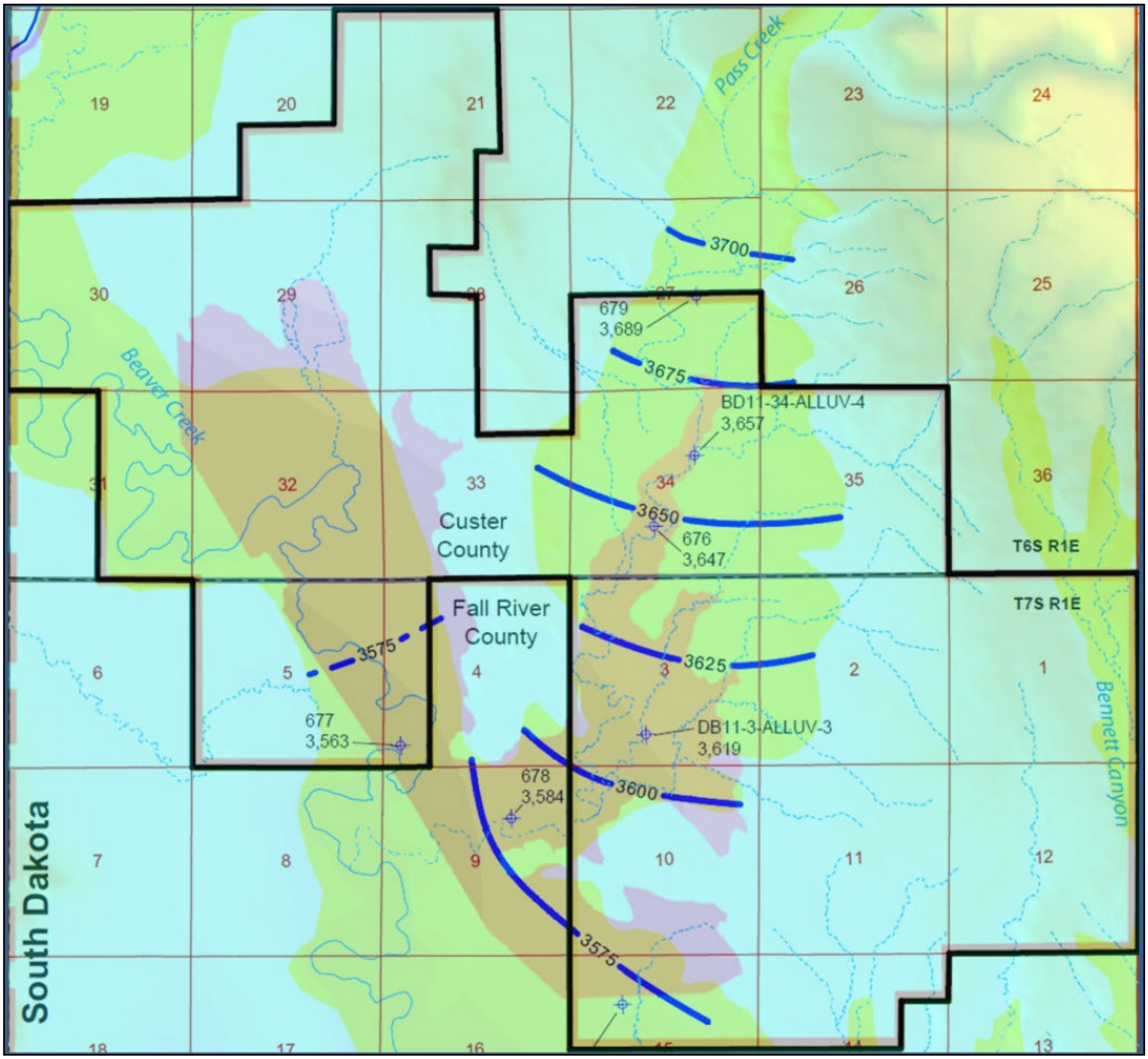


Figure 13. Map Showing Area where the Fall River Aquifer Potentiometric Surface Is Above Ground Surface and Extent of Alluvium in the Dewey-Burdock Project Area

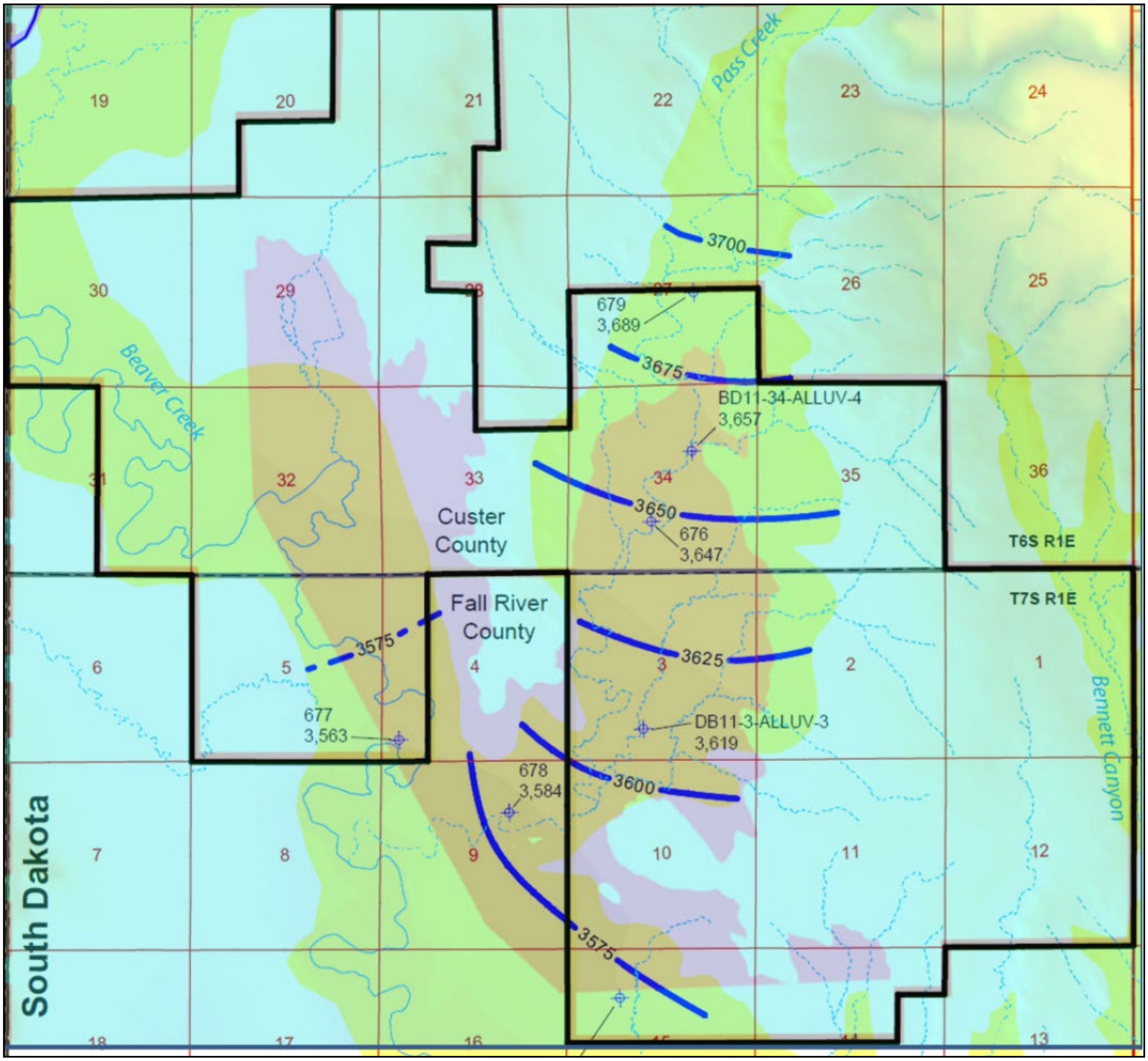


Figure 14. Map Showing Area where the Chilson Aquifer Potentiometric Surface Is Above Ground Surface and Extent of Alluvium in the Dewey-Burdock Project Area

4.5 Color Infrared (CIR) Imagery

To evaluate possible groundwater discharge to the ground surface and into the alluvium within the Beaver and Pass Creek drainages, the Permittee obtained CIR satellite imagery from the National Agriculture Imagery Program (NAIP) of the USDA Farm Services Agency for the project area and vicinity. The imagery was photographed in 2010 and produced with a resolution of one meter. CIR imagery is commonly used to delineate areas of active vegetative growth. In semiarid regions such as the Dewey-Burdock Project Area, such areas are often indicative of enhanced water supply, such as occurs with irrigation or subsurface irrigation.

CIR imagery for the project area and vicinity is presented in Permit Application Figure 4.3. The CIR imagery was examined visually for any anomalies that may suggest groundwater discharge at or near the surface, such as from upward flow through an open borehole or a natural spring. Within the project area, there are several flowing artesian wells that at times are allowed to discharge groundwater to the surface. These areas are generally visible on the CIR imagery. An area called the alkali area has a noticeable signature on CIR (ponded water surrounded by discolored soil) and is depicted in Permit Application Figures 4.4 and 4.5.

The CIR imagery clearly shows two springs outside the project area near the town of Dewey along the Dewey Fault (Class III Permit Application Figure 4.6). These locations were later verified by Powertech staff and the springs were sampled for water quality analysis. Results of those samples indicate the spring water most closely resembles Fall River water quality; those data clearly distinguish the spring water from the alluvium and Unkpapa Formation aquifer fluids. The results of this investigation strongly support the use of CIR data to identify areas of groundwater discharge, and with the exception of the alkali area support the lack of such discharge from exploration drillholes within the project area.

4.6 Possible Breaches in Confining Zones

With one exception, groundwater discharging to the ground surface is limited to flowing artesian wells, which will be controlled and mitigated as described in the corrective action requirements discussed in Section 6.2. The only feature identified that was indicative of groundwater discharge from exploration drillholes at or near surface was the alkali area in the southwestern corner of the Burdock portion of the project area (N1/2 NE1/4 Section 15, T7S, R1E). The location of the alkali area is shown in Figure 15. The Permittee has identified this area as a possible location where groundwater may be discharging to the surface from the Fall River and possibly the Chilson to the surface through an abandoned exploration drillhole. The "alkali area" lies within the proposed location of Burdock Wellfield 2. The hydraulic communication between the Fall River and Chilson Sandstone aquifers and the ground surface will be investigated more closely during the wellfield delineation drilling and wellfield pump tests (discussed in Section 5.0 and required in Part II of the Class III Area Permit) for Burdock Wellfields 1 and 2. The observation wells for the wellfield 1 and 2 pump tests will be more numerous and more closely-spaced than those for the Powertech Burdock Area pump test conducted in 2008 and the TVA Burdock pump tests conducted in 1979. Comparing the responses in each wellfield pump test observation well will help identify more closely the locations of the leaks through the confining zones at the site and help narrow down the locations of the leaking drillholes or other breaches in confinement. Part II of the Class III Area Permit includes the best available technology requirements the Permittee must implement to locate leaking drillholes or water wells and Part III includes corrective action requirements to prevent lixiviant migration along communication pathways between the Fall River and Chilson through the Fuson Shale or through the Graneros confining zone to the ground surface.

Another possible explanation for the apparent leak in the Fuson confining zone is the connection between the Fall River and the Chilson aquifers in TVA's pumping well labeled Hydro ID 668. Well 668 has 10-inch-steel casing with 55 feet of screen in the Fall River Formation and 8-inch steel casing and 75 feet of screen in the Chilson Sandstone. A well of this size causes a large enough communication pathway between the two aquifers that could account for the almost immediate drawdown in the Fall River observation well in response to the onset of pumping of the Chilson Sandstone aquifer. The location of well 668 is also shown in Figure 15. The Permittee plans to either plug and abandon this well or install a packer between the two screened intervals to prevent hydraulic communication between the Fall River and Chilson aquifers during future Burdock wellfield pump tests.

As shown in Figure 15, the wellfield that will be most directly impacted by a breach in the Fuson confining zone in the Alkali Area is Burdock Wellfield 2. Figure 16 and Figure 17 show cross sections in Burdock Wellfields 2 and

3. Wellfield 2 will be targeting ore in the Lower Chilson, which is separated from the Fall River by two additional overlying confining zones. Burdock Wellfield 3 is outlined in green because it is will be targeting ore in the Upper Chilson where the Fuson is the overlying confining zone. It will be very important to carefully characterize the overlying confining zone during the wellfield pump testing for Burdock Wellfields 1, 2 and 3 to identify the locations of leakage in the Fuson confining zone. The Permittee will not be able to begin injection activity until this issue is resolved. Resolution of the issue may involve locating and plugging of improperly plugged historic drillholes, locating and performing corrective action on nearby wells that create a pathway through the Fuson confining zone, or a pumping, injection and monitoring plan that demonstrates control of lixiviant in the areas where the breaches in the Fuson confining zone have been identified.

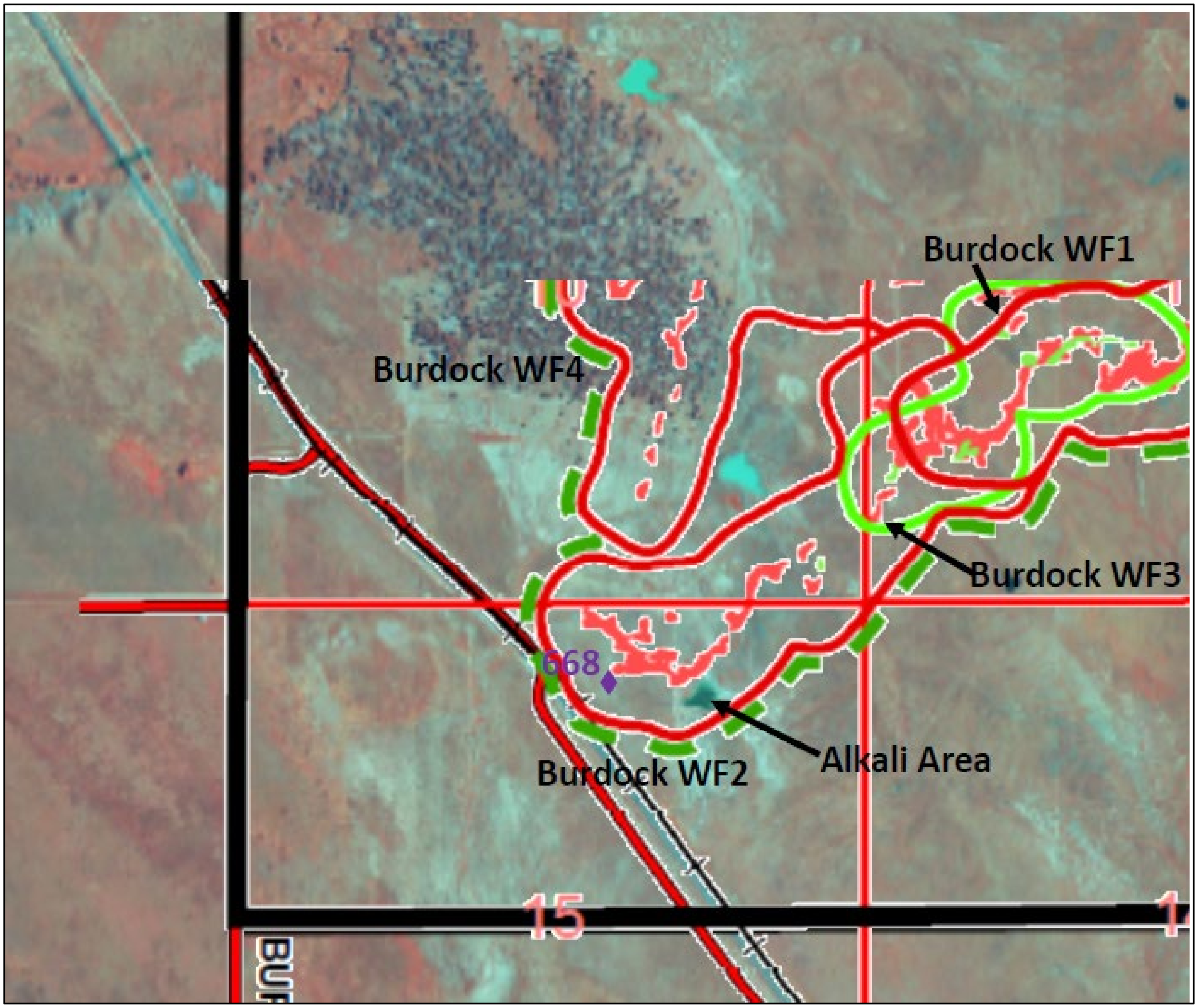


Figure 15. Location of the Alkali Area and TVA's Burdock Area Pumping Well, Hydro ID 668

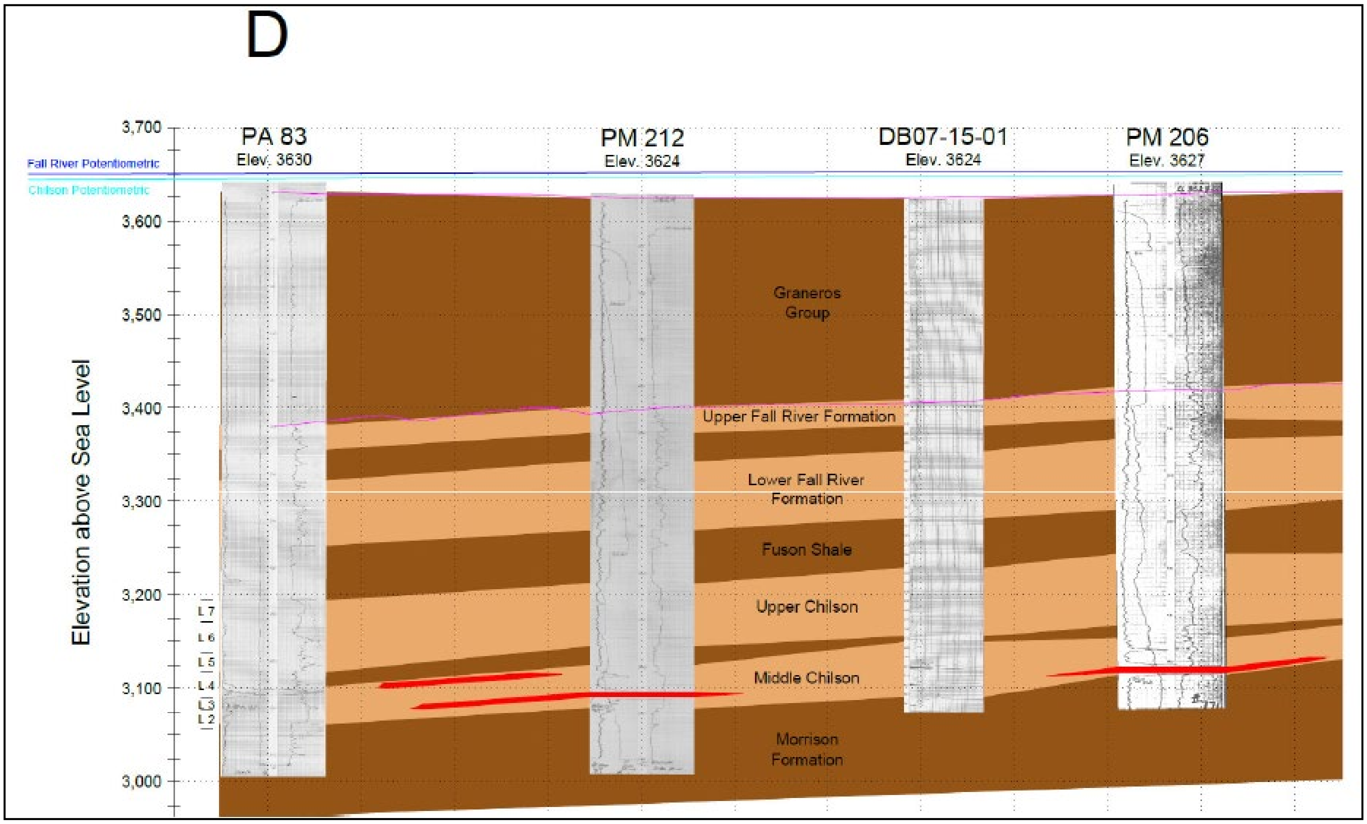


Figure 16. West End of Cross Section D-D' in Burdock Wellfield 2 Showing Ore in the Middle Chilson

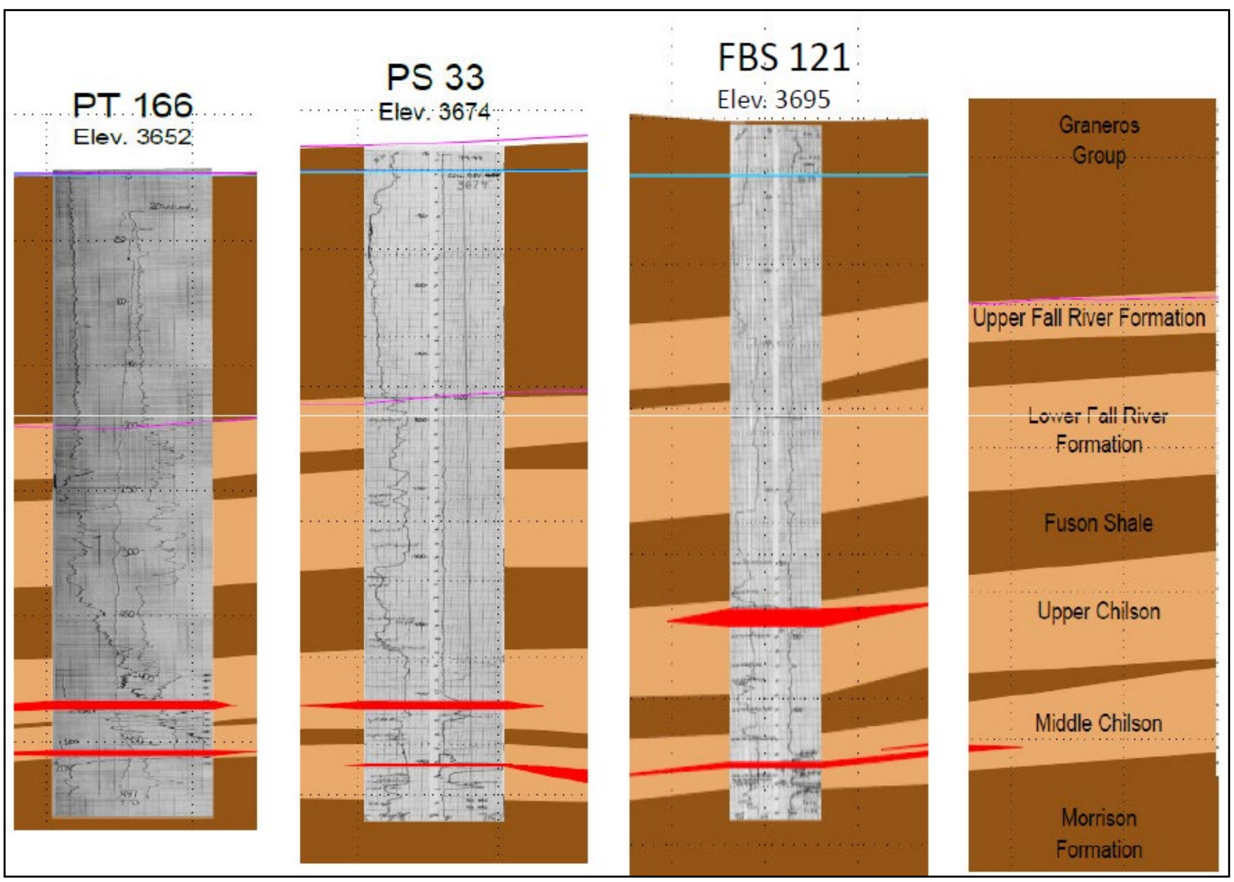


Figure 17. Cross Sections in Burdock Wellfield 3 Showing the Fuson Shale and Ore in the Upper Chilson

4.7 Wellfield Delineation Drilling and Pump Testing

Part II of the Class III Area Permit requires detailed characterization of geologic confinement and hydrogeologic conditions for each wellfield before the UIC Program Director (Director) will grant an Authorization to Commence Injection for each wellfield. Further evaluation during the wellfield delineation drilling and wellfield-scale pump testing prior to the development of each wellfield should help locate any breaches in confining zones so corrective action can be performed to prevent potential upward groundwater movement through unplugged or improperly plugged drillholes or natural geologic features as discussed in Sections 5.0 and 6.0. As discussed in Section 6.0, corrective action may involve locating and plugging of improperly plugged historic drillholes, locating and plugging nearby wells that create a pathway through the confining zones, or a pumping, injection and monitoring plan that demonstrates control of lixiviant in the areas where the breaches in the Fuson confining zone have been identified but cannot be mitigated by any other method.

4.8 Abandoned Mines

There are historical uranium mine workings, including surface and underground mines, along the eastern portion of the project area. Underground workings are associated with four former shallow underground uranium mines and two adits in open-pit walls. The locations of historical surface and underground mining operations in the Triangle Mine area and the Darrow Mine area are shown on Figure 18. Susquehanna Western Inc. drove adits short distances into open-pit walls to recover additional uranium ore that was adjacent to the pit. These types of underground workings were common at historical surface mines and were considered to be extensions of the open-pit mining operations.

All of the underground workings within the project area are associated with open-pit remnants that are clearly visible or, in the case of the Triangle Mine, have been backfilled and partially reclaimed. There are no underground mines within the project area that are not associated with, adjacent to, or extensions of the open pits, all of which are within the upper portion of the Lower Fall River Formation. The underground mines consisted of declines (downward sloping ramps) ranging in depth from 0 to 80 feet below land surface. The adits (horizontal tunnels) were driven into the sidewalls of the historical open-pit mines. All underground workings were conducted within sandstones of the Fall River Formation at or above the water table and above the Fuson Shale confining zone such that these workings did not penetrate or otherwise compromise the integrity of the Fuson Shale confining zone.

Figure 19 shows an electric log from an exploration drillhole located approximately 200 feet north of the Triangle Mine. The gamma activity shown on the log indicates the portion of the Fall River sand that was mined at the Triangle Mine and its position relative to the Fuson Shale confining zone. The ore-bearing zone of the Lower Fall River is approximately 45 feet above the Fuson Shale confining zone. All excavation at the Triangle Mine took place well above the Fuson Shale, which averages 50 feet thick in this area. Accordingly, these historical mining operations did not compromise the integrity of the Fuson Shale confining zone.

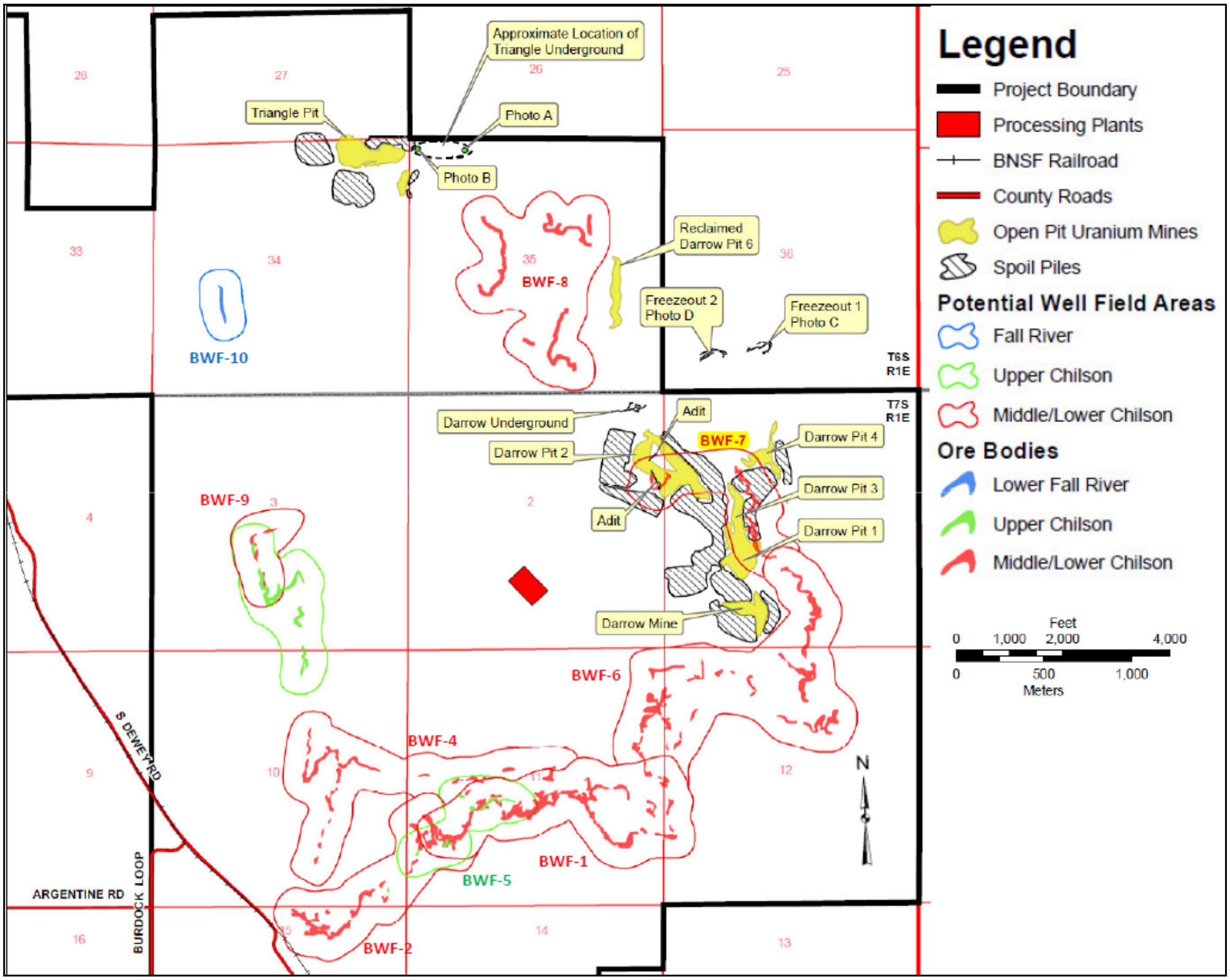


Figure 18. Location of Historic Abandoned Uranium Mine Workings

Burdock Wellfield 10, located approximately 3,000 feet down-gradient from the Triangle Pit, will be the closest wellfield to the abandoned mines targeting the Lower Fall River ore body. Burdock Wellfield 10 will be in hydrologic communication with the water in the Triangle Pit. However, there is little chance the uranium-bearing lixiviant will flow into the Triangle Pit because the Burdock Wellfield 10 is located down-gradient from the Triangle Pit. The lixiviant would have to travel up-dip along the Lower Fall River aquifer approximately 3,000 feet to reach the Triangle Pit. The inward groundwater gradient that must be maintained during uranium recovery operations and subsequent groundwater restoration at Burdock Wellfield 10 has the potential to pull the Triangle Pit water down-gradient at a faster rate than is already occurring under the natural groundwater flow regime. Because of exposure to the atmosphere, the Triangle Pit groundwater will have higher dissolved oxygen than is typical of Chilson groundwater. Impacts from Triangle Pit water on Burdock Wellfield 10 will be examined during the wellfield pump testing (Class III Area Permit Part II, Section F.5) and evaluated in the wellfield Injection Authorization Data Package Report (Class III Area Permit Part II, Section H.3.n). At present there is no monitoring well completed in the Fall River aquifer located between the Triangle Mine and Burdock Wellfield 10. However, both the NRC license and Part IX, Sections B.2.c and d of the Class III Area Permit require the Permittee to install a monitoring well SWNE Section 34 between the Triangle Mine and Burdock Wellfield 10.

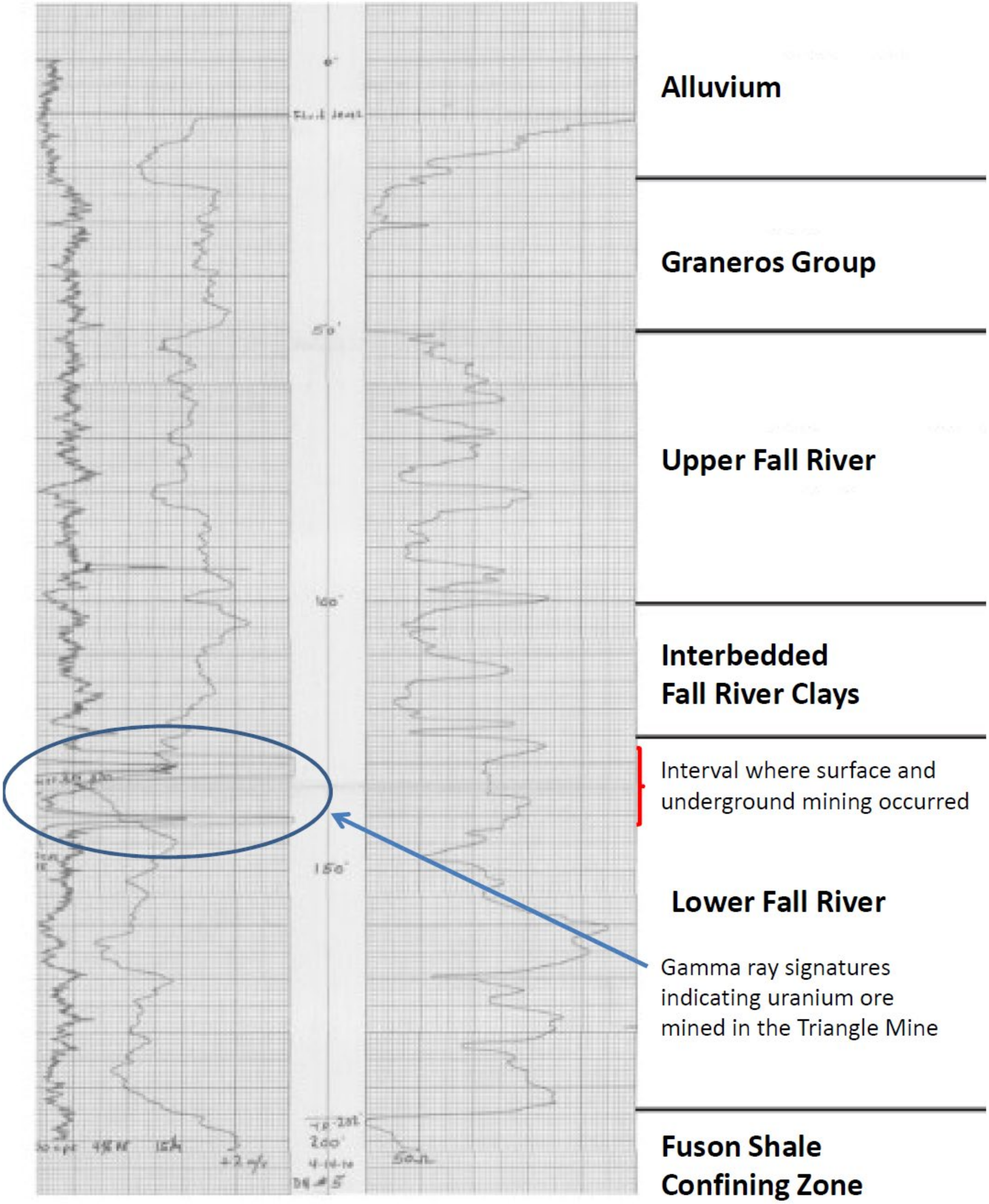


Figure 19. Electric Log from Drillhole near the Triangle Pit

Figure 20 shows an electric log from an exploration drillhole located near the Darrow Mines and the proposed location for Burdock Wellfield 7. The gamma activity shown on the log indicates that the portion of the Fall River sand that was mined at the Darrow Mines is approximately 30 feet above the Fuson Shale confining zone.

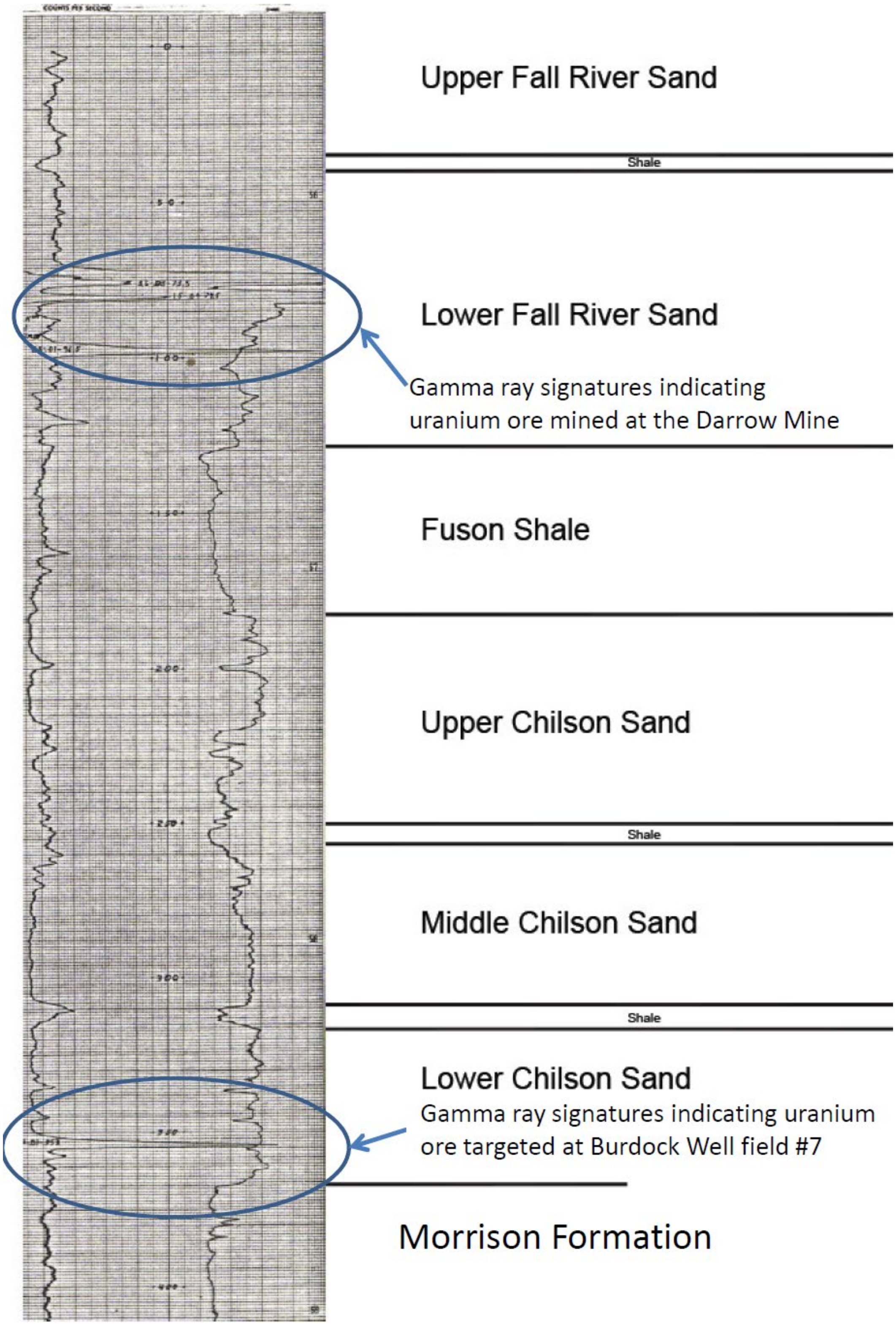


Figure 20. Electric Log from Drillhole Located near the Darrow Mines and Burdock Wellfield 7

The Fuson Shale thickness shown on this log is about 50 feet. The ore zone targeted in Burdock Wellfield 7 is the Lower Chilson Sandstone, which is approximately 188 feet below the base of the Fall River Formation. The Lower Chilson ore zone is also separated from the Fall River by 50 feet of the Fuson Shale confining zone, as well as two interbedded shale intervals within the Chilson Member – one 7 feet thick and the other 8 feet thick.

The surface and underground workings will not affect the Permittee's proposed ISR operations in this area. The Permittee will not develop wellfields within Fall River Formation sandstones in the portion of the project area where the Darrow Mines are located. Burdock Wellfields 6 and 7 will be targeting ore in the Lower Chilson Sandstone. The Fuson Shale confining zone is intact and has not been breached by any of the abandoned mine workings.

4.9 Breccia Pipes

Breccia pipes have been studied and mapped in the southern Black Hills region and are known to occur in anhydrite and gypsum sequences within the upper portion of the Minnelusa Formation. Dissolution of these evaporite sequences by underlying Minnelusa and/or Madison artesian water created solution cavities into which overlying Permian sediments collapsed. Where these breccias pipes occur, they create disruption of overlying confining zones, so it is important to determine where they are located in relation to the Dewey-Burdock Project Area. The probable maximum down-gradient limit of dissolution, or dissolution front, where these breccias pipes occur has been mapped by the USGS and is more than 6 miles northeast of the Dewey-Burdock Project Area.

The EPA evaluated the potential for breccia pipes to occur in and around the Dewey-Burdock Project Area and concluded that there is no evidence indicating that breccia pipes are present at the Project Site based on the detailed evaluation presented by the Permittee in Permit Application Appendix E. This information is summarized below.

There is no evidence of dissolution of the Minnelusa Formation in the Dewey-Burdock Project Area based on evaluation of an electric log from an abandoned oil and gas test well within the Project Area. In areas where there has been no dissolution in the Minnelusa, there is no geologic foundation for the creation of breccia pipes in overlying sediments.

Further evidence supporting the absence of breccia pipes at the Dewey-Burdock Project Area is presented in Class III Permit Application Appendix E. Appendix E includes discussions on exploration drilling, field investigations for breccia pipes, an evaluation of Inyan Kara water temperatures, regional pump tests and evaluation of CIR imagery.

The EPA evaluated drillhole logs for the oil and gas test wells listed in Table 10. All available logs indicated that the thick anhydrite layers present in the Minnelusa that would be dissolved away during breccia pipe formation are intact and have not been affected by dissolution.

In addition to information provided by the Permittee, the UIC Class V Area Permit requires verification of the integrity of the confining zone above the Minnelusa Formation in the Dewey-Burdock Project Area as described in the Fact Sheet for the Class V Area Permit.

4.10 Seismology

The Dewey-Burdock Project Area is located in an area of historically low seismic potential. There are no known capable faults within 100 km and a relatively low number of historical earthquakes. Seismic hazards around the

Project Area include low to moderate ground shaking associated with regional and local earthquake sources. Class III Permit Application Figures 6.5 and 6.6 include seismicity and peak ground acceleration (PGA) maps for the Project Area, and Class III Permit Application Appendix H provides a summary of the USGS database results for historical earthquakes recorded within 100 and 200 km from the Project Area since 1973.

There are no capable faults (as defined in the NRC regulation at 10 CFR Part 100, Appendix A, Section III(g)) known to be present within 100 km of the project area. The closest capable fault zone to the project area is located nearly 345 km (200 miles) west of the site in central Wyoming. Therefore, the most significant seismic hazard is considered to be the randomly occurring or “floating” earthquake. This is the maximum credible earthquake estimated for the project area based on available literature, geologic information of the surrounding area, and historical data. A magnitude Mmax = 6.1 is estimated for this event.

According to the USGS 2008 Seismic Hazard Mapping Program, PGA derived from the probabilistic maximum bedrock acceleration with a 10% exceedance in 50 years (475-year return period) is 0.02 to 0.03g for the southwestern part of South Dakota as shown in the map in Permit Application Figure 6.6. The probabilistic maximum bedrock acceleration with a 2% chance of exceedance in 50 years (2,475-year return period) is 0.07 to 0.10g for the region as shown in Permit Application Figure 6.7. Both of these estimates reflect a low ground motion hazard.

As discussed further in Permit Application Section 13.5.2, all buildings, structures, foundations, and equipment will be designed in accordance with recommendations in the latest versions of the International Building Code and ASCE-7 published by the American Society of Civil Engineers. Maps published in ASCE-7, and the latest version of the USGS Earthquake Ground Motion Tool, along with information regarding soil characteristics provided by the project professional geotechnical engineer, will be used to determine seismic loadings and design requirements.

Seismic monitoring is required under the UIC Class III Area Permit under Part IX, Section D. For any seismic event of magnitude 4.0 or greater reported within two miles of the permit boundary, the Permittee must immediately cease injection and report to the Director within twenty-four (24) hours according to Part XII, Section D.10.e of this permit. The Director will determine if any structural testing of the facility infrastructure is required before injection resumes. Types of analysis that will determine if any structural damage has occurred include observing all the gauges within the header houses where injection pressures, flow rates and volumes are measured to see if any unexpected increases or decreases are observed or if any automatic shut-downs have been triggered by threshold value exceedances. Injection must not resume until the Permittee has obtained approval to recommence injection from the Director.

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 this seismic activity to the Director on a quarterly basis, as required Class III Area Permit Part IX, Section B, Table 14.G and Section D.

5.0 REQUIREMENTS FOR AUTHORIZATION TO COMMENCE INJECTION

In order to obtain Authorization to Commence Injection, Part II of Class III Area Permit requires the Permittee to thoroughly characterize the geohydrologic setting of each wellfield by performing pre-operational well-field delineation drilling, formation testing and data analysis. The following sections describe the well-field delineation and formation testing procedures. An extensive wellfield pump test program must be designed and implemented prior to operation of each wellfield to evaluate the integrity of the confining zones, assess the ability to control injection interval fluids and test the effectiveness of the wellfield monitoring system. The wellfield delineation drillhole logging, formation testing and pump test results will be included in the Injection Authorization Data Package Reports prepared for the EPA described in Section 5.6. In addition to the Injection Authorization Data Package Reports, the Permittee must also demonstrate that each injection and production well has mechanical integrity before the EPA will issue Authorization to Commence Injection into the wellfield wells.

5.1 Wellfield Delineation Drilling and Logging

The purpose of wellfield delineation required under Part II, Section B of the Class III Area Permit is to determine the horizontal and vertical extent of the uranium ore bodies targeted by each wellfield, along with confining zones and aquifer units. The end result will be a more detailed conceptual geology and hydrogeology in order to finalize wellfield design and to determine the wellfield design parameters including:

1) the horizontal and vertical extent of the proposed injection intervals based on ore deposit locations,
2) the presence and thickness of overlying confining zones, and
3) the presence and thickness of overlying aquifer units requiring non-injection interval monitoring wells.

As discussed in Section 3.4.3 no monitoring is required below the Morrison Formation lower confining zone of the Inyan Kara Group during ISR operations. If the lower confining zone for the target injection interval is not the Morrison Formation, then delineation drillholes will penetrate below the proposed injection interval through the first underlying aquifer unit to evaluate:

1) the presence and thickness of the confining zone underlying the injection target injection interval, and
2) the thickness of the first underlying aquifer unit requiring non-injection interval monitoring wells.

The delineation drillholes and the pump test wells drillholes will be logged to determine lithologic horizons and the extent of the ore zones within the wellfield. The list of logs to be performed on the drillholes is included in Table 11. This information will be provided to the EPA in the form of a descriptive narrative containing detailed map or maps and cross sections.

Table 11. Delineation and Pump Test Well Drillhole Logging Program

TYPE OF LOG	PURPOSE
Gamma Ray	To identify ore depth and thickness
Self Potential	To identify confining zones and aquifer units.
Resistivity	To identify confining zone depth and thickness
Physical Geologic Log	To identify lithology and stratigraphy

After drilling and logging, all delineation holes will 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 discussed under Section 5.4.

5.2 Monitoring System Design

After the wellfield delineation drilling and logging has been performed to identify

- the vertical and horizontal extent of the ore deposits,
- the wellfield injection interval,
- the confining zones and
- the non-injection intervals to be monitored,

Part II, Section D of the Class III Area Permit requires the Permittee to design and install the monitoring well system. The purpose of the monitoring well system is to demonstrate that injection interval fluids do not migrate horizontally or vertically out of the approved injection interval during ISR operations. These monitoring wells must be installed prior to the wellfield pump test to verify the integrity of confining zones, to identify and locate any breaches in confining zones, and to verify that injection interval monitoring wells are hydraulically connected to the wellfield pump test pumping wells.

To monitor horizontal containment of injection interval fluids, monitoring wells must be completed in the injection interval around the perimeter of each wellfield approximately 400 feet from the wellfield boundary. These wells are known as the perimeter monitoring well ring. Non-injection interval monitoring wells must be installed above, and in some cases below, the injection interval of each wellfield to monitor vertical containment of injection interval fluids. Non-injection interval monitoring wells will be completed in each overlying aquifer for all wellfields. Non-injection interval monitoring wells will be completed in the first aquifer underlying the injection interval if the aquifer lies above the Morrison Formation.

As discussed in Section 3.4.3, no underlying non-injection interval monitoring wells are required below the Morrison Formation for the monitoring of ISR operations in wellfields targeting ore in the Lower Chilson for the following reasons:

1) The Morrison Formation is continuous across the entire Dewey-Burdock Project Area with a thickness ranging from 60 to 140 feet. The Morrison Formation will act as an aquitard between the Unkpapa and the Fall River and Chilson. The integrity of the Morrison Formation confining zone was demonstrated by the pump tests conducted by the Permittee, where no response occurred in the Unkpapa during pumping of either the Fall River or Chilson.
2) The Unkpapa Sandstone is the first underlying aquifer below the Morrison Formation confining zones. The Unkpapa Sandstone aquifer shows a substantially higher potentiometric surface than the Fall River and Chilson aquifers throughout the permit area under pre-ISR conditions, indicating that the Unkpapa Sandstone aquifer has a higher fluid pressure than the Fall River and Chilson aquifers. During ISR operations, the Chilson and Fall River potentiometric heads will be lowered within each wellfield because a greater volume of fluid is pumped from the production wells than is injected into the wellfield, to produce the inward hydraulic gradient. Flow into the Unkpapa from injection intervals in the Fall River and Chilson would be impossible because the fluid pressures within these two aquifers are lower than the fluid pressure within the Unkpapa aquifer even under normal conditions before ISR operations begin. Under ISR operation, the fluid pressures of the Fall River and Chilson aquifers are further lowered by producing the inward hydraulic gradient at each wellfield bleed creating an even greater pressure barrier between the Inyan Kara and Unkpapa aquifers.

5.3 Formation Testing

Once all the pump test wells and monitoring wells are installed, Part II, Section E of the Class III Area Permit requires formation tests to be conducted to further characterize the wellfield hydrogeology, evaluate the hydraulic isolation of the proposed injection interval, and verify the integrity of the operational confining zones. These tests are listed in Table 12.

5.3.1 Water Level Measurements

Prior to the pump test, static potentiometric water levels must be measured in every pump test well under Part II, Section E.2.a.i. The data points must be used to map the pre-operational baseline potentiometric surface for each unit including alluvium, where present. Because of the high density of wells and flowing artesian conditions at the site, any leakage across confining zones due to improperly plugged drillholes or wells should become apparent while preparing potentiometric surface maps. Part VIII, Section C.2 of the Class III Area Permit also requires confirmation of the injection interval potentiometric surface before wellfield operation begins. After the construction of all wellfield injection, production and monitoring wells is completed and the static potentiometric surface for each aquifer has stabilized from well development activities and the wellfield pump tests, the static potentiometric water levels must be measured in every well in the monitoring system prior to the initiation of injection into the wellfield. This round of water level measurements will determine the degree to which the injection interval potentiometric surface has recovered after the wellfield pump tests. 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.

5.3.2 Water Quality Analyses

The Permittee must also collect water samples from all monitoring wells and analyze the samples for the baseline parameters listed in Table 13. To ensure that representative samples are collected from each monitoring well, Part II, Section E.2.b.i requires the Permittee to measure pH, specific conductance, and temperature at the surface as fluid is pumped out of the well to determine when collection of a representative sample is possible. Once each field parameter meets the stabilization criteria in Table 7 of the Class III Area Permit, that is indication that residual contaminants from well drilling and construction or stagnated groundwater in the wellbore has been purged. At that time a groundwater sample is reasonably expected to be representative of ambient groundwater quality. If parameter stabilization does not occur and the procedure has been strictly followed, then a sample may be collected once a minimum of three casing volumes have been removed from the well. The Class III Area Permit requires that all fluid samples collected for the purpose of compliance with the Class III Area Permit must be handled according to the requirements found in 40 CFR part 136 Table II – *Required Containers, Preservation Techniques, and Holding Times*. Review of water quality analytical data will help identify any anomalous conditions that might signal potential areas of leakage across confining zones due to improperly plugged drillholes or wells.

Table 12. 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, and • To identify any potential areas of leakage across confining zones due to improperly plugged boreholes or wells, improperly constructed 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.
Water sample collection and analysis for all pump test 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 begin establishing baseline water quality in monitoring wells.	Prior to initiation of pump testing activities
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 constructed wells or naturally occurring features such as fractures.	Prior to receiving written Authorization to Commence Injection from the Director

Baseline sampling for the injection interval aquifer, both in the wellfield and at the perimeter monitoring well ring, and aquifers overlying and underlying the injection interval begins at this point. As required under Part IX, Section B.2 of the Class III Area Permit, the Permittee must determine baseline water quality according to the requirements under Section 11.3 *Establishment of Commission-Approved Background Water Quality* in the NRC License. The Class III Area Permit requires sample collection from each wellfield non-injection interval monitoring well until the end of the restoration stability monitoring phase; however, the frequency for sample collection will vary as indicated in Table 14 under Part IX, Section B and Part IX, Section C of the Class III Area Permit.

5.3.3 Baseline Water Quality Constituents

UIC regulations at 40 CFR § 144.12(b) prohibits movement of any contaminant into an underground source of drinking water. The definition of contaminant under 40 CFR § 144.3 includes any physical, chemical, biological, or radiological substance or matter in water. ISR contaminants will be chemical and radiological. Therefore, the list of baseline water quality constituents in Table 13 includes all major cations (ions with a positive charge) and anions (ions with a negative charge) that are known to occur commonly in natural groundwater systems. The list also contains radioactive constituents known to occur in association with uranium, based on the uranium radioactive isotope decay chain and based on association with uranium in roll front deposits. For more information on the uranium radioactive isotope decay chain, see EPA's website on radioactive decay. For more information on radioactive isotopes in groundwater, see USGS Fact Sheet 012-00 *Naturally Occurring Radionuclides in the Ground Water of Southeastern Pennsylvania*. The Table 13 list of baseline water quality parameters also includes most of the inorganic constituents with drinking water standards or health based standards in the according to the *2018 Edition of the Drinking Water Standards and Health Advisories* that may occur naturally at the site. The 2018 edition of this document is the most recent version and is found at https://www.epa.gov/sites/production/files/2018-03/documents/dwtable2018.pdf . Constituents such as ammonia, asbestos, bromate, chloramine, chlorine, chlorine dioxide, chlorite, cyanide, nitrate, nitrite, perchlorate and white phosphorus from this document were not included in Table 13, because they do not occur naturally at the site and will not be produced during the ISR process. Metals known to occur with uranium in the ore deposits, such as arsenic, iron, manganese, molybdenum, selenium, thorium and vanadium are included in the Table 13 list. Table 13 in this Fact Sheet is similar to Safety Evaluation Report Table 5.7-2 except additional analytes, such as silicon, are included for development of the geochemical model.

Table 13. Baseline 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
Specific Gravity	Ratio to density of water	ASTM D1429-13, SM 2710F
Turbidity	NTU (nephelometric turbidity units)	EPA-NERL: 180.1
Groundwater-quality parameters related to mobility of uranium and other metals		
Temperature	°C	2018 EPA Region 4 SOP (Temperature)
Dissolved Oxygen	mg/L	2017 EPA Region 4 SOP (DO)
Oxidation-Reduction Potential	millivolts (mV)	2017 EPA Region 4 SOP (ORP)
Carbon Dioxide	mg/L	
Total Organic Carbon	mg/L	415.3, 9060A
Dissolved Organic Carbon	mg/L	415.3, 9060A
Common Elements and Ions		
Total alkalinity (as Ca CO_3)	mg/L	A2320B
Bicarbonate Alkalinity (as Ca CO_3)	mg/L	A2320B (as HCO_3)
Calcium	mg/L	E200.7
Carbonate Alkalinity (as Ca CO_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, Si	mg/L	E200.7

Sodium, Na	mg/L	E200.7
Sulfate, SO_4	mg/L	A4500-SO_4 E; E300.0
Dissolved Metals		
Arsenic, As	mg/L	E200.8
Barium, Ba	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
Iron, Fe	mg/L	E200.7
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
Uranium, U	mg/L	E200.7, E200.8
Vanadium, V	mg/L	E200.7, E200.8
Zinc, Zn	mg/L	E200.8
Radiological Parameters		
Gross Alpha****	pCi/L	E900.0
Gross Beta	pCi/L	E900.0
Radium, Ra-226	pCi/L	E903.0
Radium, Ra-228	pCi/L	E904.0

*Laboratory analysis only, except where indicated.
**Field and Laboratory
***Required for first stability monitoring sampling only.
****Excluding radon and uranium

5.4 Pump Testing Procedures

Part II, Section F of the Class III Area Permit requires the Permittee to conduct a pump test for each wellfield. Pump testing will involve inducing stress on the injection interval aquifer unit by operating one or more pumping wells located within the wellfield area and completed in the injection interval. The goal of the test will be to demonstrate suitable conditions for ISR operations. This will be done by causing drawdown in the injection interval extending to all perimeter monitoring wells in the injection interval perimeter monitoring well ring, creating a cone of depression across the wellfield area. The cone of depression also creates an inward vertical gradient which tests the integrity of the confining zones between the injection interval and the overlying and underlying aquifer units and alluvium, if present.

The flow rate of the pump test will be based on well capacity and design requirements. A pump test using more than one pumping well may be required to create drawdown in all monitoring wells in the injection interval perimeter monitoring well ring. Measurements during pump testing will include instantaneous and totalized flow, periodic pressure transducer measurements, barometric pressure, and time. A pumping step rate test will be performed initially to determine the optimum pumping rate at which the pump test should be performed.

The purpose of the pumping step rate test is to determine the pumping rate that stresses the aquifer adequately to provide the data needed without creating a cone of depression in the aquifer potentiometric surface to a level below the pump in the pump test pumping well. Groundwater pumped to the surface during the pump tests will not be injected back into the subsurface.

The pumping step rate test differs from the injection step rate test discussed in Section 5.8 in that the pumping step rate test involves pumping water from the well at increasing flow rates for fixed time intervals. The injection step rate test involves injection at increasing injection flow rates for fixed time intervals.

After the initial pumping step rate test, there will be an initial stabilization phase with no pumping in order to allow the aquifer's potentiometric surface to recover from the pumping step rate test. Then the pump test will involve pumping groundwater at the flow rate established by the pumping step rate test, creating a stress period on the aquifer at constant rate of flow, followed by a recovery period with no flow. Water levels in all pump test monitoring wells will be gathered during both the stress and recovery phases of the test.

The wells in the wellfield perimeter monitoring well ring are required to be completed in the injection interval around each wellfield to detect horizontal migration of lixiviant out of the wellfield as discussed in Section 12.5.5. The wellfield pump tests will verify that the production and injection wells are hydraulically connected to the perimeter monitoring well ring. Hydraulic communication is verified when drawdown is observed in the water levels of the wellfield perimeter monitoring wells as the test well is pumped, creating a cone of depression in the injection interval potentiometric surface. Part II, Section F.4 of the Class III Area Permit requires the Permittee to recomplete or replace a perimeter monitoring well ring well that cannot be verified to be in hydraulic connection with the injection interval.

The non-injection interval monitoring wells are completed in aquifers above and below the injection interval to detect vertical migration of the lixiviant out of the injection interval. The wellfield pump test will determine if the production and injection wells are hydraulically isolated from non-injection interval monitoring wells. A breach through a confining zone created by improperly plugged exploration drillholes, improperly constructed wells or associated with naturally occurring geologic features will result in draw-down in a non-injection interval aquifer monitoring well. If there is hydraulic communication between the injection interval and the non-injection interval aquifers through breaches in confining zones, the wellfield pump tests will help narrow down the location of the confining zone breach, so that corrective action can be performed. If a breach in a confining zone is detected during a pump test, the relative responses in the overlying, underlying, and/or alluvial monitoring wells will indicate the proximity and direction toward the source of the breach.

If saturated alluvium is present within the wellfield, alluvial monitoring wells will be installed and monitored above the injection interval and within an appropriate distance from the wellfield. The water level in the alluvium will be measured prior to testing and monitored during pump testing. If there are anomalous conditions that cause communication between the injection interval and alluvium such as an improperly plugged borehole, these conditions will be identified through responses in the alluvial monitoring wells.

The following wells must be monitored during the pumping test for characterization and other requirements outlined in this Area Permit:

1) Pumping wells,
2) Monitoring wells within the injection interval,
3) Monitoring wells forming a perimeter injection interval monitoring well ring,
4) Monitoring wells in the immediately overlying non-injection interval aquifer unit,

5) Monitoring wells in each subsequently overlying non-injection interval aquifer unit,
6) Monitoring wells in the alluvium, if present,
7) Monitoring wells in the immediately underlying non-injection interval aquifer unit,
8) Any additional wells installed for investigating other hydrogeologic features,
9) Any other wells within ¼ mile of the wellfield perimeter monitoring well ring, and
10) Any other wells determined to be necessary by the EPA or the Permittee.

The Permittee plans to monitor the water levels in the pump test monitoring system wells using downhole data logging pressure transducers, which will be corrected for variations in barometric pressure. Some manual measurements with electronic meters also may be made.

The pump test duration must be sufficient to create a drawdown response in the injection interval perimeter monitoring well ring: a maintainable, statistically-significant drawdown not attributable to changes in barometric pressure. To provide an idea of the timeframes that may be needed to complete a wellfield pump test, the 2008 Dewey Area pump test was conducted for 3.08 days and produced drawdown in observation wells ranging from 13 to 1.5 feet. The 2008 Burdock Area pump test was conducted for 3.0 days and produced drawdown in observation wells ranging from 17 to 3.1 feet. If any injection interval perimeter monitoring wells do not respond during the first pump test, Part II, Section F.3 of the Class III Area Permit requires additional pump tests to be performed until drawdown is observed in each injection interval perimeter monitoring well. If any of these wells do not respond, Part II, Section F.4 of the Class III Area Permit requires the Permittee to recomplete or replace the monitoring well and verify that the recompleted or new well is in hydraulic communication with the wellfield injection interval.

5.5 Additional Characterization of Burdock Wellfields 6, 7, and 8

5.5.1 Characterization of Down-gradient Injection Interval Aquifer Geochemistry

Because the Chilson Sandstone down-gradient from Burdock Wellfields 6, 7 and 8 has been partially oxidized by native groundwater, Part II, Sections G1. and G.2 of the Class III Area Permit requires the Permittee to evaluate the capacity of the Chilson Sandstone down-gradient from these three wellfields to remove residual ISR contamination from restored wellfield groundwater as it travels down-gradient toward the aquifer exemption boundary. The permit requires the Permittee to develop a Conceptual Site Model for wellfields 6, 7 and 8 by conducting all the sampling and testing required for all wellfields as described under Part II of the Area Permit. In addition, the Permittee shall expand the Conceptual Site Model for wellfields 6, 7 and 8 by collecting samples from the down-gradient injection interval for the purposes of characterizing the geochemistry of the down-gradient injection interval. In addition, the Permit requires the Permittee to further expand the Conceptual Site Model for wellfields 6, 7 and 8 by conducting column testing, batch sorption testing, or other appropriate laboratory and field testing methods to provide site-specific inputs into the geochemical model, as specified in Part IV, Section C. The Permittee must calibrate the geochemical model using analytical data from field and laboratory testing. The Class III Area Permit requires the Permittee to 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 down-gradient aquifer exemption boundary. This information must be submitted to the Director *before* the Director will grant authorization to inject into these wellfields.

In accordance with Part IV, Section B.6, the Permittee must submit information about uncertainty analyses along with the results of the geochemical model. If model results indicate there is a likelihood that a down-gradient contaminant plume would persist from a restored wellfield, the Permittee must also include a plan describing groundwater treatment measures. If the Permittee is not able to demonstrate that ISR operations can be conducted in wellfields 6, 7 and 8 without ISR contaminants crossing the down-gradient aquifer exemption boundary, the Director will not issue authorization to inject into those three wellfields. In all cases, the Permittee will not be authorized to inject into Burdock wellfields 6, 7 or 8 if it cannot be demonstrated that USDWs will be protected during ISR operations, groundwater restoration, and that ISR contaminant concentrations remain stable after stability monitoring has been completed in these wellfields.

5.5.2 Wellfield Testing of Partially Saturated Aquifers in Burdock Wellfields 6, 7 and 8

In the areas of Burdock Wellfields 6, 7, and 8, the potentiometric surface of the Fall River aquifer falls below the formation top. Specifically, Figure 21a shows Burdock Wellfield 8 in map view and indicates the location of the cross section shown in Figure 21b where the elevation of the Fall River aquifer potentiometric surface is below the top of the Fall River Formation, which means that the Fall River aquifer is partially saturated in this area. Figure 22 shows the area in Burdock Wellfield 8 where the Fall River potentiometric surface is below the base of the Fall River Formation. In this area, the Fall River does not contain any groundwater. The Permittee does not propose any ISR operations in the Fall River sandstone units in those areas, because a partially saturated aquifer does not offer ideal conditions for conducting the ISR process.

The Permittee is proposing to conduct ISR operations only in the underlying Chilson at Burdock Wellfields 6, 7, and 8. As shown in Figure 21b and Figure 21c, in the area of Burdock Wellfield 8, the Chilson Sandstone aquifer is fully saturated under pre-ISR operation conditions. In Burdock Wellfield 8, the targeted ore zone is located in the Middle Chilson sand unit, which is approximately 90 feet below the Chilson potentiometric surface elevation. However, once ISR operations begins and a cone of depression is created in the wellfield, the potentiometric surface will be drawn down lower than it is under pre-ISR conditions. That is why the Class III Area Permit contains additional wellfield testing requirements to evaluate potentially unsaturated conditions in the injection interval aquifers for Burdock Wellfields 6, 7, and 8.

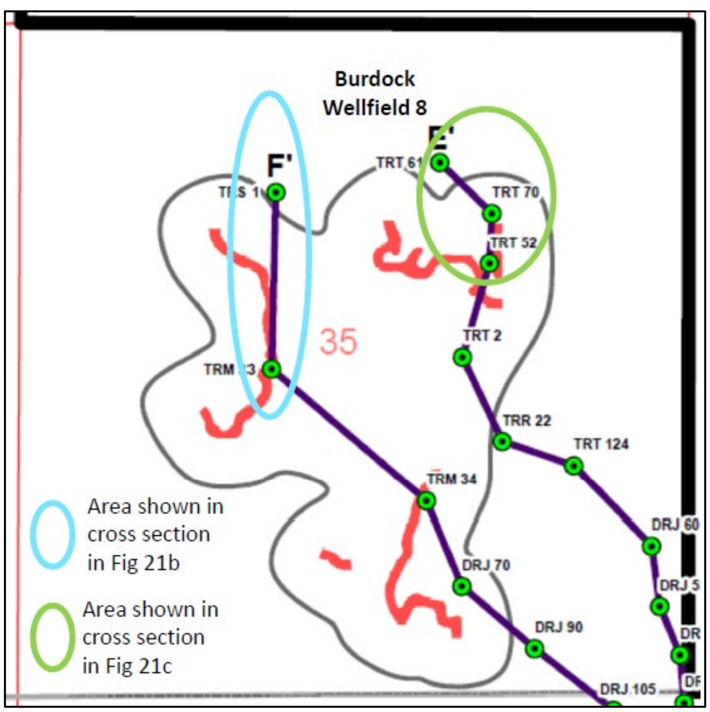


Figure 21a. Burdock Wellfield 8 where the Fall River is Partially Saturated

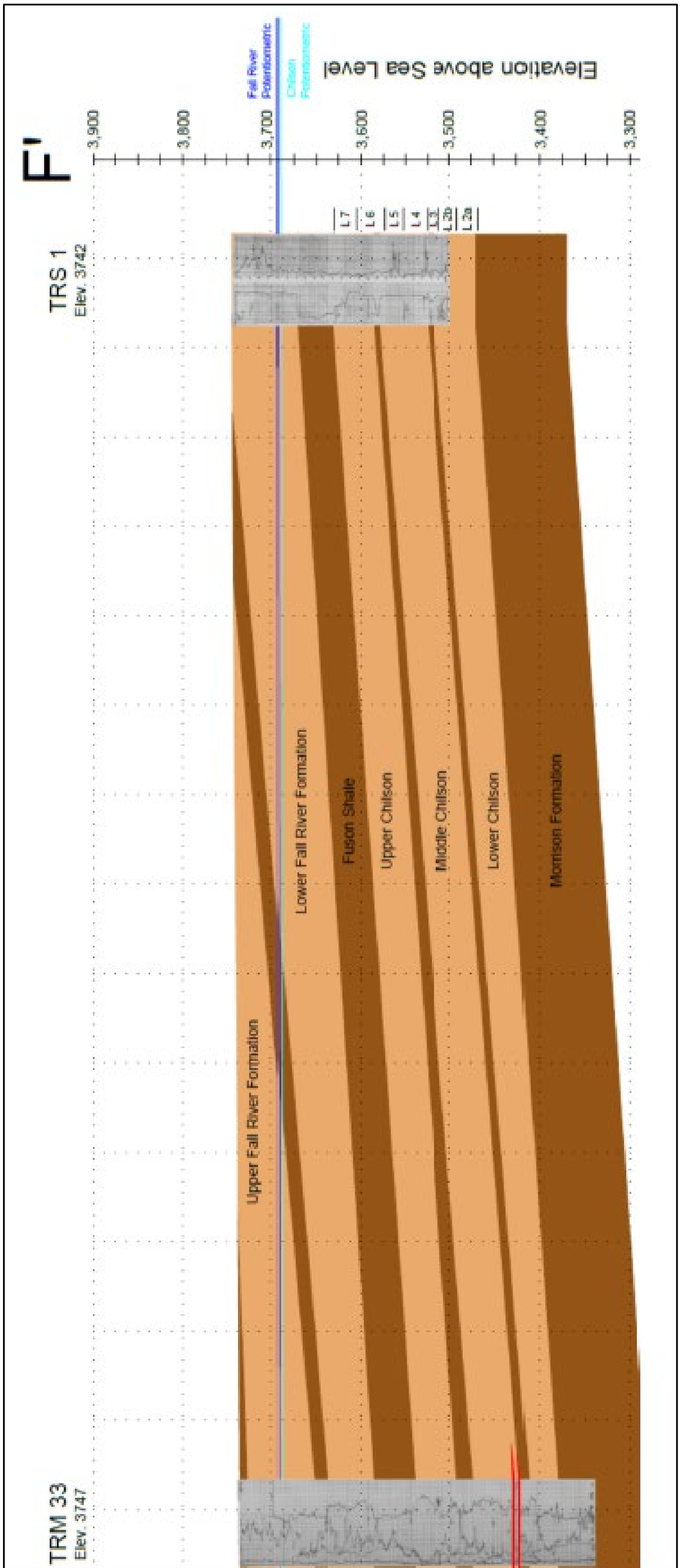


Figure 21b. Cross section through Burdock Wellfield 8 Showing Fall River Potentiometric Surface Elevation

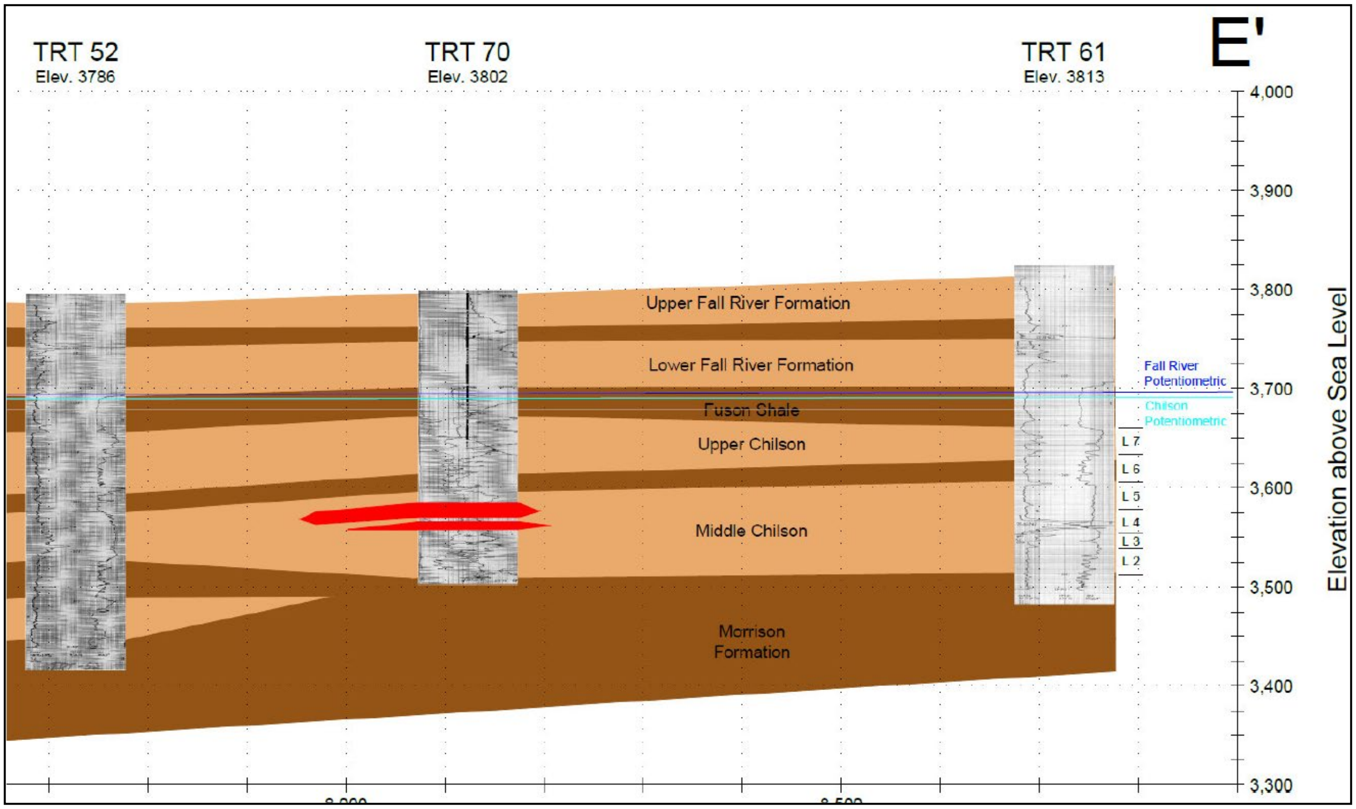


Figure 21c. Northern End of Geologic Cross Section E-E' in Burdock Wellfield 8.

In the areas of Burdock Wellfields 6 and 7, the potentiometric surface of the Chilson Sandstone aquifer is below the base of the Fuson Shale confining zone, which means that the Chilson aquifer, as a whole, is partially saturated in those areas. Along the eastern edges of Burdock Wellfields 6 and 7, the targeted ore zone is located in the Lower Chilson sand unit. The potentiometric surface of the Chilson Sandstone aquifer is above the base of the Middle Chilson overlying confining zone, which means both the Lower Chilson and Middle Chilson sand units are fully saturated in this area. The overlying confining zone for the Lower Chilson is expected to provide adequate confinement to enable the Lower Chilson to behave as a hydraulically separate aquifer from the overlying Middle and Upper Chilson sand units. As a result, ISR operations in Burdock Wellfields 6 and 7 are expected to have sufficient head above the ore body and adequate hydraulic confinement to control ISR solutions. The overlying Middle Chilson sand unit, which will be the first overlying hydrologic unit monitored above the injection interval in those wellfields, is also expected to be locally confined so that in that area it will behave as a separate aquifer unit from both the overlying Upper Chilson and the underlying Lower Chilson. This characteristic is important for providing the best hydraulic conditions for monitoring the overlying aquifer for vertical excursions.

Geologic Cross Section E-E' (Permit Application Plate 6.17) shows the Fall River and Chilson potentiometric surfaces as well as the interbedded shales and siltstones within the Fall River and Chilson in the areas of Burdock Wellfields 7 and 8. The cross section also shows the location of the uranium ore bodies in the Chilson in relation to the Chilson potentiometric surface. The northern extent of Cross Section E-E' shows the potentiometric surface of the Chilson aquifer above the base of the overlying Fuson confining zone from E' southward through drill log DRW 1. The Chilson potentiometric surface at drillholes TRT 52, TRT 70 and TRT 61 (see Figure 21a and 21c), which are located in Burdock Wellfield 8, demonstrates the fully saturated conditions that are expected within the Chilson aquifer in this wellfield. Figure 21c shows uranium ore in the Middle Chilson sand unit and the Chilson potentiometric surface above the base of the Fuson Shale.

Figure 22a shows the southern end of Cross Section E-E' in Burdock Wellfield 7 where the Chilson potentiometric surface occurs at the base of the Upper Chilson sand unit and below the top of the local confining zone separating the Upper and Middle Chilson sand units. This portion of the cross section is shown in Figure 22b. Drillholes DRM 21, DRJ 109 and DRS 47 are located in the ore zone of Burdock Wellfield 7. Here the uranium ore is located in the Lower Chilson sand unit, which is expected to be locally hydraulically confined in the area of Burdock Wellfield 7.

Figure 22c shows the northern end of Cross Section B-B' (Permit Application Plate 6.14) located in Burdock Wellfield 6. In Figure 22c the Chilson potentiometric surface occurs at the base of the Upper Chilson sand unit and below the top of the local confining zone separating the Upper and Middle Chilson sand units. The uranium ore is located in the Lower Chilson sand unit, which is expected to be locally hydraulically confined in the area of Burdock Wellfield 6.

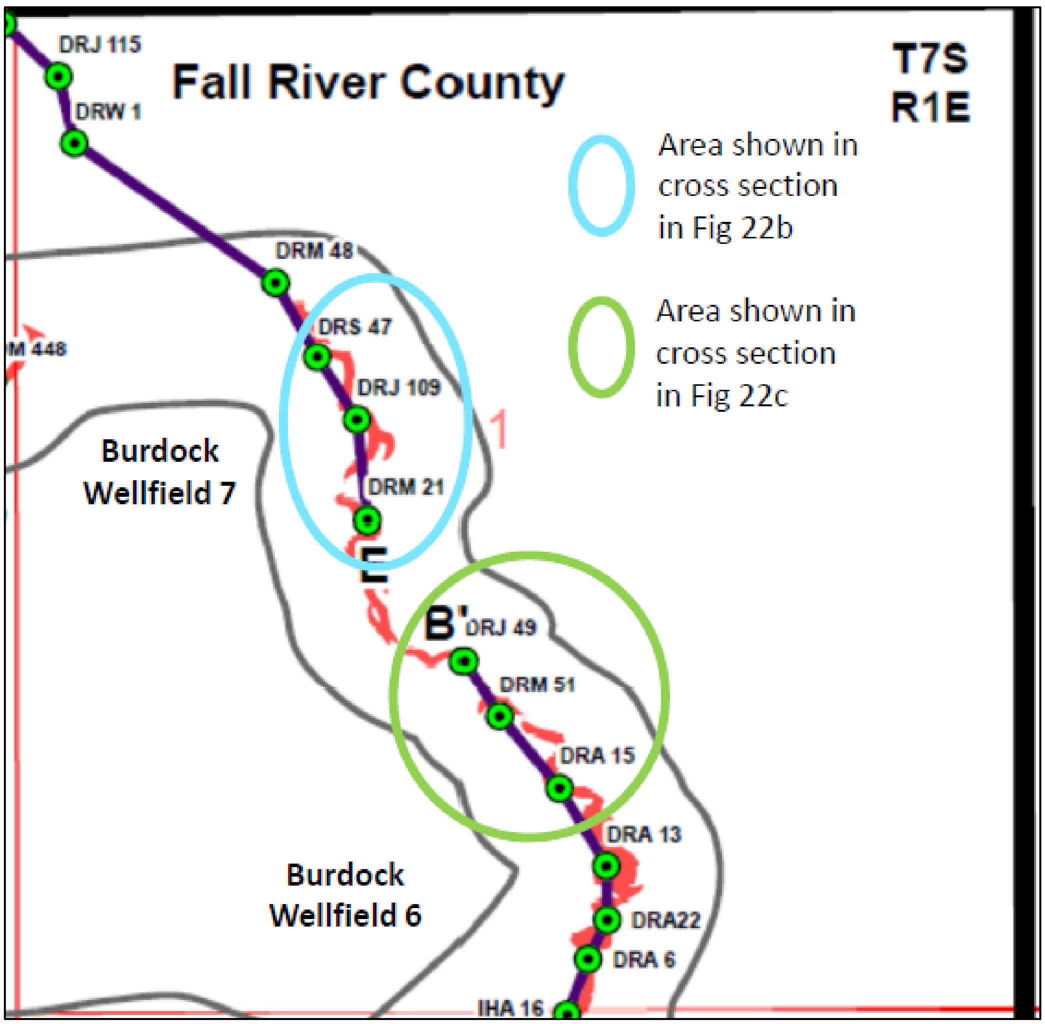


Figure 22a. Burdock Wellfields 6 and 7 where the Chilson is Partially Saturated

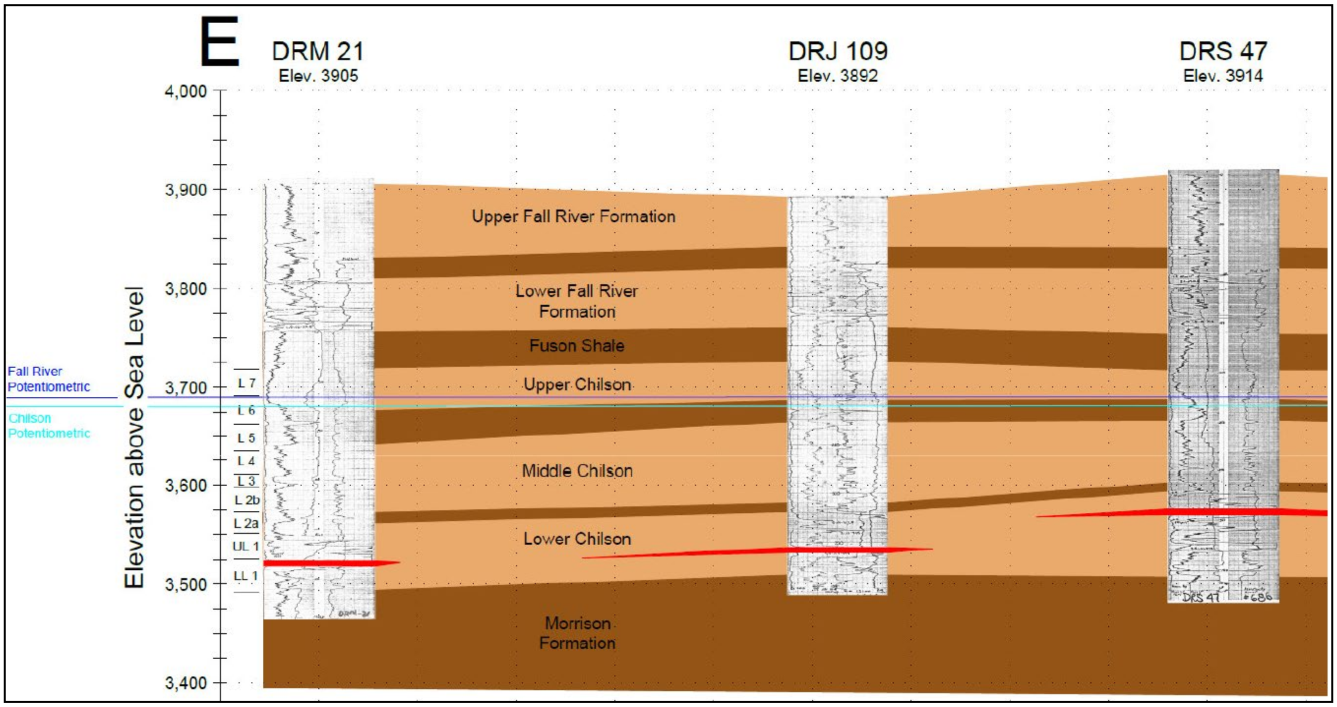


Figure 22b. Southern End of Geologic Cross Section E-E' in Burdock Wellfield 7

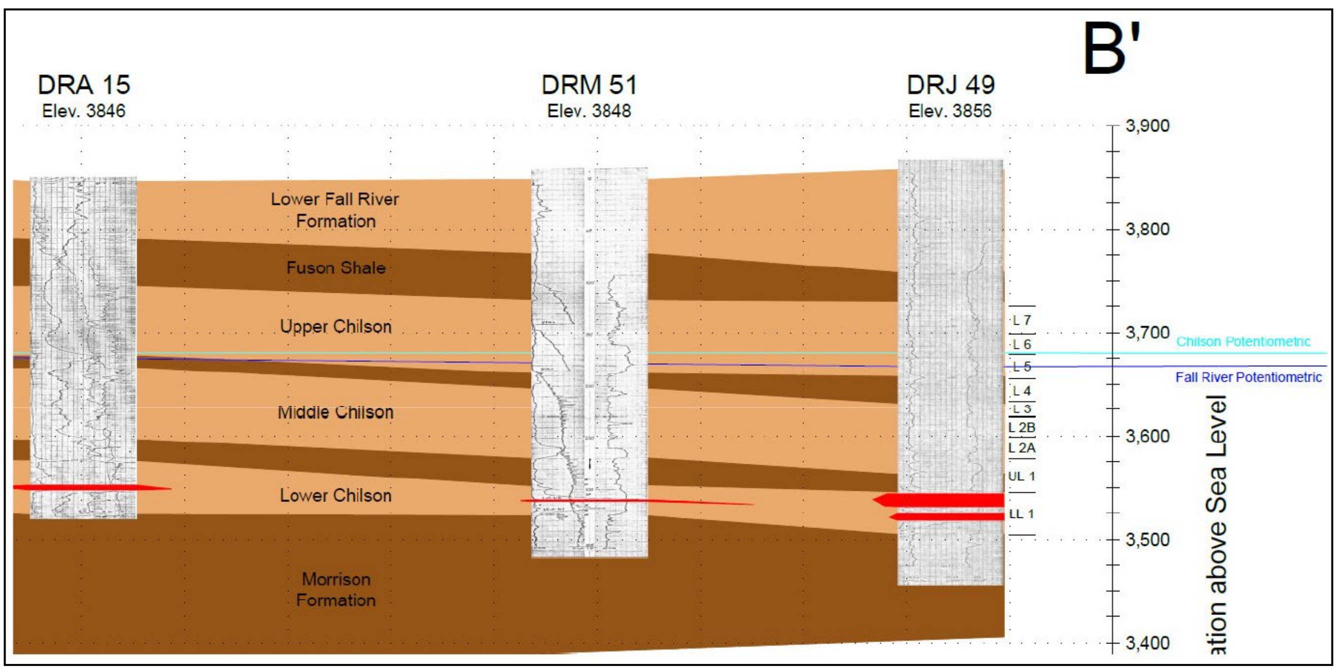


Figure 22c. Northern End of Geologic Cross Section B-B' in Burdock Wellfield 6.

Based on the information provided in Figures 21a, b, and c and 22a, b and c, the Chilson potentiometric surface is nearly 100 feet higher than the uranium ore bodies targeted by the Burdock Wellfields 6, 7 and 8. As discussed above, the locally occurring intervening shale units that separate the Chilson sands into Upper, Middle, and Lower units serve to further confine the ore-bearing Chilson sand units. This distance between the Chilson Sandstone potentiometric surface and the targeted ore zone, which provides a buffer of 100 feet of vertical distance between the Chilson potentiometric surface and the ore-bearing injection interval, is expected be adequate to allow the drawdown required in each wellfield to maintain the inward hydraulic gradient, without pulling the Chilson potentiometric surface down so far as to create conditions of partial saturation in the Lower Chilson sand unit.

Hydraulic confinement of the separate Chilson aquifer sand units will be evaluated during the wellfield pump tests for Burdock Wellfields 6, 7 and 8. Part II, Section G.3 of the Class III Area Permit requires that the pumping rates used during the pump tests simulate those that will be used during ISR operations and wellfield restoration to determine if the resulting drawdown of the potentiometric surface results in creating partially saturated conditions in the injection interval. If partially saturated conditions are created, the Class III Area Permit requires the Permittee to develop a 3-D unsaturated groundwater flow model for the area where unsaturated conditions are anticipated. Specifically, the Area Permit requires that

- the model be calibrated to site-specific hydrologic conditions and verified by use of wellfield-specific pump test data;
- the model assesses 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;
- the model incorporates 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.

Partially saturated conditions, if encountered in the Middle and Lower Chilson sand units in Burdock Wellfields 6, 7 and 8, would be similar in many respects to conditions at the Moore Ranch uranium ISR facility in Campbell County, Wyoming. Hydrologic testing was conducted and a 3-D groundwater flow model was developed for the Moore Ranch site to simulate the partially saturated aquifer conditions encountered in one of the injection intervals at Moore Ranch. One of the hydrologic tests included an injection/extraction test to assess how the partially saturated aquifer would respond to realistic well field operating conditions. The hydrologic testing is discussed in Section 2.4.3.2.2 of the NRC Safety Evaluation Report for Moore Ranch. The groundwater flow model is discussed in Section 3.1.3.3.1 of the NRC Safety Evaluation Report for Moore Ranch. The model results verified that an inward hydraulic gradient was able to be maintained in the partially saturated portion of the aquifer during ISR operations and subsequent groundwater restoration.

The Permittee must include the modeling results in the Injection Authorization Data Package for each of these wellfields. After review of groundwater flow model results, if the EPA 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 to allow reinjection of groundwater pumped from the field test site pumping well(s) for the purposes of hydrologic testing only.

5.6 Injection Authorization Data Package Reports

Part II, Section H of the UIC Class III Area Permit requires the Permittee to prepare an Injection Authorization Data Package Report for each wellfield and submit it to the EPA for review in order to obtain written Limited Authorization to Inject for each wellfield. Each Injection Authorization Data Package Report must contain a description of all logging and testing procedures required under Part II, Sections B through F of the Class III Area Permit and the results of such logs and tests. For Burdock Wellfields 6, 7 and 8, each Injection Authorization Data Package Report must also contain information required under Part II, Section G. This information will be used to update the Conceptual Site Model discussed in Section 15.2.

In summary, each Injection Authorization Data Package Report must contain the following:

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

2. A description of the proposed wellfield, including a map delineating the ore zones, color-coded to differentiate the different ore levels within the wellfield injection interval.
3. Map(s) showing the proposed production and injection well patterns and locations of all monitoring wells.
4. Map showing all plugged and abandoned exploration drillholes within the wellfield perimeter monitoring ring. Identification of any exploration drillholes that had to be re-plugged.
5. 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 well ring.
6. Map showing all plugged and abandoned wellfield delineation drillholes within the wellfield perimeter monitoring ring.
7. 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.
8. Isopach maps showing the thickness of the injection interval and the first confining zones overlying and underlying the wellfield injection interval.
9. 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.
10. Description of well construction activities, including well completion reports and mechanical integrity test dates and results. This includes the locations and plugging reports for any wells that had to be plugged and abandoned because mechanical integrity could not be demonstrated.
11. The results from the formation testing required under Part II, Section E of the Class III Area Permit.
12. Discussion of how pump testing was performed. This includes results and conclusions. This also includes pump testing raw data, drawdown match curves, potentiometric surface maps, water level graphs, drawdown maps and, when appropriate, directional transmissivity data and graphs.
13. 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.
14. The report For Burdock Wellfield 10 shall include an analysis of impacts from Triangle Pit water on the operation and groundwater restoration of Burdock Wellfield 10.
15. 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 the Class III Area Permit and depth measurement 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.
16. 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.
17. A corrective action plan (as required under Part III of the Class III Area Permit) 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 ore zone through identified breaches.
18. A description of any wellfield operational controls designed to contain injectate and injection interval fluids within the injection interval when operational controls are the method of corrective action. Include description of how operation controls address breaches in confining zones that cannot be precisely located or for which other types of corrective action cannot be performed successfully. Also 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).
19. 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.

20. 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.
21. Proposed locations for Step Rate Tests.
22. Proposed source of fluid that will be injected during the Step Rate Test described in Section 5.8 below.
23. Information about the location of 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.

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

The Director will review each Injection Authorization Data Package Report to determine if the following requirements have been met:

1. All requirements under Part II, B through F (and G, if applicable) of the Class III Area Permit have been met;
2. Hydraulic connection is demonstrated between the production and injection wells and all injection interval perimeter monitoring wells;
3. The overlying and underlying confining zones provide vertical confinement of the injection interval;
4. Calculation of the hydraulic conductivity, storativity, and transmissivity of the injection interval aquifer unit;
5. Evaluation of directional variation (anisotropy) of hydrologic parameters within the injection interval aquifer unit has been conducted;
6. 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;
7. The number and location of monitoring wells fulfill permit requirements, provide indication of hydraulic control of injection interval fluids and are capable of detecting any potential excursions;
8. A demonstration that wellfield injection and production wells have mechanical integrity, as required under Part VII, Section B.2 of the Class III Area Permit; and
9. Analytical results from the proposed Step Rate Test injectate for concentrations of the baseline constituents listed in Table 13.

The NRC will be reviewing similar information related to each wellfield. The EPA will request a copy of the NRC's comments to include in our review.

If the Director determines that an Injection Authorization Data Package Report is complete, a written Limited Authorization to Inject will be issued only for the purpose of conducting a Step Rate Test. The Limited Authorization to Inject document will include specification of the approved injectate that will be injected during the Step Rate Test described in Section 5.8. In all cases, the Permittee will not be authorized to inject unless it can demonstrate that USDWs will be protected during ISR operations and groundwater restoration, and that ISR contaminant concentrations remain stable after stability monitoring has been completed in these wellfields.

The Class III Area Permit prohibits injection into Burdock Wellfields 6 and 7 unless the Aquifer Exemption of Inyan Kara groundwater has been approved by the Director for those two wellfields.

5.8 Step Rate Tests and Determining Fracture Pressure

Part II, Section I.4.b and Part II Section J.1.a of the Class III Area Permit requires the Permittee to conduct step rate tests in order to determine the fracture pressure for the Fall River and Chilson injection intervals in the Dewey and Burdock Area for the purpose of calculating fracture gradient through the Inyan Kara in the Dewey and Burdock Areas. Because conducting a step rate test involves injection activity, it cannot be conducted until after the Director issues a written Limited Authorization to Inject issued solely for the purpose of conducting the step rate test.

5.8.1 Step Rate Test Locations

Part II Section I.4.b of the Class III Area Permit requires one step rate test in the Burdock Area for the Lower or Middle Chilson, as indicated in Table 9 of the Class III Area Permit. The Class III Area Permit requires two step rate tests in the Dewey Area: one for the Lower Fall River Formation and one for the Lower or Middle Chilson formation as indicated in Table 9 of the Class III Area Permit. The Permittee will decide the locations to conduct each step rate test. The test location in the Burdock area will most likely be a perimeter monitoring well ring well completed in the Lower and /or Middle Chilson. In the Dewey area, the test locations will most likely be two perimeter monitoring well ring wells, one completed in the Lower Fall River Formation and one in the Lower and/or Middle Chilson injection interval.

5.8.2 Fracture Pressure Determination

The fracture pressure is the pressure at which injected fluid creates fractures in the injection interval formation or propagates existing fractures already occurring in the injection interval. The fracture pressure increases with depth because the pressure from the weight of overburden strata acts to resist fracturing of the geologic unit. The amount of change in fracture pressure with depth is the fracture gradient.

A step rate test is conducted by injecting a fluid into the formation at a series of increasing pumping rates. The Area Permit requires the use of pressure sensors located within the injection interval and at the wellhead during the step rate test. At each step, the injection pumping rate is increased an incremental amount. That rate is held for a period of time to allow pressure conditions in the injection interval to stabilize. The stabilized injection interval pressure for each rate is recorded. For a more detailed explanation of how fracture pressure is determined from step rate test data, see Section 5.3.4.2 of the Class V Area Permit Fact Sheet.

The most practical place to run a step rate test is at a perimeter monitoring well ring well which will be located approximately 400 feet away from the wellfield boundary. Because the step rate test involves injecting water at increasing injection rates until fractures begin to form in the injection interval, it is not practical to conduct a step rate test within the wellfield. Fractures in the injection interval will be preferred pathways for the lixiviant to flow through instead of through the pore spaces where the uranium has precipitated. Fracturing the ore zone would decrease the effectiveness of uranium recovery. The fractures that will be formed during the step rate test will be small and will not propagate very far from the injection well at which the step rate test is conducted.

5.8.3 Fracture Gradient Calculation

After the fracture pressure for the injection interval has been determined based on the step rate test results, the fracture gradient is 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

The fracture gradient will be used to calculate the maximum allowable injection pressure as discussed in Section 9.1.1.

5.9 Initial Demonstration of Mechanical Integrity

Part VII, Section B.2 of the Class III Area Permit requires the Permittee to demonstrate that each wellfield injection and production well has mechanical integrity before the Authorization to Commence Injection will be issued for each well. The mechanical integrity requirements are discussed in Section 8.0.

6.0 CORRECTIVE ACTION PLAN

Part III of the Class III Area Permit contains the corrective action requirements stating that the Permittee must use best available technology and best professional practices to locate any breaches in injection interval confining zones. Section 4.0 of the Class III Permit Application describes the best available technology and best professional practices that the Permittee has already used to locate drillholes and wells in the vicinity of potential wellfield areas. These include review of historical records, use of color infrared imagery, field investigations, aquifer characterization and aquifer potentiometric surface evaluation as discussed in the Area of Review procedures under Section 4.0 of this Fact Sheet. The best available technology described in the procedures under Part II of the Class III Area permit, including the pump testing that will be conducted for each wellfield in order to generate information for the Injection Authorization Data Package Reports (refer to Section 5.6), will complete this effort.

The Class III Area Permit requires the Permittee to properly plug and abandon or mitigate any of the following should they have the potential to impact the control and containment of wellfield solutions within the project area:

1) Historical wells and exploration drillholes (Part III, Corrective Action),
2) Holes drilled by the Permittee for the purposes of exploration and wellfield delineation that are not used for installing an injection, production or monitoring well (Part II, Section B.3),
3) Any injection, production and monitoring wells failing mechanical integrity demonstration or testing (Part VI, Section B.5 and Part VII, Section F and Part II, Section D.4.e), and
4) Any stock wells or other types of wells located near the wellfields that could impact wellfield fluids control during ISR operations or groundwater restoration when evaluated during the wellfield pump tests.

As discussed in the Section 5.4, the wellfield pump tests must be designed and implemented to provide data that either verify there are no breaches in the injection interval confining zones or locate any naturally-occurring or man-made structures causing a breach in a confining zone. If the structure is man-made, corrective action can be performed to repair that breach. Pump test data and historical records will assist the Permittee in determining the location of leaky historic exploration drillholes. The Permittee indicated in the Section 4.4 of the Class III Permit Application that attempts will be made to reenter improperly plugged drillholes using a drill rig, followed by plugging and abandoning the drillhole according to current state regulations. Examples of corrective action for wells causing a confining zone breach include repairing the well casing, adding cement to the annulus around the outside of the well casing or plugging and abandoning the well.

The UIC regulation at 40 CFR § 144.55(b)(4) requires the EPA to consider the overall effect of the project on the hydraulic gradient in potentially affected USDWs, and the corresponding changes in potentiometric surface(s) and flow direction(s) rather than the discrete effect of each well, when setting corrective action requirements. If a decision is made that corrective action is not necessary based on the determinations above, the monitoring program required in §146.33(b) must be designed to verify the validity of such determinations.

If the structure is naturally occurring, such as a fracture or leaky area in a confining zone, the corrective action method will be operational controls such as adjustments in the location and pumping rates of production and injection wells to better control lixiviant flow in that area. When operational controls are used as the method of corrective action, Part III, Section B.4 of the Class III Area Permit requires the Permittee to demonstrate that the number and placement of non-injection interval monitoring wells are capable of detecting any loss of hydraulic control in that area.

6.1 Well Replacement Procedures

During the design and pump testing of each potential wellfield, Part II, Section F.1.i of the Class III Area Permit requires all wells within ¼ mile of the wellfield monitoring well ring to be monitored in order to be evaluated for the potential to be impacted by ISR operations or the potential to interfere with ISR operations. The results of the evaluation will be contained within a well replacement plan and included in the Injection Authorization Data Packages for each wellfield.

The Permittee stated in Section 4.4.2 of the Class III Permit Application that all domestic wells within the Project Area Boundary and all stock wells within ¼ mile of wellfields will be removed from private use or, at a minimum, the domestic wells will be removed from drinking water use. These wells are shown in Figure 4.11 of the Class III Permit Application. Depending on the well condition, location and screen depth, the Permittee may continue to use the well for monitoring or plug and abandon the well. During wellfield operations, operational monitoring of existing water supply wells is required as described in Section 12.6.

The Permittee has lease agreements in place with property owners for the entire Project Area. The agreements allow the Permittee to remove and replace water supply wells as needed. The well owner will be notified in writing prior to removing any well from private use. The Permittee will work with the well owner to determine whether a replacement well or alternate water supply is more appropriate.

Replacement wells will be located an appropriate distance from the potential wellfields and will target an aquifer outside of the ore zone that provides water in a quantity equal to that of the original well and of a quality which is suitable for the same uses as the original well, subject to the lease agreement and South Dakota water law.

The Permittee provides an example of a potential water supply replacement in Permit Application Figure 4.10. The Permittee plans to install at least one well completed in the Madison aquifer to supply water by pipeline to local stock tanks.

6.2 Wells to Be Removed from Use

The Permittee will remove all existing domestic wells within the Project Area from private use prior to ISR operations if a well has the potential to interfere with maintaining an inward flow gradient for a wellfield. If a well does not interfere with the inward hydraulic gradient, depending on the well condition, location and screen depth, the Permittee may continue to use the well for monitoring rather than plug and abandon the well. All domestic wells will be removed from drinking water use.

Stock wells within the project area will be evaluated as potential wellfields are designed and pump tested. At a minimum, all stock wells that are within ¼ mile of any wellfield will be removed from private use prior to operation of that wellfield. Stock wells beyond ¼ mile that could be adversely affected by, or could adversely affect, ISR operations will also be removed from private use.

Permit Application Figure 4.11 shows the locations of all domestic and stock wells that the Permittee currently anticipates removing from private use. Before ISR operations begin, the Permittee will secure the wellheads to prevent unauthorized access.

The well with Hydro ID 16 has already been removed from drinking water use, but is currently being used for stock watering. The Class III Area Permit requires the Permittee demonstrate that well 16 does not currently serve as a source for drinking water before the EPA will approve the aquifer exemption for Burdock wellfields 6 and 7 as discussed in the EPA Dewey-Burdock Aquifer Exemption ROD that is a part of the Administrative Record for this EPA UIC permitting action.

6.3 Plugging and Abandonment Procedures

Part II, Section B.3 of the Class III Area Permit requires the Permittee to plug and abandon all drillholes completed during the process of exploration and delineation drilling that are not used for the construction of a well. As discussed in Section 6.0, the corrective action requirements address any historic exploration drillholes or wells that are found to cause a breach in a confining zone. Part VII, Section F requires the Permittee to plug and abandon any wells which fail to demonstrate mechanical integrity and cannot be repaired. Well plugging and abandonment procedures are discussed in Section 16.0.

6.4 Operational Controls

Corrective action would ideally consist of re-plugging leaking drillholes and plugging or recompleting any leaking water wells. However, as stated above, 40 CFR § 144.55(b)(4) allows the Director to consider the overall effect of the project on the hydraulic gradient in potentially affected USDWs, and the corresponding changes in potentiometric surface(s) and flow direction(s). The Class III Area Permit requires an inward hydraulic gradient for wellfield groundwater, which results in lowering the injection interval potentiometric surface and changing the groundwater flow directions inward toward the wellfield. The operator can control the potentiometric surface drawdown and hydraulic gradient through operational controls such as the pumping rate and injection pressure and rate to contain injection interval fluids within the injection interval. When operational controls are employed as a means of corrective action, additional monitoring is required to verify that operational controls are effectively preventing injection interval fluids from leaving the injection interval through any breaches that could not be located or eliminated using best available technology. Groundwater modeling or additional pump testing may be required to provide demonstration that the wellfield design and monitoring systems are sufficient to control and detect any potential excursions in areas where operational controls are used as the corrective action method. (Excursions are discussed in Section 12.5)

The UIC Regulatory Program Statement of Basis explains this concept further:

> *If it [the AOR evaluation process] did indicate a problem, however, the well operator would be expected to correct it. Correcting the problem could mean that the well operator would have to plug a faulty well at his/her expense. In other cases, the operator might simply have to modify injection pressure to assure that the rise of fluids caused would not cause fluids to enter an underground source of drinking water.*
>
> *With respect to corrective action itself, the regulations impose a flexible standard. Corrective action required for each well will be fashioned by the Director on a case by case basis after considering a variety of site specific criteria. EPA prefers this approach because of the variety of problems or conditions which can trigger the need for corrective action. In one instance, the only corrective action which may be needed to prevent the migration of fluids into an underground source of drinking water through a faulty well might be a reduction of the pressure at which fluids are injected. In other instances, monitoring of nearby wells coupled with a contingency plan to remedy any problems which result from the injection operation*

might be feasible. In still other cases, it might be necessary to correct the wells. This range of possibilities, as well as the significant costs which corrective action can generate, have encouraged the Agency to adopt the more flexible approach.

7.0 WELL CONSTRUCTION

The well construction plan that the Permittee proposed in Section 11.0 of the Class III Permit Application has been reviewed by the EPA and determined to be protective of USDWs. The approved well construction plan has been incorporated into Part V of the Class III Area Permit and will be binding on the Permittee. Modification of the approved construction plan is allowed under 40 CFR § 144.52(a)(1). Changes in construction plans during construction may be approved by the Administrator as minor modifications (40 CFR § 144.41). No such changes may be physically incorporated into construction of the well prior to approval of the modification by the EPA.

The following construction diagrams are included in Part V of the Class III Area Permit:

1) The injection or production well with open hole and screened completions,
2) The injection wellhead,
3) The injection header;
4) The injection well header detail; and
5) The production wellhead.

The production well design is identical to that of an injection well except for the addition of a submersible pump in the production well.

7.1 Wellfield Design

Each ISR wellfield will consist of a series of injection and production wells completed within the target ore-bearing zone. Prior to design and layout of the wells, the ore bodies locations will be identified vertically and horizontally by the delineation drilling and drillhole logging required under Part II, Section B of the Class III Area Permit. The Class III Area Permit does not have any requirements related to layout of the injection/producing well patterns. All wells completed within the wellfield injection interval may be used as either injection or production wells, so that flow patterns can be changed as needed to recover uranium and restore groundwater quality in the most efficient manner. Therefore, both types of wells will be subject to permit requirements regardless of whether a well is being used as an injector or a production well.

For all injection and production wells, the top of the screened or open hole interval will be at or below the base of the confining zone overlying the ore-bearing zone. The screened or open hole interval will be completed only across the targeted ore zone. An example of a 100 x 100 ft grid wellfield layout is illustrated in Figure 23. This layout will be adapted to the lateral distribution and grade of one of the uranium deposits within the Project Area based on information from the wellfield delineation drilling and logging. The well patterns may differ from wellfield to wellfield, but the expected pattern will consist of five wells, with one well in the center and four wells surrounding it oriented in four corners of a square measuring between 50 and 150 feet on a side. A production well will usually be located in the center of the pattern, and the four corner wells will be injection wells. Figure 23 depicts an example of a 5-spot wellfield pattern. Other wellfield designs may be considered and proposed in the wellfield Injection Authorization Data Package Reports discussed in Section 5.6.

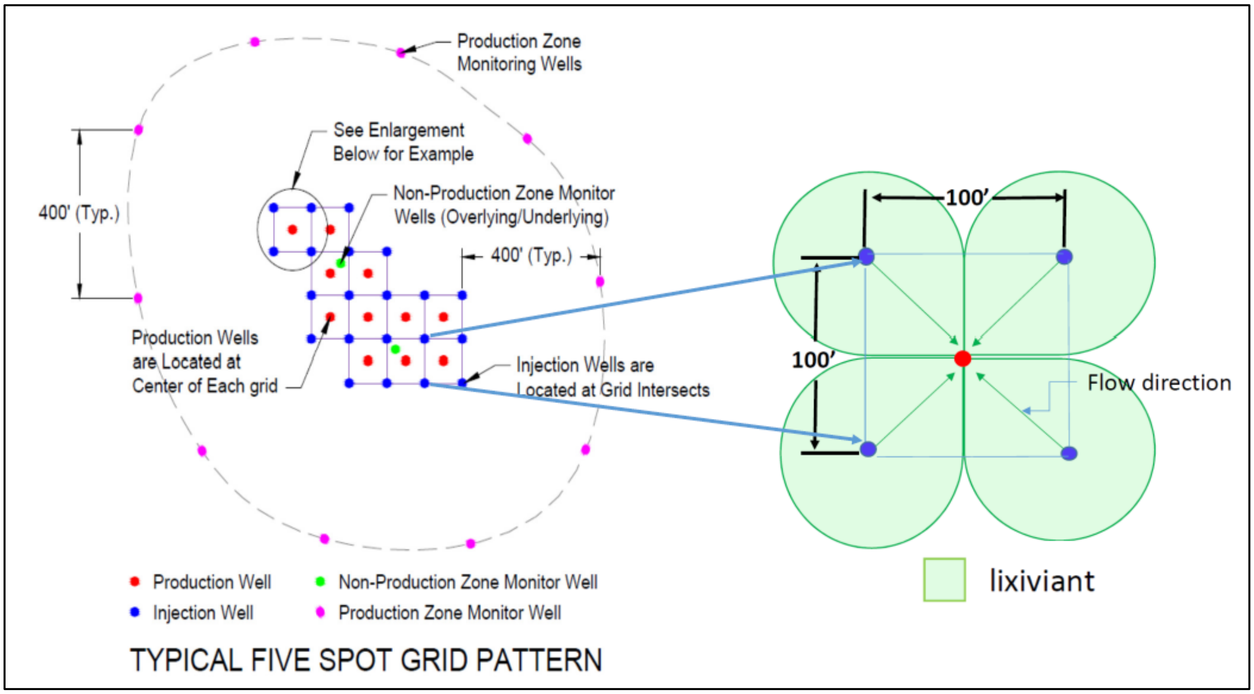


Figure 23. Wellfield Injection, Production and Monitoring Well Location Scheme

Figures 2, 4a and 4b depict the project ore bodies proposed for uranium recovery and shows all Lower Fall River ore bodies in blue, all ore bodies within the Upper Chilson Member of the Lakota Formation in green and Middle/Lower Chilson ore bodies in red. All wellfields and their perimeter monitoring well rings will be located within the Area Permit Boundary. The Permittee stated in Section 10.3.1 of the Class III Permit Application that no wellfields will be located within 1,600 feet of the project boundary in order to establish an operational buffer between the wellfields and the Area Permit Boundary. After reevaluating extent of the uranium ore bodies, the Permittee has updated the buffer to 1,000 feet. The Permittee does not plan to locate any injection and production wells within the 1,000-foot buffer zone; however, wellfield perimeter monitoring well rings will be located within the buffer zone as shown in Figure 24. The 1,000-foot buffer zone is included as a requirement under Part II, Section A of the Class III Area Permit. In addition, no wellfields are proposed within Fall River ore bodies in the eastern portion of the project area where the Graneros Group overlying confining zone is absent, as discussed in Section 3.4.1.

The piping from the injection and production wells will terminate at a header house where each well will be connected to manifolds equipped with control valves, flow meters, check valves, and pressure sensors as shown in Class III Area Permit, Part V, Figures 8 and 9. Injection wells will also have oxygen and carbon dioxide feed systems. The Permittee anticipates that 20 production and 80 injection wells will be connected to a header house. A header house design plan is shown on Permit Application Plate 7.2. Wellhead connection details for injection and production wells are illustrated in Figures 6 and 7, respectively, in Part V of the Class III Area Permit. Piping between the wells and header house will consist of high-density polyethylene (HDPE) pipe with heat-welded joints, buried at least 5 feet below grade. Part V, Section E.1.d of the Class III Area Permit requires that the piping used has a pressure rating greater than the highest maximum injection pressure within the wellfield.

The injectate, which will be barren Lixiviant, will originate from the Burdock Central Processing Plant or the Dewey Satellite Processing Plant and piped through the injectation header trunkline to the wellfield header

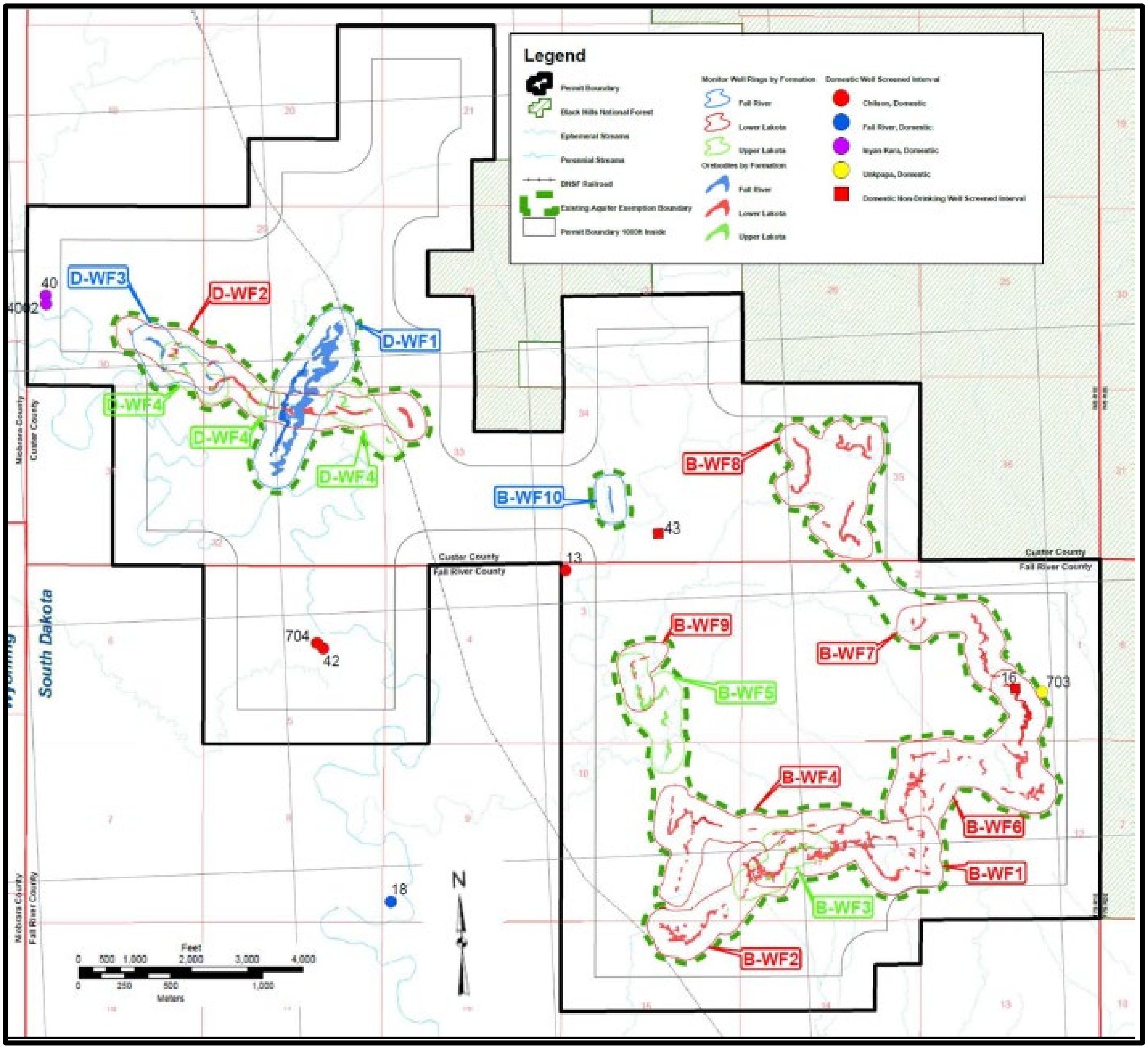


Figure 24. The 1,000-foot buffer zone between wellfield injection and production wells and the Permit Boundary.

houses. Carbon dioxide is added before the manifold. The manifold is where the flow is divided into each of the injection well headers. The oxygen is added at the individual injection well headers. Permit Application Plate 7.2 contains the piping detail for injection and production headers in a typical header house. The Class III Area Permit, Part V, Figure 8 shows a portion of this piping detail with the injection header instrumentation. The Class III Area Permit, Part V, Figure 9 is a detailed illustration of an injection well header.

7.2 Monitoring Wells

Part II Section D of the Class III Draft Area Permit specifies the design requirements for the wellfield monitoring system. Table 14 lists the vertical and horizontal distribution requirements for monitoring well installation. As discussed in Section 5.2, the perimeter monitoring well ring will be installed around each wellfield and completed in the injection interval to detect any potential horizontal migration of ISR solutions away from the intended injection interval. Non-injection interval monitoring wells must be completed within each wellfield in the aquifers overlying the injection interval and underlying the injection interval, if the lower confining zone is *not* the Morrison Formation. These wells are used to detect any vertical migration of lixiviant constituents.

The Permittee proposes a monitoring well construction design similar to that of the injection and production wells shown in Figure 5 in the Class III Area Permit. To eliminate the possibility that a monitoring well is a potential pathway through a confining zone along the cement-filled annulus between the well casing and the borehole wall, Part IX, Section E.4 of the Class III Area Permit requires the Permittee to submit a well completion report for each monitoring well to the EPA for review of the well cementing record as demonstration of external mechanical integrity. Demonstrating external mechanical integrity for each monitoring well will limit confining zone breaches detected during the wellfield pump test to historic exploration drillholes and previously constructed wells. A more detailed description of the monitoring system design and monitoring well placement is contained in Section 12.4.

Table 14. 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 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 wellfield area. 2) Monitor 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.

7.3 Well Construction Procedures

The Permittee proposes beginning production and injection well installation by drilling a pilot borehole all the way through to the base of the ore zone to obtain a measurement of the uranium grade and thickness. The ore depth is anticipated to range from 200 to 800 feet. Part V, Section C of the Class III Area Permit requires geological and geophysical logging to be performed on the well bore hole. After logging, the well bore hole the Permittee proposes reaming the hole to the appropriate diameter to the top of the target completion zone. Part V, Section D.1 of the Area Permit requires the drillhole diameter to be at least 2 inches larger than outside diameter of the well casing in order to provide space for the required grout volume to properly seal off the casing-drillhole annulus through the overlying confining zones and aquifers.

The Permittee proposes using thermoplastic well casing material, such as polyvinyl chloride (PVC), ranging from 4.5 to 6-inch nominal diameter. Part V, Section E.2.d of the Class III Area Permit requires the Permittee to use casing joining methods recommended by the casing manufacturer to ensure a watertight seal. The Permittee anticipates the PVC casing joints will be approximately 20 feet apart and joined mechanically with a watertight O-ring seal and a high strength nylon spline to ensure watertight joints above the well screen or open hole interval. Part V, Section D.2 of the Class III Area Permit requires the Permittee to place a continuous string of joined PVC casing into the reamed borehole. Part V, Section D.3 of the Class III Area Permit requires the Permittee to install casing centralizers as appropriate to maintain a consistent annular space around the casing, using a minimum of two. The centralizers hold the well casing a consistent distance from the borehole wall to ensure the cement is evenly distributed around the well casing, preventing any pathways for fluid movement through overlying confining zones.

Part V, Section E.4 of the Class III Area Permit contains the cementing requirements for the annular space between the borehole wall and the well casing. These requirements are summarized as follows:
Once the casing is in place, the Permittee must install cement/bentonite grout by pumping it under pressure into the casing and allowing the grout to circulate out the bottom of the casing and back up the casing annulus to the ground surface, thus pressure-grouting the annulus. The casing and grout must be allowed to set undisturbed for a minimum of 24 hours. After the grout has set, if the annular seal observed from ground surface has settled below ground surface, the Permittee must place additional grout into the annular space to bring the grout seal to ground surface. The Class III Area Permit requires the Permittee to calculate the volume of grout necessary to fill the annulus using the borehole diameter, the outer diameter of the casing and the length of the annular space, then use a sufficient additional grout to achieve 20% volume returning to surface. Grout remaining inside the well casing must be displaced by water to minimize the column of the grout plug inside the casing. Part V, Section E.4.e of the Class III Area Permit requires the Permittee to leave a small grout plug at the bottom of the casing to ensure the grout is continuous all the way from the casing bottom to the ground surface.

After the grout has been installed and allowed to set for a 24-hour period, well construction may be completed by installing the well screen or left as an open hole completion. Class III Area Permit Figure 3 and the following discussion represent the anticipated injection well construction methods. Figure 3 in Part V of the Class III Area Permit depicts the two options for well construction design, the well screen and the open hole completion. Part V, Section E.5 of the Class III Area Permit contains the well completion requirements. The Permittee must drill through the grout plug at the bottom of the well casing and through the target completion zone to the specified total well depth indicated from the wellfield delineation drilling information. The open borehole must then be under-reamed to a larger diameter. As proposed in Section 11.2 of the Class III Permit Application, the well screen assembly will be lowered through the casing into the open hole. The top of the well screen assembly must be positioned inside the well casing and centralized and sealed inside the casing using K packers, shown in Figure 3 in Part V of the Class III Area Permit. With the drill pipe attached to the well screen, the Permittee proposes inserting a 1-inch diameter tremie pipe through drill pipe and screen and through the sand trap check valves at the bottom of well screen assembly. The use of filter pack is optional. If used, it will be composed of well-rounded silica sand sized to optimize hydraulic communication between the target zone and well screen. The filter pack will be placed between the well screen and the formation. The filter pack material will not extend upward beyond the K packers due to packer design. Alternatively, if the injection interval rock is competent and produces clear water with low sediment content during well development, the Permittee may elect to use an open hole completion. Figures 4 and 5 in Part V of the Class III Area Permit depict the injection and production wellheads, respectively.

Changes in construction plans during construction may be approved by the Administrator as minor modifications (40 CFR § 144.41). No such changes may be physically incorporated into construction of the well prior to approval of the modification by the EPA in accordance with 40 CFR § 144.52(a)(1). Part V, Section G of the Class III Area Permit requires the Permittee to prepare a well construction report for each well.

7.4 Well Logging

Part V, Section C, Table 10 of the Class III Area Permit requires that the gamma log, self-potential and single point resistivity electric logs be run in the drillholes for each well. The purpose for running these logs is to determine the location and grade of uranium and the sand and shale unit depths to properly plan each pattern of injection and production wells within the wellfield. Physical logging of geologic formations intersecting the borehole will be performed during drilling to identify stratigraphy and lithology.

7.5 Well Casing and Cementing Requirements

The Permittee proposes using thermoplastic well casing material, such as PVC, with no greater than Standard Dimension Ratio (SDR) of 17 with regard to pipe wall thickness. This means the ratio of pipe diameter to wall thickness is no greater than 17.

The SDR can be expressed as

$$SDR = D / T$$

where

D = pipe outside diameter (inches)

T = pipe wall thickness (inches)

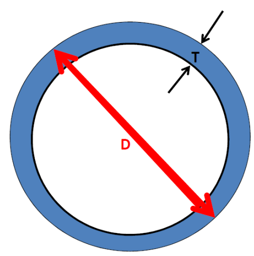


Figure 25. Standard Dimension Ratio

SDR 17 means that the outside diameter - D - of the pipe is seventeen times the thickness - T - of the pipe wall. Pipe with a high SDR ratio the pipe wall is thin compared to the pipe diameter; pipe with a low SDR ratio the pipe wall is thick compared to the pipe diameter. As a consequence, a high SDR pipe has a low-pressure rating and low SDR pipe has a high-pressure rating.[8]

The Permittee proposes using 4.5 to 6-inch external diameter well casing pipe. Part V, Section E.2.a of the Class III Area Permit requires that the well casing meet or exceed the specifications of ASTM Standard F480 and NSF Standard 14 for thermoplastic pipe, including PVC. Table 15 shows the minimum wall thickness the well casing pipe will have given an SDR of 17 and the minimum drillhole diameter requires to provide enough annular space for adequate cement.

Table 15. Proposed Range for Well Casing Dimensions

Proposed	Minimum	Minimum

[8] From http://www.engineeringtoolbox.com/sdr-standard-dimension-ratio-d_318.html

Casing Pipe Diameter (inches)	Casing Pipe Wall Thickness (inches)	Drillhole Diameter (inches)
4.5	0.265	6.5
6.0	0.353	8.0

Part V, Section E.2.c of the Class III Area Permit requires that the well casing pipe have a pressure rating greater than the maximum injection pressure for the wellfield as calculated under Part V, Section F.4 of the Class III Area Permit. However, in the Dewey Area where the proposed injection interval is deep (from approximately 516 to over 700 feet to the top of the proposed injection interval; see Table 1), the Permittee may use casing that is pressure rated below the fracture pressure calculated at the top of the targeted ore zone. In that case, the Maximum Allowable Injection Pressure (MAIP) for the header house will be set at or below the pressure rating of the well casing pipe as discussed in Section 9.1.2 and required under Part V, Sections F.5 and F.6 of the Class III Area Permit, so the requirement under Part V, Section E.2.c of the Class III Area Permit is fulfilled.

Inside the well casing, polyethylene (PE) pipe injection pipe of 1.0 to 1.5 inches in external diameter with no greater than SDR 11 will be used to convey the lixiviant through the well casing. Part V, Section E.3.a of the Class III Area Permit requires that the PE injection pipe meet or exceed the specifications of ASTM Standard D3350 for PE pipe. Table 16 shows the minimum wall thickness the injection pipe will have given an SDR of 11.

Table 16. Proposed Range Injection Pipe Dimensions

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

PE pipe is known for its strength and is the standard for high pressure water conveyance. Part V, Section E.3.c of the Class III Area Permit requires the use of PE pipe with a minimum pressure rating greater than the MAIP for the wellfield. If the Permittee chooses not to use PE pipe pressure rated above the fracture pressure calculated at the top of the injection interval in the Dewey Area, then the MAIP for the header house will be set at or below the pressure rating of the PE injection pipe as discussed in Section 9.1.2 and Part V, Sections F.5 and F.6, so the requirement under Part V, Section E.3.c of the Class III Area Permit is fulfilled.

7.6 Surface Casing and Cementing Requirements under 40 CFR § 147.2104(d)

Regulation 40 CFR § 147.2104(d) requires that the well casing and cement used in the construction of all wellfield production and injection wells protect USDWs by:

(1) (i) Setting surface casing 50 feet below the lowermost USDW.
(ii) Cementing surface casing by recirculating the cement to the surface from a point 50 feet below the lowermost USDW (see above); or
(iii) Isolating all USDWs by placing cement/bentonite grout between the outermost casing and the well bore: The annular seal will be pressure-grouted with neat cement/bentonite grout as described above.

(2) Isolate any injection intervals by placing sufficient volume of cement/bentonite to fill the calculated space between the casing and the well bore to a point 250 feet above the injection interval: The entire annular seal will be pressure-filled with cement/bentonite grout as described above.

Except for the alluvium associated with Beaver Creek and Pass Creek, the Fall River Formation and Chilson are the shallowest aquifers potentially classified as USDWs in the Project Area. Since the portion of the Fall River and Chilson within the wellfields will be in an exempted aquifer and since injection wells will not target aquifers deeper than the Fall River or Chilson, there will not be any USDWs between the ground surface and the total injection well depth, so the Class III Area Permit does not require surface casing to be installed for most wellfield wells. The exception would be if a well intersects alluvium. Part V, Section E.1.b of the Class III Area Permit requires that surface casing be installed through the alluvium extending to 50 feet below the alluvium regardless of whether the alluvium is classified as a USDW. Figure 11 and Figures 12a and 12b show where alluvium is present within the Dewey-Burdock Project Area.

In addition, the Part V, Section E.4.b of the Area Permit includes the 40 CFR § 147.2104(d)(3) requirements for cement, including using cement/bentonite grout

- (i) of sufficient quantity and quality to withstand the maximum operating pressure;
- (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 cement off a zone.

7.6.1 Thermoplastic Well Casing Variance Request

In Section 11.1.1 of the Class III Permit Application, the Permittee requests a variance from the requirement in 40 CFR § 147.2104(b)(1) that plastic well casing materials, including PVC, ABS or others, not be used in new injection wells deeper than 500 feet in the State of South Dakota. The EPA has reviewed the Permittee's request for variance to use PVC casing for injection wells deeper than 500 feet and has determined that the Permittee has demonstrated that USDWs are protected by using the type of casing the Permittee proposes for the injection and production wells. Part V of the Area Permit requires the implementation of the proposed protective measures discussed in Section 7.6.2.

The variance is requested pursuant to 40 CFR § 147.2104(d)(4), which states that the Regional Administrator may approve alternate casing provided that the owner or operator demonstrates that such practices will adequately protect USDWs.

This variance is requested on the following bases:

1) Collapse pressure calculations and well casing manufacturer specifications indicate that PVC well casing can be used at depths greater than 500 feet considering the site-specific well construction methods as discussed in Section 7.3 (also see Permit Application Section 11.1.1.1).
2) PVC well casing has been used successfully for wells deeper than 500 feet at uranium ISR facilities for many years (see Permit Application Section 11.1.1.2).
3) PVC well casing is commonly used for other wells in South Dakota deeper than 500 feet (see Permit Application Section 11.1.1.3).
4) Thermoplastic well casing is the preferred well casing material for ISR facilities due to corrosion resistance. The corrosion resistance of PVC compared to carbon steel well casing is well documented.
5) The Class III Area Permit Part VII, Section C.4.d requires that each new injection and production well be pressure tested to confirm the integrity of the casing prior to being used for ISR operations. Part VII, Section G.1 of the Class III Area Permit requires that mechanical integrity testing on an active well be repeated every 5 years and Part VI, Section B requires demonstration of mechanical integrity after any well workover affecting the well tubing, casing or cement.
6) Part V, Section E.2.c and Part V, Sections F.5 and F.6 of the Class III Area Permit ensure that the maximum allowable injection pressure within the wellfield does not exceed the pressure rating of injection and production well casing.

7) Part II, Section D and Part IX, of the Class III Area Permit require that an extensive monitoring program must be implemented by installing and sampling monitoring wells around the wellfield perimeter within the injection interval and in overlying and underlying aquifer units to detect potential excursions of ISR solutions into USDWs such as would occur with a leaking injection well.
8) Injection pressures must be monitored through automated control and data recording systems that will include alarms and automatic controls to detect and control a potential release such as would occur through an injection well casing failure.

South Dakota state regulations under ARSD 74:02:04 also supports the use of PVC well casing for other types of wells to depths greater than 500 feet. For example, Section 36 of ARSD 74:02:04 provides construction requirements for SCH 80 PVC private domestic and noncommercial livestock wells more than 1,000 feet deep.

ARSD 74:02:04, Sections 42 and 43 discuss general well casing requirements. Section 42 says, “Casing materials may be thermoplastic, steel, nonferrous metal, fiberglass, precast curbing, or concrete” but that, “[c]asing may only be used under conditions that meet manufacturer’s recommendations and specifications for its type.” Section 43 provides thermoplastic casing requirements, including that PVC well casing 5 inches or greater in diameter must have a minimum wall thickness of 0.250 inch. The Permittee will ensure that all PVC well casing 5 inches or greater in diameter has a minimum wall thickness of 0.250 inch. This means that 5-inch PVC well casing will be SCH 40 or heavier or SDR 17 or heavier. Section 43 also requires thermoplastic pipe to conform to ASTM F480. Compliance with the requirements in ASTM F480 is described in Section 11.1.1.1 of the Permit Application.

7.6.2 Hydraulic Collapse Pressure Calculations

To ensure that the use of thermoplastic casing will withstand hydrostatic pressure as it increases with depth variance, Part V, Section D.4 of the Class III Area Permit requires the Permittee to adhere to the requirements in ASTM F480, Standard Specifications for Thermoplastic Well Casing Pipe and Couplings Made in Standard Dimension Ratios (SDR), SCH 40 and SCH 80 when specifying well casing and during installation procedures. ASTM F480 requires that “the depth at which thermoplastic well casing can be used is a design judgment.” There is no depth of installation limit in ASTM F480 except that PVC well casing should be “used under conditions that meet manufacturer’s recommendations for its type” and that “the driller shall install the thermoplastic casing in a manner that does not exceed the casing hydraulic collapse resistance.”

In accordance with these requirements, the Permittee must ensure that all thermoplastic well casing meets the manufacturer’s recommendations for its type and is installed in a manner that does not exceed the hydraulic collapse resistance. The net hydrostatic pressure on the well casing is calculated as the difference between the exterior and interior hydrostatic pressure. The hydrostatic pressure is calculated as the fluid density multiplied by the fluid depth. The Permittee proposes using a cement grout density of 90 lb/ft^3 to fill the annulus of all injection, production and monitoring wells. Recognizing that the inside of the well casing will always be full of water before the cement cures (with a density of at least 62.4 lb/ft3 depending on whether additives are used), the pressure versus depth gradient will be about 27.6 lb/ft3 or about 0.2 psi/ft of depth. According to CertainTeed (2011), the hydraulic collapse pressure for SDR 17 PVC well casing is about 224 psi. Therefore, it would take an installation depth much greater than 1,000 ft to exceed this pressure as long as cement grout were used and the well casing remains full until the cement hardens. Both of these conditions will be met in all injection, production and monitoring well casing installations using the installation procedures required under Part V of the Class III Area Permit. Water will be used to displace the cement and force it upward into the annulus as required under Part V, Section E.4.e; therefore, the well casing will always be full of water while the cement cures.

7.7 Tubing and Packer

Part V, Section E.3.c of the Class III Area Permit requires the pipe through which the lixiviant flows inside the well casing to have a pressure rating exceeding the highest injection pressure within the wellfield as calculated under Part V, Section F.4 of the Class III Area Permit. If the injection interval is deep and the pipe through which the lixiviant flows does not have a pressure rating above the fracture pressure of the injection interval, then the MAIP will be set at the or below the pressure rating for the tubing as explained in Section 9.1.2 and required under Part V, Sections F.5 and F.6 of the Class III Area Permit.

Figure 3 of the Class III Area Permit shows a K Packer with the well construction design option using the well screen completion. The K Packer does not seal off the annulus between the tubing and casing; its purpose is only to assist with the placement of the well screen. The Class III Area Permit does not contain any requirements related to the K Packer.

7.8 Tubing-Casing Annulus

Tubing-casing annulus requirements are specified in UIC regulations for deep injection wells injecting at high pressures. The Class III injection wells are not deep enough and will not be injecting at high enough pressures to warrant additional requirements for the tubing-casing annulus. There are no tubing-casing annulus requirements under the Class III Area Permit.

7.9 Well Development

The primary goals of well development is to allow formation water to enter the well screen, flush out drilling fluids, and remove the finer clays and silts to maximize flow from the formation through the well screen. This process is necessary to allow representative samples of groundwater to be collected and to ensure efficient injection and production operations. The Permittee proposes conducting wells development immediately after construction using air lifting, swabbing, pumping or other accepted development techniques which will remove water and drilling fluids from the casing and borehole walls along the screened interval. The Permittee proposes pumping three well casing volumes from each well prior to obtaining baseline samples from monitoring wells to ensure that representative formation water is sampled. Part II, Section E.2.b, and Part IX, Section A.4 of the Class III Area Permit require that groundwater be pumped out of each well while parameters such as pH, specific conductance and temperature. Once the measurements of these parameters have stabilized, it will be possible to collect representative groundwater samples that are representative of the aquifer fluids.

7.10 Monitoring Devices

7.10.1 Header House Monitoring Equipment

As discussed earlier, the piping from each production and injection well will be connected to a manifold located in a wellfield header house. Part V, Section I of the Class III Area Permit sets the design requirements for the manifolds. The manifolds must be equipped with control valves, flow meters, check valves, pressure sensors, and programmable logic controllers. The injection and production header trunkline pipes from the wellfields will be connected to either the Burdock Central Processing Plant or the Dewey Satellite Facility.

7.10.2 Burdock Central Processing Plant and Dewey Satellite Monitoring Equipment

Part V, Section J.1 of the Class III Area Permit requires that sampling ports be located on the injection header pipe connected to each wellfield at the Burdock Central Processing Plant and Dewey Satellite or another representative sampling or measurement location for the sampling of lixiviant injected into each wellfield. Instrumentation for continuous monitoring of the injection and production flow rates and volumes for each wellfield must also be installed at the Central Processing Plant and Satellite or another representative sampling or measurement location (under Part V, Section J.2 and Part V, Section J.3, respectively). The Permittee has the option of locating the injectate sampling ports and instrumentation for the continuous monitoring in injection rate and injection volume at other locations providing the other locations provide information representative of the monitored activity as required under 40 CFR § 144.51(j)(1). The Permittee will provide these alternative locations as part of the Injection Authorization Data Package Reports as described under Section 5.6.

7.10.3 Wellhead Monitoring Equipment

40 CFR § 146.33(b)(6) states that all 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. The Class III Area Permit allows the Permittee to continuously monitor injection pressure at the manifold rather than at individual wellheads provided the Permittee demonstrates that manifold monitoring is comparable to individual well monitoring. Class III Area Permit Part V, Section I.2 contains the additional monitoring equipment required for manifold monitoring.

Part VIII, Section E.1 of the Class III Area Permit provides the Permittee the option for setting the compliance point for monitoring injection pressure at the header house manifolds as opposed to the individual wellheads. Part VIII, Section E.2 sets the requirement to demonstrate that manifold monitoring is comparable to individual well monitoring in order for the Permittee to use manifold monitoring per 40 CFR part 146.23(b)(5). Because the flow rate and volume requirements are applied on the wellfield level, the important parameter to consider in this case is injection pressure. Because of friction loss along the pipelines from the header house to the injection wells, the injection pressure measured at the header house should be greater than the injection pressure at each individual wellhead as long as:

1) The injection wells are not located down a slope from the header house, which would allow acceleration due to gravity to increase the injection pressure at the wellhead in possibly an amount greater than the friction loss in the pipes,
2) The pressure of carbon dioxide infusion into the injection header pipe (which is located in-line below the header house injection trunkline pressure gauge) does not cause in exceedance of injection pressure, or
3) The pressure of oxygen infusion into the injectate at each well header does not cause in exceedance of injection pressure.

Because of these factors that could affect the wellhead injection pressure further down the pipeline from the injection header pressure gauge, Class III Area Permit Part VIII, Section E.1 of the Class III Area Permit requires the Permittee to verify that 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.

The Class III Area Permit Part V, Section I.1 describes the bounding analysis which is the initial injection pressure calibration check to be performed as each header house is brought online. The initial injection pressure calibration check involves measuring the injection pressure at each wellhead to verify that it is not greater than the injection pressure measured at the pressure gauge on the header house injection line. If the injection pressure at any injection wellhead is greater than the pressure measured at the header house injection line pressure gauge, the pressure to the individual injection well must be adjusted so that the injection pressure at the injection wellhead is equal to or less than the injection pressure measured at the header house injection trunkline pressure gauge.

The description of how the injection pressure calibration check (bounding analysis) between the injection pressure at the header house and each connection injection wellhead is to be documented is found at Part IX, Section E.5. The demonstration will consist of listing each injection pressure measured at each wellfield injection wellhead compared to the injection pressure measured at the pressure gauge at the corresponding header house and the time and date each injection pressure measurement was collected. The Permittee will make an effort to record the measurements at the same time from wellhead pressure gauge and the header house pressure gauge. This information will be included in the next Quarterly Report after the information is compiled.

The pressure measurements will be measured using the maximum anticipated carbon dioxide and oxygen injection rates. 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 pressures set during the demonstration pressure measurements, then a new demonstration is required. The Permittee does not anticipate a significant impact on the injection pressure based on the gaseous flow rates, since the gases would be dissolved in the lixiviant.

7.10.4 Emergency Shutdown/ Protective Automated Monitoring and Shut-off Devices

Part V, Section K of the Class III Area Permit requires the Permittee to install automated control and data recording systems at the Burdock Central Processing Plant and Dewey Satellite Facility which will provide centralized monitoring and control of the process variables including the flows and pressures of production and injection streams. The systems must include alarms and automatic shutoffs to detect and control a potential release or spill. The Central Processing Plant and Satellite Facility control rooms will both receive the pressure and flow data transmitted from the wellfields, trunklines, and header houses. This information will provide the plant operators access to instantaneous data on wellfield operating conditions, enabling operators to respond appropriately to unexpected or upset conditions and to direct the wellfield operators to specific locations where immediate attention is needed.

Pressure and flow sensors must be installed, for the purpose of leak detection, on the main trunklines that connect the Central Processing Plant and Satellite Facility to the wellfields. In addition, the flow rate of each production and injection well will be measured automatically. Measurements must be collected and transmitted to both the Central Processing Plant and Satellite Facility control systems. Should pressures or flows fluctuate outside of normal operating ranges, alarms must provide immediate warning to operators which will result in a timely response and appropriate corrective action. Both external and internal shutdown controls are required to 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 a header house shutdown, the permit requires that 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 Central Processing Plant and Satellite Facility control rooms.

An external header house shutdown must activate an electrical disconnect switch located on the outside of the header house or at the transformer pole which will shut down all electrical power to the header house. This will mitigate potential electrical hazards while de-energizing the header house and operating equipment. The production pumps must be de-energized which will result in flow stopping from all production wells. A control valve that will close when de-energized will be used on the injection header, which will stop the flow to all injection wells.

Internal shutdown controls may not involve de-energization of the header house but must result in the same alarm condition and shutdown of flow to all production and injection wells feeding the header house.

Each header house also must include a sump equipped with a water level sensor so that if a leak occurs, and the water level approaches a preset level, the sensor will cause an automatic shutdown of the injection and production activities for all wells connected to the header house. A pressure switch must be installed on each injection header to ensure that injection pressure does not exceed the maximum designated injection pressure for the injection wells connected to that header house (see Class III Area Permit Figure 6). If the injection pressure reaches the maximum value set for the pressure switch, an automatic shutdown of the injection and production activities for all wells connected to that header house will occur.

Monitoring requirements are discussed later under Section 12.0.

7.11 Postponement of Construction

Usually EPA UIC permits require a permittee to complete well construction within two years of the effective date of a permit, or in the case of an area permit, within two years of the EPA authorizing the construction of an additional well. After two years, the authorization to construct and operate a permitted UIC well expires, unless the permittee has notified the Director and requested and extension of the two-year time limit in writing, stating the reasons for the delay and provide an estimated completion date. Unless the EPA grants an extension, the permittee is required to submit a new permit application for the well and complete a new area of review process. The reason for this approach is because the EPA is concerned that new wells may be constructed or plugged and abandoned within the area of review, which might require a change of monitoring requirements within the Class III Area Permit.

In the case of this Class III Area Permit, if the EPA issues a final permit decision, the State of South Dakota permitted processes must still be completed before the Permittee is able to begin work at the project site. To address any changes within the Area of Review that might occur during this time frame, the Class III Area Permit requires the Permittee to submit an Area of Review update annually to the EPA until wellfield construction commences. The required AOR update includes:

1. 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;
2. Performing a capture zone analysis for each new drinking water well constructed within the AOR and
3. Adding the new well to the list of operational monitoring wells discussed in Part IX, Section B.3.

8.0 MECHANICAL INTEGRITY REQUIREMENTS

Part VII, Section B.2 of the Class III Area Permit requires the Permittee to demonstrate each injection and production well has mechanical integrity before injecting into a well.
An injection well has mechanical integrity if:

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

8.1 Initial Mechanical Integrity Testing

8.1.1 Initial Demonstration of Internal Mechanical Integrity

All injection, production, and monitoring wells must be pressure tested to demonstrate the mechanical integrity of the well casing before injecting into a well can be authorized. Part VII, Section B.1 of the Area Permit prohibits injection into a well which lacks mechanical integrity. The Director will not issue Authorization to Commence Injection until the Permittee provides mechanical integrity test results demonstrating that each injection and production well has mechanical integrity. The Class III Area Permit does not require the Permittee to submit ongoing internal mechanical integrity test results for the monitoring wells, because the monitoring wells will not be used for injection of lixiviant.

Part VII, Section B of the Area Permit requires that injection and production wells demonstrate mechanical integrity prior to injection and periodically thereafter. Each well must demonstrate both internal and external mechanical integrity. The methods and frequency for demonstrating internal and external mechanical integrity are dependent upon well-specific conditions as explained below.

8.1.2 Internal Mechanical Integrity Test Procedure

Part VII, Section C of the Class III Area Permit specifies the procedure for the internal mechanical integrity test. The bottom of the casing must be sealed with a plug, downhole inflatable packer, or other suitable device. The casing must be filled with water, and the top of the casing must be sealed with a threaded cap, mechanical seal or downhole inflatable packer. The well casing then must then be pressurized with water or air and monitored with a calibrated pressure gauge. The pressure used for the internal mechanical integrity test depends on how the MAIP was determined for the injection or production well:

1) If the MAIP is based on the pressure rating of the casing and tubing, then the internal casing pressure will be increased to 125% of the maximum operating pressure rating of the well casing (which is always less than the maximum pressure rating of the pipe).
2) If the MAIP is set at 90% of the calculated formation fracture pressure based on the injection formation fracture pressure as discussed in Section 9.1.1, the test pressure will be the MAIP.

A well must maintain 90% of this pressure for a minimum of 10 minutes to pass the test. If the pressure drops by more than 10% during the 10-minute period, the seals and fittings on the packer system will be checked and/or reset and another test will be conducted. If the pressure drops less than 10% the well casing will have demonstrated acceptable mechanical integrity. If a well cannot pass a mechanical integrity test, it must be plugged and abandoned as required under Part VII, Section F of the Class III Area Permit.

8.1.3 Initial Demonstration of External Mechanical Integrity

External mechanical integrity test requirements found at 40 CFR § 146.8(c)(1) stipulate that a temperature or noise log must be used to demonstrate that there is no significant fluid movement through vertical channels in the cement between the injection well borehole wall and well casing. 40 CFR § 146.8(c)(3) states for Class III wells where the nature of the casing precludes the use of the logging techniques prescribed at paragraph (c)(1) of this section, cementing records demonstrating the presence of adequate cement to prevent such migration may be used to fulfill the external mechanical integrity demonstration requirements. 40 CFR § 146.8(c)(4) adds the stipulation that for Class III wells where the EPA elects to rely on cementing records to demonstrate the absence of significant fluid movement, the monitoring program prescribed by 40 CFR § 146.33(b) must be designed to verify the absence of significant fluid movement.

Part VII, Section D.1 of the Class III Area Permit requires the use of cementing records to demonstrate that cement filling the borehole-well casing annulus contains no pathways that could allow fluid migration through the confining zone. The well construction requirements described in Section 7.0 are designed to ensure that the cement has been placed appropriately within the borehole-well casing annulus of each injection and production well to fulfill the external mechanical integrity demonstration. The EPA will review the well construction reports to evaluate whether the grout/cement placed within the borehole-well casing annulus is adequate for demonstration of external mechanical integrity.

Because the Class III Area Permit requires the use of cementing records to demonstrate external mechanical integrity, the monitoring requirements discussed in Section 12.0 are designed to verify the absence of significant fluid movement as required under 40 CFR § 146.8(c)(4). Specifically, design of the non-injection interval monitoring well system discussed in Section 12.4.2 and the monitoring requirements for non-injection interval wells discussed in Section 12.5.5.2.2 address this requirement.

8.2 Ongoing Demonstration of Mechanical Integrity

In addition to the initial testing after well construction, a mechanical integrity test is required to be conducted every five (5) years from the previous test and on any well following any repair after well workover which impacts the well casing or injection piping.

8.3 Loss of Mechanical Integrity

If the Permittee discovers that an active well does not meet the mechanical integrity testing criteria, Part VII, Section I of the Class III Draft Area Permit requires that the well be removed from service and shut-in within 48 hours. The casing may be repaired and the well re-tested, or the well may be plugged and abandoned. Well plugging requirements are described in Section 16.0. The Permittee must notify the Director when any active well loses mechanical integrity or fails a mechanical integrity test by following the reporting procedures described in Section 13.4. Injection operations must not be resumed until after the well has successfully been repaired and demonstrated mechanical integrity, and the Director has provided written approval to resume injection. If a repaired well passes the mechanical integrity test, it may be employed in its intended service following written approval from the Director. If an acceptable test cannot be demonstrated following repairs, the well will be plugged and abandoned according to the requirements under Part XI of the Class III Area Permit and replaced with a newly constructed well. A plugging and abandonment report is required for the old well under Part XI, Section D of the Class III Area Permit. The well construction report and initial mechanical integrity demonstration for the new well are required under Part V, Section G and Part VII, Section D.1 of the Class III Area Permit, respectively.

9.0 INJECTION WELL OPERATING CONDITIONS

9.1 Injection Pressure Limitation

Under 40 CFR § 146.33(a)(1), except during well stimulation, injection pressure at the wellhead must be calculated so as to assure that the pressure in the injection interval during injection does not initiate new fractures or propagate existing fractures in the injection interval. In no case should the injection pressure initiate fractures in the confining zone or cause the migration of injection or formation fluids into an underground source of drinking water. The fracture pressure is the pressure at which fluid injection is expected to create fractures, or to propagate existing fractures, within the receiving formation. The Maximum Allowable Injection Pressure (MAIP) is the permit limit that the injection pressure must not exceed. The Class III Area Permit sets the MAIP at 90% of the fracture pressure.

9.1.1 Determination of MAIP Based on Calculated Fracture Pressure

As discussed in Section 5.8.2, the fracture pressure for geologic units increases with depth because the pressure of overburden strata acts to resist fracturing of the geologic unit. The amount of change in fracture pressure with depth is expressed as a site-specific fracture gradient. The fracture gradient is a pressure value expressed in the units of psi/foot indicating that the fracture gradient is the change in pressure in psi exerted by the weight of the geologic units increasing with each foot of depth. As discussed in Section 5.8, Part II, Section J.1 of the Class III Area Permit requires the Permittee to conduct step rate tests to determine the fracture pressure in order to calculate the fracture gradient using the equation in Section 5.8.3.

As required under Part V, Section F of the Class III Area Permit, fracture pressure will be calculated using the fracture gradient values determined from the step rates test entered into the following formula:

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

FP = formation fracture pressure (psi)
fg = fracture gradient (psi/ft)
sg = specific gravity (of injected fluid)
d = depth to top well screen (ft)

The Depth values used in the equation must be the depth to the top of the well screen or the top of the open-hole interval, because that is the depth that injectate is entering the injection interval. This depth will be determined from the well logging information required under Class III Area Permit Part V, Section C and the well construction reports required under Class III Area Permit Part V, Section G and will correspond to the top of the uranium ore body targeted by the wellfield. The wellfield injection well and production well screened interval will be placed only within the ore body to increase the efficiency of lixiviant flow by restricting it to the ore interval.

The specific gravity value that will be used in the fracture pressure calculation is the equivalent of the maximum TDS estimated for the lixiviant listed in Table 19: 12,000 mg/L TDS, which is equivalent to a specific gravity of 1.009[9].

The MAIP for each injection well will be a pressure value set at 90% of the formation fracture pressure calculated for each injection well using the above formula. The pumps for the injection wells will be located where needed to maintain the injection pressure to move the barren lixiviant to the wellfields and to the injection wells. The Technical Report the Permittee prepared for the NRC license describes the booster pumps in Section 3.2.2 stating "a booster pump station may be required to achieve the required injection pressure; Booster pumps may be used . . . to convey barren lixiviant from the Satellite Facility or the Central Processing Plant to the well field. These pumps will be in-line centrifugal pumps, and will each have the capacity to pump 50 percent of the design flow. The pumps will be equipped with pressure indicators on the discharge lines, and a flow meter and flow indicator transmitter in the discharge line. Flow will be indicated both locally and in the control room located in the SF or CPP, respectively. The measured flow will be used to control pump motor speed via a variable frequency drive." As described in Section 9.1.3, the point at which the MAIP will be

[9] http://www.hamzasreef.com/Contents/Calculators/SalinityConversion.php

measured to determine compliance with the MAIP permit limit is at the injection trunkline pressure gauge at the header house.

Table 17 shows estimated Fracture Pressure and MAIP values for each wellfield. These values are not permit limits; they are shown to provide information only. The depth used in the fracture pressure calculations is the depth to the top of the proposed injection interval at the shallowest location within each wellfield where injection wells will be located. Because the geologic strata at the Dewey-Burdock Project Area are not flat, but dip to the southwest, an injection interval stratum occurs at different depths within a wellfield. The depth used in each wellfield fracture pressure calculation is the top of the injection interval at the drillholes indicated in Table 17. A fracture gradient of 0.70 psi/foot was used to estimate the Dewey-Burdock fracture pressure calculations shown in Table 17. This is the fracture gradient used by the Wyoming Department of Environmental Quality to calculate the fracture pressure for shallow injection wells. This value is appropriate to use for estimating the fracture gradient at the Dewey-Burdock Project Area, because it is located along the Wyoming/South Dakota border and has a geologic setting similar to that of eastern Wyoming. This calculation is only an estimation to provide an idea of and the actual fracture pressure might be at the location of each ISR wellfield. As discussed in Section 5.8, Class III Area Permit Part II, Section J.1 requires the Permittee to conduct step rate tests to determine site specific fracture pressures at locations discussed in Section 5.8.1 and required according to the Class III Area Permit Table 9. The site specific fracture pressures will be used to calculate the facture gradient at the Dewey and Burdock Areas as discussed in Section 5.8.3 of this document and required in Class III Area Permit Part II, Section J.2. This fracture gradient will be used to calculate the site-specific fracture pressure at each injection well location as required in Class III Area Permit Part V, Section F and discussed in this Section.

The drillholes listed in Table 4, from which the injection interval depths have been taken, have been included in Table 17. The drillholes are shown in the cross sections of Class III Permit Application Plates 6.13 through 6.21. Dewey Wellfield 4 is divided into 3 sections, as shown in Figure 4b; each section has a different calculated fracture pressure. Burdock Wellfields 1 and 6 include more than one injection interval. Each injection interval within these wellfields has a separate calculated fracture pressure.

Table 17. Estimated Fracture Pressure for Each Injection Interval Based on Depth to Top of Injection Interval

Wellfield	Injection interval Formation	Depth to Injection interval Top (ft below ground surface)	Fracture Pressure at injection interval top (psi)	Estimated MAIP (psig)
Burdock 1	Lower Chilson east end Middle Chilson west end	West-322' at FBS 192 East-385' at FBM 75	West-84 East-101	West-76 East-91
Burdock 2	Middle Chilson	435' at PS 43	114	103
Burdock 3	Upper Chilson	290' at FBM 75	76	68
Burdock 4	Middle Chilson	327' based on FBM 105	86	77
Burdock #5	Upper Chilson	455' at DB07-3-4	119	107
Burdock 6	Lower Chilson NE section Middle Chlilson middle section Lower Chilson SW section	NE-271' at DRA 15 Middle-290' at IHA 13 SW-345' at FBJ 16	NE-71 Middle-76 SW-90	NE-64 Middle-68 SW-81
Burdock 7	Lower Chilson	308' at DRM 48	81	72
Burdock 8	Middle Chilson	205' at TRT 70	53	48
Burdock 9	Middle Chilson	535' at KLA 9	140	126
Burdock 10	Lower Fall River	328' at SNF 17	86	77
Dewey 1	Lower Fall River	516' at ELR 60	135	122
Dewey 2	Middle and/or Lower Chilson	663' at DWA 74	174	157
Dewey3	Lower Fall River	530' at ELM 103	139	125
Dewey 4	Upper Chilson	West-707' at DWT 72 Middle-670' at DB08-32-11 East-567' at DWA 50	West-186 Middle-176 East-149	West-167 Middle-158 East-134

9.1.2 Alternative MAIP Set at Well Casing and Injection Pipe Operating Pressure

In the Dewey Area where the Chilson Sandstone injection intervals are greater than 500 feet deep, the Permittee may use well casing pipe or injection pipe or pipe fittings within the well casing that have a manufacturer-specified maximum operating pressure below the calculated fracture pressure based on the depth to the ore zone. In cases where the Permittee chooses to use well casing pipe or any well component with a manufacturer-specified maximum operating pressure below 90% of the calculated fracture pressure, the MAIP permit limit will be set at the lowest manufacturer-specified maximum operating pressure. In any case, fracture pressure must still be calculated using the equation under Section 9.1.1 as required by Part V, Section F.3 of the Class III Area Permit and the MAIP must be no higher than 90% of the calculated fracture pressure as required by Part V, Section F.4.

9.1.3 MAIP Compliance Point and Verification Test

As discussed in Section 7.10.3, Part VIII, Section E.1 of the Class III Area Permit provides the Permittee the option for setting the compliance point where MAIP must be measured for comparison to the permit limit at the header house manifolds instead of at each wellhead. To verify that injection pressure at each wellhead connected to a header house is lower than the injection pressure measured at the header house, Part VIII, Section E.2 of the Class III Area Permit requires an initial verification test when each header house is brought on line to demonstrate that manifold monitoring is comparable to individual well monitoring per 40 CFR part 146.23(b)(5). A description of the requirements involved in demonstrating how injection pressure monitoring at the header house manifold is equivalent to injection pressure monitoring at individual wellheads is included under Part V, I.1 and Part IX, Section E.5.

9.2 Hydraulic Wellfield Control

Part VIII, Section F of the Class III Area Permit requires the Permittee to maintain hydraulic control of each wellfield from the first injection of lixiviant through the end of groundwater restoration. During uranium recovery, the groundwater removal rate in each wellfield must exceed the lixiviant injection rate, creating a cone of depression within each wellfield and producing a wellfield *bleed*. Permit Application Section 7.1 states that ISR operation wellfield bleed rate will be 0.5 to 3% of the volume of lixiviant pumped from the wellfield through the production wells. The lowest bleed rate that maintains hydraulic control will be used to minimize the consumptive use of Inyan Kara groundwater. A higher bleed rate may be needed occasionally to maintain hydraulic control of the lixiviant within the wellfield. During groundwater restoration, the expected bleed rate will be 1.0% to 17% of groundwater removal rate in each wellfield. If there are any delays between uranium recovery and groundwater restoration for a wellfield, production wells will continue to be operated as needed to maintain the cone of depression within the wellfield extending to the injection interval perimeter monitoring well rings. Evidence of the cone of depression will consist of measuring the water level in the perimeter monitoring well ring to ensure it is maintained below baseline groundwater levels. Measurement of baseline water levels is discussed in the Class III Area Permit Part II, Section E.2.a, which is the requirement to measure initial aquifer potentiometric surfaces and again in Part VIII, Section C.2, which requires reevaluation of baseline water level measurements after the wellfield pump test in case initial potentiometric surface elevations have not been fully recovered before wellfield operation begins. The Permittee proposes to use pressure transducers or manual electronic meters to measure groundwater levels in injection interval perimeter monitoring well rings. Groundwater level measurements must be recorded twice a month and no more than 14 days apart during ISR operations and every 60 days during groundwater restoration as described in Section 12.5.5.2. During an excursion, Part IX, Section C.4.a of the Class III Area Permit requires weekly measurements of groundwater level measurements in injection interval wellfield perimeter monitoring well and non-injection interval monitoring wells impacted by the excursion. Part IX, Section C.4.c requires the Permittee to conduct weekly monitoring of the nearest injection interval monitoring wells that have not been impacted by excursion.

9.3 Anticipated Injection Flow Rate and Volume

The Class III Area Permit does not contain any permit limit on the injection flow rate or volume because limits on these parameters are not needed for the protection of USDWs. Part VIII, Section F of the Class III Area Permit requires the Permittee to maintain hydraulic control of each wellfield from the initiation of injection through the end of groundwater restoration. To do this, the Permittee must ensure that the groundwater removal rate in each wellfield exceeds the volume of injectate going into the wellfield. The result of this action is an inward hydraulic gradient directed toward the wellfield that will protect USDWs from migration of injected fluids. Verifying the cone of depression created by this inward hydraulic gradient by measuring groundwater levels in the wellfield perimeter monitoring well ring is a more direct method of monitoring hydraulic control than relying on a limitation of flow rate or volume. The purpose of the following discussion of injection flow rate and volume is to provide information about the volume of Inyan Kara groundwater lost from the aquifer system.

The Permittee estimates that the injection flow rates for individual Class III injection wells will range from approximately 5 to 30 gallons per minute (gpm). The project-wide injection flow rate will fluctuate depending on the number of wellfields undergoing uranium recovery and groundwater restoration. The project-wide injection flow rate is expected to increase from the onset of uranium recovery in the first wellfield through the period of concurrent uranium recovery and groundwater restoration. The Permittee expects that individual wellfield uranium recovery times will be about 2 years. It is possible that more than one wellfield in the Dewey and/or

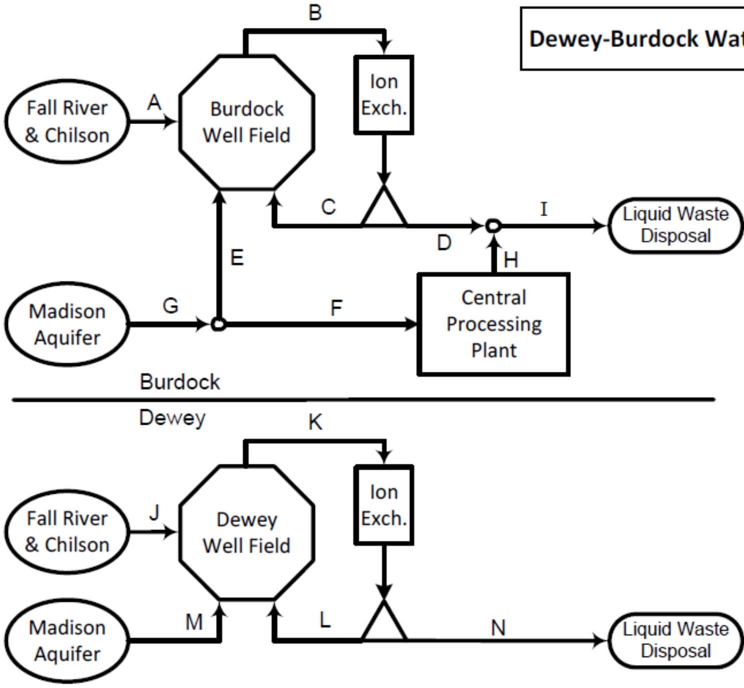
Burdock areas may be in the uranium recovery phase at any given time, if the Central Processing Plant or Satellite Plant have the treatment capacity. Groundwater restoration will be completed following uranium recovery in each wellfield. Therefore, concurrent uranium recovery and groundwater restoration is anticipated to begin approximately 2 years after initial wellfield operation. Permit Application Figure 10.2 depicts the anticipated project schedule.

Table 18 summarizes the anticipated project-wide flow rates with a maximum gross pumping rate of 8,000 gpm during concurrent uranium recovery at all active ISR wellfields and all wellfields conducting groundwater restoration. Although the maximum gross pumping rate from producing wellfields is currently set by NRC license conditions at a rate of 4,000 gpm, the Permittee may eventually request a license amendment from the NRC to increase the maximum allowable gross pumping rate to 8,000 gpm to provide operational flexibility. The production bleed during ISR operations is estimated to range from approximately 0.5% to 3%, but expected to be approximately 0.875% most of the time. At a maximum gross pumping rate of 8,000 gpm, the estimated injection rate would therefore range from about 7,760 to 7,960 gpm, but expected to be approximately 7,930 gpm most of the time. This demonstrates that the vast majority of water pumped from the injection interval will be reinjected, such that the net withdrawal rate will be only a small fraction of the gross pumping rate. The maximum anticipated gross pumping rate from wellfields undergoing groundwater restoration will be 500 gpm, with an expected restoration bleed of 1.0%. The expected injection rate for groundwater restoration, therefore, may range up to 495 gpm. The total estimated bleed during concurrent uranium recovery and groundwater restoration is estimated to be about 75 gpm, or about 0.88% of the maximum gross pumping rate of 8,500 gpm. The ISR operational bleed and restoration bleed may vary, but the total injection rate is not anticipated to exceed 8,500 gpm. The maximum amount of groundwater that will be lost from the Inyan Kara aquifer system is expected to be 75 gpm, the bleed amount.

Table 18. Anticipated Project-Wide Injection Flow Rates Corresponding to Maximum Anticipated Gross Pumping Rates and Bleed Rates (without Groundwater Sweep)

Operation Phase	Extraction Flow Rate (gpm)	Bleed (%)	Injection Flow Rate (gpm)	Bleed (gpm)
Uranium Recovery	8,000	0.875%	7,930	70
Groundwater restoration	500	1.0%	495	5
Concurrent Uranium Recovery and Groundwater restoration	8,500	0.88%	8,425	75

Figure 26 depicts the anticipated project-wide flow rates during concurrent uranium recovery and groundwater restoration. For injection, the key streams are identified as C, E, L, and M on Figure 26. Streams C and L represent the primary injection streams into the Burdock and Dewey wellfields, respectively. Streams E and M represent injection of makeup water from the Madison Limestone or another suitable aquifer.



Stream ID	Description
A	Burdock Aquifer Bleed
B	Burdock Extraction Composite
C	Burdock Reinjection
D	Burdock Well Field Bleed
E	Burdock Madison Make-up
F	Burdock Fresh Brine Make-up
G	Burdock Madison, Total
H	Burdock CPP Brine
I	Burdock Liquid Waste
J	Dewey Aquifer Bleed
K	Dewey Extraction Composite
L	Dewey Reinjection
M	Dewey Madison Make-up
N	Dewey Liquid Waste

Water Balance Flow Rates (gpm)											
Operation Phase	**Aquifer Bleed Options**	**Disposal Option**	**Burdock Stream ID**								
			A	**B**	**C**	**D**	**E**	**F**	**G**	**H**	**I**
Recovery	0.875%	Deep Disposal Wells	42	4800	4758	42	0	12	12	12	54
		Land Application	42	4800	4758	42	0	12	12	12	54
Restoration	Without Groundwater Sweep	Deep Disposal Wells	2.5	250	175	75	73	0	73	0	75
		Land Application	2.5	250	0	250	247.5	0	247.5	0	250
	With Groundwater Sweep	Deep Disposal Wells	42	250	175	75	33	0	33	0	75
		Land Application	42	250	0	250	208	0	208	0	250

Water Balance Flow Rates (gpm)							
Operation Phase	**Aquifer Bleed Options**	**Disposal Option**	**Dewey Stream ID**				
			J	**K**	**L**	**M**	**N**
Recovery	0.875%	Deep Disposal Wells	28	3200	3172	0	28
		Land Application	28	3200	3172	0	28
Restoration	Without Groundwater Sweep	Deep Disposal Wells	2.5	250	175	73	75
		Land Application	2.5	250	0	247.5	250
	With Groundwater Sweep	Deep Disposal Wells	42	250	175	33	75
		Land Application	42	250	0	208	250

Figure 26. Anticipated Project-Wide Flow Rates during Uranium Recovery and Groundwater Restoration

During uranium recovery, the sum of C and L is expected to be 7,930 gpm, which matches the project-wide value in Table 18. During groundwater restoration, if land application is the waste fluid disposal method, the sum of C, E, L and M is expected to be 416 to 495 gpm. If deep well injection is the waste fluid disposal method, the sum of C, E, L and M is expected to also be 416 to 495 gpm. The lower value corresponds to the optional use of groundwater sweep. The groundwater sweep involves no injection into the wellfield, only pumping groundwater out of the wellfield, pulling in clean water from the surrounding aquifer. The cumulative injection flow rate at the maximum gross pumping rate of 8,500 gpm, the expected ISR operational bleed rate of 0.875%, and no groundwater sweep, will be about 8,425 gpm, which matches the value shown in Table 1.

9.4 Approved Injection Fluid

9.4.1 Injection Fluid Composition

The following types of fluids may be injected into the wellfields.

1) During uranium recovery, lixiviant consisting of injection interval groundwater fortified with oxygen and carbon dioxide will be injected into the wellfields.
2) During post-ISR groundwater restoration, reverse osmosis permeate (clean water from the reverse osmosis treatment process) clean makeup water from the Madison Formation or another suitable aquifer will be injected into wellfields 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.

9.4.2 Lixiviant Description

Because the lixiviant will be composed mainly of injection interval groundwater, before operations begin it will be the same as the Fall River or Chilson groundwater quality, except for the higher oxygen and carbon dioxide. A summary of Fall River groundwater analytical results can be found in Permit Application, Appendix N, pages N-7 and N-8; a summary of Chilson groundwater analytical results can be found in Permit Application, Appendix N, pages N-11 and N-12 and Permit Application Table 17.5.

The dissolved oxygen is added to the lixiviant to oxidize the solid-phase uranium to a soluble valence state. The carbon dioxide is added to form a complex with the soluble uranium ions so they remain in solution as the uranium-bearing lixiviant is transported through the ore body.

Because the injection interval groundwater is recycled a number of times through the ion exchange process to remove uranium, then refortified with oxygen and carbon dioxide before injection back into the wellfield, it will, over time, increase in total dissolved solids and dissolved metals from the ore deposit. Table 19 describes the anticipated range of concentrations for various constituents in the lixiviant injected during uranium recovery.

Table 19. Anticipated Lixiviant Chemistry

Constituent	Units	Concentration Range	
		Minimum	Maximum
Sodium	mg/L	≤400	6,000
Calcium	mg/L	≤20	500
Magnesium	mg/L	≤3	100
Potassium	mg/L	≤15	300
Carbonate	mg/L	≤0.5	2,500
Bicarbonate	mg/L	≤400	5,000
Chloride	mg/L	≤200	5,000
Sulfate	mg/L	≤400	5,000
Uranium	mg/L	≤0.01	<2
Vanadium	mg/L	≤0.01	100

TDS	mg/L	≤1,650	12,000
pH	Standard units	≤6.5	10.5

Source: Table 7.2 in Class III Permit Application

9.4.3 Groundwater Restoration Permeate or Clean Water

As discussed below under Section 11.0, Groundwater Restoration, if the UIC Class V deep injection wells are used for the disposal of ISR process waste fluids, it will be possible to use reverse osmosis to treat the groundwater extracted from the wellfields during groundwater restoration. The reverse osmosis treatment process removes 90% of the dissolved constituents from the groundwater and produces clean permeate which meets drinking water standards. The permeate will be reinjected back into the wellfield.

10.0 AQUIFER EXEMPTION OF INYAN KARA AQUIFERS

10.1 Criteria for Aquifer Exemption

In conjunction with this Class III Area Permit, the EPA is proposing the exemption of the Inyan Kara Group Fall River Formation aquifer and the Lakota Formation Chilson Sandstone aquifer in the 14 proposed wellfield areas under the criteria at 40 CFR § 146.4(a) and (b)(1). Under this criteria, the EPA has determined that the Inyan Kara aquifers:

1) do not currently serve as a source of drinking water and
2) cannot now and will not in the future serve as a source of drinking water because it is mineral, hydrocarbon or geothermal energy producing, or can be demonstrated by a permit applicant as part of a permit application for a Class II or III operation to contain minerals or hydrocarbons that considering their quantity and location are expected to be commercially producible.

After evaluating the information submitted in Section 17.0 of the Class III Permit Application associated with this aquifer exemption request, the EPA has determined that the Permittee provided sufficient information to meet the Federal criteria for the exemption of the Inyan Kara aquifers. For a more detailed discussion of the information addressing the Federal criteria, see the EPA Dewey-Burdock Aquifer Exemption ROD that is a part of the Administrative Record for this EPA UIC permitting action.

10.2 Options for Aquifer Exemption Approval

As discussed in the Aquifer Exemption ROD document, the Permittee identified one private drinking water well inside the proposed aquifer exemption boundary. Well ID 16 is the only well located within the proposed AE boundary that has used the Inyan Kara groundwater for drinking water. No record of this well was found in the South Dakota water well databases. The Permittee found information for this well in TVA records indicating that the well is 330 feet deep. Based on that depth, the well is completed in the Chilson Sandstone and is therefore drawing groundwater from within the Inyan Kara aquifer in the area proposed for exemption.

The Permittee analyzed the groundwater produced from well 16 and found radium and gross alpha are above the primary drinking water standards, and radon is also high. Once the well owner understood the risks of using the groundwater from well 16 for human consumption and for indoor use, the Permittee set up an agreement with the well owner that removed the well from drinking water use and supplied bottled water as drinking water to the well owner. The Permittee disconnected the well from the residence by removing the pipeline between the well and the residence. The well will continue to be used for stock water until the Permittee begins ISR operations. The Permittee submitted a Water Well Completion Report to the South Dakota State Engineer which classifies the current well use as stock watering. Under South Dakota regulation found at Chapter 46-1. Definitions and General Provisions, section 46-1-6, Definition of terms, (7) Domestic Use includes stock watering as well as drinking water for human consumption. Based on this regulatory definition, the well is still legally classified for use as a drinking water well under South Dakota regulations. Therefore, classifying the well as a stock watering well does not legally exclude the well from potentially supplying human drinking water. Because of the lack of distinction between a stock watering well and a drinking water well under South Dakota regulations, the EPA cannot make a definitive legal determination that well 16 does not currently supply Inyan Kara groundwater for use as drinking water for human consumption.

Because the Permittee plans to use well 16 as a monitoring well during wellfield pump testing and ISR operations, the Permittee has the option of submitting a South Dakota Water Well Completion Report to classify well 16 as a monitoring well. Under South Dakota regulation 74:02:04:20 (34), the definition of a monitoring well is “a cased well used for measuring groundwater levels or collecting water samples,” which would no longer include the well use under the legal definition of domestic well. The EPA acknowledges that a legal definition does not prevent a person from drinking water from well 16. However, the current well owner is aware of the risks of future use of well 16 for drinking water and indoor use. The Permittee will attach documentation to the South Dakota Water Well Completion Report stating that 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 radon levels are high enough that indoor use should be avoided. The South Dakota State Engineer’s office will include this information in the well files for future well owners to access. The EPA also acknowledges that plugging and abandoning well 16 is the best way to prevent the well from being used for drinking water. However, the well is needed for stock watering until the Permittee installs an alternative water source.

The EPA is offering and requesting comment on three options for approval of the AE area based on the status of well 16:

Option 1 includes approval of the AE area shown in Figure 27, excluding Burdock Area Wellfields 6 and 7 shown in blue. The Permittee may request the exemption of Burdock Wellfields 6 and 7 once Well 16 is plugged and abandoned after the alternative water supply is in place. Both Burdock Wellfields 6 and 7 are being excluded from this option because it appears that the southeastern end of Burdock Wellfield 7 partially overlaps the northeast end of Burdock Wellfield 6 in the area of Well 16 as shown in Figure 27.

Option 2 allows the Permittee to plug and abandon well 16 before the issuance of the final AE Record of Decision. After well 16 has been plugged and abandoned, the EPA will be in a position to determine that the groundwater within the AE boundary for Burdock Wellfields 6 and 7 is not a current source of drinking water and can approve the portion of the AE area shown in blue in Figure 27 as part of the final AE Record of Decision.

Option 3 allows the Permittee to submit a South Dakota Water Well Completion Report to classify well 16 as a monitoring well and attach documentation stating that 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 radon levels are high enough that indoor use should be avoided. With Option, the EPA will be in a position to determine that the groundwater within the AE boundary for Burdock Wellfields 6 and 7 is not a current source of drinking water and can approve the portion of the AE area shown in blue in Figure 27 as part of the final AE Record of Decision.

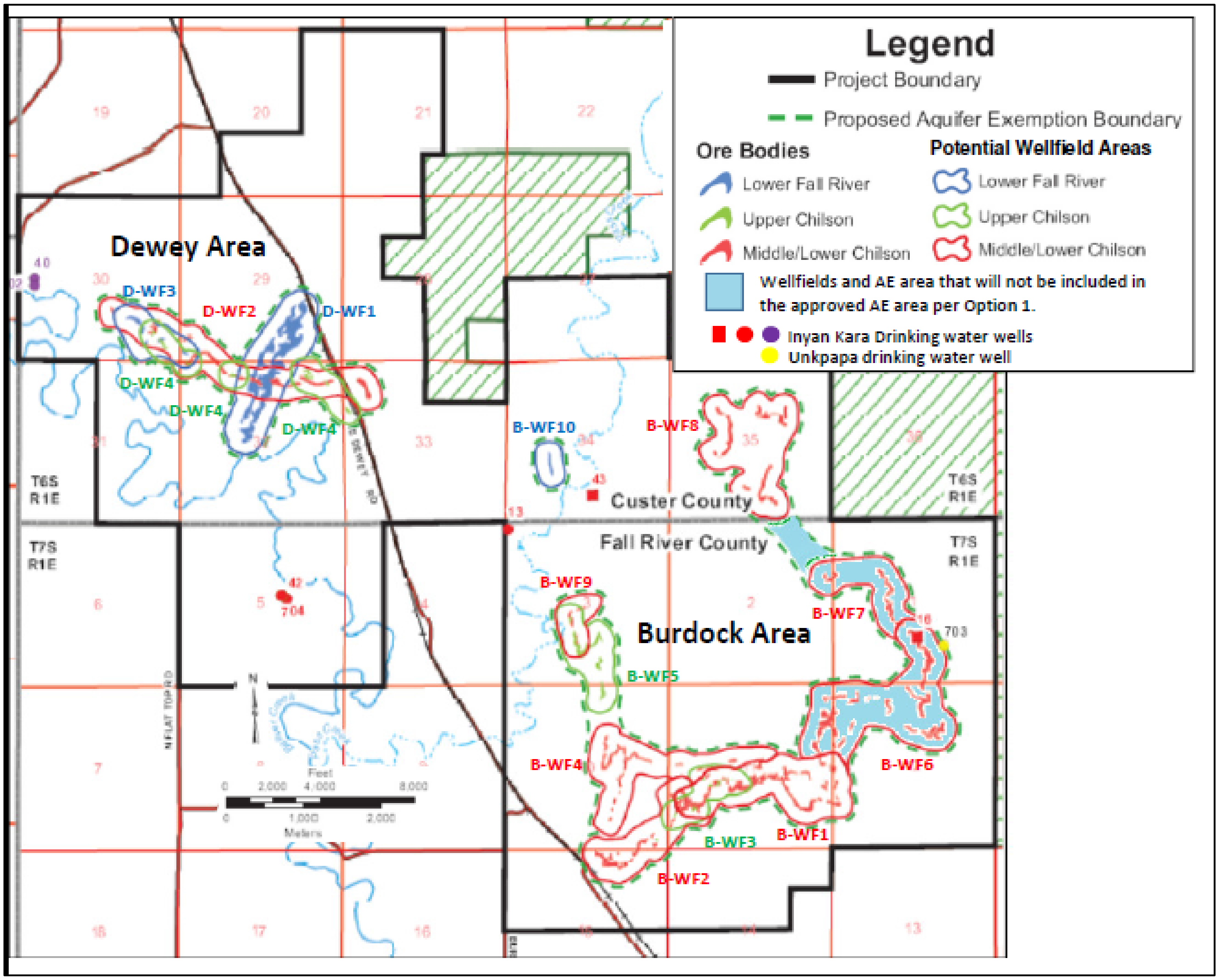


Figure 27. Option for Aquifer Exemption Approval Excluding Burdock Wellfields 6 and 7.

11.0 GROUNDWATER RESTORATION

Groundwater quality in the injection interval will be degraded during ISR operations by the injection of the lixiviant into the uranium ore bodies. After uranium recovery is complete in each wellfield the groundwater restoration process begins. As required under the NRC license, the Permittee must initiate groundwater restoration activities to restore the injection interval to NRC-approved baseline water quality limits, drinking water standards (Maximum Contaminant Levels or MCLs) or NRC-approved alternative water quality limits (Alternative Concentration Limits or ACLs) for the baseline water quality constituents listed in Table 14.2 of the Class III Permit Application. Once the target concentrations are met within the wellfield, a period of restoration stability monitoring occurs during which the groundwater quality within the wellfield is monitored to confirm that the constituent concentrations do not increase above the target restoration goals. The Permittee proposes conducting restoration stability monitoring for a minimum of one year at each wellfield. The NRC license requires the Permittee to conduct restoration stability monitoring until the data show that the most recent four consecutive quarters indicate no statistically significant increasing trend for all constituents of concern that would lead to an exceedance above the respective standard in 10 CFR Part 40, Appendix A, Criterion 5B(5). The NRC approves wellfield restoration once it is complete.

Part IV, Section D of the Class III Area Permit requires the Permittee to develop a Wellfield Closure Plan that is based on the Conceptual Site Model required in Part IV, Section A and reactive transport geochemical modeling required in Part IV, Section B. The purpose of the geochemical modeling is to evaluate the potential for ISR contaminants to cross the aquifer exemption boundary into the surrounding USDWs. Part IV, Section C of the Class III Area Permit includes requirements to calibrate the geochemical model for each wellfield based on site-specific sampling and analysis of the geochemical and water quality information acquired according to the specifications in the Conceptual Site Model. The Conceptual Site Model includes monitoring requirements that are tied to the timing of groundwater restoration and stability monitoring phases as discussed under Section 12.6.4. The Wellfield Closure Plan shall demonstrate that the wellfield closure, including plugging and abandonments of all wellfield injection and production wells, will result in adequate protection of USDWs as required under 40 CFR § 146.10(a)(4). The Director will determine whether the Wellfield Closure Plan provides adequate protection based on site specific information, such as the nature and concentration of any residuals, the hydrogeology of the aquifer, the economic and technical feasibility of cleanup actions, the proximity of water wells, and the number of people relying on the USDW down-gradient from the mining site. If the Wellfield Closure Plan does not demonstrate adequate protection of USDWs, the Director shall prescribe aquifer cleanup and monitoring where he deems it necessary and feasible to insure adequate protection of USDWs to fulfill the requirements under 40 CFR § 146.10(4).

12.0 MONITORING REQUIREMENTS

Table 20 lists the types of monitoring required by the Class III Area Permit.

Table 20. Required Monitoring

Type of Monitoring	Purpose	Permit Section
Continuous monitoring of injection pressure	To ensure that injection activity does not create new fractures or propagate existing fractures in the confining zones or injection interval.	Part IX, Section B.1.b
Continuous monitoring of injection and production flow rates and volumes	To ensure that the amount of groundwater pumped from each wellfield is greater than the volume injected so than an inward hydraulic gradient is maintained	Part IX, Section B.1.c and d
Injectate Analysis	To monitor constituents injected into the injection interval	Part IX, Section B.1.g
Excursion Monitoring	To ensure that injection interval fluids do not migrate horizontally or vertically out of the injection interval	Part IX, Section C
Operational monitoring	To monitor selected domestic, stock and monitoring wells outside of the wellfield monitoring system to ensure that groundwater quality is not impacted by ISR operations	Part IX, Section B.3
Ongoing Demonstration of Mechanical Integrity	To demonstrate that wellfield injection and production wells have mechanical integrity	Part VII, Sections B and G
Seismic activity	To determine if injection activities increase the level of seismic activity in the area.	Part IX, Section D

12.1 Injection Pressure Monitoring

The Class III Area Permit requires continuous monitoring of injection pressure. Injection pressure must be recorded daily at a pressure gauge installed at each header in front of the injection manifold of each header house injection trunkline. Average, minimum and maximum injection pressure will be determined for each month and reported quarterly.

As discussed in Section 9.1.1 the MAIP will be established on a header house basis as a Class III Area Permit requirement after the drilling and logging of each injection and production well determines the depth to the ore zone. In the wellfield areas where the depth to the ore is greater than 500 feet, the well casing or injection piping manufacturer’s recommended operating pressure may be used to establish the MAIP permit limit. Wells with similar injection pressure will be connected to the same header house. A MAIP will be designated as the permit limit for each header house based on the well with the lowest MAIP connected to the well house. The designated MAIP will be posted near the injection trunkline pressure gauge used to monitor injection pressure. There will also be a pressure sensor installed in the injection line of each header house. If the injection pressure reaches the maximum set value in the pressure switch, the header house will automatically shut down. This practice will ensure the injection formation fracture pressure is not exceeded according to 40 CFR § 146.33(a)(1).

As discussed under Section 7.10.4, the Permittee must install automated control and data recording systems at the Burdock Central Processing Plant and the Dewey Satellite Facility which will provide centralized monitoring and control of the process variables including the injection pressure in each header house. Injection pressures must be monitored continuously through automated control and data recording systems that will include alarms and automatic controls to detect and control a potential release such as would occur through an injection well casing failure (see Section 14.2). With the required system design, if pressures or flows fluctuate outside of normal operating ranges, alarms will provide immediate warning to operators which will result in a timely response and appropriate corrective action. Pressure gauges installed at each injection wellhead or at the injection manifold must also be manually recorded at least daily.

12.2 Injection and Production Flow Rate and Volume

The Class III Area Permit requires continuous monitoring of the injection and production flow rates for each wellfield. The injection and production flow rates must be recorded daily at flow gauges located at the injection and production trunklines for each wellfield at the Burdock Central Processing Plant and the Dewey Satellite facility, or another representative location, to ensure that a greater volume of groundwater is being pumped out of each wellfield than is being reinjected back into the wellfield, which creates an inward hydraulic gradient directed toward the wellfield. The inward hydraulic gradient is manifested as a cone of depression in the potentiometric surface of the injection interval aquifer and demonstrates hydraulic control of the injection interval fluids. If the Permittee selects another location to locate the flow gauges, the locations must be included in the Injection Authorization Data Packages and provide information that is representative of the flow rate and volumes being measured in compliance with 40 CFR § 144.51(j)(1).

12.3 Injection Fluid Monitoring

The Class III Area Permit requires monitoring of injectate chemistry and physical properties listed in Table 21. The injection fluid in each operating wellfield must be sampled monthly. Samples must be collected from the injection trunklines conveying the injectate from the Burdock Central Processing Plant and the Dewey Satellite facility to the wellfield header houses, or another representative location. Other representative injectate sampling locations must yield samples that are representative of the lixiviant in compliance with 40 CFR § 144.51(j)(1). During uranium ISR operations the injectate is limited to lixiviant which will be sampled before it is fortified with oxygen and carbon dioxide at the header houses. During groundwater restoration, the injectate is limited to treated groundwater which is not fortified with oxygen or carbon dioxide before injection.

Sample collection, sample preservation and sample handling procedures must be conducted according to the requirements found in 40 CFR part 136 Table II – *Required Containers, Preservation Techniques, and Holding Times*. Samples must be submitted to an EPA-certified laboratory and analyzed for the parameters in Table 21. The injectate samples must be collected in a manner that allows them to be analyzed using the methods shown in the Table 21 or other equivalent methods approved by the Director in advance. The analytical results must be reported to the Director quarterly as part of the Quarterly Monitoring Report.

Table 21. Injection Fluid Characterization Parameters

Test Analyte/Parameter	Units	Analytical Method
Physical Properties		
pH (field and laboratory)	pH units	A4500-H-B
TDS (laboratory only)	mg/L	A2540 C
Specific conductance	mmhos/cm	A2510B or E120.1

Specific Gravity	Ratio to density of water	ASTM D1429-13, SM 2710F
Common Elements and Ions		
Total Alkalinity (as $CaCO_3$)	mg/L	A2320 B
Chloride, Cl^-	mg/L	A 4500-Cl B; E300.0
Sulfate, SO_4	mg/L	A 4500-SO_4 B; E300.0
Dissolved Metals		
Arsenic (As)	mg/L	200.7, 200.8, 200.9
Iron (Fe)	mg/L	200.7
Lead (Pb)	mg/L	200.8, 200.9
Manganese (Mn)	mg/L	200.8
Selenium (Se)	mg/L	200.8, 200.9
Strontium (Sr)	mg/L	200.8
Uranium (U)	mg/L	200.7, 200.8
Vanadium (V)	mg/L	200.7, 200.8
Radiological Parameters		
Gross Alpha	pCi/L	E900.0
Radium-266	pCi/L	E903.0
Radium-268	pCi/L	E904.0

12.4 Monitoring Network

12.4.1 Injection Interval Wellfield Perimeter Monitoring Wells

Monitoring wells completed in the injection interval must be positioned around the perimeter of each wellfield as illustrated in the diagram of the Dewey Wellfield 1 in Figure 28. The perimeter monitoring well ring serves two purposes:

1) to monitor any horizontal migration of excursion indicators outside of the injection interval and
2) to monitor the cone of depression verifying hydraulic control of injection interval fluids.

Perimeter monitoring wells must be located no farther than 400 feet from the edge of the wellfield. The perimeter monitoring wells will be distributed along a ring surrounding the wellfield with a maximum spacing between them of either 400 feet or the spacing that will ensure a minimum of 70-degree angle between adjacent perimeter monitoring wells and the nearest injection well as illustrated in Figure 28. This maximum distance is based on and consistent with standard monitoring practices at operating ISR facilities. This distance is also supported by site-specific data and evaluation through the numerical groundwater flow modeling the Permittee submitted to NRC in support of the license application. The numerical groundwater flow modeling results demonstrate the maximum perimeter monitor ring spacing of 400 feet is adequate to detect an excursion and that an excursion can be controlled.

Monitoring wells in the perimeter monitoring well ring must be screened across the entire thickness of the ore zone between the two operational confining zones (discussed in Section 3.4.4), which will be determined following completion of delineation drilling for each wellfield required under Part II, Section B of the Class III Area Permit. As described in Section 3.4.2, the Fuson Shale is pervasive throughout the Project Area and forms a confining zone between the Fall River and Chilson. No monitoring well will be screened across the Fuson Shale, because that would cause a breach in the Fuson confining zone. Prior to initiating ISR operations in each wellfield, the Permittee must conduct pre-operational pump tests to confirm that the perimeter monitoring wells are hydraulically connected to the wellfield injection and production wells as discussed earlier. The pre-operational pump tests will also evaluate the degree to which the local confining zones are effective in limiting the flow of lixiviant vertically to the ore-bearing injection interval and horizontally to the wellfield.

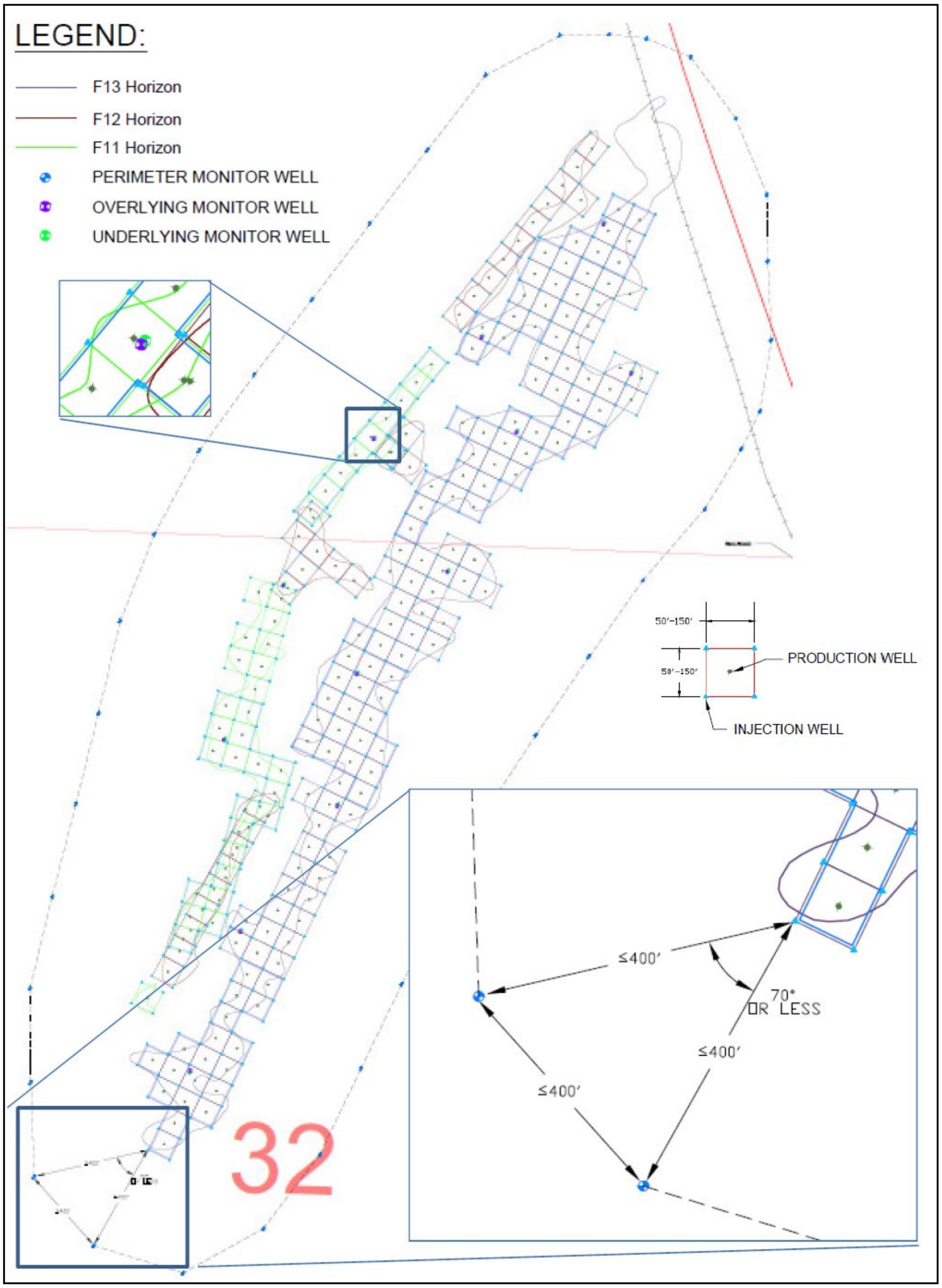


Figure 28. Proposed Wellfield Design Showing the Location of Injection and Production Wells Relative to Ore Body Distribution and the Location of the Injection Interval Perimeter Monitoring Well Ring and Non-injection Interval Monitoring Wells in Overlying and Underlying Aquifers.

12.4.2 Non-Injection Interval Monitoring wells

Part II, Section D of the Class III Area Permit sets the criteria for design and installation of the overlying and underlying monitoring well systems that are effective at detecting potential vertical excursions. Non-injection interval monitoring wells must be completed within each aquifer overlying the injection interval aquifer and within the first underlying aquifer, except when the injection interval is the Lower Chilson. The underlying aquifer for the Lower Chilson injection interval is protected by the Morrison Formation which is a thick, competent confining zone. No monitoring wells are proposed in the aquifer underlying the Morrison Formation as discussed in Section 3.4.3 and Section 5.2. As required under Part IX, Section B.2 of the Class III Area Permit, the overlying and underlying monitoring wells will be used to obtain baseline water quality data for the overlying and underlying zones for use in detecting a vertical migration of lixiviant. The screened intervals for the overlying and underlying monitoring wells will be determined from the logging information from the delineation drillholes and wellfield pump test wells required under Part II, Section B of the Class III Area Permit and documented in the well construction reports required under Part V, Section G and Part IX, Section E.4 of the Class III Area Permit.

As discussed under Corrective Action in Section 6.0, if there is a breach in a confining zone that cannot be repaired, the UIC regulations at 40 CFR § 144.55(b)(4) allows operational controls to suffice as corrective action but requires that the monitoring program be designed to verify that hydraulic control of injection interval fluids is maintained. To accomplish this, additional overlying or underlying monitoring wells will be required beyond the minimum density specified below to verify that the lixiviant is being contained within the injection interval. Following sections describe each of the non-injection interval monitoring well types.

12.4.2.1 Overlying Monitoring Wells

The overlying monitoring wells will be designed to provide detection of any upward movement of injection interval fluids that may occur from a breach in the overlying confining zones such as potential leakage through a production, injection or monitoring well casing or annulus into any overlying aquifer.

Part II, Section D.4.b of the Class III Area Permit requires the Permittee to install monitoring wells in all aquifer units overlying the injection interval. The Permittee proposes designating identification numbers for monitoring wells completed in the first overlying aquifer unit with the prefix MO. These wells will have a density of at least one well per 4 acres of wellfield pattern area. Identification numbers for monitoring wells completed in subsequent overlying aquifer units will be designated with prefixes MO2, MO3, etc. and will have a density of at least one well per 8 acres of wellfield pattern area.

As discussed in Section 3.4.4, local confining zones within the Fall River or Chilson will be utilized as the operational confining zones in the wellfield monitoring scheme. The presence and horizontal continuity of these local confining zones will be confirmed with delineation drilling and logging and mapped in more detail in the process of developing each Injection Authorization Data Package Report (refer to Section 5.6). These local confining zones will serve to direct horizontal flow within the injection interval aquifer between the injection and production wells. Wellfield pump tests will verify that these local confining zones are continuous enough to allow a cone of depression to form in the injection interval around the wellfield to control injection interval fluids within the wellfield. Figure 29 and Figure 30 depict the conceptual monitoring schemes for the initial Burdock and Dewey wellfields, respectively. The following is a brief summary of the conceptual monitoring well layouts. Note that additional monitoring wells may be installed as needed.

For Burdock Wellfield 1 (Figure 29, left half), the anticipated injection interval is the Middle and/or Lower Chilson and the Morrison Formation is the lower confining zone. Since the injection interval is anticipated to be in the lowermost aquifer unit above the Morrison Formation, no monitoring is required in the underlying aquifer unit (Unkpapa) as discussed in Section 3.4.3 and Section 5.2. The cross section in the left half of Figure 29 shows the monitoring well configuration at eastern end of Burdock wellfield 1 looking toward the west, where the ore is in the Lower Chilson and the Middle Chilson is thin, as seen at the A' (eastern) end of Plate 6.13 Cross Section A-A'. Monitoring wells must be installed in the first overlying aquifer unit, the Middle Chilson in this location, for approximately the eastern one-third of Burdock Wellfield 1. The minimum density of monitoring wells in the first overlying aquifer above the injection interval is one well per 4 acres. Monitoring wells must be installed in all other overlying aquifer units with a minimum density of one well per 8 acres. This includes the Upper Chilson, Lower and Upper Fall River, and alluvium (where present).

For Burdock Wellfield 3 (the right half of Figure 29), the anticipated injection interval is the Upper Chilson. In this case the immediately overlying aquifer unit would be the Lower Fall River Formation in which monitoring wells must be completed at a minimum density of one well per 4 acres. Other overlying aquifer units must be monitored at a minimum density of one well per 8 acres, including the Upper Fall River and alluvium (where present). The first underlying aquifer unit is the Middle Chilson in which monitoring wells must be completed at a minimum density of one well per 4 acres.

For Dewey Wellfield 1 (the left third of Figure 30), the anticipated injection interval is the Lower Fall River. In this case overlying aquifer units would only include the Upper Fall River and alluvium (where present). The first underlying aquifer unit would be the Upper Chilson. Similar monitoring configurations are shown for Dewey Wellfields 2 and 4 in Figure 30.

Within one injection interval aquifer, there may be ore bodies that are vertically stacked with no substantial or continuous confining layers between the ore bodies. In these areas, the monitoring wells in the perimeter monitoring well ring would be screened across the full thickness of the stacked ore bodies and the ore bodies treated as a single injection interval. An example of this situation is Dewey Wellfield 1 where ore bodies occur at different levels within the Lower Fall River without continuous intervening shale layers to act as confining zones. The ore zones at different levels are represented in Figure 28 by ore bodies outlined in different colors: the F11 ore horizon is outlined in green; the F12 ore horizon is outlined in brown and the F13 ore horizon is outlined in black. The perimeter monitoring wells will be screened through the entire Lower Fall River as shown in Figure 30.

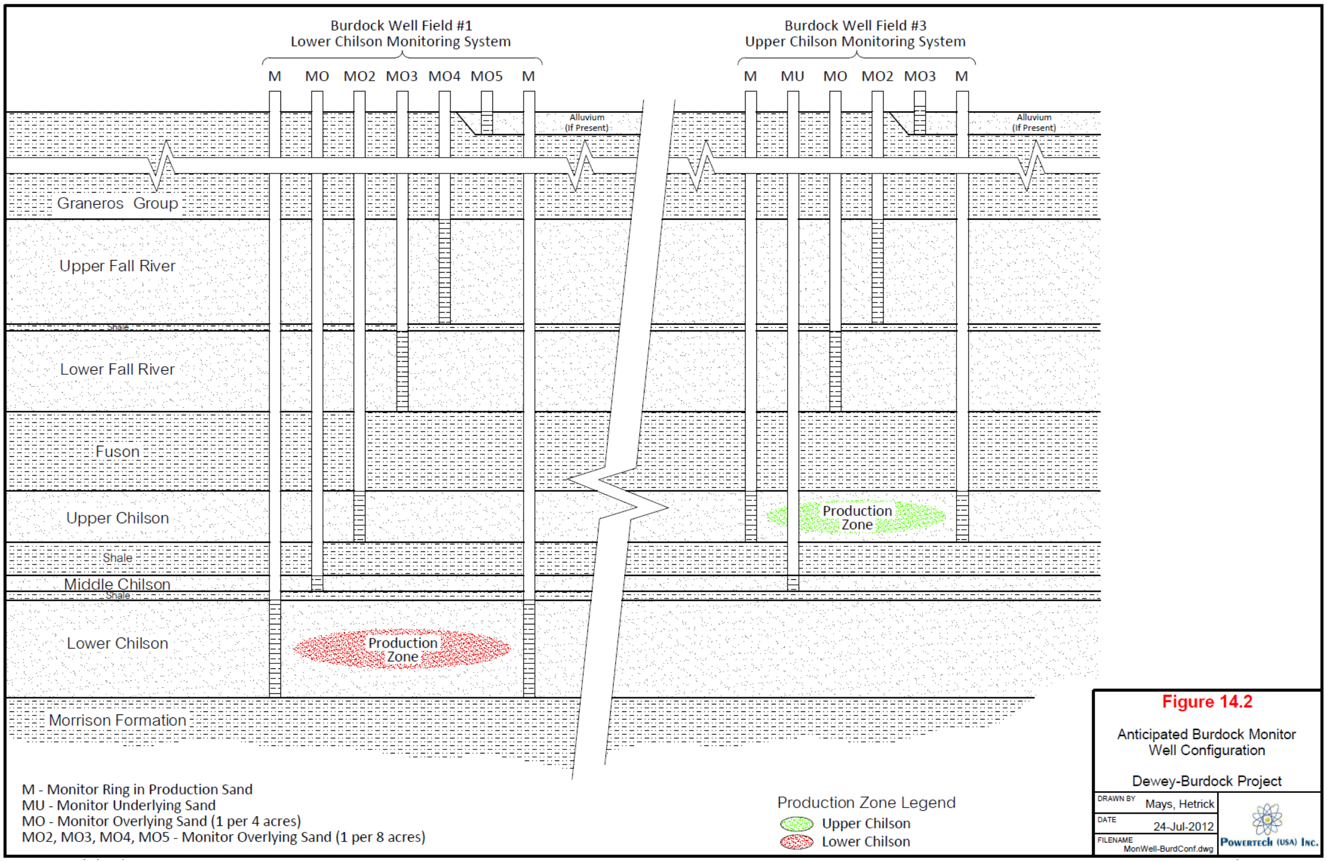


Figure 29. Example of Anticipated Burdock Monitoring Well Configuration

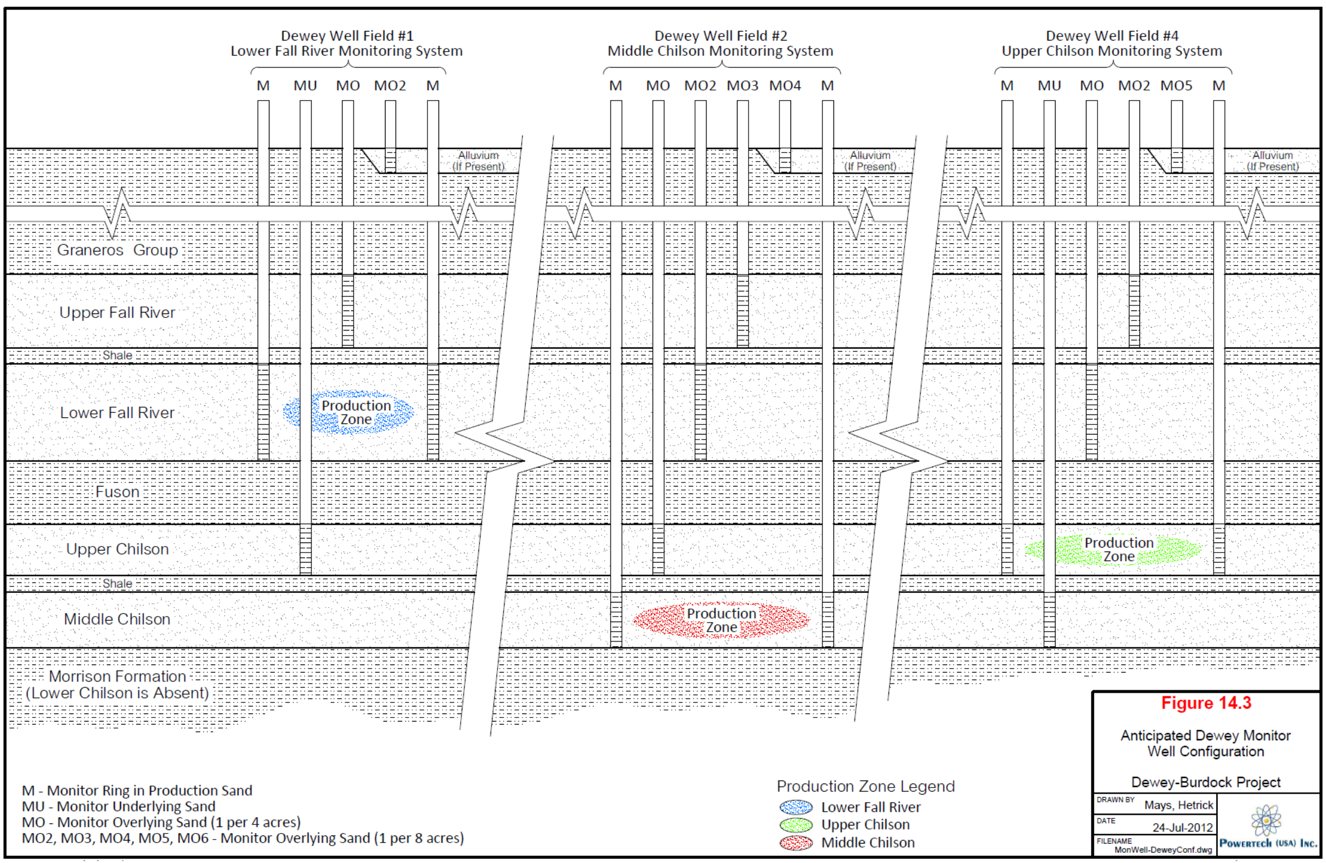


Figure 30. Example of Anticipated Dewey Monitoring Well Configuration

12.4.2.2 Underlying Monitoring wells

Part II, Section D.4.c of the Class III Area Permit requires the Permittee to install monitoring wells in all aquifer units underlying the injection interval. The underlying monitoring wells must be designed to provide monitoring of any downward movement of ISR solutions from the injection interval. The Permittee proposes designating the identification numbers for monitoring wells completed in the first underlying aquifer unit with the prefix MU. These wells must have a density of one well per 4 acres of pattern area. The Class III Area Permit requires that only the first underlying aquifer unit is monitored, unless the injection interval is the Lower Chilson. No monitoring of the underlying aquifer is required below the Morrison Formation confining zone as discussed in Section 3.4.3 and Section 5.2.

12.5 Excursion Monitoring

12.5.1 Definition of Excursion

"Excursion" is a term used by the NRC and is not a term defined under UIC Program regulations. As described by NUREG-1910, Supplement 1, "An excursion is defined as an event where a monitoring well in the overlying, underlying, or perimeter well ring detects an increase in specific water quality indicators, usually chloride, specific conductance and total alkalinity, which may signal that fluids are moving out from the wellfield …." The occurrence of an excursion is not a violation of the Class III Area Permit unless it involves contaminants crossing the aquifer exemption boundary into a USDW. The purpose of excursion monitoring is the early detection of incipient loss of control of injection interval fluids so that control may be regained before any contamination reaches the aquifer exemption boundary.

12.5.2 Excursion Indicators

The specific water quality indicators used to determine if an excursion has occurred are called *excursion indicators*. Excursion indicators are constituents that occur in the lixiviant that are highly mobile in groundwater and not influenced significantly by pH changes or oxidation-reduction reactions. Excursion indicators ideally do not interact chemically with the aquifer mineralogy and, therefore, act as conservative tracers. These indicators travel along with groundwater flow more rapidly that other lixiviant constituents that are affected by pH changes, oxidation-reduction reactions and/or interaction with the aquifer mineralogy. As a result, excursion indicators are capable of providing early indication of a potential excursion. The excursion indicators that will be used at the Dewey-Burdock Project Area are chloride, specific conductance (also called conductivity) and total alkalinity and are commonly used excursion indicators at uranium ISR sites.

12.5.3 Establishing Upper Control Limits for Excursion Indicators

A maximum concentration value must be established for each excursion indicator that serves as the threshold concentration that, if exceeded in a monitoring well, indicates the well has been impacted by lixiviant migrating outside the wellfield injection interval. This threshold concentration is known as an Upper Control Limit (UCL). According to the NRC Safety Evaluation Report, to calculate UCLs, the Permittee will collect four groundwater samples from all monitoring wells twice a month and no more than 14 days apart and analyze the samples for the parameters shown in Safety Evaluation Report Table 5.7-2. Table 13 in this Fact Sheet is similar to Safety Evaluation Report Table 5.7-2 except for additional analytes included in Table 13 as discussed in Section 5.3.3. The parameters in Table 13 will be used to develop a reactive transport geochemical model to evaluation the potential for ISR contaminant to cross the aquifer exemption boundary as discussed in Part IV, Section B.

The NRC license requires that the UCLs for the excursion parameters (chloride, specific conductance and total alkalinity) be calculated as the mean plus 5 standard deviations for each parameter. UCLs will be specific to a production zone. For chloride, the UCL will be the mean plus 5 standard deviations or the mean plus 15 mg/L, whichever is greater. This is an NRC requirement, not a UIC requirement, so there are no comparable requirements for establishing UCLs in the Class III Area Permit. This discussion about establishing upper control limits is included in this Fact Sheet for informational purposes only.

12.5.4 Excursion Control

Part IX, Section C of the Class III Area Permit imposes conditions that provide for the detection of injection interval fluids migrating out of the approved injection interval before they reach the aquifer exemption boundary and contaminant USDWs. The movement of injection interval fluids can be vertical into overlying or underlying aquifers or horizontal within the injection interval aquifer.

12.5.4.1 Horizontal Control

To prevent horizontal excursions, Part VIII, Section F of the Class III Area Permit requires that an inward hydraulic gradient must be maintained in the injection interval aquifer for each wellfield during ISR operations and groundwater restoration. This inward hydraulic gradient is created by pumping a greater volume of groundwater and lixiviant from the wellfield production wells than is being injected into the wellfield injection wells. This practice creates a net groundwater withdrawal from the injection interval aquifer known as the ISR operational bleed. For the Dewey-Burdock ISR Project, The Permittee plans to maintain a 0.5 to 3% ISR operational bleed rate. During groundwater restoration, a greater volume of groundwater will be pumped from the wellfield than the volume of clean treated groundwater being injected into the wellfield. This net groundwater withdrawal is known as the restoration bleed. The Permittee plans to maintain a 1.0% restoration bleed rate. Recovering more groundwater than is injected during ISR operation and restoration will maintain a localized cone of depression in the potentiometric surface of the injection interval aquifer at each wellfield. This induced gradient from the surrounding area toward the wellfield will serve as a control over the movement of ISR solutions and minimize the potential for horizontal excursions.

12.5.4.2 Vertical Control

The integrity of the injection interval confining zones and external mechanical integrity of injection, production and monitoring wells are the key factors in preventing vertical excursions. The inward hydraulic gradient will assist in preventing vertical excursions by decreasing the aquifer hydraulic pressure in the area of the wellfield. However, if there is a breach in one of the confining zones the inward hydraulic gradient would prevent a vertical excursion only if it lowers the potentiometric surface of the injection interval aquifer to an elevation below the overlying and/or underlying aquifer potentiometric surfaces.

To assure the integrity of the injection interval confining zones, the Permittee must characterize the thickness and continuity of the confining zones through wellfield delineation drilling and wellfield pump testing. The preoperational pump testing will demonstrate vertical confinement and hydraulic isolation between the injection interval and overlying and underlying units or detect any breaches in the confining zones allowing communication between the injection interval and overlying and underlying aquifers. The Permittee will perform corrective action on any improperly plugged historic exploratory drillholes or improperly constructed water wells identified in and near the wellfield areas that cause hydraulic communication across confining zones.

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 injectate and injection interval fluids within the injection interval. When features causing a breach cannot be precisely located or corrective action cannot be 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). 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.

The Permittee is required to adhere to the well construction procedures and documentation required in the Part V of the Class III Area Permit to demonstrate adequate cement in the annulus between the well casing and the borehole wall to prevent any pathways along the wellbore for vertical excursions to travel. Part II, Section D.4.e of the Class III Area Permit requires initial demonstration of external mechanical integrity for monitoring wells. The Permittee must demonstrate external mechanical integrity for monitoring wells, because they pass through confining zones. Monitoring wells could be a potential breach in the confining zone if the cement between the outside of the well casing and the borehole contains open spaces through which injection interval fluids could flow.

Part VII, Section B.2 of the Class III Area Permit requires demonstration of both internal and external mechanical integrity for injection and production wells. Part VII, Section D.1 of the Class III Area Permit requires initial external mechanical integrity to be demonstrated through documentation of adequate cement in the well construction reports. Demonstration of internal mechanical integrity is also required before using an injection well or production well for ISR operations to assure that well casing is not compromised and will not provide a pathway for vertical excursions to travel. The Director must review the Permittee's demonstration of both internal and external mechanical integrity for all wellfield injection, production and external mechanical integrity for monitoring wells before issuing written Authorization to Commence Inject. The external mechanical integrity of injection, production and monitoring wells is further verified through the wellfield pump tests, which are reviewed by the Director before issuance of the Authorization to Commence Injection. The Permittee must receive the written Authorization to Commence Injection from the Director before injection is allowed. After operation begins, Class III Area Permit Part VII, Section G requires ongoing demonstration of injection and production wells. Ongoing demonstration of mechanical integrity of monitoring wells is not required because they are not used for injection.

12.5.5 Excursion Monitoring Requirements

Perimeter monitoring wells must be positioned to detect any ISR solutions that may potentially migrate away from the injection interval due to an imbalance in wellfield pressure. The monitoring well detection system described in Section 12.5 is a proven method used at historically and currently operating facilities. Prior to injecting lixiviant into each wellfield, pre-operational pump testing must be conducted to demonstrate hydraulic connection between the production and injection wells and all monitoring wells in the injection interval perimeter monitoring well ring as described in Section 5.4. The pump test results must be included in the Injection Authorization Data Package Reports prepared for each wellfield as described in Section 5.6. Monitoring wells must also be installed within overlying and underlying aquifer units. Sampling of monitoring wells will occur according to the schedule in Table 14 under Part IX, Section B of the Class III Area Permit.

The monitoring system and operational procedures have proven effective in ISR operations for early detection of potential excursions of ISR solutions for the following reasons:

1) Wellfield bleed will create a cone of depression in the injection interval potentiometric surface that will maintain an inward hydraulic gradient toward the wellfield that should prevent injection interval fluids from migrating horizontally out of the wellfield.
2) Monitoring hydrostatic water levels in all of the monitoring wells in the injection interval perimeter monitoring well ring will provide immediate verification of the cone of depression, draw rapid attention in the event of a rise in water levels, and provide the ability for early excursion detection and implementation of corrective response.
3) Regular sampling for excursion indicator parameters (such as chloride) that are highly mobile can detect ISR solutions at low levels well before an excursion is created.
4) The natural groundwater gradient and slow rate of natural groundwater flow is small relative to ISR activities and the induced gradient caused by the ISR operational and restoration bleed.

Controls for preventing and detecting migration of ISR solutions to overlying and underlying aquifers consist of:

1) Demonstration of mechanical integrity for all injection and production wells before issuance of Authorization to Commence Injection for each wellfield injection or production well or after well workover which impacts the well casing or injection piping.
2) Routine mechanical integrity testing of all injection and production wells on a regular basis (at least every 5 years) to reduce any possibility of casing leakage.
3) Demonstration of external mechanical integrity for monitoring wells as required in Part II, Section D.4.e of the Class III Area Permit.
4) Regular monitoring of injection interval groundwater levels and sampling for analysis of excursion indicator parameters in perimeter monitoring well ring wells.
5) Regular monitoring of non-injection interval groundwater levels and sampling for analysis of excursion indicator parameters in monitoring wells completed within the overlying and underlying aquifer units.
6) Proper plugging and abandonment of all wells which cannot pass mechanical integrity tests or that become unnecessary for use.

12.5.5.1 Monitoring of Injection and Production Flow Rates

The Class III Area Permit requires an excursion monitoring program that includes monitoring:

1) Wellfield injection and production flow rates,
2) Groundwater level in all monitoring wells,
3) Concentrations of excursion indicator constituents in monitoring wells, and
4) Injection pressure.

The inward hydraulic gradient will be created in a wellfield by pumping a greater volume from the production wells than is being injected in the wellfield injection wells. Continuous monitoring of the injection and production flow rates to confirm that the production rate is greater than the injection rate for each wellfield will provide the first verification that an inward hydraulic gradient is being created and maintained. The difference in production and injection flow rates can be observed even before the water level in the perimeter monitoring wells begins to decrease as the cone of depression is formed in the potentiometric surface of the injection interval aquifer. Injection and production flow rates must be monitored continuously and measured for each wellfield at the injection and production trunklines in the Burdock Central Processing Plant and Dewey Satellite facility, or another representative location compliant with 40 CFR § 144.51(j)(1). Injection and production flow rates for each wellfield must be recorded daily. Minimum, maximum and average injection and production flow rates must be calculated for each month and reported quarterly in the Quarterly Monitoring Report.

12.5.5.2 Monitoring Well Water Level Measurements

12.5.5.2.1 Injection Interval Perimeter Monitoring Well Ring

The Class III Area Permit Part IX, Section C.1.a requires measuring the groundwater levels in monitoring wells twice a month and no more than 14 days apart during ISR operations. Measuring the initial decrease in water levels in the monitoring wells of the injection interval perimeter monitoring well ring as the cone of depression forms in the injection interval potentiometric surface verifies that an inward hydraulic control is being maintained in the wellfield. As long as water levels in the perimeter monitoring wells are maintained below the baseline potentiometric surface for the injection interval measured as required under Part VIII, Section C.2 of the Class III Area Permit, then inward hydraulic gradient exists in the wellfield. However, if water level monitoring indicates that the water level is beginning to rise in one or more perimeter monitoring wells, this could be an indication that the wellfield injection and production rate balance is shifting. This would prompt the operator to reevaluate the injection and production flow rates in the header houses nearest to the perimeter monitoring wells showing the increase in water level. An increase in water level in the injection interval monitoring well ring is the first possible indication of an excursion and will be detected before excursion indicators are detected in the perimeter monitoring wells by sampling and analysis, and in this manner should prevent an excursion from occurring.

12.5.5.2.2 Non-Injection Interval Well Monitoring

As discussed under in Section 8.1.3, the Class III Area Permit requires the use of cementing records to demonstrate external mechanical integrity. The monitoring requirements for non-injection interval monitoring wells are designed to verify the absence of significant fluid movement through confining zones as required under 40 CFR § 146.8(c)(4).

The Class III Area Permit, Part IX, Section C.1.a also requires measuring the groundwater levels in the non-injection interval monitoring wells twice a month and no more than 14 days apart during ISR operations in order to verify that vertical excursions are not occurring in the aquifers overlying or underlying the injection interval. Observing either an increase or decrease in water level in an overlying monitoring well will prompt further investigation of the wellfield in that area. For example, a mechanical integrity test may be conducted on the injection or production wells nearest the overlying monitoring well to verify that there is no casing leak. If mechanical integrity is confirmed, then rebalancing the injection and production rates in that portion of the wellfield may be the next step to correct the vertical excursion. The overlying monitoring well may be sampled for excursion parameters ahead of schedule to determine if injection interval fluids are moving upward into the overlying aquifer. If excursion indicators are detected in the overlying aquifer, this would not constitute a violation of the UIC permit as long as the aquifer is within the exempted Inyan Kara Group aquifers. If the impacted overlying aquifer is the alluvium, which is not an exempted aquifer, the excursion would be a violation because the alluvium is a USDW. An overlying aquifer impacted by injected fluids must be restored to pre-excursion water quality for excursion parameters as required under Part IX, Section C.6 of the Class III Area Permit.

Vertical excursions into underlying aquifers are not expected to occur because the potentiometric surfaces for deeper formations are generally higher than those of overlying aquifers in the Dewey-Burdock area. The exception is the eastern portion of the Burdock area where the Fall River aquifer has a slightly higher potentiometric surface than the Chilson aquifer as shown in Figures 21a, b and c and Figures 22a, b and c. The Permittee does not propose any ISR operations in the Fall River in this area; only Chilson aquifer ore will be targeted in the wellfields in this area.

12.5.5.3 Excursion Monitoring Sampling Requirements

The Class III Area Permit, Part IX, Section C.1.b requires collection of water samples twice a month and no more than 14 days apart during uranium recovery operations from injection interval and non-injection interval monitoring wells and analyzing monitoring well samples for the three excursion indicators. The three excursion indicator parameters are chloride, specific conductance and total alkalinity. The excursion indicator concentrations must be compared to the upper control limits (UCLs) for these constituents as required under the NRC license. The UCLs will be established for the monitoring wells in each wellfield, as described in Section 12.5.3.

12.5.6 Excursion Occurrence

According to the NRC License, an excursion has occurred if at least two excursion parameters exceed the respective UCLs in any monitoring well or if any one excursion indicator parameter exceeds its UCL by 20%. If an excursion is indicated from a monitoring well sampling event, a second sample must be taken from the impacted well within 48 hours after results of the first analysis are received. If an excursion is not confirmed by a second sample, a third sample must be taken within 48 hours after the second set of sampling data are received. The Permittee proposes if the results of the second verification sampling are not received within 30 days of the initial sampling event, then the excursion will be considered confirmed for the purpose of meeting the reporting requirements. If the second or third samples indicate an excursion has occurred, the well producing these results will be placed on excursion status and the Permittee must initiate a corrective response. If neither the second nor the third sample confirms the excursion, the first sample will be considered to be in error, and the well will not be placed on excursion status.

If an excursion is confirmed, Part IX, Section E.9.a of the Class III Area Permit requires the Permittee to notify the Director within 24 hours by telephone or email. Within five (5) days after the excursion is confirmed in accordance with Part XII, Section D.10.e, the Permittee must submit a written report. The written report must contain:

a) Location of excursion,
b) Monitoring wells impacted,
c) How the excursion was detected,
d) Date of previous excursion monitoring activities in the area,
e) Estimation of how far excursion plume may have traveled (include map showing estimated excursion plume), and
f) Actions to correct the excursion.

In the event of an excursion, Part IX, Section C.4.a and b of the Class III Area Permit requires the sampling frequency of impacted monitoring wells to be increased to weekly.

12.5.6.1 Monitoring of an Excursion in the Injection Interval

If the excursion is confirmed in an injection interval wellfield perimeter monitoring well, in addition to more frequent monitoring of the wells confirmed to be "on excursion," Part IX, Section C.4.c of the Class III Area Permit requires that the nearest unimpacted wells on each side of the well(s) confirmed to be on excursion are also to be monitored weekly. More frequent monitoring of the nearest unimpacted wells will allow more timely detection of an expanding excursion plume. The criteria and verification of an expanding excursion plume are found in Part IX, Sections C.4.d and C.4.e of the Class III Area Permit.

12.5.6.2 Monitoring of an Excursion in a Non-Injection Interval

Part IX, Section C.4.f.i of the Class III Area Permit contains additional Requirements for excursions detected in non-Injection Interval monitoring wells if:

1) excursion parameter concentrations increase for four consecutive weekly sampling periods in the impacted well or

2) if an excursion plume in a non-injection interval expands to include an adjacent non-injection interval monitoring well. In addition to the monitoring required under Part IX, Section C, 3a and 3b, the Permittee must collect a groundwater sample from the impacted well(s) and analyze the sample for the baseline parameters in Table 13 (Table 8 of the Class III Area Permit). Part IX, Section C.4.f.iii requires the Permittee to continue analyzing groundwater samples from impacted monitoring wells for the baseline parameters in Table 8 on a monthly basis until excursion parameter concentrations show decreasing concentrations for three consecutive weekly sampling periods. Part IX, Section C.5 requires the Permittee to update the Conceptual Site Model with the analytical results and develop a reactive transport model to evaluate the characteristics and potential extent of the expanding excursion plume and to evaluate the potential of the excursion plume to cross the aquifer exemption boundary and impact down-gradient USDWs. Part IX, Section C.5.d of the Class III Area Permit states that 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. 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 baseline parameters in Table 13 to determine if additional aquifer remediation is required in the excursion-impacted area of the non-injection interval.

12.5.7 Geochemical Modeling of an Expanding Injection Interval Excursion Plume

If monitoring of an expanding injection interval excursion plume shows that the concentrations of excursion parameters are increasing for four consecutive weekly sampling periods or if an expanding plume expands further to include an adjacent monitoring well, then Part IX, Section C.4.f.ii requires the Permittee to collect a groundwater sample from the impacted wells and analyze the samples for the baseline parameters in Table 13 (Table 8 of the Class III Area Permit). Part IX, Section C.4.f.iii requires the Permittee to continue analyzing groundwater samples from impacted monitoring wells for the baseline parameters in Table 8 on a monthly basis until excursion parameter concentrations show decreasing concentrations for three consecutive sampling periods. Part IX, Section C.5 requires the Permittee to update the Conceptual Site Model with the analytical results and develop a reactive transport model to evaluate the characteristics and potential extent of the expanding excursion plume and to evaluate the potential of the excursion plume to cross the aquifer exemption boundary and impact down-gradient USDWs. Part IX, Section C.5.d of the Class III Area Permit states that 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.

12.5.8 Excursion Corrective Response

The Class III Area Permit requires excursion monitoring, reporting and remediation of excursions, but does not specify the types of excursion corrective responses that must occur. The Permittee may implement any of the following standard industry practices as corrective responses for excursions:

- Adjusting the flow rates of the production and injection wells to increase the aquifer bleed in the area of the excursion;
- Terminating injection into the portion of the wellfield from which the excursion originated;

- Installing pumps in injection wells in the portion of the wellfield from which the excursion originated to retrieve ISR solutions;
- Plugging and abandoning, then replacing injection, production or monitoring wells that are not able to pass a mechanical integrity test; and
- Installing new pumping wells adjacent to the well on excursion status to recover ISR solutions.

12.6 Operational Groundwater Monitoring

Part IX, Section B.3 of the Class III Area Permit requires that operational groundwater monitoring be conducted to detect potential changes in groundwater quality in and around the Project Area as a result of ISR operations. The operational groundwater monitoring program includes domestic wells, stock wells and monitoring wells located hydrologically up-gradient and down-gradient of ISR operations. Wells to be included in the operational monitoring program include domestic wells within 1.2 miles of the Project Area, stock wells within the Project Area Boundary, and additional monitoring wells within the Project Area completed in the alluvium, Fall River, Chilson and Unkpapa.

12.6.1 Operational Groundwater Monitoring - Domestic Wells (for Household Use)

From the onset of ISR operations until groundwater restoration is approved by NRC, the Permittee must monitor all domestic wells within 1.2 miles of the wellfield perimeter monitoring well rings. Samples must be collected quarterly and analyzed for the baseline constituents listed in Table 13. Analytical results shall be reported to the Director quarterly in one of the Quarterly Monitoring Reports, as required in Part IX, Section E.8.c.iv of the Class III Area Permit. Figure 8 in the Class III Area Permit shows the locations of the domestic wells that will be monitored.

12.6.2 Operational Groundwater Monitoring - Stock Wells

During the design and implementation of each wellfield pump test, all stock wells within ¼ mile of the wellfield perimeter monitoring well ring must be evaluated for the potential to be adversely affected by ISR operations or to adversely affect ISR operations. During ISR operation, the Permittee must monitor all stock wells within the Project Area. Samples must be collected quarterly and analyzed for water level and the three excursion indicators of chloride, specific conductance and total alkalinity. Analytical results shall be reported to the Director quarterly, as required in Part IX, Section E.8.c.iv of the Class III Area Permit. Figure 9 in the Class III Area Permit shows the locations of the stock wells that will be monitored. Some of the stock wells may need to be plugged based on evaluation of impact on ISR operations; plugged wells will not need to be monitored.

Note that well 41 is classified as a stock water well in Figure 9 of the Class III Area Permit. Plate 3.1, which is the Area of Review Map included with the Class III Permit Application, indicates that there is a residence located near the well and TVA records indicate that well 41 was a domestic well at some time in the past. The EPA asked the Permittee to determine if there actually is a residence located near well 41 and, if so, to find out what the drinking water source for that residence is. The Permittee checked the residence, found that no one was currently living in the residence and informed the EPA that the residence is uninhabitable. The Permittee could not identify what the drinking water source was for the abandoned residence. The EPA considers well 41 to be a stock water well for the purposes of operation groundwater monitoring under Part IX, B.5.b. Because TVA records shows well 41 was once a drinking water well for the nearby residence, the EPA completed a capture zone analysis for well 41 as part of the evaluation of the Permittee’s aquifer exemption request.

12.6.3 Operational Groundwater Monitoring - Monitoring wells

As part of the operational groundwater monitoring program the Permittee must monitor wells listed in Table 16 of the Class III Area Permit which are located hydrologically up-gradient and down-gradient of ISR operations from the onset of ISR operations until groundwater restoration is approved by NRC. The monitoring wells listed in the Class III Area Permit Table 16 include wells completed in the alluvium, Fall River, Chilson, and Unkpapa. The monitoring wells must be monitored quarterly and analyzed for baseline constituents listed in Table 13 of this Fact Sheet. Analytical results shall be reported to the Director quarterly, as required in Part IX, Section E.8.c.iv of the Class III Area Permit. Figures 10 through 12 in the Class III Area Permit show the locations of the wells that must be monitored.

12.6.4 Monitoring during Groundwater Restoration and Stability Monitoring

The frequency of excursion monitoring during groundwater restoration and stability monitoring phases is every 60 days, as required in Part IX, Section C.2 and Section B, Table 14F of the Class III Area Permit. The requirements related to development of the Conceptual Site Model in Part IV, Section A.1.c.i *Characterization of aqueous geochemistry* and Part IV, Section A.3.b and A.3.c include the water quality analyses during groundwater restoration and stability monitoring phases.

12.7 Ongoing Demonstration of Mechanical Integrity

After initial demonstration of mechanical integrity as required in Part VII, Section B.2 of the Class III Area Permit, the Permittee must demonstrate internal mechanical integrity within five (5) years of the last successful mechanical integrity test even if the well is not active as required in Part VII, Section G of the Class III Area Permit. Results of mechanical integrity tests must be submitted to the Director with the next scheduled Quarterly Report, unless the mechanical integrity test occurred within 45 days before the due date of the Quarterly Report. In that case, the mechanical integrity test results must be submitted with the following Quarterly Report. Failing to provide the Director with a successful demonstration of mechanical integrity conducted in a timely manner will be a violation of this permit.

12.8 Seismic Activity Monitoring

Injection activities under the Class III Area Permit will not cause any seismic activity. No faults or fractures have been detected within the Dewey-Burdock Project Area to provide sources for seismic activity, and the injection pressures and rates allowed under the Class III Area Permit will be too low to induce any movement, even if these structures did exist in the area. The purpose for requiring seismic monitoring under the Part IX, Section D of the Class III Area Permit is to provide opportunity to pause operations if a seismic event of large enough magnitude and intensity occurs to be detectible to humans in the form of ground surface motion. The intensity of such an event would be level IV under the Abbreviated Modified Mercalli Intensity Scale which is equivalent to a magnitude of 4.0 on the moment magnitude scale. An explanation of the Abbreviated Modified Mercalli Intensity Scale and the measurable magnitude of earthquakes can be found at the US Geological Survey website: https://www.usgs.gov/natural-hazards/earthquake-hazards/science/modified-mercalli-intensity-scale?qt-science_center_objects=0#qt-science_center_objects. Explanation about measuring the size of an earthquake can be found at the US Geological Survey website:https://www.usgs.gov/natural-hazards/earthquake-hazards/science/science-earthquakes?qt-science_center_objects=0#qt-science_center_objects .

If a seismic event of magnitude 4.0 on the moment magnitude scale is detected within 2 miles of the Dewey-Burdock Project Boundary, Part IX, Section D of the Class III Area Permit requires the Permittee to immediately cease injection and report to the Director within twenty-four (24) hours. The Director will determine if any structural testing of the facility infrastructure is required before injection resumes. Types of analysis that will determine if any structural damage has occurred include observing all the gauges within the header houses where injection pressures, flow rates and volumes are measured to see if any unexpected increases or decreases are observed or if any automatic shut-downs have been triggered by threshold value exceedances. The Permittee will not resume Injection until after obtaining approval to recommence injection from the Director.

Under certain conditions, disposal of fluids through injection wells has the potential to cause human-induced seismicity. For discussion of these conditions, see Section 8.1.2.1 of the Fact Sheet for the Class V Area Permit.

13.0 REPORTING AND RECORDKEEPING REQUIREMENTS

13.1 Parameter Recording Frequency

The parameters listed in Table 14 under Part IX, Section B of the Class III Draft Area Permit will be recorded and reported according to the frequencies shown in Table 14.

13.2 Quarterly Monitoring Reports

Results from ongoing monitoring of wellfield operational parameters will be submitted to the Director in Quarterly Monitoring Reports. At a minimum, the Quarterly Monitoring Reports will include the information listed in Table 14 under Part IX, Section B of the Class III Area Permit. Quarterly Monitoring Reports must consist of monthly summary information for the project as required in Part IX, Section E.8 of the Class III Area Permit. A narrative description of any deviations from permit limitations must be included. Maintenance activities, instrument calibration activities, mechanical integrity testing activities, and other significant events that took place during the reporting period will be described.

13.3 Certification and Signatory Requirements

Monitoring reports must be signed and certified according to Class III Area Permit Part XII, Section D.9. Quarterly reports may be submitted electronically but must be accompanied by a letter containing the certification included under Class III Area Permit Part XII, Section D.9(d).

13.4 Twenty-four Hour Reporting Requirements

The Area Permit, Part XII, Section D.10.e requires the Permittee to report verbally to the Director within 24 hours of the event and follow up within 5 days in written form when the following events occur:

1. 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.
2. Injection pressure measured above the MAIP for a header house.
3. If any seismic event measuring 4.0 magnitude (MMI scale) or greater is reported within two miles of the permit boundary per Part IX, Section D
4. 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.
5. Initial excursions as described in Part IX, Section E.9.a.
6. An expanding excursion plume as described in Part IX, Section E.9.c
7. Discovery that excursion indicator concentrations are increasing in excursion-impacted monitoring wells as described in Part IX, Section E.9.d.
8. Upon discovery of any other noncompliance as described in Part XII, Section D.10.e.

13.5 Recordkeeping

Part X, Section A of the Class III Area Permit requires that the Permittee keep records of all data used to complete permit applications and any supplemental information submitted under § 144.31 for a period of at least 3 years from the date the application is signed consistent with the requirement under 40 CFR § 144.31(f).

Part X, Section B of the Class III Area Permit requires the Permittee to retain the following records of monitoring data:

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 to the Director 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.

At the end of the retention period, the owner or operator must deliver the records to the EPA or obtain written approval from the EPA to discard the records. The records discussed above (originals or copies) will be retained on site unless written approval to discard the records is provided by the EPA. Copies of these records (or originals) will be maintained for all observation records throughout the operating life of each well. The Permittee also will maintain an electronic database containing well completion and mechanical integrity test records for all injection wells. The database will be provided to the EPA upon request.

14.0 PLANS FOR SYSTEM FAILURES

Section 13.0 of the Class III Permit Application includes a description of the following contingency plans to cope with system shut-ins or failures to prevent migration of fluids into any USDWs. The automated monitoring and shut-off devices described below that provide additional protection to USDWs have been incorporated into the Class III Area Permit Part V, Section K.

14.1 Shutdowns

Each injection well must have 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. There will be a manual flow control valve and a flow meter on each production and injection well to regulate the flow to and from each well and to balance the individual well patterns. The flow meters will be labeled with designated well identification numbers. The block valves will be closed for the appropriate injection or production well for shutdown.

The Permittee will install automated control and data recording systems at the Dewey satellite facility and the Burdock central processing plant which will provide centralized monitoring and control of the process variables including the flows and pressures of production and injection streams. The systems will include alarms and automatic shutoffs to detect and control a potential release or spill.

Pressure and flow sensors will be installed, for the purpose of leak detection, on the main trunklines that connect the Burdock Central Processing Plant and Dewey Satellite facility to the wellfields. In addition, the flow rate of each production and injection well will be measured automatically. Measurements will be collected and transmitted to both the Burdock Central Processing Plant and Dewey Satellite Facility control systems. Should pressures or flows fluctuate outside of normal operating ranges, alarms will provide immediate warning to operators which will result in a timely response and appropriate corrective action.

Both external and internal shutdown controls will be installed at each header house to provide for operator safety and spill control. The external and internal shutdown controls are designed for automatic and remote shutdown of each header house. In the event of a header house shutdown, an alarm will occur and the flows of all injection and production wells in that header house will automatically stop. 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 Dewey Satellite facility control rooms.

An external header house shutdown will activate an electrical disconnect switch located on the outside of the header house or at the transformer pole which will shut down all electrical power to the header house. This will mitigate potential electrical hazards while shutting off all electrical power to the header house and operating equipment. The production pumps will be de-energized which will result in flow stopping from all production wells. A control valve that will close when de-energized will be used on the injection header, which will stop the flow to all injection wells.

Internal shutdown controls will not involve shutting off all electrical power to the header house but will result in the same alarm condition and shutdown of flow to all production and injection wells feeding the header house. Each header house also will include a sump equipped with a water level sensor so that if a leak occurs, and the water level approaches a preset level, the sensor will cause an automatic shutdown of the header house. A pressure switch will be installed on each injection header to ensure that fluid pressure does not exceed the MAIP permit limit for the injection wells served by that header house (refer to Class III Area Permit Figure 6). If the injection pressure reaches the maximum set value in the pressure switch, an automatic header house shutdown will occur.

14.2 Well Casing Failure

Well casing failure is unlikely to occur due to the well construction requirements in the Class III Area Permit Part V and the initial demonstration of mechanical integrity before an injection or production well is put into operation. The ongoing demonstration of mechanical integrity at least every 5 years and routine monitoring of the injection pressure for each well prevent well casing failure in operating wells. The required monitoring program will be in place to rapidly detect any excursions in the event of a well casing failure. The excursion corrective response plan will minimize potential impacts from excursions and protect USDWs.

Should an injection or production well casing failure occur, the Permittee must remove the well from service and examine the well casing and internal piping to verify the condition of the well. The Permittee may conduct resistivity or video logs to identify the location of the well casing failure. The Permittee may perform a workover if any repair is needed. A mechanical integrity test must follow any workover that involves the well casing or cement. If the well is not able to pass a mechanical integrity test, the Permittee must plug and abandon the well according to the requirements under Part XI of the Class III Area Permit.

14.3 Mitigation Measures for Other Potential Environmental Impacts

The EPA analyzed the effects to the environment from the drilling and operation of all the injection wells at the Dewey-Burdock Project Site. As part of this analysis, the EPA reviewed mitigation measures proposed by the Permittee, required by the NRC in source materials license and required in the proposed DENR Large Scale Mine Permit. For a detailed discussion of mitigation measures for environmental impacts potentially resulting from the drilling and operation of the injection wells at the Dewey-Burdock Project Site, see the document entitled *Cumulative Effects Analysis of the Dewey-Burdock Uranium In-Situ Recovery Underground Injection Control Area Permits*, which is part of the Administrative Record for this permitting action. The Administrative Record is found under Docket EPA-R08-OW-2019-0512 on the Regulations.gov website. 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) provides instructions for accessing Docket EPA-R08-OW-2019-0512.

15.0 REQUIREMENTS FOR DEVELOPMENT OF A CONCEPTUAL SITE MODEL AND A REACTIVE TRANSPORT GEOCHEMICAL MODEL

15.1 The Conceptual Site Model and Geochemical Model Versus Post-Restoration Monitoring

The previous Class III draft Area Permit required the Permittee to conduct post-restoration monitoring to demonstrate that no ISR contaminants would cross the aquifer exemption boundary. This updated Class III draft Area Permit now requires the Permittee to develop a reactive transport geochemical model to evaluate the potential for ISR contaminant to cross the downgradient aquifer exemption boundary. To improve the predictive capabilities of the geochemical model, the Class III draft Area Permit requires the Permittee to first develop a Conceptual Site Model (CSM) and conduct targeted monitoring to calibrate the model as discussed later in this section.

The EPA acquired technical support from Cadmus, an EPA contractor, to evaluate criteria for an effective CSM and geochemical model specific to a uranium ISR site. Cadmus provided the EPA with a series of documents that supported the EPA's development of permit requirements that will result in effective tools for evaluating the fate and transport of ISR contaminants. Cadmus also provided acceptance criteria to assist the EPA in evaluating the resulting CSM and geochemical model the Permittee will develop according to the permit requirements. These documents are available for public review as part of the Administrative Record for the Class III draft Area Permit.

The previous Class III draft Area permit required the Permittee to develop a post-restoration monitoring plan that included a line of post-restoration monitoring wells monitoring located down-gradient from the restored wellfield. This line of post-restoration monitoring wells served as a surrogate compliance boundary where ISR contaminants were required to meet baseline concentrations before they were able to cross the aquifer exemption boundary and trigger a violation of the UIC Permit. Challenges with this approach include:

1) Determining the best location for the post-restoration monitoring wells for a given wellfield,
2) Establishing the baseline concentrations that would serve as the permit limit at each of the post-restoration monitoring wells,
3) The time line for the restored wellfield groundwater to reach the post-restoration monitoring wells and
4) The time line to determine how the groundwater upgradient from the restored wellfield would impact the restored wellfield injection interval and identification of the problem areas within the wellfield where contaminant rebound might occur.

The Permittee was required to determine the locations of post-restoration monitoring wells at the time the wellfield was being constructed so baseline monitoring could begin early enough to establish the permit limits for the post-restoration monitoring wells. This timing meant that the wells locations were determined before any site-specific data could be obtained to identify where lixiviant flare zones or areas with high contaminant concentrations in the wellfields might occur. These areas are not evident until the groundwater restoration phase of the process.

Developing a CSM over the ISR process life-cycle and using the geochemical modeling approach will allow the EPA and the Permittee to identify areas with the potential to have elevated concentrations of ISR contaminants earlier in the process allowing the Permittee and the EPA to focus monitoring and remediation efforts where needed. Identifying problem areas within the wellfield itself, rather than at down-gradient monitoring wells, makes identification easier, because there is a greater difference between baseline and elevated concentration of ISR contaminants at the source area. This approach removes the need for the complicated statistical analyses previously required to identify an elevated concentration of an ISR contaminant at the post-restoration monitoring well. Detection at the source area within the wellfield will reduce the size of a down-gradient plume which needed to form to be detected at the down-gradient monitoring wells. Earlier identification of the problem areas results in earlier remediation efforts which decreases the likelihood that elevated concentrations of ISR contaminants will cross the aquifer exemption boundary. Monitoring and modeling the effects of the up-gradient groundwater on the restored wellfield will be more timely at the source area, allowing any rebounded concentrations of ISR contaminants to be addressed more quickly.

15.2 Requirements for the CSM

The first step in laying the foundation for an effective geochemical model is developing a robust CSM that documents the changes in site geochemical and hydrogeologic conditions from pre-ISR conditions through ISR operation, groundwater restoration and post-restoration stability monitoring. Development of the CSM results in the acquisition of site-specific field data that will be used as input for the geochemical model.

The CSM is a representation of the site geologic, geochemical, and hydrogeologic characteristics and the anticipated geochemical processes. The CSM describes: the geologic setting of the project site, including the stratigraphy and lithologies of the Inyan Kara Group (i.e., the ore body) and the Graneros Group and Morrison Formation (the upper and lower confining zones); hydrogeologic properties of the site, including static characteristics (e.g., aquifer and confining zone petrophysical properties) and those that will change over the course of the project (such as groundwater flow); and baseline groundwater and sediment geochemistry as well as information on how these change over time. Both the geochemical model and the supporting CSM will be iterative and will be refined as data are collected during ISR process life-cycles and the post-restoration phase to improve confidence in the results and their usefulness in ensuring USDW protection.

Part IV, Section A of the Class III Area Permit lists the requirements the Permittee must follow in developing the CSM. The Permittee must collect data to adequately characterize the geology, hydrologic properties and geochemical characteristics for each wellfield. In addition, the Permittee must also characterize the geochemical processes that occur through the ISR operations that result in the changes to the injection interval geochemistry which will affect the groundwater restoration process. Synthesis of available geologic, hydrogeologic, and geochemical data and collection of additional data where needed will lead to an improved ability to simulate the mobilization and transport of contaminants at the site. A CSM based on a sufficient data set (i.e., types and amount of data) will support the development of a robust geochemical model for predicting fluid movement and groundwater quality changes throughout the project life cycle. Modeling based on a well-developed CSM will also improve the potential for detection of excursions of uranium or other metals beyond the aquifer exemption area and rebounding of uranium concentrations after site restoration.

The Permittee must update the CSM on as additional data is collected during the development of each new wellfield. This iterative process will support identifying and filling data gaps over time and facilitate calibration of the geochemical model as geochemical conditions change during the ISR process. In the event that unresolved data gaps or uncertainty are identified concerning geology, hydrologic properties, geochemical characteristics, and/or geochemical processes that could affect mobility and transport of uranium and other metals, the Director may require the Permittee to develop more than one CSM to characterize a range of potential site conditions. This approach will allow the geochemical model to simulate different scenarios around the uncertainty and indicate a potential range of outcomes.

The Permittee is required to update the CSM once groundwater restoration monitoring begins. The NRC license requires excursion monitoring at 60-day intervals during groundwater restoration. The NRC license states that the Permittee must collect samples from the wellfield monitoring wells that were used to determine the Commission approved background water quality values. (For more information about Commission approved background see the section 7.3.1.1 of the NRC SEIS. The NRC will allow the Permittee to determine a sampling interval that is sufficient for determining the success of aquifer restoration efforts and determine if any areas of the wellfield need additional attention. The NRC license also requires the Permittee to evaluate any flare zones where ISR contaminants have migrated out of the wellfield or hot spots (areas of high contaminant concentration) in the wellfield where ISR contaminants are resisting groundwater restoration efforts. A sufficient frequency for monitoring is dependent on the site-specific conditions at each wellfield and cannot be effectively determined before groundwater restoration begins.

Once groundwater restoration has been completed in a wellfield, the Permittee begins the stability monitoring phase. The NRC requires excursion monitoring at 60-day intervals during the stability monitoring phase, as stated in the Section 6.1.3.6 of the NRC Safety Evaluation Report. The NRC license requires the Permittee to collect water quality samples quarterly. The Class III Area permit requires the Permittee to update the CSM with the data provided during quarterly post-restoration stability monitoring and include information from additional evaluation of any hot spots identified within the wellfield.

The Permittee shall update the CSM upon the identification of an expanding excursion plume as discussed under Section 12.5.7 of this Fact Sheet in order to conduct reactive transport geochemical modeling to evaluate the characteristics and potential extent of the expanding excursion plume and provide an opportunity for remedial action before an excursion plume crosses the aquifer exemption boundary into the USDW and becomes a UIC violation.

The data set on which the CSM is based will:

1) Include information about the injection interval, the upper and lower confining zones, and all USDWs that that may be affected by ISR-related activities;
2) Be based on historic data and additional baseline data collection and updated with monitoring data during the course of the project;
3) Represent the entire project, including upgradient and potentially affected downgradient areas;
4) Be as detailed as possible to reflect any localized variability/heterogeneity;
5) Reflect baseline conditions and the entire lifecycle of the project (i.e., ISR, restoration, and post-restoration); and
6) Explain any data gaps and their potential impact on the certainty of the modeling results.

The Permittee must provide updates of the CSM to the Director in the Quarterly Monitoring Reports.

15.3 The Geochemical Modeling Process

The objective of the geochemical model is to simulate as accurately as possible the potential for ISR contamination to cross the aquifer exemption boundary. To achieve this objective, the geochemical model must simulate the movement of groundwater and restoration fluids and their interactions with the injection zone mineralogy throughout the project site (i.e., within the ore zone and in the downgradient injection interval) to explore the potential for migration of uranium and other metals within the ore zones that might be mobilized during the ISR process, such as vanadium, arsenic, and selenium. Specifically, the geochemical model will simulate various geochemical processes to evaluate the potential for:

1) mobilization of uranium and other metals beyond the aquifer exemption boundaries;
2) the role of natural attenuation in controlling the migration of ISR contaminants;
3) projected concentrations of constituents with MCLs and
4) NRC-approved ACLs and
5) potential rebound mobilization of uranium after site restoration.

For these interactions to be accurately simulated, iterations of and improvements to first the CSM, and then to the geochemical model will incorporate information such as baseline water quality, analysis of mineralogy and the results of monitoring during groundwater restoration and post-restoration stability monitoring.

The input data for the geochemical model will be based on the CSM discussed in the previous section. The CSM data characterizing the geology, hydrogeology and geochemistry of the site, will be generated throughout the ISR lifecycle, from pre-ISR conditions though post-restoration stability monitoring. The CSM will inform the relevant site characteristics and geochemical processes to be incorporated into the geochemical model. Geochemical modeling, coupled with the results of site-specific monitoring (which will provide inputs for future iterations of the model), can help demonstrate compliance with the UIC permits and NRC license by showing that the site behaves as predicted through the project's lifecycle; analyze expanding excursion plumes; and support updates to monitoring, the CSM and the geochemical model.

The accuracy of the model—and, therefore, its utility as a tool in evaluating the potential for ISR contaminants to cross the aquifer exemption boundary—is improved by the amount and quality of available data on which to base the CSM and geochemical model, including the number of data points and their spatial/temporal distribution. Assessing the gaps in this knowledge supports an understanding of the model's limitations and uncertainties, which can support interpreting the results and designing monitoring programs (baseline and during operational and restoration phases) to fill in data gaps.

Part IV, Section B of the Class III Area Permit lists the requirements for the development of the geochemical model. The Permittee must include the following scenarios into the geochemical/reactive transport model:

1) Evaluation of the restored wellfield's capacity to maintain long-term stability as upgradient groundwater flows across the wellfield.
2) Assessment of the down-gradient portion of the exempted aquifer to attenuate residual contamination as restored groundwater flows out of the wellfield.
3) Evaluation of any localized, elevated concentrations above the restoration criteria remaining in the wellfield injection interval following restoration.

The Permit requires the geochemical modeling to simulate different phases of the project lifecycle on an iterative basis and when field and laboratory measurements can be used to calibrate the model and additional data can be collected as needed to verify simulation results. To achieve this objective, the Permittee must conduct iterative modeling for calibration and verification including representation of:

1) Interactions between restoration fluids and groundwater in the wellfield injection interval during the restoration phase; and
2) Wellfield conditions during the post-restoration stability monitoring phase.

The geochemical model must simulate both the physical movement of groundwater and restoration fluids and their chemical interactions with injection zone mineralogy throughout the project site (i.e., within the orebody and downgradient) to explore the potential for migration of uranium and other metals (e.g., vanadium, arsenic, molybdenum, etc.). Specifically, the geochemical model will simulate various geochemical processes to evaluate the potential for: mobilization of uranium and other metals beyond the aquifer exemption boundaries; the role of natural attenuation in controlling the migration of contaminants; projected concentrations of constituents with MCLs and NRC-approved ACLs; and potential rebound mobilization of uranium after site restoration. Iterations of and improvements to the geochemical model will incorporate multiple rounds of baseline water quality and solids sampling and the results of monitoring throughout the extraction, restoration, and post-restoration phases.

In order for the geochemical model to be an effective tool for evaluating the potential for ISR contaminants to cross the aquifer exemption boundary, the model must be calibrated using site-specific data and laboratory testing. Model calibration is the process of iteratively adjusting model parameter estimates to improve the fit between the model output and an independent set of measured data (referred to hereafter as observations) that are based on sampling and analysis of groundwater collected at the site or experimental results. Based on the level of agreement between model outputs and the observations, the model is either considered successfully calibrated or model input and parameters are revisited for further calibration. Calibration typically involves a combination of manual adjustment of parameters based on perceived graphical agreement between modeled and observed data and goodness-of-fit statistics (often referred to as a trial-and-error approach) and the use of automated methods termed inverse models that attempt to optimize parameter values using statistical techniques and many iterative model runs. Part IV, Section C of the permit describes the permit requirements for monitoring, laboratory testing, and field investigations to calibrate the geochemical model. Part IV, Section B.5 contains the permit requirements for model calibration.

Given that a geochemical model is an estimation of the processes occuring at the site, it is important to identify the sources and magnitude of uncertainty in the model results. A sensitivity analysis can provide an understanding of how uncertainties in parameter inputs translate to uncertainty in model outputs. Evaluating and reporting on model uncertainty is important for informing how model findings fit into decision making processes. A sensitivity analysis is a systematic and methodical investigation of the effects of alternative model parameter values on simulation results. The application of a sensitivity analysis as part of geochemical modeling is typically completed to enhance the conceptual understanding of the modeled system, identify parameters of greater interest for model calibration, and better understand how uncertainties in parameter values may translate to uncertainty in model outputs. There is no single universal approach to sensitivity analysis; examples of model processes to consider for a sensitivity analysis of a mine site geochemical model include mineral solubility, sorption reactions, gas exchange, fracture depth and density, groundwater flow rates and influent chemistry, and effective porosity. Even though uncertainty is inherent in geochemical model outputs, the uncertainty in model parameters and outputs can be characterized with confidence and prediction intervals. Performing uncertainty analyses can provide insight on the relevance for the application of model results at the site and how they can be used for decision-making, such as identifying the potential for ISR contaminants to cross the aquifer exemption boundary and remediation efforts that would be effective as decreasing concentrations of ISR contaminants. Quantifying prediction uncertainty based on a range potential parameter values and CSMs provides a clearer understanding about the range of potential environmental outcomes. Part IV, Section B.6 contains the permit requirements for uncertainty analyses.

The details involved in the development of a geochemical model are complex. The Cadmus document entitled *Geochemical Model Criteria Support Document for the Dewey-Burdock Project* provides a more detailed explanation of the steps involved in generating the model, the input data to the model, model calibration and sensitivity analyses and uncertainty predictions.

15.4 The EPA's Determination of the Effectiveness of the Geochemical Model

The end results of the CSM and the geochemical modeling is that the Permittee will use this information in a Wellfield Closure Plan as described in Part IV, Section D of the Permit. The Permittee must submit a Closure plan to the Director for approval describing the geochemical modeling results. The plan must include a description of all work completed under Part IV of the Permit to evaluate the potential for ISR contaminants to cross the boundary down-gradient aquifer exemption boundary and to demonstrates adequate protection of USDWs as required under 40 CFR § 146.10(4).

Documentation for the Closure Plan should include discussion of the following:

1. Geology, hydrologic properties, geochemical characteristics, and geochemical processes of the CSM.
2. Any data gaps or aspects of the CSM that are uncertain or poorly characterized.
3. Results of data collected from monitoring, laboratory testing, and field investigations.
4. Analysis and uncertainty of data from monitoring, laboratory testing, or other investigations.
5. Model structure, domain, and discretization.
6. Geochemical inputs to the model.
7. Processes and reactions represented by the model, including updates or modifications to the model's thermodynamic database. It should be noted if there are 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.
8. Geochemical model results, including an assessment of the potential for ISR contamination to cross the aquifer exemption boundary.
9. Uncertainty of model results, including sensitivity analyses and evaluation of predictions over a range of potential site conditions.

The exception to using the geochemical modeling results in a wellfield closure plan, is in Part II, Section G where the Permit requires this information as part of the Injection Authorization Data Package Reports for Burdock wellfields 6, 7 and 8 as discussed in Section 5.5 of this Fact Sheet. Another exception is in Part IX, Section C.5, where the Permit requires geochemical modeling for an expanding excursion plume, as described in Section 12.5.7 of this Fact Sheet.

As discussed at the beginning of this section, the EPA has determined that the geochemical modeling approach, supported by the CSM requirements, provides a more effective method to identify the problem areas that could result in migration of ISR contaminants across the aquifer exemption boundary. Even given the inherent uncertainty in modeling results, the Permit requirements for model calibration will make the model a more effective predictive tool and the Permit requirements for uncertainty analysis will constrain the uncertainty in model parameters and outputs so they can be characterized with confidence and prediction intervals.

16.0 PLUGGING AND ABANDONMENT REQUIREMENTS

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

16.1 Prenotification Requirement

The Class III Area Permit Part XI, Section A requires the Permittee to notify the EPA at least 45 days prior to plugging and abandoning the wellfield injection and production wells. The notification must include concurrence from NRC that the wellfield is restored or the Director will not concur with well closure. 40 CFR § 146.10(a)(4) states that the plugging and abandonment plan required in 40 CFR § 144.51(o) and § 144.52(a)(6) must, in the case of a Class III project which underlies or is in an aquifer which has been exempted under § 146.04, also demonstrate adequate protection of USDWs. The Director may prescribe aquifer cleanup and monitoring where it deems it necessary and feasible to insure adequate protection of USDWs.

16.2 Plugging and Abandonment Plan

Class III Area Permit, Part XI, Section C contains the requirements of the approved plugging and abandonment plan. This plan meets the EPA requirements for protection of USDWs, 40 CFR § 146.10 and South Dakota regulations for well closure.

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 a well, if the Director determines the present plan is not protective of USDWs.

16.3 Plugging and Abandonment Report

Class III Area Permit Part XI, Section D and 40 CFR § 144.51(p) require that the Permittee must submit a plugging and abandonment report to the Director. The report must be certified as accurate by the person who performed the plugging operation. Such report must consist of either:

1) A statement that the well was plugged in accordance with the approved plan required in the Class III Area Permit; or
2) Where actual plugging differed from the approved plan, an updated version of the plan, specifying the differences from the approved plan.

17.0 FINANCIAL RESPONSIBILITY

17.1 Demonstration of 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, as required by Part XIII of the Class III Area Permit. The Permittee must show evidence of such financial responsibility to the Director by the submission of a surety bond, or other adequate assurance such as financial statements or other materials acceptable to the Director. The Regional Administrator may, on a periodic basis, require the holder of a lifetime permit to submit a revised estimate of the resources needed to plug and abandon the well to reflect inflation of such costs, and a revised demonstration of financial responsibility if necessary. Initially, the Permittee has proposed to demonstrate financial responsibility with an irrevocable letter of credit with a standby trust agreement, as indicated in the June 2011 RAI Response TR RAI MI-4(a) submitted to the NRC. The Permittee must set up a separate agreement with the EPA per Class III Draft Area Permit Requirement Part XIII.

Depending on the type of financial instrument used to demonstrate financial responsibility, evidence of continuing financial responsibility may be required to be submitted to the Director annually. Each year the Permittee will submit a list of wells that will be constructed and for which financial responsibility will be required. The financial instrument may be updated each year to provide for the cost of plugging and abandonment of the additional wells.

17.2 Estimated Cost to Plug and Abandon Injection Wells

Table 22 presents a preliminary estimate of the cost to plug and abandon the injection wells that will be in place at the end of the first year of ISR operations. The preliminary cost estimate is based on the anticipated number of installed injection wells and cost estimates from independent contractors to plug and abandon the injection wells and to supply cement grout (refer to Permit Application Appendix L for cost estimates). The preliminary estimate in Table 22 is subject to change prior the Class III UIC permit issuance based on ongoing facility planning efforts. Part XIII, Section C requires the Permittee to provide the Director with an updated cost estimate for plugging and abandonment of all planned injection and production wells for the first wellfield to be developed before issuance of the Final Permit. The Permittee must provide the Director with demonstration of adequate financial responsibility to cover the plugging and abandonment of all planned injection and production wells for Burdock Wellfield #1 prior to issuance of the Final Permit. Once wellfield construction begins, 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.

The NRC determined that the financial responsibility required by the EPA fulfills a portion of the decommissioning activities cited in the U.S. NRC Materials License SUA-1600, pursuant to Title 10 Code of Federal Regulations Part 40, Appendix A, Criterion 9.

Table 22. Preliminary Well Plugging and Abandonment Cost Estimate for First Year of Operation

	Value	Units	Source
Assumptions			
Total injection wells to be plugged and abandoned	411	wells	Powertech (2011)
Average well depth	550	ft	Burdock ~450'; Dewey ~600'
Inside casing diameter	4.90	in	5" SDR 17 PVC
Quantity Calculations			
Plugging volume per well	72.0	ft^3	Calculated
Volume cement grout per 94-lb bag	1.27	ft^3	Assumes approximately 6 gal. water per bag
Volume cement grout per ton bulk cement	27.0	ft^3/ton	Calculated
Mass cement per well	2.7	tons	Calculated
Unit Cost Estimates			
Equipment and Labor (includes water and water hauling)			
Wells plugged per week per 3-man crew	16	wells	Quote
Equipment and labor cost per well	$1,000	$/well	Quote
Bulk cement			
Bulk cement cost	$140.42	$/ton	Quote
Cement cost per well	$380	$/well	Calculated
Cement storage pig rental			
Rental cost per week	$625	$/week	Quote
Rental cost per well	$40	$/well	Calculated
Total cost per well	$1,420	$/well	Calculated
Total cost estimate	**$583,620**		Calculated

17.3 Timing for Updated Cost Estimate and Demonstration of Financial Responsibility

1. The Permittee is required provide the Director with an updated cost estimate for plugging and abandonment of all planned injection and production wells for the first wellfield to be constructed before issuance of the Final Permit.
2. The Permittee shall provide the Director with demonstration of adequate financial responsibility to cover the plugging and abandonment of planned injection and production wells for the first wellfield to be constructed prior to issuance of the Final Permit.

18.0 CONSIDERATIONS UNDER FEDERAL LAW

As part of the permit process, pursuant to 40 CFR §144.4, the EPA is required to consider whether other federal laws, specifically Section 106 of the National Historic Preservation Act and Section 7 of the Endangered Species

Act, apply to the issuance of a UIC permit. The EPA determined that these laws are applicable and followed the requirements and procedures of each as described below.

18.1 The National Historic Preservation Act

The updated document entitled *The Environmental Protection Agency National Historic Preservation Act Compliance and Review for the Proposed Dewey-Burdock In-Situ Uranium Recovery Project*, which is part of the Administrative Record for the updated UIC Class III Draft Area Permit, discusses how the EPA intends to comply with Section 106 of the National Historic Preservation Act. The EPA still is considering whether to rely solely on the NRC's section 106 review and consultation, which would be accomplished by adopting the Programmatic Agreement (PA) signed by the NRC, the BLM, and the Advisory Council for Historic Preservation, and potentially by developing and agreeing to an EPA-specific addendum, or whether to complete a separate section 106 process. While the EPA is deciding which of these two approaches to take, the agency is proceeding to address its section 106 responsibilities, as described in the document described above. Regardless of the approach the EPA takes to comply with section 106 of the EPA, the following mitigation measures have been incorporated in the draft Class III and Class V Area Permits:

1. The Permittee shall abide by the stipulations of the Programmatic Agreement among U.S. Nuclear Regulatory Commission, U.S. Bureau of Land Managment, South Dakota State Historic Preservation Office, the Permittee (USA), Inc. and Advisory Council on Historic Preservation Regarding the Dewey-Burdock In-Situ Recovery Project Located in Custer and Fall River Counties South Dakota (PA) dated March 19, 2014, and the EPA addendum to the PA.
2. When evaluated properties are NRHP-eligible, avoidance of the properties will be the preferred option. When avoidance is not possible and adverse effects will result, adverse effects will be resolved in accordance with Stipulation 5 of the PA: Resolution of Adverse Effects.
3. The Permittee will ensure employees and/or contractors involved in all phases of the Project are aware of and comply with the requirements of the PA. The Permittee may use measures such as initial orientation training, as well as pre-job briefings to inform employees and contractors of their responsibilities under the PA accordance with Stipulation 13A of the PA.
4. In the event a previously unknown cultural resource is discovered during the implementation of the Dewey-Burdock Project, all ground disturbance activities shall halt within 150 feet of the area of discovery to avoid or minimize impacts until the property is evaluated for listing on the NRHP by qualified personnel. The Permittee shall ensure the steps listed under Stipulation 9 of the PA are followed.

The EPA is requesting comment on the identification of historic properties, effects to historic properties, and ways to mitigate or avoid adverse effects.

18.2 The Endangered Species Act

Section 7(a)(2) of the Endangered Species Act (ESA), 16 U.S.C. § 1536 (a)(2), requires federal agencies to ensure that actions they authorize, fund, or carry out are not likely to jeopardize the continued existence of federally-listed endangered or threatened species or result in the destruction or adverse modification of designated critical habitat of such species. The EPA has determined that a decision to issue Class III and V area permits and an aquifer exemption for authorization of injection well operations at the proposed Dewey-Burdock uranium in-situ recovery site constitutes actions that are subject to the Endangered Species Act and its implementing regulations (50 CFR part 402).

The EPA developed a Biological Assessment (BA) document and submitted it to the US Fish and Wildlife Service (USFWS) for review and concurrence (see below). The purpose of the BA was to address the effects that UIC Class III and Class V Area Permit issuance may have on species listed as endangered or threatened under the Endangered Species Act (ESA), and their designated critical habitat.

On May 1, 2019, the EPA started reviewing the USFWS Section 7 Consultation website called Information for Planning and Consultation (IPaC) for a list of species and critical habitat that may be present within the project area. The USFWS website was also used to research critical habitats and population for the species that may be present. The eBird Range map (https://ebird.org) recommended by the USFWS website resources section, was also used to research habitat and population for bird species. The following are the three species that may be present inside the project area:

1. NORTHERN LONG-EARED BAT (MYOTIS SEPTENTRIONALIS) - According to the USFWS website, no critical habitat has been reported inside the project area for this species. The Powertech wildlife survey identified bats but did not identify the species. There are no reports of critical habitat for the northern long-eared bat inside the project area. There are mine shafts reported inside the project area that must be investigated for bat populations. The species of bat observed at the site should be identified.
2. RUFA RED KNOT (CALIDRIS CANUTUS RUFA) - According to the USFWS website, no critical habitat has been reported inside the project area for this species. According to the eBirdRange Map, there are no reports of this species inside the project area.
3. WHOOPING CRANE (GRUS AMERICANA) - According to the USFWS website, no critical habitat has been reported inside the project area for this species. According to the eBird Range Map, there are no reports of this species inside the project area.

As a result of its analyses of potential effects on these species and their critical habitat, the EPA concluded in the BA that issuance of the UIC Class III and Class V Area Permits *may affect, but is not likely to adversely affect*, the listed threatened or endangered species or the designated critical habitat for the species found in/near the project area. The EPA submitted its findings in the BA, including appropriate mitigation measures (see below), to the USFWS on June 14, 2019. The USFWS responded in writing on July 8, 2019 concurring with EPA's findings.

The EPA has incorporated the following measures into the UIC Class III and Class V draft Area Permits to avoid, minimize or mitigate any potential effects:

1. If the whooping crane, the rufa red knot or the northern long-eared bat are sighted within one mile of the well sites or associated facilities during construction or operation, all work within one mile of the species' location must cease, and the Powertech must contact the Director and the USFWS immediately. In coordination with the USFWS, work may resume after the terrestrial species leave the area.
2. 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 bat.
3. In the event that construction is planned during the migratory bird nesting and breeding season, a qualified biologist must conduct pre-construction surveys for migratory birds and their nests within five days prior of the initiation of any construction activities.

4. Spills or leaks of chemicals and other pollutants at the UIC well site must be reported to the appropriate regulatory agencies. The procedures of the surface management agency must be followed to contain leaks or spills.
5. If supplemental lighting is used during construction or operation, the lights must be directed and/or sheltered to minimize the amount of light escaping the work or project site.
6. The Permittee shall install netting, use bird balls or other acceptable bird deterrent method to prevent birds and bats from accessing the ponds.
7. Tree removal activities must be conducted outside of the northern long-eared bat active season (April 1 to October 31). This will minimize impacts to northern long-eared bat pups at roosts not yet identified.
8. During the northern long-eared bat active season (April 1 to October 31), the Permittee shall 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 shall investigate the shaft to determine if bats are inside the shaft. If no bats are inside the shaft, the Permittee shall cover the entrance to the shaft with finer mesh to prevent bats from entering. If bats are observed in the shaft, the Permittee shall 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.