STATEMENT OF BASIS

POPLAR RESOURCES LLC

EPU 5-D

ROOSEVELT COUNTY, MT

OEP PERMIT NO. FPT2481-1296

CONTACT: Fort Peck Assiniboine and Sioux Tribes
Office of Environmental Protection
511 Medicine Bear Road, Box 1027
Poplar, Montana 59255
Phone: (406)768-2329

This STATEMENT OF BASIS gives the derivation of site-specific UIC Permit conditions and reasons for them. Referenced sections and conditions correspond to sections and conditions in the Permit.

OEP UIC permits regulate the injection of fluids into underground injection wells so that the injection does not endanger underground sources of drinking water. OEP UIC permit conditions are based upon the authorities set forth in regulatory provisions at Title XXII CCOJ Ch. 2, and address potential impacts to underground sources of drinking water. Under Title XXII CCOJ Ch. 2, SubCh. 3, Sec. 221(b)(4), issuance of this permit does not convey any property rights of any sort or any exclusive privilege, nor authorize injury to persons or property of invasion of other private rights, or any infringement of other Federal, State or local laws or regulations. Title XXII CCOJ Ch. 2, 3, and 4, certain conditions apply to all UIC Permits and may be incorporated either expressly or by reference. General Permit conditions for which the content is mandatory and not subject to site-specific differences (Title XXII CCOJ Ch. 2, 3, 4, and 5) are not discussed in this document.

Upon the Effective Date when issued, the Permit authorizes the construction and operation of injection wells so that the injection does not endanger underground sources of drinking water, governed by the conditions specified in the Permit. The Permit is issued for the operating life of the injection well or project unless terminated for reasonable cause under Title XXII CCOJ Ch. 2, SubCh. 3, Sec. 221(b)(5) and SubCh. 4, Sec. 231(d). The Permit is subject to OEP review at least once every five (5) years to determine if action is required under Title XXII CCOJ Ch. 2, SubCh. 3, Sec. 221(b)(5).

PART I. General Information and Description of Facility

POPLAR RESOURCES LLC PO BOX 547 POPLAR, POPLAR 59255

on

March 09, 2020

submitted an application for an Underground Injection Control (UIC) Program Permit or Permit Modification for the following injection well or wells:

EPU 5-D T29N R51E S19, SESE ROOSEVELT County, MT

Regulations specific to Fort Peck Indian Reservation: Assiniboine & Sioux Tribes—Class II injection wells are found at 40 CFR 147 Subpart JJJ and at Title XXII Chapter 2 of the Fort Peck Tribes' Comprehensive Code of Justice.

The EPU 5-D has been a saltwater disposal well since 1976. The well disposes of fluids from the Mississippian Madison A, B and C formations in the East Poplar Field into the Dakota Formation. When the UIC program became effective in Montana on June 25, 1984, all existing injection wells were granted authorization by rule and an aquifer exemption of the injection zone 1/4 mile from the well bore. A permit was issued January 6, 1987 by EPA Region 8.

The application, including the required information and data necessary to issue or modify a UIC Permit in accordance with Title XXII CCOJ Ch. 2, was reviewed and determined by OEP to be complete.

TABLE 1.1 shows the status of the well or wells as "New", "Existing", or "Conversion" and for Existing shows the original date of injection operation. Well authorization "by rule" under 40 CFR Part 144 Subpart C expires automatically on the Effective Date of an issued UIC Permit.

TABLE 1.1 **WELL STATUS / DATE OF OPERATION**		
NEW WELLS		
Well Name	**Well Status**	**Date of Operation**
EPU 5-D	ACTIVE BUT NOT INJECTING	2/22/1976

PART II. Permit Considerations (Title XXII CCOJ Ch. 2, SubCh. 4, Sec. 231(n))

Hydrogeologic Setting

The majority of the Fort Peck Reservation is overlain by glacial and/or alluvial deposits and the water table aquifer is relatively shallow. Domestic wells in the area are often installed in this shallow aquifer.

Major producing oil bearing formations within the reservation include the Charles and Mission Canyon, Nisku, and Duperow.

Geologic Setting (TABLE 2.1)

The Flaxville Formation The Flaxville Formation is mainly valley fill consisting of silt, sand, and gravel; includes some terrace deposits and glacial drift of Pleistocene age. The glacial till, gravel deposits and alluvium overlay the Hell Creek Formation.
The Hell Creek Formation The Hell Creek Formation is a series of fresh and brackish-water clays, mudstones, sandstones deposited during the last part of the Late Cretaceous-Tertiary period. The lithology consists of gray sandstone and greenish shaly clay and mudstone containing dinosaur bones. There are a few thin lignite and subbituminous coal beds.
The Fox Hills Sandstone The Fox Hills Sandstone is of Late Cretaceous age. It is typically shaly sandstone grading upward into massive brownish sandstone with white sandstone of the Colgate member locally at the top. The Fox Hills Formation overlies the Bearpaw Shale.
The Bearpaw Shale The Bearpaw Shale contains shale, sandstone and claystones with numerous betonite seams of Late Cretaceous age. The Bearpaw consists of dark-gray and brownish clay/shale, thick units of nonfissile bentonitic shale and calcareous and ferruginous concretions throughout. The Bearpaw Shale overlies the Judith River.
The Judith River Formation The Judith River formation if primarily composed of light colored sandstones, somber-gray sandy shales, and siltstones. Some mudstones and coals are evident. The Judith River is of Late Cretaceous age and overlies the Claggett Formation.
The Greenhorn Formation The Greenhorn Formation is Late Cretaceous in age and is marine deposited. The Greenhorn consists of light gray marly and calcareous shale and chalk, occasional limestone nodules.

The Belle Fourche Formation

The Belle Fourche Formation is of Early Cretaceous in age and is marine shelf deposited. It consists of gray to black shale with ironstone concretions and numerous bentonite beds.

The Mowry Shale

The Mowry Shale is Early Cretaceous in age and is marine deposited. The Mowery shale is light gray silicified shale, claystones and siltstones, contains some bentonite. This rock is a fine grained mixed clastic. The Mowry shale is typically a non porous and very low permeability confining zone which overlies the Dakota Silt.

The New Castle Formation

The New Castle Formation is of Early Cretaceous in age. It consists primarily of mudstone. Most of the interval is to be considered not very porous or permeable because of the presence of silt and shale. There are sandstone, fine to course grained, thinly to massively bedded.

The Skull Creek Formation

The Skull Creek Formation is of Early Cretaceous in age. It consists of primarily a shale that is medium to dark grey, soft, and micaceous.

The Dakota Silt

The Dakota Silt is Early Cretaceous in age. This silty section is nonporous and nonpermeable and creates a good confining zone above the Dakota Sand. There are several shale zones in addition to the Dakota Silt which provide confinement between the Dakota Sand and the nearest up hole USDW including the Mowry, Greenhorn, Niobrara and the Telegraph Creek.

The Dakota Sandstone

The Dakota Sandstone is of Early Cretaceous Age and has been deposited in both marine and non-marine environments. The Dakota Sand in this area consists of widespread alternating series of porous sands and shale layers. The porous sand lobes vary in thickness from 6 to 16 feet and porosities range from 18 to 27 percent which make this zone suitable for fluid injection. The Dakota Sand overlies the Kootenai Fuson Formation.

The Kootenai Fuson Formation

The Kootenai Fuson Formation is Early Cretaceous in age and consists of silty shale and mudstones purplish and green in color. This silty shale/mudstone creates a confining zone between the Dakota Sandstone and the Lakota Formation.

The Swift Formation

The Swift Formation is Late Jurassic in age and consists of dark gray-greenish gray shale interbedded with siltstone. The Swift is good confining zone below the Lakota.

The Rierdon Formation

The Rierdon Formation is Late Jurassic in age and consists of alternating gray to dark gray limy shale and limestones. The thin calcareous to noncalcareous beds contain dense nodular limestone. The Rierdon overlies the Piper Silt.

The Piper Limestone Formation

The Piper Limestone Formation is Middle Jurassic in age and includes red beds, gypsum, and associated marine beds underlying the Rierdon Formation. The Piper consists of the red siltstones and gypsum grading into gray shale, limestone. The Piper Formation overlies the Spearfish Formation.

The Firemoon Formation
The Firemoon Formation is an interval of bioclastic carbonate and green calcareous shales.

The Kline Formation
The Kline Formation is a member that consists of limestone and shale.

The Spearfish Formation
The Spearfish Formation is Permian and Triassic in age and was marine deposited. The Spearfish can be divided into the Saude, Pine Salt, and a lower shale member. The Spearfish Formation consists of red, sandy clay, or shale with some gypsum. Fissile gray shale can be interbedded with reddish-orange siltstone and mudstone with anhydrite and dolomite beds. The Spearfish unconformably overlies the Amsden Formation.

The Madison Group
The Madison Group includes the Charles, Mission Canyon and the Lodgepole Formations and is Early to Late Mississippian in age. The depositional environment was marine and consists of interfingering carbonate and evaporite sequences.

The Mission Canyon Formation
The Mission Canyon Formation is Early to Late Mississippian in age. It consists of light to dark brown limestone, ranging from crypto-crystalline to micro-crystalline, with fossiliferous intervals.

The Lodgepole Formation
The Lodgepole Formation is Early Mississippian in age and was marine deposited. The Lodgepole Formation is a dark gray to brown argillaceous limestone finely crystalline to granular, sometimes chalky to cherty. The Lodgepole Formation overlies the Bakken Formation.

The Bakken Formation
The Bakken Formation is Late Devonian and Early Mississippian in age and was offshore marine deposited. The Bakken consists of an Upper Shale, Middle Dolomite Siltstone and a Lower Shale. The Upper and Lower members consist of dark gray to black shale. The Middle member consists of light gray siltstone – dolomitic, calcareous and locally sandy. The Bakken Formation overlies the Three Forks Formation.

The Three Forks Formation
The Three Forks Formation is Late Devonian in age and the depositional environment was near shore marine. The Three Forks Formation consists of grayish brown to olive-gray interbedded siltstones and dolostone and interbedded shale, dark gray to dark brown. The Three Forks Formation overlies the Nisku Formation.

The Nisku Formation
The Nisku Formation (Birdbear) is Late Devonian in age and was nearshore marine deposited. The Nisku Formation is predominately brown to light grayish brown to tan limestone with some dolomite and can be anhydritic. The Nisku Formation overlies the Duperow Formation.

The Duperow Formation
The Duperow Formation is Late Devonian in age and is a near shore marine deposit. The top of the Duperow is identified by the Ireton shale marker to the top followed by a thick series of carbonates consisting of limestone, dolomatized limestones, and dolomite with anhydrite and minor shale.

TABLE 2.1
GEOLOGIC SETTING
EPU 5-D

Formation Name	Top (ft)	Bottom (ft)	TDS (mg/l)	Lithology
Alluvium/Glacial Deposits	0	60		Sand, Gravel
Flaxville	60	70		Sand, Gravel
Fort Union	70	80		Shale, Siltstone, Sandstone
Hell Creek	80	150		Sand
Fox Hills	150	200		Sandstone, Siltstone
Bearpaw	200	711	< 3000	Shale
Judith River	711	1101	< 10000	Sandstone
Eagle	1101	1966		Sandstone
Niobrara	1966	2316		Shale, Siltstone
Green Horn	2316	2510		Calcareous Shale, Chalk
Graneros	2510	2874		
New Castle	2874	2909		
Skull Creek	2909	3066		
Dakota Silt	3066	3134		Siltstone, Shale
Dakota Sandstone	3134	3506	7200	Sandstone, Shale
Kootenai Fuson	3506	3588		

Proposed Injection Zone(s) (TABLE 2.2)

An injection zone is a geological formation, group of formations, or part of a formation that receives fluids through a well. The proposed injection zones are listed in TABLE 2.2.

Injection will occur into an injection zone that is separated from USDWs by a confining zone which is free of known open faults or fractures within the Area of Review.

The approved injection zone in the original permit issued by EPA Region 8 was from 3100 to 3505 feet. This permit issued by OEP is extending the injection top from 3100 to 3066 feet to include to the entire Dakota Silt formation located at 3066 to 3134 feet.

TABLE 2.2
INJECTION ZONES
EPU 5-D

Formation Name	Top (ft)	Base (ft)	TDS (mg/l)	Fracture Gradient (psi/ft)	Porosity	Exempted?*
DAKOTA	3066	3506	7200	0.569	16	P

*** C - Currently Exempted**
E - Previously Exempted
P - Proposed Exemption
N/A - Not Applicable

Confining Zone(s) (TABLE 2.3)

A confining zone is a geological formation, part of a formation, or a group of formations that limits fluid movement above the injection zone. The confining zone or zones are listed in TABLE 2.3.

TABLE 2.3
CONFINING ZONES
EPU 5-D

Formation Name	Formation Lithology	Top (ft)	Base (ft)
SKULL CREEK	BLACK GREY SHALE	2909	3066
KOOTENAI FUSON	SHALE	3506	3588

Underground Sources of Drinking Water (USDWs) (TABLE 2.4)

Aquifers or the portions thereof which contain less than 10,000 mg/l total dissolved solids (TDS) and are being or could in the future be used as a source of drinking water are considered to be USDWs. The USDWs in the area of this facility are identified in TABLE 2.4.

TABLE 2.4
UNDERGROUND SOURCES OF DRINKING WATER (USDW)
EPU 5-D

Formation Name	Formation Lithology	Top (ft)	Base (ft)	TDS (mg/l)
Alluvium/Glacial Deposits	Sand, Gravel	0	60	
Flaxville	Sand, Gravel	60	70	
Fort Union	Shale, Siltstone, Sandstone	70	80	
Hell Creek	Sand	80	150	
Fox Hills	Sandstone, Siltstone	150	200	
Judith River	Sandstone	711	1101	< 10000
Dakota	Sandstone, Shale, Siltstone	3066	3506	7200

PART III. Well Construction (Title XXII CCOJ Ch. 2, SubCh. 5, Sec. 241(e))

TABLE 3.1
WELL CONSTRUCTION REQUIREMENTS
EPU 5-D

Casing Type	Hole Size (in)	Casing Size (in)	Cased Interval (ft)	Cemented Interval (ft)
Surface	12.250	9.625	0 - 942	0 - 942
Longstring	8.750	7.000	0 - 3583	260 - 3583
Liner	6.366	5.000	0 - 3156	158 - 3156
Tubing		2.875	0 - 3130	Not cemented

The approved well completion plan will be incorporated into the Permit as APPENDIX A and will be binding on the Permittee. Modification of the approved plan is allowed under Title XXII CCOJ Ch. 2 SubCh3. Sec 221(b)(9) provided written approval is obtained from the Director prior to actual modification.

Casing and Cementing (TABLE 3.1)

The well construction plan was evaluated and determined to be in conformance with standard practices and guidelines that ensure well injection does not result in the movement of fluids into USDWs. Well construction details for this "new" injection well is shown in TABLE 3.1.

Remedial cementing may be required if the casing cement is shown to be inadequate by cement bond log or other demonstration of Part II (External) mechanical integrity.

Tubing and Packer

Injection tubing is required to be installed from a packer up to the surface inside the well casing. The packer will be set above the uppermost perforation. The tubing and packer are designed to prevent injection fluid from coming into contact with the outermost casing.

Tubing-Casing Annulus (TCA)

The TCA allows the casing, tubing and packer to be pressure-tested periodically for mechanical integrity, and will allow for detection of leaks. The TCA will be filled with fresh water treated with a corrosion inhibitor or other fluid approved by the Director.

Monitoring Devices

The permittee will be required to install and maintain wellhead equipment that allows for monitoring pressures and providing access for sampling the injected fluid. Required equipment may include but is not limited to: 1) shut-off valves located at the wellhead on the injection tubing and on the TCA; 2) a flow meter that measures the cumulative volume of injected fluid; 3) fittings or pressure gauges attached to the injection tubing and the TCA for monitoring the injection and TCA pressure; and 4) a tap on the injection line, isolated by shut-off valves, for sampling the injected fluid.

All sampling and measurement taken for monitoring must be representative of the monitored activity.

PART IV. Area of Review, Corrective Action Plan (Title XXII CCOJ Ch. 2, SubCh. 3, Sec. 221(b)(12) and (13))

TABLE 4.1
AOR AND CORRECTIVE ACTION

Well Name	Type	Status (Abandoned Y/N)	Total Depth (ft)	TOC Depth (ft)	CAP Required (Y/N)
EPU 44-19H	Producer	N	8940	2600	N
EPU 107	Producer	Y	5821	See Note below	N

Note: During P&A of the EPU 107, cement was squeezed into perfs at the following depths 2537',1046', 75'

TABLE 4.1 lists the wells in the Area of Review ("AOR") and shows the well type, operating status, depth, top of casing cement ("TOC") and whether a Corrective Action Plan ("CAP") is required for the well. If TABLE 4.1 is not included in this document, then there are no Area of Review wells for this injection well.

Area Of Review

Applicants for Class I, II (other than "existing" wells) or III injection well Permits are required to identify the location of all known wells within the injection well's Area of Review (AOR) which penetrate the injection zone, or in the case of Class II wells operating over the fracture pressure of the formation, all known wells within the area of review that penetrate formations which may be affected by increased pressure. Under Title XXII CCOJ Ch. 2, SubCh. 5, Sec. 241(b) the AOR may be a fixed radius of not less than one quarter (1/4) mile or a calculated zone of endangering influence. For Area Permits, a fixed width of not less than one quarter (1/4) mile for the circumscribing area may be used.

Corrective Action Plan

For wells in the AOR which are improperly sealed, completed, or abandoned, the applicant shall develop a Corrective Action Plan (CAP) consisting of the steps or modifications that are necessary to prevent movement of fluid into USDWs.

The CAP will be incorporated into the Permit as APPENDIX F and become binding on the permittee.

PART V. Well Operation Requirements (Title XXII CCOJ Ch. 2, SubCh. 5, Sec. 241(f))

TABLE 5.1 INJECTION ZONE PRESSURES EPU 5-D			
Formation Name	**Depth Used to Calculate MAIP (ft)**	**Fracture Gradient (psi/ft)**	**Initial MAIP (psi)**
Dakota	3190 (top perf)	0.569	780

Approved Injection Fluid

The approved injection fluid is limited to Class II injection well fluids pursuant to Title XXII CCOJ Ch. 2, SubCh. 1, Sec. 204(1), (2), and (3). For disposal wells injecting water brought to the surface in connection with natural gas storage operations, or conventional oil or natural gas production, the fluid may be commingled and the well used to inject other Class II wastes such as drilling fluids and spent well completion, treatment and stimulation fluid. Injection of non-exempt wastes, including unused fracturing fluids or acids, gas plant cooling tower cleaning wastes, service wastes, and vacuum truck and drum rinsate from trucks and drums transporting or containing non-exempt waste, is prohibited.

Injection Pressure Limitation

Injection pressure, measured at the wellhead, shall not exceed a maximum calculated to assure that the pressure used during injection does not initiate new fractures or propagate existing fractures in the confining zones adjacent to the USDWs.

The applicant submitted injection fluid density and injection zone data which was used to calculate a formation fracture pressure and to determine the maximum allowable injection pressure (MAIP), as measured at the surface, for this Permit.

TABLE 5.1 lists the fracture gradient for the injection zone and the approved MAIP, determined according to the following formula:

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

FP = formation fracture pressure (measured at surface)
fg = fracture gradient (from submitted data or tests)
sg = specific gravity (of injected fluid)
d = depth to top of injection zone (or top perforation)

Injection Volume Limitation

Cumulative injected fluid volume limits are set to assure that injected fluids remain within the boundary of the exempted area. Cumulative injected fluid volume is limited when injection occurs into an aquifer that has been exempted from protection as a USDW.

Mechanical Integrity (Title XXII CCOJ Ch. 2, SubCh. 5, Sec. 241(c))
An injection well has mechanical integrity if:

1. there is no significant leak in the casing, tubing, or packer (Part I); and
2. there is no significant fluid movement into a USDW through vertical channels adjacent to the injection well bore (Part II).

The Permit prohibits injection into a well which lacks mechanical integrity.

The Permit requires that the well demonstrate mechanical integrity prior to injection and every five (5) years thereafter in accordance with Title XXII CCOJ Ch. 2, SubCh. 5, Sec. 241(c). A demonstration of mechanical integrity includes both internal (Part I) and external (Part II). The methods and frequency for demonstrating Part I and Part II mechanical integrity are dependent upon well-specific conditions as explained below.

The results of the test shall be submitted to the Director no later sixty (60) after the demonstration, unless the test is witnessed by a representative of OEP.

PART VI. Monitoring, Recordkeeping and Reporting Requirements

Injection Well Monitoring Program
At least once a year the permittee must analyze a sample of the injected fluid for total dissolved solids (TDS), specific conductivity, pH, and specific gravity. This analysis shall be reported to OEP annually as part of the Annual Report to the Director. Any time a new source of injected fluid is added, a fluid analysis shall be made of the new source.

Instantaneous injection pressure, injection flow rate, cumulative fluid volume and TCA pressures must be observed on a weekly basis. A recording, at least once every thirty (30) days, must be made of the injection pressure, annulus pressure, monthly injection flow rate and cumulative fluid volume. This information is required to be reported annually as part of the Annual Report to the Director.

PART VII. Plugging and Abandonment Requirements (Title XXII CCOJ Ch. 2, SubCh. 5, Sec. 241(d))

Plugging and Abandonment Plan

Prior to abandonment, the well shall be plugged in a manner that isolates the injection zone and prevents movement of fluid into or between USDWs, and in accordance with any applicable Federal, State or local law or regulation. Tubing, packer and other downhole apparatus shall be removed. Cement with additives such as accelerators and retarders that control or enhance cement properties may be used for plugs; however, volume-extending additives and gel cements are not approved for plug use. Plug placement shall be verified by tagging. Plugging gel of at least 9.2 lb/gal shall be placed between all plugs. A minimum 50 ft surface plug shall be set inside and outside of the surface casing to seal pathways for fluid migration into the subsurface. Within sixty (60) days after plugging the owner or operator shall submit Plugging Record (OEP Form FPT-UIC-4-0109) to the Director. The Plugging Record must be certified as accurate and complete by the person responsible for the plugging operation. The plugging and abandonment plan is described in Appendix E of the Permit.

PART VIII. Financial Responsibility (Title XXII CCOJ Ch. 2, SubCh. 3, Sec. 221(a))

Demonstration of Financial Responsibility

The permittee is required to maintain financial responsibility and resources to close, plug, and abandon the underground injection operation in a manner prescribed by the Director. The permittee shall 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 Director 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 operator has chosen to demonstrate financial responsibility with:

SCHEDULE A AND SCHEDULE B TRUST AGREEMENT dated November 22, 2019 for $398,200

Evidence of continuing financial responsibility is required to be submitted to the Director annually.