UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 8
1595 Wynkoop Street
DENVER, CO 80202-1129
Phone 800-227-8917
http://www.epa.gov/region08

Ref: 8P-W-UIC

APR 0 1 2014

Don Smith
Slawson Exploration CO, Inc.
1675 Broadway, Suite 1600
Denver, Colorado 80202-4714

RE: Public Notice for Proposed Aquifer Exemption and Related Draft Major Permit Modification
Formation: Inyan Kara
Well: Big Bend 1-5 SWD
UIC Permit No: ND22184-08837
Fort Berthold Indian Reservation
Mountrail County, North Dakota.

Dear Mr. Smith:

The purpose of this letter is to notify you that the U.S. Environmental Protection Agency (EPA) Region 8 is making an additional revision to the Draft Major Modification letter that was sent to you on March 21, 2014. This revision corrects the depth for the Inyan Kara Formation of the Dakota Group that was originally submitted based on nearby well logs. The driller's log puts the formation at (13) thirteen feet deeper than originally permitted. The revised Appendix C and Statement of Basis reflects the depth to be from 4,845-5,274 feet below ground surface.

If you have questions or concerns, please contact Craig Boomgaard of my staff at (303) 312-6794.

Sincerely,

Douglas Minter

Douglas Minter
Acting UIC Program Unit Chief
Office of Partnerships and Regulatory Assistance

Enclosures:

1) Revised Draft Major Permit Modification to Appendix C
2) Revised Statement of Basis

cc:

Edmund Baker, Environmental Director
Three Affiliated Tribes
404 Frontage Road
New Town, North Dakota 58763

cc: Cover Letter Only
Tex Hall. Chairman
Three Affiliated Tribes
404 Frontage Road
New Town, ND 58763

Mark Bohrer
North Dakota Industrial Commission-Oil & Gas Division
Dept. 405
600 East Blvd.
Bismarck, ND 58505

Bureau of Indian Affairs
Great Plains Regional Office
115 Fourth Avenue S.E.
Aberdeen, SD 57401

APPENDIX C

OPERATING REQUIREMENTS

MAXIMUM ALLOWABLE INJECTION PRESSURE:

Maximum Allowable Injection Pressure (MAIP) as measured at the surface shall not exceed the pressure(s) listed below.

WELL NAME	MAXIMUM ALLOWED INJECTION PRESSURE (psi) ZONE 1 (Upper)
BIG BEND 1-5 SWD	1,350

INJECTION INTERVAL(S):

Injection is permitted only within the approved injection interval listed below. Injection perforations may be altered provided they remain within the approved injection interval and the Permittee provides notice to the Director in accordance with Part II, Section A, Paragraph 6. Specific injection perforations can be found in Appendix A.

WELL NAME: BIG BEND 1-5 SWD

FORMATION NAME	APPROVED INJECTION INTERVAL (KB, ft) TOP	BOTTOM	FRACTURE GRADIENT (psi/ft)
Inyan Kara	4,845.00 -	5,274.00	0.800

ANNULUS PRESSURE:

The annulus pressure shall be maintained at zero (0) psi as measured at the wellhead. If this pressure cannot be maintained, the Permittee shall follow the procedures listed under Part II, Section C. 6. of this permit.

MAXIMUM INJECTION VOLUME:

WELL NAME: BIG BEND 1-5 SWD

FORMATION NAME	MAXIMUM VOLUME LIMIT (bbls)
Inyan Kara	71,500,000.00

STATEMENT OF BASIS

SLAWSON EXPLORATION CO, INC.

BIG BEND 1-5 SWD
MOUNTRAIL COUNTY, ND

EPA PERMIT NO. ND22184-08837

CONTACT: Patricia Pfeiffer
U. S. Environmental Protection Agency
Ground Water Program, 8P-W-GW
1595 Wynkoop Street
Denver, Colorado 80202-1129
Telephone: 1-800-227-8917 ext. 312-6271

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.

EPA UIC permits regulate the injection of fluids into underground injection wells so that the injection does not endanger underground sources of drinking water. EPA UIC permit conditions are based upon the authorities set forth in regulatory provisions at 40 CFR Parts 144 and 146, and address potential impacts to underground sources of drinking water. Under 40 CFR 144.35 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. Under 40 CFR 144 Subpart D, 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 (40 CFR Parts 144, 146 and 147) 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 40 CFR 144.39, 144.40 and 144.41. The Permit is subject to EPA review at least once every five (5) years to determine if action is required under 40 CFR 144.36(a).

PART I. General Information and Description of Facility

Slawson Exploration CO, INC.
1675 Broadway, Suite 1600
Denver, CO 80202-4714

on

June 25, 2010

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

BIG BEND 1-5 SWD
2500' FNL & 2400' FWL, SENW S5, T151N, R92W
Mountrail County, ND

Regulations specific to Three Affiliated Tribes injection wells are found at 40 CFR 147 Subpart G.

The application, including the required information and data necessary to issue or modify a UIC Permit in accordance with 40 CFR Parts 144, 146 and 147, was reviewed and determined by EPA to be complete.

This well is replacing both the Fox 1-28 SWD and Van Hook SWD 1-21 that were submitted previously. Those applications were pulled by the operator due to Three Affiliated Tribes concern about the locations. Both wells were located over the New Town Aquifer. The current well location is not over the New Town Aquifer.

The Permit will expire upon delegation of primary enforcement responsibility (primacy) for applicable portions of the UIC Program to the Three Affiliated Tribes or the State of North Dakota unless the delegated agency has the authority and chooses to adopt and enforce this Permit as a Tribal or State Permit.

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**
BIG BEND 1-5 SWD	New	N/A

PART II. Permit Considerations (40 CFR 146.24)

Hydrogeologic Setting

Two cross sections provided by the operator demonstrate that within at least three miles of the proposed location of Slawson Exploration's saltwater disposal (SWD) well in southern Mountrail County, North Dakota, the Lower Cretaceous injection formation (Inyan Kara (Kik), lower Dakota Group) is uniformly overlain by 3000' ± 100' of relatively impermeable sedimentary rocks belonging to several Cretaceous formations. Furthermore, the sections show the Inyan Kara is uniformly underlain in the same area by over 400' of relatively impermeable Jurassic Swift Formation sedimentary rocks.

List of the exhibits in EPA Permit file under Permit Application section include:

* SW-NE stratigraphic section, datum top Dakota Group, Inyan Kara (Kik), Big Bend SWD area
* NW-SE stratigraphic section, datum top Dakota Group, Inyan Kara (Kik), Big Bend SWD area
* Cross-section index map, Big Bend SWD area
* Top Dakota structure contour map, Big Bend SWD area

Explanation of the exhibits on file:

* Cross-section lengths: roughly 12 miles (each)
* These sections run well-to-well along a zig-zag path, as opposed to a linear section into which the well data are projected. (Refer to index map)
* Well-to-well spacing is not specifically indicated on the sections, but these distances may be inferred from the map.
* Most of the wells shown on the map include the wells' lateral segments in plan view. The surface location of each horizontal well, where the elogs were run, is indicated on the map by the small circle.
* The cross-section intersection lies roughly one-quarter mile east of the proposed SWD location, as shown on the index map by the red star. A second red star on the upper right side of the map shows the location of a second Slawson SWD well, just north and outside of the Reservation boundary (green line).
* The sections display electric logs (elogs) from suitable wells in which elogs were recorded. (Current practice is to run elogs in the vertical portions of new horizontal wells at a map density of roughly one well per square mile. As a result, elogs are available from slightly less than half of the wells currently drilled. Gamma ray logs were recorded in all wells, per state requirement, but these gamma logs are inferior to elogs for purposes of well-to-well formation correlation.)
* Cross-section stratigraphic interval: Jurassic Piper Formation to Upper Cretaceous Fox Hills Formation. The sections are stratigraphic, rather than structural, using the top Dakota (KDAK) as the datum horizon.
* The Inyan Kara Formation (lower Dakota Group) is highlighted yellow near the bottom of either section. The Fox Hills (and younger) beds are highlighted yellow at the top of either section. Inyan Kara water salinity is significantly higher than that of the Fox Hills.
* The formation tops are indicated by horizontal black, or sometimes red, lines across each elog. The lithology of these units is described below.

The formation tops are picked based on characteristics of the elogs' resistivity and gamma ray (or spontaneous potential, or SP) curves. When only a gamma ray log is available, the well-to-well correlations are less reliable.

The top of Pierre shale/base Fox Hills contact is very approximate, based on a slight gamma ray decrease or SP increase, indicating less clay and consequently more permeability in the overlying

Fox Hills. This pick is further compromised because, as is the intent, it roughly coincides with the base of surface casing. Gamma radiation recorded through the surface casing is significantly attenuated by the steel pipe, and the resulting shift in the gamma curve at the base casing can mask the decrease in the natural formational gamma from Pierre into Fox Hills.

The structure map shows the subsea depth to top Inyan Kara (Kik, lower Dakota Group). Generalized formation dip is NW at roughly 30 feet per mile, although local to the SWD location the dip rate is less.

Faulting is rare and of minor (< 5 feet) displacement in this area, as evidenced by the many horizontal wells drilled without fault complications.

This data was prepared by Bob Bogle, geologist, Slawson Exploration.

Geologic Setting (TABLE 2.1)

Expected depths, thicknesses and general lithology of units to be encountered in Big Bend 1-5 SWD. Depths measured from cased hole logs just outside the ¼ mile area of review (Jericho 2-5H-TF and Coyote 1-32H).

Note: tops and thicknesses from surface through base of Foxhills/top Pierre inferred from surface exposures and shallow boreholes. Top of Pierre, and tops and thicknesses of units below this point, are projected from deep well-log control.

Measured Depth (thickness)

0 (23) Coleharbor, Pleistocene: unconsolidated sediments, genetically related to glacial processes and a northerly clastic sediment source area. Three general categories: pebbly, sandy, silty clay (87%); sand and gravel (8%); and silt and clay (5%). The pebbly, sandy, silty clay unit is inferred to be glacial till, has low permeability, and consequently is an aquitard (as opposed to aquifer). The sand and gravel unit, thought to be derived from glacial rivers, is a well-sorted, highly-permeable aquifer, and is the largest source of potable groundwater in Mountrail County. The silt and clay unit is another low-permeability aquitard, and was deposited in larger glacial lakes.

23 (535) Bullion Creek, Paleocene: Silt and clay, brownish-gray, varying amounts of sand, lignite, natural brick, limestone, and sandstone; river, lake, and swamp sediment. Equivalent to strata previously referred to the Tongue River Formation.

558 (485) Cannonball, Paleocene: Sand and mudstone, brownish-yellow and light gray, with lenticular and concretionary sandstone, marine shoreline and offshore sediment.

1043 (370) Hell Creek, Cretaceous: sand, somber shades of light-gray to brownish-gray, and cross bedded sandstone with lignite shale and dark-purple, manganese-oxide –stained concretions; river sediment and some estuarine sediment.

1413 (300) Fox Hills, Cretaceous: Silt and shale, sandy shale, sandstone, and siltstone, shades of buff to yellowish-brown; interbedded with lignitic shale laminae; some beds fossiliferous; intermittent sandstone at top is grayish-brown to white, fine, siliceous; silt and shale gradational downward with shale of the Pierre Formation; largely marine coastal sediment.

1713 (1874) Pierre, Cretaceous: Shale, light to medium or dark-gray, fissile, flaky to blocky, generally noncalcareous; marine offshore sediment.

3587 (268) Niobrara, Cretaceous: Shale, medium-light-gray to medium-gray, calcareous with white, limey inclusions (First White Specks); marly zone near the middle.

3855 (230) Carlile, Cretaceous: Shale, medium-dark-gray to black, non-calcareous, soft; large ellipsoidal concretions containing abundant gypsum (selenite); zone of fine, secondary crystals at the top.

4085 (182) Greenhorn, Cretaceous: Shale, dark gray, calcareous, soft; thin-bedded shaly limestone; good electric and radioactivity log marker; (Second White Specks).

4267 (221) Belle Fourche, Cretaceous: Shale, medium to dark-gray, soft, micaceous, lumpy to massive, spongy, includes beds of light-bluish-gray bentonitic clay.

4488 (357) Mowry (Upper Confining Interval): Shale, medium to dark gray, soft, flakey to splintery, spongy; traces of light-blue-gray bentonitic clay with no effective porosity or permeability; top is marked by radioactive zone. In the New Town area, the sandy Newcastle Formation ("Muddy") is absent, and the Mowry is instead underlain by the Skull Creek: shale, medium to dark gray, micaceous, soft, flaky to lumpy.

4845 (416) Inyan Kara, Cretaceous (Injection Zone): Upper part is mainly marine sandstone, light-gray, fine to coarse, quartzose; and shale, gray, silty, and lumpy. Lower part is mainly nonmarine sandstone, medium to coarse, angular to subrounded, quartzose, occasional lenses of gray, bentonitic shale commonly contains manganese-siderite spherulites (pellets).

5261 (446) Swift, Jurassic (Lower Confining Interval): Shale, dark-gray to greenish, fissile, waxy, silty, calcareous; local limestone and glauconitic sandstone.

5706 (90) Rierdon, Jurassic: Shale, varicolored shades of gray, green, and red, calcareous; some limestone. Offshore marine deposits.

5796 (448) Piper, Jurassic: Shale; red, purple, and greenish gray; silty; gypsum, and anhydrite layers. Limestone; white, brown, or gray; dolomitic; finely crystalline, dense, oolitic, fossiliferous. The Piper is subdivided based upon three general lithologies; shale, limestone, and salt (Dunham). The upper Piper contains offshore marine deposits and the lower Piper (Dunham salt) is a shallow marine, redbed evaporite sequence.

6244 (246) Spearfish, Triassic: Siltstone; light to reddish brown. Sandstone; light brown to reddish brown; fine grained; rounded, frosted grains; slightly calcareous. Mudstone; reddish orange; traces of pyrite and dolomite. Halite; clear; silty; large crystals, massive; contains anhydrite. Interbedded with gray, fissile, shale.

6490 (47) Spearfish-Pine Salt member, Triassic: as above, containing salt and may be bounded by unconformities. Shallow marine deposits.

6537 (391) Opeche, Permian: Shale to mudstone; reddish orange, silty; slighty dolomitic, contains gypsum and anhydrite laminae; and up to 200' salt. Shallow, restricted marine deposits.

6928 (141) Minnelusa (Broom Creek), Permian: Sandstone; gray reddish orange to brownish red; shaly; fine grained to medium grained, subangular to well rounded; locally dolomitic, anhydritic, or cherty; interbedded with microcrystalline dolomite, pinkish gray to reddish gray; and shale; reddish gray; anhydrite and ripup clasts at the unconformable upper contact. Shallow marine deposits.

7069 (199) Amsden, Pennsylvanian: Dolostone; pinkish gray to yellowish brown: microcrystalline to crystalline; silty; interbedded shale that is reddish brown to dark brown; silty; blocky. Sandstone; light red to gray; fined grained; near top of unit. Anhydrite; white to gray; fine crystalline; dolomitic. Shallow marine deposits.

7268 (205) Tyler, Pennsylvanian: Shale to mudstone; light gray to black, red and green hues, varicolored, sometimes mottled; laminated; interbedded sandstone lenses; carbonaceous, occasional thin coal stringers; calcareous to non-calcareous; some pyrite; brecciated in places, intraclasts. Sandstone; grayish brown to reddish brown; fine grained to medium grained; coarser grained lenses; subrounded to well rounded; massive to laminated; basal lag conglomerate. Limestone; gray to black, varicolored, micritic, argillacaceous; locally anhydritic. Fossils of marine animals locally abundant. Marine to non-marine, fluvial channels, swamp, beach, and barrier island deposits.

7473 (165) Otter, Mississippian: Shale; greenish gray, reddish gray; carbonaceous, variegated along basin margin. Limestone; gray to green; marly; thin bedded; fossiliferous; oolitic. Offshore marine deposits.

7638 (322) Kibbey, Mississippian: Sandstone; light gray to reddish gray; fine grained to medium grained, silty. Shale; reddish to variegated; silty; interbedded gypsum. Limestone; white to brown; dolomitic. A persistent limestone bed in the middle of the unit (Kibbey Lime) is an excellent marker on elogs. Shallow marine deposits.

7960 (710) Charles- Madison Group, Mississippian: In the area of the proposed Big Bend SWD well, the Charles Formation consists of two intervals: Poplar and Ratcliffe. The Poplar interval contains interbedded anhydrite, halite, dolostone, mudstone and shale, with common iron staining. This interval contains most of the halite in the Madison Group. The Ratcliffe interval contains limestone, yellowish-brown to brown; dolomitic; oolitic; alternating with dolomitic limestone, anhydrite, and shale beds.

8670 (616) Mission Canyon-Madison Group, Mississippian: In the area of the proposed Big Bend SWD well, the Mission Canyon Formation consists of two intervals: Frobisher-Alida and Tilston. The Frobisher-Alida interval consists of limestone, yellowish-brown to pink; fine-grained, fragmental, oolitic and pseudo-oolitic; with intertonguing lenses of anhydrite and shaly, dolomitic limestone. The Tilston interval consists of limestone; yellowish-brown to pink; dolomitic; cherty; fine-grained to coarsely crystalline; oolitic and crinoidal; anhydrite; some gray shale.

9286 (823) Lodgepole-Madison Group, Mississippian: In the area of the proposed Big Bend SWD well, the Lodgepole Formation is represented by a single interval: Bottineau. The Bottineau is limestone, dark gray to brown, light orange, or pinkish; dolomitic to cherty to argillaceous; fragmental; finely crystalline to granular; oolitic; dense; vuggy to fine-intergranular.

10109 (20) Bakken-upper, Mississippian: Shale; dark to black; carbonaceous; noncalcareous; fissile; pyritic. Offshore marine deposits.

10129 (45) Bakken-middle , Devonian: Siltstone; light gray; dolomitic, calcareous; locally sandy. Offshore marine deposits.

10174 (43) Bakken-lower, Devonian: Shale: dark to black; carbonaceous; noncalcareous; fissile; pyritic. Offshore marine deposits.

10217-10230 (TVD) Three Forks, Devonian: Dolostone and Limestone; grayish brown to olive-gray interbedded with greenish blue, yellowish brown, and purplish gray lenses; argillaceous; silty; cross-laminated, mottled, mud cracks; anhydritic; pyritic; fossiliferous zones. Interbedded shale; dark gray to dark brown. Nearshore marine deposits.

References:

Clayton, Lee, 1972. Geology of Mountrail County, North Dakota, North Dakota Geological Survey Bulletin 55-IV.

Murphy, Edward, State Geologist, Helms, Lynn, Director of Department Minerals, North Dakota Geologic Society, North Dakota Stratigraphic Column Miscellaneous Series 91, 2009

Bluemle, John P., Sidney B. Anderson, John A. Andrew, David W. Fischer and Julie A. LeFever, 1986. North Dakota Stratigraphic Column, North Dakota Geological Survey Miscellaneous Series 66.

All TDS values are actual lab measurements of recovered DST water, as listed in the Catalog of North Dakota Water Chemistries. The specific well data used is in the permit application file.

TABLE 2.1
GEOLOGIC SETTING
BIG BEND 1-5 SWD

Formation Name	Top (ft)	Base (ft)	TDS (mg/l)	Lithology
Coleharbor		23		sand, silt, clay
Bullion Creek	23	558	2,110	silt, sand, clay, lignite, limestone
Cannonball	558	1,043		sand, mudstone
Hell Creek	1,043	1,413	1,530	sand, lignite shale
Fox Hills	1,413	1,713	1,530	silt, shale, sand, siltstone
Pierre	1,713	3,587	> 10,000	shale
Niobrara	3,587	3,855		shale
Carlile	3,855	4,085		shale
Greenhorn	4,085	4,267		shale
Belle Fourche	4,267	4,488		shale
Mowry	4,488	4,845		shale
Inyan Kara	4,845	5,274	6,150 - 9,170	sand
Swift	5,261	5,706		shale
Rierdon	5,706	5,796		shale
Piper	5,796	6,244		shale
Spearfish	6,244	6,490	314,953	siltstone, sand, mudstone, shale
Spearfish: Pine Salt member	6,490	6,537		salt
Opeche	6,537	6,928		shale to mudstone, salt
Minnelusa Broom Creek	6,928	7,069	324,800 - 325,730	sand, dolomite
Amsden	7,069	7,268		dolostone
Tyler	7,268	7,473	280,721 - 336,143	shale, mudstone
Otter	7,473	7,638		shale, mudstone
Kibbey	7,638	7,960	271,725 - 277,496	sand
Charles	7,960	8,670	324,000	anhydrite, dolostone, limestone
Mission Canyon	8,670	9,286	303,400	limestone
Lodgepole	9,286	10,109	303,400	limestone
Bakken: upper	10,109	10,129		shale
Bakken: middle	10,129	10,174	244,272	siltstone
Bakken: lower	10,174	10,217		shale
Three Forks	10,217	10,230	295,557	dolostone, limestone

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 Inyan Kara (Injector) is Cretaceous and is described as: Upper part is mainly marine sandstone, light-gray, fine to coarse, quartzose; and shale, gray, silty, and lumpy. Lower part is mainly nonmarine sandstone; medium to coarse, angular to subrounded, quartzose, occasional lenses of gray, bentonitic shale commonly contains manganese-siderite spherulites (pellets).

Only sand intervals with porosity will be perforated and utilized for injection. After reviewing the open hole logs, it is anticipated that there will be 177 feet of porous zone available for perforations and injection. The average porosity for these intervals has been determined to be 21.58. The total dissolved solids for the formation range between 6,150-9,170 after 715 swab volume (bbls).

TABLE 2.2

INJECTION ZONES

BIG BEND 1-5 SWD

Formation Name	Top (ft)	Base (ft)	TDS (mg/l)	Fracture Gradient (psi/ft)	Porosity	Exempted?*
Inyan Kara	4,845	5,274	6,150 - 9,170	0.800	20.00%	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.

Confining zones above and below the injection zone, the Mowry and Swift shales respectively, were confirmed through basin cross-sections provided by the operator. From the data provided, both confining layers have been demonstrated to be intact and uniform in both elevation and composition within at least a three mile radius around the proposed injection location.

The Inyan Kara is confined above by the Mowry Shale approximately 357' thick in the proposed well and confined below by the Swift Shale, approximately 446' thick while the Inyan Kara is expected to be approximately 416' thick.

The Mowry (Upper Containment) is Cretaceous and is described as: Shale, medium to dark gray, soft, flakey to splintery, spongy; traces of light-blue-gray bentonitic clay, with no effective porosity or permeability; top is marked by radioactive zone. In the New Town area, the sandy Newcastle Formation (Muddy) is absent, and the Mowry is instead underlain by the Skull Creek: shale, medium to dark gray, micaceous, soft, flaky to lumpy.

The Swift formation (Lower Containment) is Jurassic and is described as: Shale, dark gray to greenish, fissile to splintery, dull to sub waxy texture, calcareous; local limestone and glauconitic sandstone.

TABLE 2.3
CONFINING ZONES
BIG BEND 1-5 SWD

Formation Name	Formation Lithology	Top (ft)	Base (ft)
Upper Confining Zone: Mowry	Shale, medium to dark gray, soft, top is marked by radioactive zone.	4,488	4,845
Lower Confining Zone: Swift	Shale, dark-gray to greenish, silty, calcareous.	5,274	5,707

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.

All surface water strata, down to and including the Fox Hills formation (+/- 1713') are considered to be USDWs. Below lists the names of USDW strata and TDS information:

Formation Name	(Top Depth in feet)	(TDS mg/L)
Coleharbor Formation	(0 ft)	(N/A)
Bullion Creek Formation	(23 ft)	(2110)
Cannonball Formation	(558 ft)	(N/A)
Hell Creek Formation	(1,043 ft)	(1,530)
Fox Hills Formation	(1,413 ft)	(1,530)
Inyan Kara	(4,845 ft)	(6,150-9,170)

Depth Source:

Clayton, Lee, 1972. Geology of Mountrail County, North Dakota, North Dakota Geological Survey Bulletin 55-IV.

Bluemle, John P., Sidney B. Anderson, John A. Andrew, David W. Fischer and Julie A. LeFever, 1986. North Dakota Stratigraphic Column, North Dakota ?Geological Survey Miscellaneous Series 66.

TDS Source:

USGS Water Resources of North Dakota/Water Resources of the Fort Berthold Indian Reservation, West Central North Dakota,
Report 98-4098

All TDS values are actual lab measurements of recovered DST water, as listed in the Catalog of North Dakota Water Chemistries, except for the Inyan Kara Formation. After the completion of the

Big Bend 1-5 SWD, the well was perforated and the Inyan Kara Formation was swab to obtain the value ranges listed above.

The use of two strings of casing, two cement jobs designed to surface, and tubing will minimize the risk. The tubing annulus will be monitored daily for pressure, and if detected, the SWD will be shut down immediately and necessary repairs made.

TABLE 2.4
UNDERGROUND SOURCES OF DRINKING WATER (USDW)
BIG BEND 1-5 SWD

Formation Name	Formation Lithology	Top (ft)	Base (ft)	TDS (mg/l)
Coleharbor	sand, silt, clay		23	
Bullion Creek	silt, sand, clay, lignite, limestone	23	558	2,110
Cannonball	sand, mudstone	558	1,043	
Hell Creek	sand, lignite shale	1,043	1,413	1,530
Fox Hills	silt, shale, sand, siltstone	1,413	1,713	1,530
Inyan Kara Formation of the Dakota Group	sand	4,845	5,274	6,150 - 9,170

Exempted Aquifer(s) (40 CFR 144.7 and 146.4)

Aquifers exempted from protection as a USDW are listed in TABLE 2.5. Exempted is that portion of the aquifer between the depths listed ("TOP" and "BASE") and within the Exempted Radius of the well's surface location, or for an Area Permit, one-quarter (1/4) mile exterior to the defined Area Permit boundary. "Criteria" corresponds to the appropriate criteria (below) for exemption. "VOLUME" is the maximum volume of fluid which can be injected into the exempted area before the injected fluids exceed the exemption boundary, calculated using the following formula:

V = Pi * radius2 * height * porosity / 5.615

where V = VOLUME (in barrels)
Pi = 3.1416
radius2 = Exempted Radius (squared) - generally 1/4 mile
height = height of reservoir ("BOTTOM" - "TOP")
porosity = reservoir porosity (in percent)
5.615 = conversion factor (cubic feet per barrel)

The specific extent of the proposed aquifer exemption will be within 1900 feet of the Big Bend 1-5 SWD well located in the SENW, Section 5 T151N R92W. The approved injection zone includes the Inyan Kara Formation of the Dakota Group from the depth of 4,845 to 5,261 feet.

A limitation on the volume of injectate that may be injected into the well during its operational life is required. The EPA plans to limit the total maximum volume of injectate that may be injected in the well to 71,500,000 barrels. This is based on conservative EPA estimates for overall average injection zone porosity of 20% for the Inyan Kara Formation. The actual porosity over the 177 feet of perforated intervals was determined to be 21.58%. As actual porosity values for the injection zone may vary away from the wellbore (out to a distance of 1,900 feet), this conservative approach (using reduced values for porosity) will help ensure that injectate will remain in the exempted portions of Inyan Kara Formation.

TABLE 2.5
AQUIFER EXEMPTION
BIG BEND 1-5 SWD

Formation Name	Top (ft)	Base (ft)	Criteria	Volume (bbl)
Inyan Kara	4,845	5,274	c	71,500,000

An aquifer or a portion thereof may be determined to be an "exempted aquifer" provided it meets criteria, listed below.

a It does not currently serve as a source of drinking water; AND

Based on the Mountrail County (and peninsula) population trends and the amount of available water in the Sentinel Butte, Tongue River, Fox Hills/Hell Creek Formations, New Town and Sanish Aquifers, there is sufficient quantity of ground water in these resources to serve the current and future population of Mountrail County and the peninsula without the development of the exempted portion of the Inyan Kara Formation. Also, the Missouri River/Lake Sakakawea is the primary source of drinking water for most of the reservation. The lake holds a permanent pool of 4,980,000 Ac-Ft with a top range of 23,821,000 Ac-Ft with a useable volume up to 18,841,000 Ac-ft. Lake Sakakawea currently provides drinking water for Four Bears, Mandaree, Parshall, Twin Buttes and White Shield.

b(1) It 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 for a Class II or III operation to contain minerals or hydrocarbons that considering their quantity and location are expected to be commercially producible; OR

b(2) It cannot now and will not in the future serve as a source of drinking water because it is situated at a depth or location which makes recovery of water for drinking water purposes economically or technically impractical; OR

b(3) It cannot now and will not in the future serve as a source of drinking water because it is so contaminated that it would be economically or technologically impractical to render that water fit for human consumption; OR

b(4) It cannot now and will not in the future serve as a source of drinking water because it is located over a Class III well mining area subject to subsidence or catastrophic collapse; OR

c The total dissolved solids content of the ground water is more than 3,000 and less than 10,000 mg/l and it is not reasonably expected to supply a public water system.

The estimated costs to develop the proposed exempted aquifer as a water supply source including any treatment costs and costs to develop alternative water supplies is discussed below. It includes costs for well construction, transportation, and water treatment for each source.

The primary factor controlling the cost of developing the proposed exempted aquifer as a water supply source is depth and water quality. As shown above, the Inyan Kara Formation is found at approximately 4,898 feet below land surface, with a total depth of 5,444 feet. In contrast, the better quality Fox Hills/ Hell Creek Formation is available at approximately 1,413 feet below land surface and an approximate TD of 1,710 feet, with several other acceptable formations at shallower depths.

Slawson recently drilled, cased, and partially perforated the Big Bend 1-5 SWD for a cost of $1,085,900. A phone conversation with Rex at Backman Drilling (701) 734-6667 located in Wilton, ND provided verbal information for 5" cased domestic wells of $31.00/foot. Agri Industries Inc. (Williston, ND) provided verbal information for 100-200 gallon per minute industrial wells for 200 foot 10 inch casing of approximately $40,000, a 900 foot Fort Union well around $60,000 and a 1600 foot Fox Hills well approximately $150,000. Dennis Water Well Service located in New Town, ND (701) 627-2390 provided a verbal quote of $280,000 to drill a Fox Hills well. These costs represented do not include location construction or surface equipment, as it is assumed that these additional costs would be the same for each formation.

As can be observed above, drilling cost varies by depth, size of hole, and contractor. The estimated total depth drilling cost to drill an Inyan Kara water supply well exceeds the cost of drilling a Fox Hills water supply well by an estimated $805,900, with additional savings and shallower depths. Therefore, based on cost, the quantity, and quality of the water available in the Fox Hills/Hell Creek aquifers and other supplies located at shallower depths, this suggests that the proposed exempted aquifer is situated at a depth which makes recovery for USDW purposes economically impractical.

PART III. Well Construction (40 CFR 146.22)

TABLE 3.1
WELL CONSTRUCTION REQUIREMENTS
BIG BEND 1-5 SWD

Casing Type	Hole Size (in)	Casing Size (in)	Cased Interval (ft)	Cemented Interval (ft)
Surface	13.50	9.63	0 - 1,863	0 - 1,874
Longstring	8.75	7.00	0 - 5,410	0 - 5,444
Tubing	6.24	3.50	0 - 4,799	-

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 40 CFR 144.52(a)(1) 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 (40 CFR 144.55)

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.

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 40 CFR 146.6 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.

There are no production wells within the 1/4 mile area of review. However, there are two oil production wells within 1/2 mile of the proposed disposal well's location. The Slawson Jericho 2-5H-TF (NWNE S5 T151N R92W), and the Slawson Coyote 1-32H (NWNE S5 T151R92W), both horizontal wells penetrate the injection zone approximately 1/4 mile past the north part of the eastern perimeter of the AOR.

The Jericho 2-5H-TF well (NWNE S5 T151N R92W, 14,460' MD, 10,230 TVD) was completed in June 2010 (North Dakota Well Completion Report Form 6 is in the EPA Permit file under the Permit Application tab). Construction of the 2-5H-TF1-21H includes 9 5/8" 36# J55 casing below the Fox Hills @ 1676' MD cemented to surface with 540 sacks, 7" 29 & 32# P110 intermediate casing @ 10,520' MD (10,224' TVD) cemented with 680 sacks, and 4 ½" 11.6# P110 liner with liner hanger pack-off, 20 external swell packers and 17 sleeves @ 9,698-14,429' MD. The 7" casing primary cement job covers the injection zone (Dakota group) with the TOC at approximately 2,450'. A copy of the CBL was provided. The well poses no threat at this time, but will be monitored per requirements in Appendix B.

The Coyote 1-32H well (NWNE S5 T151R92W, 14,460' MD, 10,230 TVD) was completed in September 2009 (North Dakota Well Completion Report Form 6 is in the EPA Permit file under the Permit Application tab). Construction of the 1-32H includes 9 5/8" 36# J55 casing below the Fox Hills @ 1693' MD cemented to surface with 550 sacks, 7" 26# HCP110 & 32# P110 intermediate casing @ 10,769' MD (10,135' TVD) cemented with 710 sacks, and 4 ½" 11.6# HCP110 liner with liner hanger pack-off, 17 external swell packers and 18 sleeves @ 9,714-15,402' MD. The 7" casing primary cement job covers the Dakota group with the TOC at approximately 1,520'. A copy of the CBL was provided. The well poses no threat at this time, but will be monitored per requirements in Appendix B.

The cement in both of these wells is not considered adequate per EPA Guidance NO. 34: Cement bond logging techniques and interpretation. Therefore the operator performed an analysis to determine the length of time under radial flow conditions that it will take for the injectate to reach the area of review wells (approximately 50-55 years). A pressure falloff test is being required to determine if the injection zone has radial or linear flow. If linear flow is found, then time to reach the well could be shorter. The Braden Head in both wells will be monitored regularly, if increased pressures are detected then injection will cease and investigation of the increase will be conducted. The injected fluids will also be analyzed to determine the concentrations of some of the key constituents. A step rate test is also being required to ensure that the injection pressure is not fracturing the injection zone.

Should it become apparent that remediation is necessary in either well, injection will cease and the appropriate remedial actions will be taken. These actions could include, but are not limited to, perforating below the Dakota group and block squeezing, pressure testing, and returning the well to service.

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 (40 CFR 146.23)

TABLE 5.1
INJECTION ZONE PRESSURES
BIG BEND 1-5 SWD

Formation Name	Depth Used to Calculate MAIP (ft)	Fracture Gradient (psi/ft)	Initial MAIP (psi)
Inyan Kara	4,845	0.800	1,355

Approved Injection Fluid

The approved injection fluid is limited to Class II injection well fluids pursuant to 40 CFR § 144.6(b). 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)

A step rate test will be performed to determine the fracture gradient of the injection zone.

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 (40 CFR 146.8)

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 periodically thereafter. 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.

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 EPA 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 (40 CFR 146.10)

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 (EPA Form 7520 13) 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 (40 CFR 144.52)

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 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 operator has chosen to demonstrate financial responsibility with:

Surety Bond, received May 9, 2011

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

The operator has FR mechanism in place for $75,000.