STATEMENT OF BASIS

PETRO-HUNT LLC
STENSLAND LL 12B-3-1
ROOSEVELT COUNTY, MT
FORT PECK INDIAN RESEVATION

FORT PECK TRIBES PERMIT NO. FPT1653-2544

CONTACT: Office of Environmental Protection
Fort Peck Assiniboine and Sioux Tribes
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Poplar, Montana
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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 Ch2, 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. Under Title XXII CCOJ Ch.2, SubCh. 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, SubCh. 2, 3, 4,and 5) and are not discussed in this document.

Upon the Effective Date, the Permit governed by the conditions specified therein, 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

PETRO-Hunt LLC
on
May 5, 2009

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

Stensland LL 12B-3-1
SWNW 12-29N-48E
2375 FNL AND 330 FWL of Sec 12, Twn 29N, Rge 48E
Roosevelt County, Montana
Fort Peck Indian Reservation

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.

Petro-Hunt, LLC proposes to convert an existing production well into a Class II commercial salt water disposal well in the Palomino field injecting into the Dakota/Lakota sandstone located at a depth of 3790 feet from ground level. Produced water from the Kirven well will be the initial source water for the injection well. The Kirven is produced from the Nisku formation and has a TDS of 36,256 mg/l.

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.

TABLE 1.1

WELL STATUS / DATE OF OPERATION

NEW WELLS

Well Name	API No.	Well status	Date of Operation
Stensland LL 12B-3-1	2508521710	New	N/A

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. The Mississippian Madison Charles is the primary producer on the Fort Peck Reservation. The Charles is subdivided into several producing zones by gamma ray marker and porosity zones. The lower Madison Group is predominantly limestone with some anhydrite, dolomite, shale, and evaporites in the upper Charles Formation which is the main reservoir.

Geologic Setting (TABLE 2.1)

TABLE 2.1
GEOLOGIC SETTING
Stensland LL 12B-3-1

Formation Name	Top (ft)	Base (ft)	Lithology	TDS (mg/L)			
Alluvial Glacial	0	25	Sand and Gravel	Value Range	960	to	2200
Hell Creek	25	150	Sand	Value Range	770	to	1700
Fox Hills	150	200	Sandstone, Siltstone	Value Range	770	to	1700
Bearpaw	200	1358	Shale	Unknown		to	
Judith River	1358	1423	Sandstone	Value Range	3000	to	10000
Claggett	1423	1744	Shale	Unknown			
Eagle	1744	1796	Sandstone	Unknown			
Telegraph Creek	1796	2215	Shale, Siltstone	5800			
Niobrara	2215	2917	Shale, Siltstone	Value Range	6100	To	7000
Greenhorn	2917	3262	Calcareous Shale, Chalk	2400			
Mowry	3262	3711	Shale, Siltstone	22000			
Dakota Silt	3711	3790	Shale, Siltstone	14000			
Dakota Sandstone	3790	4187	Sandstone	Value Range	8000	to	14000
Swift	4187	4464	Shale, Siltstone	17000			
Rierdon	4464	4775	Shale, Limestone	19000			
Piper	4775	5100	Siltstone, Limstone	35000			
Spearfish	5100	5237	Shale	25000			
Amsden	5237	5370	Limestone,Sandstone	13500			
Otter	5370	5454	Shale	12000			

Formation Name	Top (ft)	Base (ft)	Lithology	TDS (mg/L)			
Kibbey	5454	5599	Sanstone, Limestone	40000			
Madison	5701	6946	Carbonate, Evaporite	Range Value	15000	-	17000
Lodgepole	6946	7474	Limestone Chalk	15000			
Bakken	7474	7509	Shale, Siltstone	10000			
Three Forks	7509	7599	Siltsone,Shale	14000			
Nisku	7599	7687	Limestone	13000			
Duperow	7687		Limestone	Unknown			

Total dissolved solids information for the formations listed were from USGS Water Resources Investigations Report 91-4032, September 1981 and resistivity logs for the Stensland LL 12B-3-1.

Geologic Setting Stensland 12B-3-1, Sec 12-T29N-R48E
Roosevelt County, MT

The Alluvium (0-25')
Alluvial Glacial – 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 (25'-150')
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 (150'-200')
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 (200'-1358')
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 (1358'-1423')
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 Claggett Formation (1423'-1744')
The Claggett Formation is dark gray shale to gray clay shale with numerous bentonite beds near the base and of Late Cretaceous age. The Claggett Shale overlies the Eagle Formation.

The Eagle Sandstone (1744'-1796')
The Eagle Sandstone is Late Cretaceous in age. It consists of sandstone, shaly sandstone with interbeded lignite stringers. The eagle Formation overlies the Telegraph Creek Formation.

The Telegraph Creek Formation (1796'-2215')
The Telegraph Creek formation is Late Cretaceous in age consisting of buff, soft, fissile sandy shale with small amounts on concretionary sandstone. The primary rock type is shale with secondary rock types consisting of siltstone, sandstone and mudstone. The Telegraph Creek overlies the Niobrara Formation.

The Niobrara Formation (2215'-2917')
The Niobrara Formation is Late Cretaceous in age. The depositional environment is marine. The Niobrara Formation is chiefly calcareous shale with limestone concretions with siltstone and bentonite beds locally.

The Greenhorn Formation (2917'-3262')
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 Mowry Shale (3262'-3711')
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 Dakota Silt (3711'-3790')
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 (3790'-3889')
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 (3889'-4019')
The Kootenai 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 Lakota Formation (4019'-4187')
The Lakota Formation is Early Cretaceous in age. The Lakota in this area consists of widespread alternating porous sands and shale. The porous sand lobes have thickness of 4 to 6 feet and porosities ranging from 13 to 30 percent. The porous and permeable sands are well suited for fluid injection. The Lakota Formation overlies the Swift Formation.

The Swift Formation (4187'-4464')
The Swift Formation is Late Jurassic in age and consists of dark gray-greenish gray shale interbedded with siltstone. The Swift is a good confining zone below the Lakota injection zone.

The Rierdon Formation (4464'-4775')
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 Formation (4775' –5100')
The Piper 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 Spearfish Formation (5100'-5237')
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 Amsden Formation (5237'-5370')
The Amsden Formation is Early – Middle Pennsylvanian in age and the depositional environment was marine. The Amsden consists of upper dolomite, brownish limestone and lower shale and sandstone/siltstone beds.
The Amsden unconformably overlies the Otter Formation.

The Otter Formation (5370'-5454')
The Otter Formation of the Big Snowy Group is Mississippian in age and was deposited in a marine environment. The Otter Formation consists mainly of variegated shale interbedded with limestone. The Otter Formation overlies the Kibbey Formation.

The Kibbey Formation (5454'-5701')
Kibbey Lime (5588'-5599')
The Kibbey Formation is the lowest formation within the Big Snowy Group and is Late Mississippian in age. The Kibbey is reddish or occasionally light-gray, medium to fine-grained, rounded sandstone with limestone or dolomite below sandstone and variegated shaly siltstone at the base. The Kibbey Formation overlies the Charles Formation of the Madison Group.

The Madison Group (5701'-6946)
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 Lodgepole Formation (6946'-7474')
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 (7474'-7509')
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 (7509'-7599')
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 (7599'-7687')
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 (top @ 7687')
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.

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 a zone that is defined as a USDW and is separated from other USDWs by a confining zone which is free of known open faults or fractures within the Area of Review. An aquifer exemption has been requested and approved for this well. A sample of the water from the injection zone will be collected prior to receiving authorization to inject. The sampling procedure is detailed in Appendix H of the permit. If the TDS of the sample is greater than 10,000 mg/l, the aquifer exemption will be revoked.

The injection zone is into the Dakota/Lakota formation situated at approximately 3790-3889 feet and approximately 4019-4187 feet respectively. The Dakota or Fall River is described as a light-gray to tan, fine to medium grained, well sorted sandstone that ranges in thickness from 50 to 300 feet. The Lakota is described as a tan, yellowish-brown, gray and green, chertbearing conglomerate and sandstone with a thickness ranging from 100 to 500 feet. The TDS is 3000 to 10,000 mg/l and is considered a potential USDW.

TABLE 2.2
INJECTION ZONES
Stensland LL 12B-3-1

Formation Name	Top (ft)	Base (ft)	TDS (mg/L)	Fracture Gradient (psi/ft)	Porosity	Exempted?*
Dakota Sandstone	3790	4187	4524	0.67	22%	P

*** C - Currently Exempted**
E - Previously Exempted
P - Proposed

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 out of the injection zone. The confining zone or zones are listed in TABLE 2.3

There are several confining formations, composed of shale and siltstone that are located above the injection zone. The Dakota Silt is immediately above the injection zone. Above the Dakota silt are the Mowry, Greenhorn, Niobrara, and Telegraph formations. The Bear Paw and Clagget formations are composed of shale and confine the formations that are currently being used as a drinking water resource.

TABLE 2.3
CONFINING ZONES
Stensland LL 12B-3-1

Formation Name	Top (ft)	Base (ft)	Lithology
Mowry/Dakota Silt	3262	3720	Shale, Siltstone

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.

Most aquifers producing potable water on the Fort Peck Indian Reservation are stream alluvium (valley-fill deposits), outwash sand and gravel, pre-glacial alluvial deposits of Pleistocene age, Flaxville Formation, Fort Union Formation, and Fox Hills and Hell Creek Formations. All of these sources are within 1000 feet of the surface on the reservation. Most domestic and public water supply wells are found at shallow depths, with few deeper than 250 feet.

At depths greater than 1000 feet, the Judith River Formation, Dakota Sandstone, and the Madison group form the known aquifers. Historically, the Dakota Sandstone has been used as receiving aquifer for injection of brines and other oilfield wastes that contain water of high salinity. Within 2 miles of the proposed injection well there are two injection wells that inject into the Dakota Sandstone, the Tribal Bear SWD and the Wolf Point Tribal #1 SWD.

The actual TDS of the Dakota Sandstone in this well is not known but the Wolf Point Tribal #1 SWD well has a representative water sample of the formation in a well that is in the same production field, the Palomino and is approximately 1 ½ miles to the east of the Stensland LL 12B-3-1. The TDS in the Wolf Point Tribal #1 SWD is 4524 mg/l, which is less than 10,000 mg/l TDS and therefore requires an aquifer exemption. A representative sample will be collected and analyzed from the proposed injection zone. If the injection zone's TDS is greater than 10,000 mg/L, then the aquifer exemption will be removed.

In the Palomino oil field, the Judith River is the lowermost USDW in use. Total dissolved solids information for the formations listed were from USGS Water Resources Investigations Report 91-4032, September 1981 and resistivity logs for the Stensland LL 12B-3-1.

TABLE 2.4
UNDERGROUND SOURCES OF DRINKING WATER (USDW)
Stensland LL 12B-3-1

Formation Name	Top (ft)	Base (ft)	Lithology	TDS (mg/L)
Alluvial Glacial	0	25	sand, gravel	960 to 2200
Hell Creek	25	150	sand	770 to 1700
Fox Hills	150	200	sandstone, siltstone	770 to 1700
Judith River	1358	1423	sandstone	3000 to 10,000
Claggett	1423	1744	Shale	unknown
Eagle	1744	1796	Sandstone	unknown
Telegraph Creek	1796	2215	Shale Siltstone	5800
Niobrara	2215	2917	Shale Siltstone	6000 to 7000
Greenhorn	2917	3262	Calcareous shale,chalk	2400
Dakota Sandstone	3790	4187	Sandstone	8000 to 14000
Duperow	7687		Limestone	unknown

Exempted Aquifer (Title XXII CCOJ Ch. 2 SubCh 5, Sec. 241 9b))

Aquifers exempted from protection as 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. "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 formula:

$$V = Pi * radius^2 * Height * Porosity / 5.615$$

where

V = volume (in barrels)
Pi = 3.1416
$Radius^2$ = exempted radius (squared) ¼ mile
Height = height of the reservoir (bottom to top)
Porosity = reservoir porosity in decimal
5.615 = conversion factor (cubic feet/bbl)

Table 2.5
AQUIFER EXEMPTION
Stensland LL12B-3-1

Formation Name	Top (ft)	Base (ft)	Criteria	Volume (bbls)
Dakota Sandstone	3790	4187	C	57,264,165

An aquifer or a portion thereof maybe 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

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 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 sourcree 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 3000 and less than 10,000 mg/l and it is not reasonably expected to supply a public water system.

The Stensland LL 12B-3-1 will be a converted from a production well to a commercial salt water disposal well. This well was originally a dry hole drilled into the Bakken formation to 7750'. The proposed injection is into the Dakota Sandstone formation to the depths listed in Table 2.2. The aquifer exemption is required because the anticipated TDS is between 3,000 and 10,000 mg/l. The actual TDS of the Dakota Sandstone formation in this well is not known. However, the Wolf Point Tribal #1 SWD well's representative water sample from the formation has a TDS of 4524 mg/l. The Wolf Point Tribal #1 SWD well is also located in the Palomino Field approximately 1 ½ miles to the east of the Stensland LL 12B-3-1 location.

A review of the Groundwater Information Center for Montana's website for existing drinking water wells within a 2 mile radius show maximum depths of 600 feet. Most aquifers producing potable water on the Fort Peck Indian Reservation are stream alluvium (valley-fill deposits), outwash sand a gravel, pre-glacial alluvial deposits of Pleistocene age, Flaxville formation, Fort Union formation, and Fox Hills and Hells Creek formations. Most wells are found at shallow depths with few deeper than 250 feet. Future water needs are anticipated to be met by the Fort Peck Rural Water System Act of 2000 (Public Law

106-382) that will bring water from the Missouri River to serve the Fort Peck Indian Reservation. The Tribes have a codified water right to receive 950,000 acre feet annually from the Missouri River (pg 6, The Fort Peck-Montana Compact, 1985). Therefore the Dakota Sandstone formation is not currently a source of drinking water and is not reasonably expected to supply drinking water to residents of the Fort Peck Indian Reservation.

Should the water sample indicate that the TDS of the formation fluid is less than 3,000 mg/L and (and no longer supports criteria (c)) or greater than 10,000 mg/L (an aquifer exemption is not required), the aquifer exemption will be null and void.

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

TABLE 3.1
WELL CONSTRUCTION REQUIREMENTS
Stensland LL 12B-3-1

Hole Casing Type	Casing Size (in)	Cased Size (in)	Cemented Interval (ft)		Interval (ft)		Cement Type
Surface	9.625	12.250	0	1936	0	1936	G&C
Longstring	7.000	8.750	0	7750	2500	7750	G

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, SubCh 4 Sec. 231 (c), (e), and (f) 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 injection well is shown in TABLE 3.1.

The CBL submitted by the Permittee indicates 33 feet of 80% bond index from 3573 feet ot 3606 feet in the confining zone, the Dakota silt which should ensure isolation of the injected fluid into the Dakota Sand.

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)installation 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 and 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.

Operator will install and maintain in continuous working order a “one-month” pressure recording chart on the well head, where it will continuously measure the surface injection pressure for the well during all times. The chart will be changed monthly by the Operator and the charts will be retained in the Operator‘s offices for reference and reporting purposes for a minimum of 5 years.

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

PART IV. Area of Review, Corrective Action Plan (Title XXIICCOJ Ch 2, SubCh3, Sec. 221 (b) (12) and (13))

TABLE 4.1
AOR AND CORRECTIVE ACTION
Stensland LL12B-3-1

Well Name	Type	Status (Abandoned Y/N)	Total Depth (ft)	TOC Depth (ft)	CAP Required (Y/N)
N/A					

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) that 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 that may be affected by increased pressure. Under Title XXII CCOJ, Ch2, 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.

There are no wells in the AOR and a corrective Action Plan is not necessary for this permit.

There are no known or identifiable faults in the area of review.

There are no known drinking water wells within the Area of Review and none within a one mile radius of the proposed injection well.

Corrective Action Plan
For wells in the AOR that 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.

No corrective action is needed.

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

TABLE 5.1
INJECTION ZONE PRESSURES
Stensland LL12B-3-1

Formation Name	Depth Used to Calculate MAIP (ft)	Fracture Gradient (psi/ft)	Initial MAIP (psi)
Dakota Sandstone	3775	0.67	815

The MAIP is based on the fracture gradient derived from the Wolf Point Tribal #1. A 95% safety factor was calculated and the result was rounded to the nearest multiple of five.

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)

The applicant is proposing a fracture gradient of 0.670 psi/ft for the Dakota Sandstone formation, based on step rate test performed on the Wolf Point Tribal #1 that is also completed in the Dakota Sandstone formation and is located approximately 11/2 miles to the east. A step-rate test following EPA guidance will be required 30 days after injection commences.

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 (MI) 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 that 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 I (Internal) MI will be demonstrated prior to beginning injection and at least once every five (5) years after the last successful demonstration of Part I MI. A demonstration of Part I MI is also required prior to resuming injection following any workover operation that affects the casing, tubing, or packer. Part I MI may be demonstrated by a standard tubing-casing annulus pressure test using the maximum permitted injection pressure or 1000 psi, whichever is less, with ten (10) percent or less pressure change over thirty (30) minutes.

The cement bond log does not show 80% or greater bonding for 33 continuous feet through the upper or lower confining zones. Thus a baseline Temperature Log and a Radioactive Tracer Survey (RTS) are required as described in Appendix B to prove confinement of fluids within the injection interval (Part II Mechanical Integrity.

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. Pressure gauges must be installed on the tubing and the TCA and must be maintained in good working order at all times. A written 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 9.6 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 a 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 (TitleXXII 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 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: U.S. Specialty Insurance Co. Surety Bond No.. B004820, in the amount of $48,000.00. Evidence of continuing financial responsibility is required to be submitted to the Director annually.