UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
UNDERGROUND INJECTION CONTROL PROGRAM

Permit No. ND22361-11336

Class II Commercial Salt Water Disposal Well

Big Bend 3-6 SWD
Mountrail County, North Dakota

Issued To

Slawson Exploration Co. Inc.
1675 Broadway, Suite 1600
Denver, Colorado 80202

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PART I. AUTHORIZATION TO CONSTRUCT AND OPERATE

Under the authority of the Safe Drinking Water Act (SDWA) and Underground Injection Control (UIC) Program regulations of the U. S. Environmental Protection Agency (EPA) codified at Title 40 of the Code of Federal Regulations (40 CFR) parts 2, 124, 144, 146, and 147, and according to the terms of this permit (Permit),

Slawson Exploration Co. Inc.
1675 Broadway, Suite 1600
Denver, Colorado 80202

hereinafter referred to as the "Permittee," is authorized to construct and to operate the following Class II well:

Big Bend 3-6 SWD
250 feet FNL and 200 feet FWL, Section 6, T151N, R92W
Mountrail County, North Dakota

This Permit is based on representations made by the applicant and on other information contained in the administrative record. Misrepresentation of information or failure to fully disclose all relevant information may be cause for termination, revocation and reissuance, or modification of this Permit and/or formal enforcement action. It is the Permittee's responsibility to read and understand all provisions of this Permit.

Where a state or tribe is not authorized to administer the UIC program under the SDWA, the EPA regulates underground injection of fluids into wells so that injection does not endanger Underground Sources of Drinking Water (USDWs). The EPA UIC permit conditions are based on authorities set forth at 40 CFR parts 144 and 146 and address potential impacts to USDWs. Under 40 CFR part 144, subpart D, certain conditions apply to all UIC permits and may be incorporated either expressly or by reference. Regulations specific to Indian country injection wells in North Dakota are found at 40 CFR § 147.1752.

The Permittee is authorized to engage in underground injection in accordance with the conditions of this Permit. Any underground injection activity not authorized by this Permit or by rule is prohibited.

Compliance with the terms of this Permit does not constitute a defense to any enforcement action brought under the provisions of Section 1431 of the SDWA or any other law governing protection of public health or the environment, nor does it serve as a shield to the Permittee's independent obligation to comply with all UIC regulations. Nothing in this Permit relieves the Permittee of any duties under applicable regulations.

This Permit is issued for the operating life of the facility or until it expires under the terms of the Permit, unless modified, revoked and reissued, or terminated under 40 CFR §§ 124.5, 144.12, 144.39, 144.40 or 144.41, and shall be reviewed at least once every five (5) years to determine if action is required under 40 CFR § 144.36(a).

Issue Date: April 5, 2019 Effective Date

/Darcy O' Connor/

Darcy O'Connor
Assistant Regional Administrator*
Office of Water Protection

* Throughout this Permit the term "Director" refers to either the Assistant Regional Administrator for the Office of Water Protection (OWP) or the Assistant Regional Administrator of Environmental Compliance, Enforcement and Justice (ECEJ).

PART II. SPECIFIC PERMIT CONDITIONS

Section A. WELL CONSTRUCTION REQUIREMENTS

These requirements specify the approved minimum construction standards for well casing and cement, injection tubing, and packer.

The EPA-approved well construction plan is incorporated into this Permit as APPENDIX A. Changes to the approved construction plan prior to authorization to inject must be approved through permit modification by the Director, prior to being physically incorporated.

1. Casing and Cement

The well or wells shall be cased and cemented to prevent the movement of fluids into or between USDWs and shall be in accordance with 40 CFR § 146.22. Remedial construction measures may be required if the well is unable to demonstrate mechanical integrity.

2. Injection Tubing and Packer

Injection tubing is required and shall be run and set with a packer. The packer setting depth may be changed, provided the well construction requirements in APPENDIX A are met and the Permittee provides notice and obtains the Director's approval for the change.

3. Sampling and Monitoring Devices

The Permittee shall install and maintain in good operating condition:

(a) a pressure actuated shut-off device attached to the injection flow line set to shut-off the injection pump when or before the Maximum Allowable Injection Pressure (MAIP) is reached at the wellhead;

(b) one-half (1/2) inch female iron pipe fitting, isolated by shut-off valves and located at the wellhead at a conveniently accessible location, for the attachment of a pressure gauge capable of monitoring pressures ranging from normal operating pressures up to the MAIP described in Part II, Section B.4:

- (i) on the injection tubing string(s);
- (ii) on the tubing-casing annulus (TCA); and
- (iii) on the surface casing-production casing (bradenhead) annulus;

(c) a sampling port such that samples shall be collected at a location that ensures they are representative of the injected fluid; and

(d) a non-resettable cumulative volume recorder attached to the injection line.

4. Pre-Injection Logs and Tests

Well logging and testing requirements prior to receiving authorization to inject are found in APPENDIX B. Well logs and tests shall be performed according to current EPA-approved procedures, or alternate procedures approved by the Director. The Director may stipulate specific test methods and criteria best suited for a specific well construction and injection operation. Limited injection is permissible prior to receiving authorization to inject only for the purposes of conducting the initial well logs and tests required in APPENDIX B.

5. Postponement of Construction or Conversion to Injection Wells

(a) For wells to be newly drilled, the permit shall expire if well construction has notbegun within two years of the Effective Date of the Permit.

(b) The Permittee may request a one-time extension of the permit expiration date, not to exceed two additional years, which must be made prior to expiration of the Permit. Notification shall be in writing and state the reasons for the delay, provide an estimated completion date, and list additional wells within the area of review (AOR) that were not included in the initial permit application. For those newly completed AOR wells that penetrate the upper confining zone, a well construction diagram, cement records and cement bond logs are also required.

Once the Permit has expired under this part, the Permittee will need to reapply for a UIC permit and restart the complete permit process, including opportunity for public comment, before injection can occur.

(c) For wells that have begun construction or are conversions to an injection well, if authorization to inject has not been provided within two years of spud date or the Effective Date of the Permit, respectively, the Permittee is subject to the conditions found in Part II, Section E.5. *Wells Not Actively Injecting* or may elect to convert the well to a non-UIC well found in Part III, Section A.2 *Conversion to Non-UIC Well.*

Section B. WELL OPERATION

1. Outermost Casing Injection Prohibition

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

2. Requirements Prior to Receiving Authorization to Inject

Well injection may commence only after all well construction and pre-injection requirements have been met and a written authorization to commence injection has been obtained from the Director.

In order to obtain written authorization to inject, the following must be satisfied:

(a) The Permittee has:

(i). submitted to the Director a notice of completion of construction and a completed EPA Form 7520-10 and required attachments. If the well construction is different than the approved construction found in APPENDIX A, the Permittee shall also provide arevised well diagram and a description of the modification to the well construction;

(ii). conducted all applicable logging and testing requirements found in APPENDIX B and submitted required records to the Director. The logging and testing requirementsinclude demonstration of mechanical integrity pursuant to 40 CFR § 146.8, in accordance with the conditions found in Part II, Section C of this permit; and

(iii). satisfied requirements for corrective action in APPENDIX F, if applicable.

(b) The Director has received and reviewed the documentation associated with the requirements in Paragraph 2(a) of this section and finds it is in compliance with the conditions of the Permit.

(c) The Director has inspected the injection well and finds it is in compliance with the conditions of the Permit. If the Permittee has not received notice from the Director of his or her intent to inspect the injection well within 13 days of the date of the notice in Paragraph 2(a)(i) above, then prior inspection is waived.

3. *Injection Zone and Fluid Movement*

Injection zone means "a geological formation, group of formations, or part of a formation receiving fluids through a well."

Injection and perforations are permitted only within the approved injection zone specified in APPENDIX C. Injected fluids shall remain within the injection zone. If monitoring indicates the movement of fluids from the injection zone, the Permittee shall notify the Director within twenty-four (24) hours and submit a written report that documents circumstances that resulted in movement of fluids beyond the injection zone.

Additional individual injection perforations may be added, provided that they remain within the approved injection zone(s), fracture gradient data submitted is representative of the portion of the injection zone to be perforated, and the Permittee provides notice to the Director in accordance with Part II, Section B.8 for workovers. The Permittee shall also follow the requirements found in Part II Section B.4 *Injection Pressure Limitation* that may result in a change to the permitted MAIP.

4. *Injection Pressure Limitation*

(a) Injection pressure at the wellhead shall not initiate new fractures or propagate existing fractures in the confining zone. In no case shall injection pressure cause the movement of injectate or formation fluids into a USDW.

(b) Except during stimulation or other well tests approved by the EPA, injection pressure shall not exceed the MAIP. The MAIP, as measured at the surface, shall equal the formation fracture pressure (FP) plus friction loss, provided the pressure loss due to friction can be adequately documented through a direct measurement.

MAIP = **FP** + friction loss (if applicable)

The **FP** (measured at the surface) must be calculated using the following equation:

$$\mathbf{FP} = [\mathbf{FG} - (0.433 * (\mathbf{SG} + 0.05))] * \mathbf{D}$$

The values used in the equation are defined as:

"FG" is the fracture gradient of the injection zone in pounds per square inch/feet (psi/ft). The **FG** value for each well shall be determined by conducting a valid step rate test, reviewed and approved by the Director.

"SG" is the specific gravity of the injection fluid obtained from a representative fluid sample.

"D" is the true vertical depth in feet. The value for **D** is the depth of the top open perforation.

(c) To determine the MAIP, the Permittee shall submit prior to authorization to inject the following for review: step rate test results to determine the fracture gradient, fluid analysis from a representative sample of the injectate that provides specific gravity, and a revised well diagram (if construction is different than the approved construction found in APPENDIX A, that specifies the depth to top perforation.) The Director will review the information and provide the MAIP in the written authorization to commence injection.

(d) During the life of the Permit, the fracture gradient, top perforation depth, and specific gravity may change. When new perforations are added to the injection zone, the Permittee shall demonstrate that the FG previously submitted is also appropriate for the new interval within the injection zone. It may be necessary to run a new step rate test to gather information from the new interval proposed for injection. Upon submission of monitoring reports, tests, or well workover records that indicate one of these parameters has changed, the MAIP calculation will be evaluated.

When the D or FG value changes, a new MAIP shall be recalculated. When a sample analysis is submitted, the newly submitted SG value will be compared to the SG used to calculate the MAIP. If the difference is greater than or less than 0.05, the MAIP will be recalculated using the newly submitted SG value.

The Director will notify the Permittee in writing of the revised MAIP. A newly calculated MAIP shall not be implemented until written approval is received from the Director.

(e) Tests to demonstrate external (Part II) Mechanical Integrity (MI) shall be conducted at the most recently approved MAIP. However, if during testing, the Permittee is unable to achieve the MAIP, the MAIP will be readjusted and set to the highest pressure achieved during the successful external (Part II) Mechanical Integrity Test (MIT). The Permittee will be notified in writing from the Director of the new MAIP, based on the Part II MIT results.

5. Injection Volume Limitation

Injection volume is limited to the total volume specified in APPENDIX C.

6. Injection Fluid Limitation

Injected fluids are limited to those identified in 40 CFR § 144.6(b) as fluids: (1) which are brought to the surface in connection with conventional oil or natural gas production that may be commingled with waste waters from gas plants which are an integral part of production operations unless those waters are classified as a hazardous waste at the time of injection, (2) used for enhanced recovery of oil or natural gas, and (3) used for storage of hydrocarbons which are liquid at standard temperature and pressure. Non-exempt wastes, including unused fracturing fluids or acids, gas plant cooling tower cleaning wastes, service wastes and vacuum truck wastes, are not approved for injection.

The Permittee may inject fluids that meet the criteria above. However, prior to introduction of a new source (e.g. different production formation, well field, etc.) into the well, a fluid analysis shall be required, as listed in Appendix D under "WITHIN 30-DAYS OF AUTHORIZATION TO INJECT AND PRIOR TO INTRODUCTION OF A NEW SOURCE." The Permittee shall provide notification to the Director as well as provide a representative sample of the new injection fluid, as required in APPENDIX B. Results of the fluid analysis may affect the MAIP as described above in Part II, Section B.4 *Injection Pressure Limitation.*

7. Tubing–Casing Annulus

The tubing-casing annulus (TCA) shall be filled with a non-corrosive fluid or other fluid approved by the Director. The TCA valve shall remain closed during normal operations and the TCA pressure shall be maintained at the lesser of either 100 psi or 10 percent of the tubing pressure during TCA evaluation.

If TCA pressure cannot be achieved, the Permittee shall report to the EPA the actions taken to determine the cause of the excessive pressure and the proposed remedy. If a loss of MI has been determined, the Permittee shall proceed with the *Loss of Mechanical Integrity* requirements found in

Part II, Section C.5.

8. Alteration, Workover, and Well Stimulation

Alterations, workovers, and well stimulations shall meet all conditions of the Permit. Alteration, workover, and well stimulation include any activity that physically changes the well construction (casing, tubing, packer) or injection formation.

Prior to beginning any addition or physical alteration to an injection well's construction or injection formation, the Permittee shall give advance notice to the Director. Additionally, the Director's written approval must be obtained if the addition or physical alteration to the injection well modifies the approved well construction. Substantial alterations or additions may be cause for modification to the permit and may include additional testing or monitoring requirements.

The Permittee shall record all alterations, workovers, and well stimulations on a Well Rework Record (EPA Form 7520-12) and submit a revised well construction diagram, when the well construction has been modified. The Permittee shall provide this and any other record of well workover, logging, or test data to the EPA within thirty (30) days of completion of the activity.

The Permittee shall complete any activity which affects the tubing, packer, or casing and provide demonstration of internal (Part I) MI within ninety (90) days of beginning the activity. If the Permittee is unable to complete work within the specified time period, the Permittee shall propose an alternative schedule and obtain Director's written approval. Injection operations shall not resume until the well has successfully demonstrated mechanical integrity. If the well lost mechanical integrity, the Permittee must receive written approval from the Director to recommence injection.

9. Well Logging and Testing

Well logging and testing requirements are found in APPENDIX B. The Permittee shall ensure the log and test requirements are performed within the time frames specified in APPENDIX B. Well logs and tests shall be performed according to current EPA-approved procedures. The Director may stipulate specific test methods and criteria best suited for a specific well construction and injection operation.

10. Site Security and Manifest System Requirements

The Permittee shall implement the site security and manifest system requirements as described in Appendix G. These measures shall be put into place prior to receiving fluids for injection, and documentation of compliance with the measures must be provided to EPA prior to authorization to inject.

Section C. MECHANICAL INTEGRITY

1. Requirement to Maintain Mechanical Integrity

The Permittee is required to ensure the injection well maintains MI at all times. Injecting into a well that lacks MI is prohibited.

An injection well has MI if:

(a) there is no significant leak in the casing, tubing, or packer (internal Part I); and

(b) there is no significant fluid movement into a USDW through vertical channels adjacent to the injection well bore (external Part II).

2. Demonstration of Mechanical Integrity

The conditions under which the Permittee shall conduct the MI testing are as follows and detailed in APPENDIX B:

(a) Prior to receiving authorization to inject and periodically thereafter as specified in APPENDIX B, the Permittee shall demonstrate both internal Part I and external Part II MI. Well-specific conditions dictate the methods and the frequency for demonstrating MI and are specified in APPENDIX B.

(b) After any rework that compromises the MI of the well and after a loss ofMI.

Other than during periods of well workover (maintenance) in which the sealed tubing-casing annulus is disassembled for maintenance or corrective procedures, the Permittee shall monitor injection tubing pressure, rate, and volume, pressure on the annulus between tubing and casing, and bradenhead pressure, as specified in APPENDIX D.

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

Results of any MIT results required by this Permit shall be submitted to the Director as soon as possible but no later than thirty (30) calendar days after the test is complete.

3. Mechanical Integrity Test Methods and Criteria

EPA approved methods shall be used to demonstrate MI. These methods may be found in documents available from the EPA at https://www.epa.gov/uic/underground-injection-control-epa-region-8-co-mt-nd-sd-ut-and-wy#guidance:

- *"Ground Water Section Guidance No. 34 Cement Bond Logging Techniques and Interpretation"*
- *"Ground Water Section Guidance No. 39 Pressure Testing Injection Wells for Part I (Internal) Mechanical Integrity"*
- *"Radioactive Tracer Surveys for Evaluating Fluid Channeling Behind Casing near Injection Perforations"*
- *"Temperature Logging for Mechanical Integrity"*

Current versions of these documents will also be available from the EPA upon request. The Director may stipulate specific test methods and criteria best suited for a specific well construction and injection operation.

4. Notification Prior to Testing

The Permittee shall notify the Director at least thirty (30) calendar days prior to any MIT. The Director may allow a shorter notification period if it would be sufficient to enable the EPA to witness the MIT or the EPA declines to witness the test. Notification may be in the form of a yearly or quarterly schedule of planned MITs, or it may be on an individual basis.

5. Loss of Mechanical Integrity

If the well fails to demonstrate MI during a test or a loss of MI becomes evident during operation (such as presence of pressure in the tubing-casing annulus, water flowing at the surface, etc.), the Permittee shall notify the Director within twenty-four (24) hours (see Part III, Section D.10(e) of this Permit), cease injection and shut-in the well within forty-eight (48) hours unless the Director requires immediate shut-in.

Within five (5) calendar days, the Permittee shall submit a follow-up written report that documents circumstances that resulted in the MI loss and how it was addressed. If the MI loss has not been resolved, the Permittee shall provide a report with the proposed plan and schedule to reestablish MI. A demonstration of MI shall be reestablished within ninety (90) calendar days of any loss of MI unless written approval of an alternate time period has been given by the Director.

Injection operations shall not resume until after the MI loss has been resolved, the well has demonstrated MI pursuant to 40 CFR § 146.8, and the Director has provided written approval to resume injection.

Section D. MONITORING, RECORDKEEPING, AND REPORTING OF RESULTS

1. Monitoring Parameters and Frequency

Monitoring parameters are specified in APPENDIX D. The listed parameters are to be monitored, recorded and reported at the frequency indicated in APPENDIX D, even when the well is not operating. In the event the well has not injected or is no longer injecting, the monitoring report will reflect its status. Sampling data shall be submitted if the well has injected any time during the reporting period.

Records of monitoring information shall include:

(a) the date, exact place, and time of the observation, sampling, or measurements;

(b) the individual(s) who performed the observation, sampling, or measurements;

(c) the date(s) of analyses and individuals who performed the analyses;

(d) the analytical technique or method used; and

(e) the results of such analyses.

2. Monitoring Methods

Observations, measurements, and samples taken for the purpose of monitoring shall be representative of the monitored activity and include:

(a) Methods used to monitor the nature of the injected fluids must comply with analytical methods cited and described in 40 CFR § 136.3 or by other methods that have been approved in writing by the Director.

(b) Injection tubing, TCA annulus, and bradenhead pressures, injection rate, injected volume, and cumulative injected volume shall be observed and recorded at the wellhead. All parameters shall be observed simultaneously to provide a clear depiction of well operation. Annulus pressure applied during standard annulus pressure tests performed during mechanical integrity tests should not be included in the annual monitoring report.

(c) Pressures are to be measured in pounds per square inch (psi).

(d) Fluid volumes are to be measured in standard oil field barrels (bbl) or thousands of cubic feet (MCF).

(e) Injection rates are to be measured in barrels per day (bbl/day) or thousands of cubic feet per day (MCF/day).

3. *Records Retention*

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

(a) Calibration and maintenance records and all original recordings for continuous monitoring instrumentation, copies of all reports required by this Permit, and records of all data used to complete the application for this Permit, for a period of at least (3) years from the date ofthe sample, measurement, report, or application. This period may be extended any time prior to its expiration by request of the Director.

(b) Nature and composition of all injected fluids until three (3) years after the completion of any plugging and abandonment (P&A) procedures specified under 40 CFR § 144.52(a)(6). The Permittee shall continue to retain the records after the three-year (3) retention period unless the Permittee delivers the records to the Regional Administrator, or his/her authorized representative, or obtains written approval from the Regional Administrator, or his/her authorized representative, to discard the records.

4. *Annual Reports*

Regardless of whether or not the well is operating, the Permittee shall submit an Annual Report to the Director that:

(a) summarizes the results of the monitoring required in Part II, Section D and APPENDIX D;

(b) includes a summary of any major changes in characteristics or sources of injected fluid. The report of fluids injected during the year must identify each new fluid source by well name and location, and the field name or facility name; and

(c) includes any additional wells within the area of review that have not previously been submitted. For those wells that penetrate the injection zone, a well construction diagram, cement records and cement bond log are also required.

The first Annual Report shall cover the period from the effective date of the Permit through December 31 of that year. Subsequent Annual Reports shall cover the period from January 1 through December 31 of the reporting year. Annual Reports shall be submitted by February 15 of the year following data collection. EPA Form 7520-8 or 7520-11 may be used or adapted to submit the Annual Report, however, the monitoring requirements specified in this Permit are mandatory even if the EPA form indicates otherwise. An electronic form may also be obtained from the EPA to satisfy reporting requirements.

Section E. PLUGGING AND ABANDONMENT

1. *Notification of Well Abandonment*

The Permittee shall notify the Director in writing at least thirty (30) days prior to plugging and abandoning an injection well. The notification shall include any anticipated changes to the plugging and abandonment plan (P&A Plan), which will be incorporated into the Permit as a modification.

2. *Well Plugging Requirements*

Prior to abandonment, the injection well shall be plugged with cement in a manner which isolates the injection zone and will not allow the movement of fluids into or between USDWs, in accordance with 40 CFR § 146.10. Additional federal, state or local laws or regulations may also apply.

3. *Approved Plugging and Abandonment Plan*

The approved P&A Plan and required tests are incorporated into this Permit as APPENDIX E. Changes to the approved P&A Plan will be incorporated into the Permit as a modification prior to beginning plugging operations and shall be submitted using EPA Form 7520-14. The Director also may require revision of the approved P&A Plan at any time prior to plugging the well.

4. *Plugging and Abandonment Report*

Within sixty (60) days after plugging a well, the Permittee shall submit a report (EPA Form 7520-13) to the Regional Administrator or his/her authorized representative. The plugging report shall be certified as accurate by the person who performed the plugging operation. Such report shall consist of either:

(a) a statement that the well was plugged in accordance with the approved P&A Plan; or

(b) where actual plugging differed from the approved P&A Plan found in APPENDIX E, an updated version of the plan, specifying the differences.

5. *Wells Not Actively Injecting*

After any period of two (2) years during which there is no injection or from the spud date of a newly drilled well or from the permit effective date of a well to be converted to an injector, the Permittee shall plug and abandon the well in accordance with Part II, Section E.2 and APPENDIX E of this Permit unless the Permittee:

(a) provides written notice to the Regional Administrator or his/her authorized representative, prior to the two-year (2) period;

(b) describes actions or procedures, satisfactory to the Regional Administrator or his/her authorized representative, that the Permittee will take to ensure that the well will not endanger USDWs during the period of temporary abandonment. These actions and procedures shall include compliance with the technical requirements applicable to active injection wells, unless waived by the Regional Administrator or his/her authorized representative; and

(c) receives written notice by the Regional Administrator or his/her authorized representative to temporarily waive plugging and abandonment requirements.

The Permittee of a well that has been temporarily abandoned shall notify the Director prior to resuming operation of the well.

Section F. MEASURES FOR PROTECTION OF ENDANGERED SPECIES

In accordance with section 7 of the Endangered Species Act § (ESA), 16 U.S.C. 1536(a)(2), the Permittee must implement the following measures:

1. If any of the following species are sighted within one mile of the well site or associated facilities during construction or operation, the Permittee shall cease all work within one mile of the species' location and contact the EPA and the USFWS immediately: ***the whooping crane, the interior least tern, the rufa red knot or the piping plover.*** In coordination with the USFWS, work may resume after the terrestrial species leave the area.

2. If construction is planned during the migratory bird nesting and breeding season, a qualified biologist must conduct per-construction surveys for migratory birds and their nest within five days prior to the initiation of all construction activities.
3. Spills or leaks of chemicals and other pollutants at the injection well site shall be reported the EPA and other appropriate regulatory agencies. The procedures of the surface management agency must be followed to contain leaks or spills.

PART III. CONDITIONS APPLICABLE TO ALL PERMITS

Section A. CHANGES TO PERMIT CONDITIONS

1. Modification, Revocation and Reissuance, or Termination

The Director may, for cause, modify, revoke and reissue, or terminate this Permit in accordance with 40 CFR §§ 124.5, 144.12, 144.39, 144.40, and 144.41. The filing of a request for modification, revocation and reissuance, termination, or the notification of planned changes or anticipated noncompliance on the part of the Permittee does not stay the applicability or enforceability of any condition of this Permit.

2. Conversion to Non-UIC Well

The Director may allow conversion of the well to a non-UIC well. Conversion may not proceed until the Permittee receives written approval from the Director, at which time this permit will expire due to the end of operating life of the facility. Once expired under this part, the Permittee will need to reapply for a UIC permit and restart the complete permit process, including opportunity for public comment, before injection can occur.

Conditions of such conversion shall include approval of the proposed well rework, demonstration of mechanical integrity, and documentation that the well is authorized by another regulatory agency.

3. Transfer of Permit

Under 40 CFR § 144.38, this Permit may be transferred by the Permittee to a new owner or operator only if:

(a) the Permit has been modified or revoked and reissued (under 40 CFR § 144.39(b)(2)), or a minor modification made (under 40 CFR § 144.41(d)), to identify the new permittee and incorporate such other requirements as may be necessary under the SDWA, or

(b) the Permittee provides written notification (EPA Form 7520-7) to the Director at least thirty (30) days in advance of the proposed transfer date and submits a written agreement between the existing and proposed new permittees containing a specific date for transfer or permit responsibility, coverage, and liability between them, and demonstrates that the financial responsibility requirements of 40 CFR § 144.52(a)(7) have been met by the proposed new permittee. If the Director does not notify the Permittee and the proposed new permittee of his or her intent to modify or revoke and reissue, or modify, the transfer is effective on the date specified in the written agreement. A modification under this paragraph may also be a minor modification under 40 CFR § 144.41.

4. Permittee Change of Address

Upon the Permittee's change of address, or whenever the operator changes the address where monitoring records are kept, the Permittee must provide written notice to the Director within thirty (30) days.

Section B. SEVERABILITY

The provisions of this Permit are severable, and if any provision of this Permit or the application of any provision of this Permit to any circumstance is held invalid, the application of such provision to other circumstances, and the remainder of this Permit shall not be affected thereby. Additionally, in a permit modification, only those conditions to be modified shall be reopened. All other aspects of the existing permit shall remain in effect for the duration of the permit.

Section C. CONFIDENTIALITY

In accordance with 40 CFR part 2 and 40 CFR § 144.5, information submitted to the EPA pursuant to these regulations may be claimed as confidential by the submitter. Any such claim must be asserted at the time of submission by stamping the words "confidential business information" on each page containing such information. If no claim is made at the time of submission, the EPA may make the information available to the public without further notice. If a claim is asserted, the information will be treated in accordance with the procedures in 40 CFR part 2 (Public Information). Claims of confidentiality for the following information will be denied:

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

Section D. ADDITIONAL PERMIT REQUIREMENTS

1. Prohibition on Movement of Fluid Into a USDW

The Permittee shall not construct, operate, maintain, convert, plug, abandon or conduct any other injection activity in a manner that allows the movement of a fluid containing any contaminant into USDWs, except as authorized by 40 CFR part 146.

2. Duty to Comply

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

3. Need to Halt or Reduce Activity Not a Defense

The Permittee shall not use as a defense in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this Permit.

4. Duty to Mitigate

The Permittee shall take all reasonable steps to minimize or correct any adverse impact on the environment resulting from noncompliance with this Permit.

5. Proper Operation and Maintenance

The Permittee shall at all times properly operate and maintain all facilities and systems of treatment and control (and related appurtenances), which are installed or used by the Permittee to achieve compliance with the conditions of this Permit. Proper operation and maintenance includes effective performance, adequate funding, adequate operator staffing and training, and adequate laboratory and process controls, including appropriate quality assurance procedures. This provision requires the operation of back-up or auxiliary facilities or similar systems only when necessary to achieve compliance with the conditions of this Permit.

6. Permit Actions

This Permit may be modified, revoked and reissued or terminated for cause. The filing of a request by the Permittee for a permit modification, revocation and reissuance, or termination, or a notification of planned changes or anticipated noncompliance, does not stay any permit condition.

7. Property and Private Rights; Other Laws

This Permit does not convey property rights of any sort or any exclusive privilege; nor does it authorize any injury to persons or property, any invasion of other private rights, or any infringement of any other federal, state or local law or regulations.

8. Duty to Provide Information

The Permittee shall furnish to the Director, within a time specified, any information which the Director may request to determine whether cause exists for modifying, revoking and reissuing, or terminating this permit, or to determine compliance with this permit. The Permittee shall also furnish to the Director, upon request, copies of records required to be kept by this Permit.

9. Inspection and Entry

The Permittee shall allow the Director, or an authorized representative, upon the presentation of credentials and other documents as may be required by law, to:

(a) enter upon the Permittee's premises where a regulated facility or activity is located or conducted, or where records must be kept under the conditions of this Permit;

(b) have access to and copy, at reasonable times, any records that must be kept under the conditions of this Permit;

(c) inspect at reasonable times any facilities, equipment (including monitoring andcontrol equipment), practices, or operations regulated or required under this Permit; and

(d) sample or monitor at reasonable times, for the purposes of assuring permit compliance oras otherwise authorized by the SDWA, any substances or parameters at anylocation.

10. Signatory Requirements

All applications, reports or other information submitted to the Regional Administrator or his/her authorized representative shall be signed and certified according to 40 CFR § 144.32. This section explains the requirements for persons duly authorized to sign documents and provides wording for required certification.

11. Reporting Requirements

Copies of all reports and notifications required by this Permit shall be signed and certified in accordance with the requirements under Part III, D.10 of this Permit and shall be submitted to the EPA:

UIC Enforcement, Mail Code: 8ENF-W-SDW
U.S. Environmental Protection Agency
1595 Wynkoop Street
Denver, Colorado 80202-1129

All correspondence should reference the well name and location and include the EPA Permit number.

(a) *Monitoring Reports.* Monitoring results shall be reported at the intervals specified elsewhere in this Permit.

(b) *Planned changes.* The Permittee shall give notice to the Director as soon as possible of any planned changes, physical alterations or additions to the permitted well, and prior to commencing such changes.

(c) *Anticipated noncompliance.* The Permittee shall give advance notice to the Director of any planned changes in the permitted facility or activity which may result in noncompliance with Permit requirements.

(d) *Compliance schedules.* Reports of compliance or noncompliance with, or any progress reports on, interim and final requirements contained in any compliance schedule of this Permit shall be submitted no later than thirty (30) calendar days following eachschedule date.

(e) *Twenty-four-hour reporting.* The Permittee shall report to the Director any noncompliance which may endanger human health or the environment, including:

(i) any monitoring or other information, which indicates that any contaminant may causean endangerment to a USDW; or

(ii) any noncompliance with a permit condition or malfunction of the injection systemwhich may cause fluid migration into or between USDWs.

Information shall be provided, either directly or by leaving a message, within twenty-four (24) hours from the time the Permittee becomes aware of the circumstances by telephoning (800) 227-8917 and requesting EPA Region 8 UIC Program SDWA Enforcement Supervisor, or by contacting the EPA Region 8 Emergency Operations Center at (303) 293-1788.

In addition, a follow up written report shall be provided to the Director within five (5) calendar days of the time the Permittee becomes aware of the circumstances. The written submission shall contain a description of the noncompliance and its cause, the period of noncompliance including exact dates and times, and if the noncompliance has not been corrected the anticipated time it is expected to continue; and the steps taken or planned to reduce, eliminate, and prevent recurrence of the noncompliance.

(f) *Other Noncompliance.* The Permittee shall report all instances of noncompliance notreported under Paragraphs 11(a), 11(b), 11(d), or 11(e) of this Section at the time the monitoring reports are submitted. The reports shall contain the information listed in Paragraph 11(e) of this Section.

(g) *Other information.* Where the Permittee becomes aware that it failed to submit any relevant facts in a permit application or submitted incorrect information in a permit application or in any report to the Director, the Permittee shall submit such facts or information to the Director within thirty (30) days of discovery of failure.

(h) *Oil Spill and Chemical Release Reporting.* The Permittee shall comply with all reporting requirements related to the occurrence of oil spills and chemical releases by contacting the National Response Center (NRC) at (800) 424-8802 or NRC@uscg.mil.

Section E. FINANCIAL RESPONSIBILITY

1. Method of Providing Financial Responsibility

The Permittee, shall demonstrate and maintain continuous compliance with the requirement to maintain financial responsibility and resources to close, plug, and abandon the underground injection well(s) covered by this Permit. The Director may, on a periodic basis, require the holder of a permit to revise the estimate of the resources needed to plug and abandon the well to reflect changes in such costs and may require the Permittee to provide a revised demonstration of financial responsibility. The Permittee may also upon written request provide an alternative demonstration of financial responsibility. No substitution of a demonstration of financial responsibility shall become effective until the Permittee receives notice from the Director that the alternative demonstration of financial responsibility is a suitable replacement.

2. Types of Adequate Financial Responsibility.

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

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

The Permittee shall utilize appropriate wording of the above financial responsibility demonstrations. The EPA's model language for this wording can be found in 40 CFR § 144.70.

A standby trust agreement acceptable to the Director shall contain wording identical to the EPA's model language. Annual reports from the financial institution managing the standby trust account shall be submitted to the Director showing the available account balance.

A surety bond acceptable to the Director shall contain wording identical to the EPA's model language and shall be issued by a surety bonding company found to be acceptable to the U.S. Department of Treasury, which can be determined by review of that department's Circular #570, currently available at: https://www.fiscal.treasury.gov/fsreports/ref/suretyBnd/c570.htm.

A letter of credit acceptable to the Director shall contain wording identical to the EPA's model language and be issued by a bank or other institution whose operations are regulated and examined by a state or federal agency.

A fully funded trust agreement acceptable to the Director shall contain wording identical to the EPA's model language. Annual reports from the financial institution managing the trust account shall be submitted to the Director showing the available account balance.

An independently audited financial statement with the Chief Financial Officer's letter acceptable to the Director shall contain wording identical to the EPA's model language and shall demonstrate that the Permittee meets or exceeds the required financial ratios. If this financial instrument is used, it must be resubmitted annually, within ninety (90) calendar days after the close of the Permittee's fiscal year, using the financial data available from the most recent fiscal year.

The Permittee shall submit a completed, originally-signed financial responsibility demonstration to:

UIC Financial Responsibility Coordinator
Mail Code: 8ECAD-SD
U.S. Environmental Protection Agency
1595 Wynkoop Street
Denver, Colorado 80202-1129

3. Determining How Much Coverage is Needed

The Permittee, when periodically requested to revise the plugging and abandonment cost estimate discussed above, may be required to adjust the given cost for inflation or pursue a new cost estimate as prescribed by the Director.

4. Insolvency

In the event of:

(a) the bankruptcy of the trustee or issuing institution of the financial mechanism;

(b) suspension or revocation of the authority of the trustee institution to act as trustee; or

(c) the institution issuing the financial mechanism losing its authority to issue suchan instrument,

the Permittee must notify the Director in writing, within ten (10) business days, and the Permittee must establish other financial assurance or liability coverage acceptable to the Director within sixty (60) calendar days after any event specified in (a), (b), or (c) above.

The Permittee must also notify the Director by certified mail of the commencement of voluntary or involuntary proceedings under Title 11 (Bankruptcy), U.S. Code naming the owner or operator as debtor, within ten (10) business days after the commencement of the proceeding. A guarantor, if named as debtor of a corporate guarantee, must make such a notification as required under the terms of the guarantee.

APPENDIX A

WELL CONSTRUCTION REQUIREMENTS

The well shall be cased and cemented to prevent the movement of fluids into or between USDWs, and in accordance with 40 CFR § 146.22 and other applicable federal, state or local laws and regulations. General requirements include:

- The casing and cement used in the construction of each newly drilled well shall bedesigned for the life expectancy of the well.
- When drilling the surface hole, unless waived by the Director, air or mud made with water containing no additives and no more than 3,000 mg/L TDS shall be used. At no time shall the permittee conduct any activity that endangers any USDW, as prohibited by 40 CFR §144.12.
- Packers must be set within 100 feet of the uppermost open perforation.

WELL CONSTRUCTION:
The Permittee plans to install conductor casing of unspecified dimension and depth.

9-5/8" J-55, 36 lbs./ft. surface casing shall be set in a 13-1/2" hole to an estimated depth of 1,776 feet (below ground level) with casing centralizers and cemented to surface.

7" N80, 23 lbs./ft. long string casing shall be set in an 8-3/4" hole to an estimated depth of 5,530 feet with casing centralizers and cemented to surface.

3-1 /2" J-55 EUE with internal plastic-coated tubing shall be installed with a packer set at the depth of about 4,865 feet (no more than 100 feet above the top perforation).

No well stimulation program is proposed during well completion. In the event the Permittee wishes to conduct well stimulation, the Permittee shall follow the requirements in Part II, Section B.8. *Alteration, Workover, and Well Stimulation.*

The Big Bend 3-6 SWD is a newly constructed well and final construction may vary from the details above.

Refer to Appendix A-2 for the wellbore schematic.

INJECTION WELL CONSTRUCTION DIAGRAM

SLAWSON
exploration company, inc

GL ELEVATION = 1956' EST
KB ELEVATION = 1970' EST
API#
NDIC#

WELLBORE DIAGRAM
BIG BEND 3-6 SWD

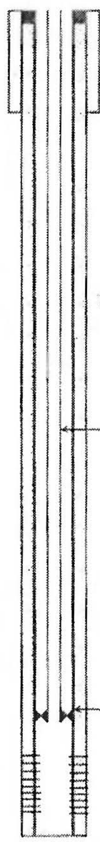
NW NW SEC 6 T151 R92
250' FNL and 200' FWL
Mountrail County, North Dakota

USDW Surface-1656' < 10,000 TDS
Coleharbor-Fox Hills

Formation	TVD KB
Coleharbor Group	0-23'
Bullion Creek	23'
Cannon Ball	558'
Hell Creek	1,043'
Fox Hills	1,413'
Pierre	1,656'
Niobrara	3,701'
Carlile	3,958'
Greenhorn	4,184'
Belle Fourche	4,367'
Mowry	4,586'
Inyan Kara (Dakota)	4,940'
Swift	5,379'
TD	5,530'

Mowry Upper confining zone 4,586'

Swift Lower confining zone 5,379'



NOTE: NOT TO SCALE

NEED CMT

String	Hole Size	Casing Size	Interval/Depth	CUFT	Yield	SXS	TOC
Surface Lead Set 'C' Surface Tail 500' G	13-1/2" 60% Xcess	9-5/8"	0-1363' 1363-1863'	1065 391	2.66 1.15	400 357	Surface 1363'
Production Lead 'Lite' Production Tail 810' G	8-3/4" 20% Xcess	7"	0-4600' 4600-5410'	830 148	2.05 1.15	405 140	Surface 4600'

APPENDIX B

LOGGING AND TESTING REQUIREMENTS

Well logging and tests shall be performed according to the EPA approved procedures. It is the responsibility of the Permittee to obtain and use these procedures prior to conducting any well logging or test required as a condition of this Permit. These procedures can be found at https://www.epa.gov/uic/underground-injection-control-epa-region-8-co-mt-nd-sd-ut-and-wy#guidance.

Well logs and test results shall be submitted to the Director within sixty (60) calendar days of completion of the logging or testing activity and shall include a report describing the methods used during logging or testing and an interpretation of the log or test results. When applicable, the report shall include a descriptive report prepared by a knowledgeable log analyst, interpreting the results of that portion of those logs and tests which specifically relate to: (1) a USDW and the confining zone adjacent to it, and (2) the injection zone and adjacent formations.

Logs and Tests.

TYPE OF LOG OR TEST	DATE DUE
Well logs and test results shall be submitted to the Director within sixty (60) calendar days of completion of the logging or testing activity.	
Injectate Water Analysis A representative water sample of the injectate shall be analyzed for the constituents found in APPENDIX D.	1. Within 30 days after Authorization to Inject 2. Annually 3. Prior to the introduction of a new source
Injection Zone Water Sample A representative water sample from the injection zone shall be analyzed. After a minimum of three successive pore volumes, a representative sample shall be determined by stabilized specific conductivity.	Prior to receiving Authorization to Inject
Injection Formation Fluid Pressure	Prior to receiving Authorization to Inject
Step Rate Test (SRT) The SRT shall be performed following current EPA guidance. The SRT shall be conducted with both surface and bottom-hole pressure gauges. This requirement may be waived with a written approval from the Director.	Prior to receiving Authorization to Inject
Surface and Production Casing Cement Bond Logs	Prior to receiving Authorization to Inject
Cement Records	Prior to receiving Authorization to Inject
Radioactive Tracer Survey (RTS) If the Director's review of the cement bond log does not show 80% bond index, a RTS is required	Prior to receiving Authorization to Inject
Temperature Log (external Part II MI)	1. Baseline temperature log required prior to receiving Authorization to Inject.

If the Director's review of the cement bond log does not show 80% bond index (based on Region 8 EPA Guidance 34), a temperature log is required.	2. First temperature log will be conducted between 60 to 90 days of authorization to inject and repeated no less than five (5) years after the last successful external (Part II) MI demonstration.
Standard Annulus Pressure (internal Part I MI) If the well has not received authorization to inject and does not have tubing installed, in lieu of the Standard Annulus Pressure test, a Casing Pressure Test can be performed.	1. Prior to receiving Authorization to Inject or within two (2) years of the permit effective date. 2. Prior to recommencing injection after any well rework that compromises the internal mechanical integrity of the well or a loss of MI. 3. At least once every five (5) years after the last successful demonstration of internal (Part I) Mechanical Integrity.
Deviation Checks	Prior to receiving Authorization to Inject
Electrical, Gamma Ray, and any combination of logs to provide formation porosity The logs shall provide information from ground level to total depth.	Prior to receiving Authorization to Inject
Mud logging record	Prior to receiving Authorization to Inject

APPENDIX C

OPERATING REQUIREMENTS

INJECTION ZONE:
Injection is permitted only within the approved injection zone listed below.

APPROVED INJECTION ZONE (GL, ft.)

FORMATION / STRATIGRAPHIC UNIT NAME	TOP (ft.) *	BOTTOM (ft.) *
Inyan Kara	4,940	5,379

*estimated top and base of formations

MAXIMUM INJECTION VOLUME:

There is no limitation on the fluid volume permitted to be injected into this well. In no case shall injection pressure exceed the MAIP.

If an aquifer exemption is required and approved for this Permit, then a volume limit will be set based on the conditions of the aquifer exemption, through the modification process.

APPENDIX D

MONITORING, AND REPORTING PARAMETERS

This is a listing of the parameters required to be observed, recorded, and reported. Refer to the Part II, Section D of the Permit, for detailed requirements for observing, recording, and reporting of these parameters.

EPA Form 7520-8 or 7520-11 may be used or adapted to submit the Annual Report, however, the monitoring requirements specified in this Permit are mandatory even if EPA Form 7520-11 indicates otherwise. An electronic form may also be obtained from the EPA to satisfy reporting requirements.

OBSERVE WEEKLY AND RECORD MONTHLY	
OBSERVE AND RECORD	Injection Tubing Pressure (psi)
	Bradenhead Pressure (psi)
	Annulus Pressure (psi)
	Injection Rate (bbl/day)
	Injected Volume (bbl)
	Cumulative Fluid Volume Injected (since injection began) (bbls)

WITHIN 30 DAYS AFTER AUTHORIZATION TO INJECT AND PRIOR TO INTRODUCTION OF A NEW SOURCE	
ANALYZE	Analyze a sample of injection fluids for the following constituents: • Total Dissolved Solids (mg/L) via Method 2540 C-97 • pH via Method 4500-H+ B-00 • Specific gravity via Method SM 2710 F • Conductivity/Specific Conductance (S/m) via Method 2510 B-97 • Cations: Ba, Na, Fe, K, Mn, Mg, Ca via Method EPA 200.7, 200.8 • Anions: Cl and SO_4 via Method D6508, Rev. 2 HCO_3 via Method SM 2320 B CO_3 via Method 310.1 • Ammonia as N via Methods 350.1, 350.2, 350.3 • Trace Metals via Method ICP • Volatile Organic Compounds via Method 8260 • Semi-Volatile Organic Compounds via Method 8270 • Gross Alpha and Beta Radiation via Method 7110 • Uranium and Radium via Method 7500 Alternative analysis methods may be used, if pre-approved

ANNUALLY	
ANALYZE (if injection occurred during reporting period)	Analyze a representative sample of injection fluids for the following constituents: • Total Dissolved Solids via Method 2540 C-97 • pH via Method 4500-H+ B-00 • Specific gravity via Method SM 2710 F • Conductivity/Specific Conductance via Method 2510 B-97 • Cations: Ba, Na, K, Mn, Ca via Method EPA 200.7, 200.8 • Anions: Cl and SO_4 via Method D6508, Rev. 2 HCO_3 via Method SM 2320 B CO_3 via Method 310.1 • Ammonia as N via Methods 350.1, 350.2, 350.3 • Uranium and Radium via Method 7500 Alternative analysis methods may be used, if pre-approved

ANNUALLY	
REPORT	Each month's maximum and averaged injection tubing pressures (psi)
	Each month's maximum and minimum annulus pressures (psi)
	Each month's maximum and minimum bradenhead pressures (psi)
	Each month's maximum and average injection rate (bbl/day)
	Each month's injected volume (bbl)
	Fluid volume injected since the well began injecting (bbl)
	Written results of annual injected fluid analysis
	Sources of all fluids injected during the year, including any wellfield and formation, noting any major changes in characteristics of injected fluid.

In addition to these items, additional logging and testing results may be required periodically. For a list of those items and their due dates, please refer to APPENDIX B – LOGGING AND TESTING REQUIREMENTS.

APPENDIX E

PLUGGING AND ABANDONMENT (P&A) REQUIREMENTS

All wells shall be plugged with cement in a manner which isolates the injection zone and will not allow the movement of fluids either into or between USDWs in accordance with 40 CFR § 146.10. Additional federal, state or local law or regulations may also apply. General requirements applicable to all wells include:

- Prior to plugging a well, mechanical integrity must be established unless the P&A plan will address the mechanical integrity issue. Injection tubing shall be pulled.
- Cement plugs shall have sufficient compressive strength to maintain adequate plugging effectiveness.
- Each plug placement, unless above a retainer or bridge plug, must be verified by tagging the top of the plug after the cement has had adequate time to set.
- A minimum 50 feet surface plug is required inside, and if necessary outside of the surface casing, to seal pathways for fluid migration into the subsurface.
- If there is more than 2,000 mg/liter difference of TDS between individual exposed USDWs, they must be isolated from each other.

At a minimum, the following plugs are required (see attached P&A diagram in E-2):

1. **Isolate the Injection Zone**: Remove down hole apparatus from the well and perform necessary clean out; displace well fluid with plugging gel.
   PLUG 1: Squeeze injection zone perforations. Set a cast iron bridge plug (CIBP) within the innermost casing string no more than 50 feet above the top perforations with a minimum 20-foot cement plug on the top of the CIBP. Alternatively, the Permittee may install a cement retainer no more than 50 feet above the top perforations, squeeze the open perforations and then place a minimum 20-foot cement plug on top of the cement retainer.

2. **Isolate Shallow USDWs from the Injection Zone**:
   PLUG 2: Set a minimum 200-foot cement plug approximately 50 feet above the contact between the Fox Hills and Pierre shale to 150 feet below the contact between the Fox Hills and Pierre Shale. This plug also covers the surface casing shoe.

3. **Isolate Surface Fluid Migration Paths**:
   PLUG 3: Set a cement plug inside the innermost casing string from 200 feet to the surface.

The Big Bend 3-6 SWD is a newly constructed well, the P&A plan may need to be modified after construction.

INJECTION WELL P&A DIAGRAM

slawson exploration company, inc

GL ELEVATION = 1956' EST
KB ELEVATION = 1970' EST
API#
NDIC#

WELLBORE DIAGRAM
BIG BEND 3-6 SWD
PROPOSED P&A

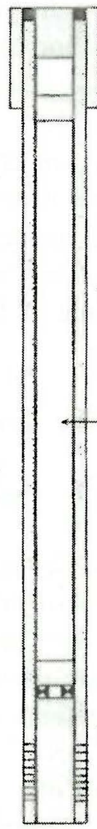
NW NW SEC 6 T151 R92
250' FNL and 200' FWL
Mountrail County, North Dakota

USDW Surface-1656' < 10,000 TDS
Coleharbor-Fox Hills

Formation	TVD
Coleharbor Group	0-23'
Bullion Creek	23'
Cannonball	558'
Hell Creek	1,043'
Fox Hills	1,413'
Pierre	1,656'
Niobrara	3,701'
Carlile	3,958'
Greenhorn	4,184'
Belle Fourche	4,367'
Mowry	4,586'
Inyan Kara (Dakota)	4,940'
Swift	5,379'
TD	5,530'

Mowry Upper confining zone 4,586'

Swift Lower confining zone 5,379'



PLUG #3 Spot 40 SXS CLASS G 0-200'

9-5/8" 36# J-55 STC @ 1,776'
SHOE BHT 78 F EST

PLUG #2 Spot 40 SXS CLASS G 1,600 - 1800
WOC & Tag w/ TBG

TOC 7" @ Surface (plan)

9.2 PPG BRINE BETWEEN PLUGS

PLUG #1 100 SXS CLASS G below PKR & 10 SXS on top 4,815-5,379' Total 110 SXS

Injection Packer @ +/ 4865' used as cement retainer

Inyan Kara Perforations from 4,940' to 5,379' Gross Est.

PBTD @ 5,485'

7" 23# N80 @ 5,530'

TD BHT 150 F EST

NOTE: NOT TO SCALE

String	Hole Size	Casing Size	Interval/Depth	CUFT	Yield	SXS	TOC
Surface Lead Set 'C'	13-1/2"	9-5/8"	0-1400'	1065	2.66	400	Surface
Surface Tail 500' G			1363-1863'	391	1.15	357	1363'
Production Lead 'Lite'	8-3/4"	7"	0-4600'	830	2.05	405	Surface
Production Tail 820' G			4600-5410'	148	1.15	140	4600'

APPENDIX F
CORRECTIVE ACTION PLAN

No corrective action is required at this time as EPA's evaluation did not identify migration pathways within the area of review.

APPENDIX G

SITE SECURITY AND MANIFEST REQUIREMENTS

Site Security

Signage
Waterproof sign(s) shall be maintained and readily visible at the entrance from public roads leading to the commercial disposal well. The sign(s) shall indicate the property is private, no trespassing is allowed, and shall include the name of the operator and emergency contact phone number.

Gates and Fences
The perimeter of the site shall be fenced with a minimum 6-foot high metal pipe fence with woven wire between the posts or an equivalent chain-linked fence. All gates and other entry points shall be locked when the facility is unattended. Only authorized personnel will have access to the site and ability to open the gates.

Surveillance
The site shall be monitored by 24-hour camera surveillance. If an electronic system is used to secure the facility when an attendant is not on duty, an automatic shut-off or alarm system must be installed to ensure that disposal operations cease if a well mechanical failure or downhole problem occurs.

Manifest System for Disposal Water
This Permit prohibits the injection of hazardous waste or non-oil and gas production waste. It is the responsibility of the Permittee to ensure that prohibited fluids are not injected into the well. Therefore, the Permittee is required to do the following to ensure that prohibited fluids are not injected for every disposal load received.

1. The Permittee shall establish and maintain a three-party custody record between the Generator (responsible party from where the fluids were generated), Transporter and Disposal Facility (Permittee):

   - Generator: company name, company address, company telephone number, the name and location of the lease from where fluids were produced (the Permittee will keep track of all production wells that are contained within each lease approved to use the Disposal Facility)
   - Transporter: company name, company address, company telephone number, truck driver name, truck identification number, location and date of pick up, volume of fluids picked up from the Generator
   - Disposal Facility: facility name, facility address, facility telephone number, date and volume of fluids unloaded at the Disposal Facility

   These records shall be kept for a minimum of three (3) years after date of disposal at the facility and shall be made available for inspection upon request.

2. The Permittee must certify that:

   I certify under penalty of law that the waste fluids that are injected into the Big Bend 3-6 SWD identified as ND22361-11336 has not been mixed with, or otherwise co-injected with hazardous waste or non-oil and gas production waste at the Underground Injection Control Class II permitted facility, and that injection of the waste fluids is in compliance with the applicable requirements contained in this Permit.

3. The Permittee must obtain certification from the Transporter that states:

   I certify under penalty of law that the waste fluids that I am transporting have not been mixed with hazardous wastes, and I have transported the waste fluids in compliance with Department of Transportation requirements for injection into a well subject to the requirements for the Class II Underground Injection Control Program of the Safe Drinking Water Act.

4. The Permittee shall submit a report to the Director describing any discrepancies in the composition, transported volumes or place of origin of the injected fluids. These discrepancies may be identified based upon personal observations or information contained on the three-party custody record. A report of discrepancy will be submitted annually to Region 8 UIC Enforcement Program with other required reports.