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

APR 23 2015

Ref: 8P-W-UIC

CERTIFIED MAIL
RETURN RECEIPT REQUESTED

Pierre Mulacek
Provident Energy of Montana
305 Camp Craft Road; Suite 525
Austin, Texas 78746

Re: DRAFT Area UIC Permit
EPA Permit MT22326-00000
Two Medicine Cut Bank Sand Unit
Blackfeet Indian Reservation
Glacier and Pondera Counties, Montana

Dear Mr. Mulacek:

Enclosed is the DRAFT Underground Injection Control Program Permit decision for Area UIC Permit MT22326-00000 for the Two Medicine Cut Bank Sand Unit (TMCBSU) on the Blackfeet Indian Reservation. Also enclosed are a Statement of Basis that discusses development of the proposed Permit decision and a copy of the Public Notice Announcement.

Environmental Protection Agency regulations and procedures for issuing UIC Permit decisions are found in Title 40 of the Code of Federal Regulations Part 124 (40 CFR §124) and require a public notice and opportunity for the public to comment on the proposed UIC permit decision.

Public notice of the opportunity to comment will be given on the EPA Region 8 website found at http://www2.epa.gov/region8/underground-injection-control, and announcements of the public comment period will be published in the following newspapers:

Cut Bank Pioneer Press, Cut Bank
Glacier Reporter, Browning
Shelby Promoter, Shelby

The public comment period will run for 30 days from the last date of newspaper publication. All relevant comments will be taken into consideration. If any substantial comments are received, or if any substantial changes are made between the draft permit decision and prior to the final permit decision, the effective date of the final permit will be delayed for an additional 30 days, as required by 40 CFR §124.15 (b), to allow for any potential appeal of the final permit decision.

If you have any questions or comments about the enclosed draft permit or Statement of Basis, please write to Jason Deardorff at the letterhead address citing "Mail Code 8P-W-UIC". You may also telephone Mr. Deardorff at (800) 227-8917, extension 312-6583 or (303) 312-6583.

Sincerely,

Douglas Minter
UIC Unit Chief
Office of Partnerships and Regulatory Assistance

Enclosures: Draft Area UIC Permit MT22362-00000
Statement of Basis

cc: Harry Barnes, Chairman
Blackfeet Tribe

Gerald Wagner
Environmental Director
Blackfeet Tribe

John Murray
Tribal Historic Preservation Officer
Blackfeet Tribe

Joseph Weatherwax
Water Quality Technician
Blackfeet Tribe

Phedis D. Crow, Superintendent
Bureau of Indian Affairs
Blackfeet Agency

George Hudak, UIC Coordinator
Montana Board of Oil and Gas Conservation
Billings, Montana

Barney Whiteman, Field Manager
Bureau of Land Management
Great Falls Field Office

Jodi Bush, Field Manager
U.S. Fish and Wildlife Montana Ecological Services Office
Helena, Montana

Tim Bodurtha
U.S. Fish and Wildlife Montana Ecological Services Office
Kalispell, Montana

Jennifer Winterstein
Tribal Program Manager
EPA Region 8 Montana Operations Office

Jay Waterman
Waterman Energy
Butte, Montana

Reggie Denny
Provident Energy of Montana
Austin, Texas

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
UNDERGROUND INJECTION CONTROL

DRAFT Area Permit

PREPARED: April, 2015

Area UIC Permit No. MT22326-00000

Class II-R (enhanced recovery) Area Injection Well Permit for

Two Medicine Cut Bank Sand Unit of the Cut Bank Oil Field
Blackfeet Indian Reservation, Montana

Issued To

Provident Energy of Montana, LLC
305 Camp Craft Road – Suite 525
Austin, TX 78746

PART 1. 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, Provident Energy of Montana (hereafter "Permittee") is authorized to construct and operate Class II-R (enhanced recovery) injection wells according to the terms and conditions of this Permit in the portion of the Two Medicine Cut Bank Sand Unit within the Blackfeet Indian Reservation further described and henceforth referred to as the Authorized Permit Area:

T32N-R6W sections 28, 33, 34, 35, the S/2 SW/4, SW/4 SE/4 of section 21, the SE/4 SW/4, SW/4 SE/4 of section 22, the SW/4, W/2 SE/4 of section 26, the W/2, SE/4, SE/4 NE/4, SW/4 NE/4, NW/4 NE/4 of section 27, the E/2 NE/4, E/2 SE/4 of section 29, the E/2 NE/4, E/2 SE/4 of section 32 and the W/2 NW/4, NW/4 SW/4 of section 36; T31N-R6W sections 2, 3, 4, 9, 10, 11 and the S/2, S/2 NE/4, S/2 NW/4, NW/4 NW/4 of section 1, the E/2 NE/4, E/2 SE/4 of section 5, the E/2 NE/4, E/2 SE/4 of section 8, the N/2 NW/4, N/2 NE/4, SW/4 NW/4 of section 12, the N/2 NW/4, N/2 NE/4 of section 14, N/2 NW/4, N/2 NE/4 of section 15 and the N/2 NE/4 of section 16, Montana Prime Meridian, Glacier and Pondera Counties, Montana.

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. Issuance of this Permit does not convey any property rights of any sort or any exclusive privilege, nor does it authorize injury to persons or property or invasion of other private rights, or any infringement of other Federal, State or local laws or regulations (40 CFR §144.35). An EPA Class II UIC Permit may be issued for the operating life of the injection well or project. However, it will be reviewed at least once every five years to determine if action is required under 40 CFR §144.36(a). This Permit is issued for the life of the well(s) unless modified, revoked and reissued, or terminated pursuant to 40 CFR §144.33(d) or 144.40. This EPA Permit may be adopted, modified, revoked and reissued or terminated if primary enforcement authority for a UIC Program is transferred to an Indian tribe or state. Upon the effective date of program authorization, reports, notifications, questions and other correspondence should be directed to the primacy agency.

Issue Date: Draft

Effective Date: Draft

Draft

Darcy O'Conner
Acting Assistant Regional Administrator*
Office of Partnerships and Regulatory Assistance (OPRA)

*NOTE: Throughout this Permit the term "Director" refers to either the Assistant Regional Administrator for the Office of Partnerships and Regulatory Assistance (OPRA) or the Assistant Regional Administrator of Environmental Compliance, Enforcement and Justice (ECEJ).

PART 2. TRANSFER OF EXISTING CLASS II-R UIC PERMITS

Upon issuance of Final Area UIC Permit No. MT22326-00000 (Area UIC Permit MTXXXXX-00000), all existing Class II-R UIC permits issued to the Permittee for wells within the Authorized Permit Area are revoked and authorization for those wells will be reissued under UIC Permit MT22326-00000. The first five numeric characters of each previously issued permit number will change to "22326" denoting authorization under Area UIC Permit MT22326-00000. The last five digits of previously issued permit numbers, referred to as the "well ID," will remain the same.

PART 3. QUARTERLY REPORTING REQUIREMENTS

There are no quarterly reporting requirements in Area UIC Permit MT22326-00000. This permit may be modified to require the Permittee to report quarterly to EPA. Any such permit modification would comply with the process at 40 CFR section 144.39, including public notice and comment.

PART 4. REQUIREMENTS FOR ADDING INJECTION WELLS TO AREA UIC PERMIT MT22326-00000

The Permittee shall not convert production wells to injection wells or commence injection into wells until Permittee has been approved to do so in accordance with the following procedures:

1. **Authorization to Construct**: Prior to converting an existing production well to an injection well, the Permittee shall submit the following materials to the UIC Permit Coordinator:

    a. a cover letter requesting authorization to convert the well referencing Area UIC Permit MT22326-00000 and the name and API number of the well;
    b. a completed EPA 7520 injection well application form;
    c. a wellbore diagram of the proposed injection well;
    d. a laboratory analysis of formation fluid produced from the subject well(s) or a statement that the water sample will be obtained during well construction and submitted under Part 4, paragraph 2(f) of this Permit;
    e. a topographic map extending to at least ¼-mile radius Area of Review (AOR) for the well;
    f. a listing of all wells penetrating the Confining Zone within the ¼-mile AOR and cementing records, including available Cement Bond Logs, for any wells within the ¼-mile AOR not previously evaluated by the EPA;
    g. a well location plat map for the requested injection well; and
    h. documentation of financial assurance (Financial Responsibility) for the requested injection well that is acceptable to the Director and meets requirements at Part 22 of this Permit.

Once EPA has confirmed that the proposed injection well meets the Permit conditions, EPA

Region 8 will authorize construction by email or other written communication to the Permittee. In addition, the construction authorization date for each well will be recorded in a List of Wells (LW), which is described below in Part 5.

2. **Injection Well Construction:** Area UIC Permit MT22326-00000 authorizes the Permittee to construct and test wells only in accordance with the terms and conditions of this Permit. The Permittee shall construct a requested injection well within 120 calendar days of the EPA construction authorization date, and shall notify the Director of the completed construction of an injection well as soon as possible but no later than 30 calendar days after the date that tubing and packer are set. Notification of well construction shall include:

    a. a cover letter referencing Area UIC Permit MT22326-00000 and the name and API number of the constructed injection well;
    b. an updated well bore schematic diagram;
    c. the results of a standard annulus pressure test and a statement of how mechanical integrity has been demonstrated according to Part 8 of this permit;
    d. an estimate of the initial pore pressure of the injection zone incorporating best available analog well data or other available information, and including a short narrative description and calculations used to determine the estimate;
    e. the Maximum Allowable Injection Pressure (MAIP) calculated for the well including the calculation used to determine the MAIP according to Part 11 of this Permit; and
    f. if not already submitted under Part 4, paragraph 1(e) of this Permit, a laboratory analysis of formation fluid produced from the subject well(s).

    EPA will review these materials to ensure that Permit conditions were complied with during well construction and that planned operating parameters are in full compliance with Area UIC Permit MT22326-00000. EPA Region 8 will authorize injection by email or other written correspondence when: 1) it is satisfied that all permit conditions have been met and 2) it has determined that the formation water quality at the subject well is not a USDW. If EPA finds, based on the formation water quality, that the receiving aquifer is a USDW, the Permittee, prior to receiving authorization to inject, will need to request and receive an aquifer exemption pursuant to 40 CFR section 146.4. Following EPA authorization to inject, the injection authorization date will be recorded in the LW, which is described below in Part 5.

3. **Commencement of Injection:** Initial injection shall commence no later than 30 calendar days following the EPA injection authorization. The Permittee shall notify the Director as soon as possible but no more than 30 calendar days after placing the well on injection. Such notification shall include:

    a. a statement of the date the well was put on injection;
    b. a statement of the MAIP for the well; and
    c. a statement of any required injection logs or tests that will be conducted, as required by EPA (for example, radioactive tracer survey or temperature log).

    All injection logs or tests required by Part 8, 3(b) of this permit and referenced above in

Part 4, 3(c), shall be completed within 180 calendar days of commencement of injection unless the Permittee requests and EPA provides written notification of an extension approval. Once EPA has reviewed and approved the log or test, and is satisfied that all permit conditions have been met, EPA Region 8 will provide written notification of approval to the Permittee by email or other written correspondence.

PART 5. LIST OF WELLS (LW) FOR AREA UIC PERMIT MT22326-00000

The EPA will record information related to this permit in a document called the List of Wells for Area UIC Permit MT22326-00000 (LW). The LW is solely intended to serve as an administrative tool for organizing and communicating oil-gas well data and other information related to Area UIC Permit MT22326-00000. The LW is maintained by EPA Region 8 and a current copy maybe be obtained by contacting the UIC Permit Coordinator at EPA Region 8. Injection wells regulated by EPA and subject to the terms and conditions of this Permit are listed in the LW with EPA Permit number MT22326 and are assigned a unique well identification number by the EPA.

PART 6. DRILLING OF INJECTION WELLS

The drilling of injection wells is not authorized under this permit. The Permittee shall notify the Director at such time the Permittee wishes to drill an injection well and request a permit modification to Area UIC Permit MT22326-00000. Any such permit modification will require compliance with the process at 40 CFR section 144.39, including public notice and comment.

PART 7. INJECTION WELL CONSTRUCTION REQUIREMENTS

These requirements represent the approved minimum construction standards for well casing and cement, well head configuration, injection tubing and packer. Deviation from the approved construction standards without prior approval from the Director is prohibited.

1. **Casing and Cement:** Injection wells shall be cased and cemented to prevent the movement of fluids into or between USDWs. The well casing and cement shall be designed for the life expectancy of the well. Remedial cementing may be required if shown to be inadequate by cement bond log or other attempted demonstration of Part II (external) mechanical integrity.

   a. Any production well added to Area UIC Permit MT22326-00000 as an injection well must have surface casing set and cemented to depths determined to be protective of USDWs by the Director.
   b. Long string casing shall be adequately cemented to at least above the base of the Confining Zone or a regular Part II (external) mechanical integrity demonstration by an approved Part II testing method is required. The depth of top of cement shall be demonstrated by cement bond log and is subject to approval by the Director.
   c. The Permittee shall not perforate uncemented intervals of long string casing in any injection well

except to squeeze cement as required to meet the conditions of this Permit.

2. **Injection Tubing and Packer:** Injection tubing and packer are required on all injection wells authorized under Area UIC Permit MT22326-00000. The packer shall be set no greater than 100 feet less than the measured depth of the first open perforation.

3. **Sampling and Monitoring Devices on the Well Head:** The Permittee shall install and maintain in good operating condition:

   a. a "tap" at a conveniently accessible location on the injection flow line between the pump house or storage tanks and the injection well, isolated by shut-off valves, for collection of representative samples of the injected fluid; and
   b. a 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 Maximum Allowable Injection Pressure:

      (1) on the injection tubing;

      (2) on the Tubing-Casing Annulus (TCA); and

   c. a pressure actuated shut-off device attached to the injection flow line set to shut-off flow from the injection pump when or before the Maximum Allowable Injection Pressure (MAIP) is reached at the wellhead in the injection tubing string(s); and
   d. a non-resettable cumulative volume recorder attached to the injection line(s).

PART 8. MECHANICAL INTEGRITY OF INJECTION WELLS

The Permittee shall maintain the mechanical integrity of all injection wells under Area UIC Permit MT22326-00000 at all times and as specified by the EPA. Injecting into a well that lacks mechanical integrity is prohibited.

1. **Definition of Mechanical Integrity:** An injection well has mechanical integrity if:

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

2. **Mechanical Integrity Demonstration Requirements:** The Permittee shall demonstrate Part I (internal) mechanical integrity prior to commencing injection and periodically thereafter as described in Part 8, 3(a) below or as required by the Director. The Permittee shall demonstrate Part II (external) mechanical integrity according to Part 8, 3(b) no greater than 180 days following commencement of injection or as required by the Director. The Director may require additional or alternative tests if the results presented by the operator are not satisfactory to the Director to demonstrate mechanical integrity. Results of mechanical integrity tests shall be submitted to the Director as soon as possible but no more than 30 calendar days after the test is complete.

c. **Approved Methods for Demonstrating Mechanical Integrity:**

a. Part I (Internal) mechanical integrity shall be demonstrated prior to commencement of injection and this demonstration shall be repeated no less than once every five years after the last demonstration. Any injection well requiring the use of Angard or other annulus plugging gel or corrective measure to pass a Part I mechanical integrity test shall have a Part I mechanical integrity demonstration conducted no less than once every 365 calendar days. Part I mechanical integrity shall be demonstrated by a standard annulus pressure test or other method approved by the Director.

b. Part II (external) mechanical integrity shall be demonstrated by:

(1) a Cement Bond Log (CBL) that the Director determines to show a sufficient interval of 80 percent cement bond index compressive strength or greater within the designated Confining Zone; or

(2) a Radioactive Tracer Survey (RTS) showing the absence of fluid movement through vertical channels adjacent to the well bore at or near the shallowest perforation accepting fluid, to be repeated at a frequency not to exceed five years after the last RTS showing the absence of fluid movement through vertical channels adjacent to the wellbore at or near the shallowest perforations accepting fluid. The RTS shall supplement a CBL on file with the EPA showing top of cement above the base of the designated Confining Zone but an insufficient interval of 80 percent cement bond index compressive strength or greater through the designated Confining Zone; or

(3) other approved Part II mechanical integrity demonstration method including a temperature log, oxygen activation log, or noise log that shall be repeated no less than once every five years.

c. EPA approved methods shall be used to demonstrate mechanical integrity. EPA Region 8[1] Ground Water Section Guidance No. 34 "Cement Bond Logging Techniques and Interpretation", Ground Water Section Guidance No. 37, "Demonstrating Part II (External) Mechanical Integrity for a Class II injection well permit", and Ground Water Section Guidance No. 39, "Pressure Testing Injection Wells for Part I (Internal) Mechanical Integrity" as well as guidelines for conducting radioactive tracer surveys are available online at http://www.epa.gov/region8/water/uic/deep_injection.html or copies will be provided upon request.

4. **Notification of Mechanical Integrity Testing:** Prior notification of mechanical integrity testing is not required under Area UIC Permit MT22326-00000. It is the Permittee's responsibility to ensure that mechanical integrity demonstration on all wells is conducted in accordance with Area UIC Permit MT22326-00000 and that all mechanical integrity test results are submitted to the Director as soon as possible but no more than 30 calendar days from completion.

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[1] EPA headquarters in Washington, D.C. issues national UIC Guidance documents with numbers that do not correspond to EPA Region 8 UIC Guidance documents. These may be found at http://water.epa.gov/type/groundwater/uic/guidance.cfm

5. **Loss of Mechanical Integrity:** If the Permittee fails to demonstrate mechanical integrity during a test or a loss of mechanical integrity becomes evident during operation (such as presence of abnormal[2] pressure in the Tubing-Casing Annulus (TCA), water flowing at the surface, etc.), the Permittee shall notify the Director within 24 hours (see Part 21, Paragraph 11(e) of this Permit) and the well shall be shut-in within 48 hours unless the Director requires immediate shut-in. Within five calendar days of discovering the loss of mechanical integrity, the Permittee shall submit a written report that documents the circumstances and repairs undertaken or a proposed remedial action plan. Injection operations shall not be resumed until after the well has successfully been repaired, has demonstrated mechanical integrity and the Permittee has received written notification from the Director. A demonstration of mechanical integrity shall be re-established within 90 days of any loss of mechanical integrity unless written approval of an alternate time period has been given by the Director.

PART 9. WELL LOGGING and TESTING REQUIREMENTS

The Permittee shall:

1. conduct all logs and tests according to current EPA approved procedures;
2. submit all logging and testing results to the Director for review within 30 calendar days of completion of the logging or testing activity;
3. include with any data and test results, a report describing the methods used during logging or testing and an interpretation of the test or log results by a qualified log or test analyst; and
4. submit logs and test data for newly drilled production wells and all injection well conversions to the EPA Region 8's Office of Partnerships and Regulatory Assistance UIC Program and submit periodically required logs and test data on existing injection wells to the EPA Region 8's UIC Technical Enforcement Program as described below:

   a. Mail initial logs and tests for bringing new injection wells on line to:

      UIC Permit Coordinator, 8P-W-UIC
      U.S. EPA Region 8
      Denver, Colorado

   b. Mail periodically required logs and tests on injection wells to:

      UIC Enforcement Coordinator, 8ENF-UFO
      U.S. EPA Region 8
      Denver, Colorado

[2] Abnormal pressure on the tubing-casing annulus is 100 psig or 10 percent of the injection tubing pressure, whichever is less.

PART 10. REQUIREMENTS FOR OPERATING INJECTION WELLS

1. **Injection Zone:** An *injection zone* is a geological formation, group of formations, or part of a formation that receives fluids through a well. The Injection Zone for Area UIC Permit MT22326-00000 consists of the Cut Bank Formation. For each injection well authorized by MT22326-00000, the Permittee is authorized to perforate casing and emplace fluids only within the stratigraphic interval designated as the Injection Zone.

2. **Confining Zone:** A *Confining Zone* is a geological formation, group of formations, or part of a formation that is capable of limiting fluid movement above an injection zone. The designated Confining Zone for Area UIC Permit MT22326-00000 is the Kootenai Shale.

3. **Injection Volume Limitation:** The volume of approved Class II fluids injected for the purpose of enhanced recovery is not limited by this Permit.

4. **Injection Fluid Limitation:** Area UIC Permit MT22326-00000 authorizes the injection of Madison Formation supply water and produced water from the Cut Bank Formation. The Permittee shall provide an annual listing of sources of injected fluids in accordance with the reporting requirements in Part 14, Paragraph 4 of this Permit. Injection of any fluid for the purpose of disposal is prohibited. Prohibited fluids include 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.

5. **Tubing-Casing Annulus (TCA):** The TCA shall be filled with water treated with a corrosion inhibitor or other fluid approved by the Director. The TCA valve shall remain closed during normal operating conditions and the TCA pressure shall be maintained at zero (0) psi. If TCA pressure cannot be maintained at zero (0) psi, the Permittee shall follow the procedures in Ground Water Section Guidance No. 35 "Procedures to follow when excessive annular pressure is observed on a well."

PART 11. MAXIMUM ALLOWABLE INJECTION PRESSURE (MAIP)

The Permittee shall calculate the MAIP based on the following equation:

$$\text{MAIP} = [1.156 - (0.433)(1.005)] * \text{Depth},$$

Where "Depth" is the Kelly Bushing depth in feet to the shallowest perforation in the long string casing. The MAIP shall not be exceeded except during well stimulation.

PART 12. AREA OF REVIEW (AOR) WELL REQUIREMENTS

All wells located within a ¼-mile radius of an injection well shall have top of cement behind the outermost casing string at the depths of the Injection and Confining Zones at least above the base of the designated Confining Zone, unless the AOR well is an EPA-authorized injection well with a demonstration of part II (external) mechanical integrity. As required under Part 4 of this Permit

(Requirements for Adding Injection wells to Area UIC Permit MT22326-00000), the Permittee shall identify all wells penetrating the Confining Zone within a ¼-mile radius of a requested injection well and provide a cement bond log for any production well that EPA has not previously evaluated. Plugged and abandoned wells in the AOR of an injection well shall either have cement behind the outermost casing string above the base of the Confining Zone or in the case of uncased, drilled and abandoned wells that penetrate the injection zone, shall have a cement plug that isolates the injection zone from USDWs.

PART 13. REQUIREMENTS FOR WORKOVERS AND ALTERATIONS

Workovers and alterations to the injection well shall meet all conditions of Area UIC Permit MT22326-00000. Workovers include well stimulation such as hydraulic fracturing, polymer gel injection and the delivery of acid to the injection zone formation and does not include the temporarily filling of the wellbore with acid to descale tubing and casing. Prior to beginning any addition, physical alteration or workover activity that may affect the tubing, packer or casing, the Permittee shall give advance notice to the Director. Such notice may be given via email correspondence, faxed letter or post. The Permittee shall record all workovers and changes to well construction on a Well Rework Record (EPA Form 7520-12) and when appropriate, provide an updated well bore diagram, and shall provide this and any other record of well workover, including monitoring, logging or test data to the Director within 30 calendar days of completion of the activity. A successful demonstration of Part I (internal) mechanical integrity is required following the completion of any well workover or alteration which affects the casing, tubing, or packer. Injection operations shall not be resumed until the well has successfully demonstrated Part I mechanical integrity, and if the well lost mechanical integrity, the Director has provided written notice.

PART 14. MONITORING, RECORDKEEPING and REPORTING OF RESULTS

1. **Monitoring Parameters, Frequency, Records and Reports:** Monitoring parameters are specified in Table 1 of this Permit. Pressure monitoring recordings shall be taken at the wellhead. The listed parameters are to be monitored, recorded and reported at the frequency indicated in Table 1 even during periods when the well is not operating.

Table 1: Monitoring and reporting requirements for each injection well

	Observe monthly and record at least once every 30 days
Observe and Record	Injection pressure (psig)
	Annulus pressure(s) (psig)
	Injection rate (bbl/day)
	Fluid volume injected since the well began injecting (bbls)
	Annually
Analyze	Injected fluid total dissolved solids (mg/l)
	Injected fluid specific gravity
	Injected fluid specific conductivity
	Injected fluid pH
	Annually
Report	Each month's maximum and averaged injection pressures (psig)
	Each month's maximum and minimum annulus pressure(s) (psig)
	Each month's injected volume (bbl)
	Fluid volume injected since the well began injecting (bbls)
	Written results of annual injected fluid analysis
	Sources of all fluid injected during the year

Monitoring records shall include:

a. the date, time, exact place and the results of the observation, sampling, measurement, or analysis;
b. the name of the individual(s) who performed the observation, sampling, measurement, or analysis; and
c. the analytical techniques or methods used for analysis.

2. **Monitoring Methods:** Monitoring observations, measurements, samples, etc. taken for the purpose of complying with these requirements shall be representative of the activity or condition being monitored. Methods used to monitor the nature of the injected fluids must comply with analytical methods cited and described in Table 1 of 40 CFR 136.3 or Appendix III of 40 CFR part 261, or by other methods that have been approved in writing by the Director.

   Injection pressure, annulus pressure, injection rate, and cumulative injected volumes shall be observed and recorded at the wellhead under normal operating conditions, and all parameters shall be observed simultaneously to provide a clear depiction of well operation. Pressures are to be measured in pounds per square inch (psi). Fluid volumes are to be measured in standard oil field barrels (bbl). Fluid rates are to be measured in barrels per day (bbl/day).

3. **Records Retention:** Records of calibration and maintenance, and all original strip chart 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 shall be retained for a period of at least three years from the date of the sample, measurement, report, or application. This period may be extended any time prior to its expiration by request of the Director. Records of the nature and composition of all injected fluids must be retained until three years after the completion of any plugging and abandonment procedures specified under 40 CFR section 144.52(a)(6) or under Part

146 Subpart G, as appropriate. The Director may require the Permittee to deliver the records to the Director at the conclusion of the retention period. The Permittee shall continue to retain the records after the three year retention period unless the Permittee delivers the records to the Director or obtains written approval from the Director to discard the records.

4. **Annual Reports:** Regardless of whether the well is operating or not, the Permittee shall submit an Annual Report to the UIC Enforcement Coordinator in Part 9, 4(b) of this Permit that summarizes the results of the monitoring required by Part 14, Paragraph 1 and Table 2 of this Permit. The report of all sources of the fluids injected during the year must identify each source by the generator's name and the well name and location, and the field name or facility name. 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 7520-11 may be copied and shall be used to submit the Annual Report. However, the monitoring requirements specified in this Permit are mandatory even if EPA Form 7520-11 indicates otherwise.

PART 15. INACTIVE INJECTION WELLS AND CONVERTING INJECTION WELLS TO NON-INJECTION WELLS

1. **Inactive Injection Wells**: After any period of two years during which there is no injection, the Permittee shall plug and abandon the well in accordance with Part 16 of this Permit unless:

   a. The Permittee provides written notice to the Director; and
   b. describes the actions or procedures that will be taken to ensure the well will not endanger USDWs during the period of inactivity, including compliance with mechanical integrity demonstration, financial responsibility and all other permit requirements; and
   c. receives written notice by the Director temporarily waiving plugging and abandonment requirements.

2. **Conversions to Non-Injection Wells:** The Director may, for cause or upon a written request from the Permittee, allow conversion of the well from a Class II injection well to a non-Class II well. Conversion may not proceed until the Permittee receives written approval from the Director. Conditions of such conversion may include but are not limited to, approval of the proposed well rework, follow up demonstration of mechanical integrity, well-specific monitoring and reporting following the conversion, and demonstration of practical use of the converted configuration.

PART 16. PLUGGING AND ABANDONMENT REQUIREMENTS

1. **Notification of Well Abandonment and Project Closure:** The Permittee shall notify the Director in writing at least forty five calendar days prior to plugging and abandoning an injection well and the closure of the Monument Butte Field enhanced oil recovery project.

2. **Well Plugging Requirements**: Injection wells shall be plugged with cement in a manner which isolates the injection zone and prevents the movement of fluids into or between underground sources of drinking water and in accordance with 40 CFR §146.10. Tubing, packer and other down hole

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. If cement retainers or bridge plugs are not used then plug placement shall be verified by tagging. Plugging gel of at least 9.0 lb/gal shall be placed between all plugs. A minimum 50 ft. surface plug shall be set inside the long string casing to seal pathways for fluid migration into the subsurface. The Plugging Record must be certified as accurate and complete by the person responsible for the plugging operation. Prior to placement of the cement plug(s) the well shall be in a state of static equilibrium with the mud weight equalized top to bottom, either by circulating the mud in the well at least once or by a comparable method.

3. **Approved Plugging and Abandonment Plan**

In addition to the requirements in Part 16, paragraph two, the Permittee shall:

a. Isolate the injection zone: Remove down hole apparatus from the well and perform necessary clean out; displace well fluid with plugging gel. Set a cast iron bridge plug (CIBP) within the innermost casing string no more than 50 ft. above the top perforation with a minimum of 20 ft. cement plug on top of the CIBP.
b. Isolate the geologic contact(s) of any formation(s) known to contain USDWs: Perforate and squeeze cement up the backside of the outermost casing string across the contact, from at least 50 feet above to at least 50 feet below, unless there is existing cement across the contact. Set a minimum 100-foot cement plug inside the longstring casing centered across contact.
c. Isolate Surface Fluid Migration Paths:

(1) If the depth of the lowermost USDW is above the base of surface casing, perforate the outermost casing string 50 ft. below the base of surface casing and circulate cement to the surface, unless there is existing cement across this interval; or

(2) If the depth of the lowermost USDW is below the base of surface casing, perforate the outermost casing string 50 ft. below the base of the lowermost USDW and circulate cement to surface; and

(3) Set a cement plug inside the innermost casing string from 50 ft. below the base of the surface casing to surface.

4. **Plugging and Abandonment Report:** Within sixty calendar days after plugging a well, the Permittee shall submit a report (EPA Form 7520-13) and a well bore diagram of the plugged well to the Director. The plugging report shall be certified as accurate by the person who performed the plugging operation. The report shall consist of either:

a. statement that the well was plugged in accordance with the approved plugging and abandonment plan; or
b. where actual plugging differed from the approved plugging and abandonment plan, an updated version of the plan, on the form supplied by the Director, specifying the differences.

PART 17. EFFECT OF PERMIT

The Permittee is allowed to engage in underground injection in accordance with the conditions of this Permit. The Permittee shall not construct, operate, maintain, convert, plug, abandon, or conduct any other activity in a manner that allows the movement of fluid containing any contaminant into underground sources of drinking water if the presence of that contaminant may cause a violation of any primary drinking water regulation under 40 CFR part 141 or may otherwise adversely affect the health of persons. Any underground injection activity not authorized by this Permit or by rule is prohibited. Issuance of 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. 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 Safe Drinking Water Act (SDWA) or any other law governing protection of public health or the environment, for any imminent and substantial endangerment to human 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.

PART 18. CHANGES TO PERMIT CONDITIONS

1. **Modification, Reissuance, or Termination:** The Director may, for cause or upon a request from the Permittee, modify, revoke and reissue, or terminate this Permit in accordance with 40 CFR §124.5, 144.12, 144.39, and 144.40. Also, this Permit is subject to minor modification for causes as specified in 40 CFR 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. **Transfer of Permit:** Under 40 CFR 144.38, this Permit is transferable provided the current Permittee notifies the Director at least 30 calendar days in advance of the proposed transfer date (EPA Form 7520-7) and provides a written agreement between the existing and new Permittees containing a specific date for transfer of Permit responsibility, coverage and liability between them. The notice shall adequately demonstrate that the financial responsibility requirements of 40 CFR 144.52(a)(7) will be met by the new Permittee. The Director may require modification or revocation and reissuance of the Permit to change the name of the Permittee and incorporate such other requirements as may be necessary under the Safe Drinking Water Act; in some cases, modification or revocation and reissuance is mandatory.

3. **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 30 calendar days.

PART 19. 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.

PART 20. CONFIDENTIALITY

In accordance with 40 CFR Part 2 and 40 CFR §144.5, information submitted to the EPA pursuant to this Permit 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 validity of the claim will be assessed 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.

PART 21. GENERAL PERMIT REQUIREMENTS

1. **Duty to Comply:** The Permittee must comply with all conditions of this Permit. Any noncompliance constitutes a violation of the Safe Drinking Water Act (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 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.

2. **Duty to Reapply:** If the Permittee wishes to continue an activity regulated by this Permit after the expiration date of this Permit, under 40 CFR §144.37 the Permittee must apply for a new permit prior to the expiration date.

3. **Need to Halt or Reduce Activity Not a Defense:** It shall not be a defense for a Permittee 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 Rights:** This Permit does not convey any property rights of any sort, or any exclusive

privilege.

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. The Permittee is required to submit any information required by this Permit or by the Director to the mailing address designated in writing by the Director.

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 and control equipment), practices, or operations regulated or required under this Permit; and
   d. Sample or monitor at reasonable times, for the purpose of assuring permit compliance or as otherwise authorized by the SDWA, any substances or parameters at any location.

10. **Signatory Requirements:** All applications, reports or other information submitted to the Director 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:**

    a. The Permittee shall give prior notice to the Director as soon as possible of any planned changes, physical alterations or additions to the permitted facility.
    b. 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.
    c. Monitoring Reports: Monitoring results shall be reported at the intervals specified in this Permit.
    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 30 calendar days following each schedule date.
    e. Twenty-four hour reporting: The Permittee shall report to the Director any noncompliance which may endanger human health or the environment, including:

       (1) Any monitoring or other information which indicates that any contaminant may cause endangerment to a USDW; or

       (2) Any noncompliance with a permit condition or malfunction of the injection system which may cause fluid migration into or between USDWs.

       Information shall be provided, either directly or by leaving a message, within 24 hours from the time the permittee becomes aware of the circumstances by telephoning (800) 227-8917 and requesting the EPA Region 8 UIC Program Compliance and Technical Enforcement Director, 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 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. 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, (202) 267-2675, or through the NRC website http://www.nrc.uscg.mil/index.htm.
g. Other Noncompliance: The Permittee shall report all instances of noncompliance not reported under paragraphs Part 21, Paragraph 11(b) or Paragraph 11(e) at the time the monitoring reports are submitted. The reports shall contain the information listed in Paragraph 11(e) of Part 21.
h. Other information: Where the Permittee becomes aware that it failed to submit any relevant facts in the permit application, or submitted incorrect information in a permit application or in any report to the Director, the Permittee shall promptly submit such facts or information to the Director.

PART 22. 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(s) to reflect changes in such costs and may require the Permittee to provide a revised demonstration of financial responsibility. No substitution of a demonstration of financial responsibility shall become effective until the Permittee receives written notification from the Director that the alternative demonstration of financial responsibility is acceptable.

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.

   A surety bond acceptable to the Director shall contain wording identical to 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 on the internet at http://fms.treas.gov/c570/c570.html.

A letter of credit acceptable to the Director shall contain wording identical to 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 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 Chief Financial Officer's letter acceptable to the Director shall contain wording identical to EPA's model language and shall demonstrate the Permittee meets or exceeds certain financial ratios. If this financial instrument is used, it must be resubmitted annually, within 90 days after the close of the Permittee's fiscal year, using the financial data available from the most recent fiscal year.
A standby trust agreement acceptable to the Director shall contain wording identical to 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.

3. **Determining How Much Coverage is Needed.** The Permittee when periodically requested to revise the plugging and abandonment cost estimate discussed above must submit 3 current independent plugging and abandonment cost estimates for EPA to accurately determine the likely cost to plug the well(s).

4. **Insolvency.** In the event of:

   a. the bankruptcy of the trustee or issuing institution of the financial mechanism; OR
   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 such an instrument;

   The Permittee must notify the Director in writing, within 10 business days, and the Permittee must establish other financial assurance or liability coverage acceptable to the Director within 60 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 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.

STATEMENT OF BASIS FOR DRAFT AREA PERMIT DECISION

PROVIDENT ENERGY OF MONTANA, LLC

Area UIC Permit MT22326-00000:
Two Medicine Cut Bank Sand Unit
Blackfeet Indian Reservation, Montana

Contact: Jason Deardorff
U.S. Environmental Protection Agency
Underground Injection Control Program, 8P-W-UIC
1595 Wynkoop Street
Denver, Colorado 80202-1129
Telephone: 1-800-227-8917 ext. 312-6583

This Statement of Basis gives the derivation of site-specific Underground Injection Control (UIC) permit conditions and the reasons for them. Referenced sections and conditions correspond to sections and conditions in the permit.

EPA UIC permits regulate the injection of fluids into underground injection wells to prevent endangerment to Underground Sources of Drinking Water (USDWs). EPA UIC permit conditions are based upon the authorities set forth in regulatory provisions at 40 CFR Parts 144 and 146, and are intended to prevent movement of contaminants into USDWs. Issuance of this permit does not convey property rights of any sort or any exclusive privilege, nor authorize injury to persons or property or invasion of other rights, or any infringement of other Federal, State or local laws or regulations. Under 40 CFR 144 Subpart D, certain conditions apply to all UIC permits and may be incorporated either expressly or by reference. General permit conditions for which the content is mandatory and not subject to site-specific differences (40 CFR Parts 144, 146 and 147) are not discussed in this document.

The EPA administers the Class II UIC program throughout Indian country in Montana, including the Blackfeet Indian Reservation. Regulations specific to injection wells located in Indian country in Montana are found at 40 CFR 147 Subpart TT. This permit will expire upon EPA authorization of primary enforcement responsibility (primacy) for applicable portions of the UIC Program to the Blackfeet Indian Tribe unless the Tribe chooses to adopt and administer this permit as a Tribal permit.

Part 1. General Information and Description of Project

Permittee:
Provident Energy of Montana, LLC
305 Camp Craft Road – Suite 525
Austin, TX 78746

Facility:
Two Medicine Cut Bank Sand Unit of the Cut Bank Oil Field, Blackfeet Indian Reservation, Montana

Project Background

Provident Energy of Montana, LLC (Provident or "the Permittee") submitted six applications to EPA Region 8's UIC Program in December, 2014, for permits to construct and operate Class II-R (enhanced recovery) injection wells on a portion of the Two Medicine Cut Bank Sand Unit (TMCBSU) located within the Blackfeet Indian Reservation. The six requested injection wells would be in addition to existing EPA-regulated Class II enhanced oil recovery injection well Tribal Max 1-2817, EPA UIC Permit No. MT22274-10103, issued final on April 7, 2014. The EPA is proposing to issue a single area UIC permit for all seven wells, instead of issuing and managing seven individual UIC Permits. The EPA considers this approach to be more protective of Underground Sources of Drinking Water (USDW) than regulation of seven injection wells via seven different UIC permits, and because an area permitting approach would include consideration of the cumulative effects of injection in the event the waterflood is expanded in the future. Provident has requested the following area to be covered by permit, which will henceforth be referred to as the Authorized Permit Area: T32N-R6W sections 28, 33, 34, 35, the S/2 SW/4, SW/4 SE/4 of section 21, the SE/4 SW/4, SW/4 SE/4 of section 22, the SW/4, W/2 SE/4 of section 26, the W/2, SE/4, SE/4 NE/4, SW/4 NE/4, NW/4 NE/4 of section 27, the E/2 NE/4, E/2 SE/4 of section 29, the E/2 NE/4, E/2 SE/4 of section 32 and the W/2 NW/4, NW/4 SW/4 of section 36; T31N-R6W sections 2, 3, 4, 9, 10, 11 and the S/2, S/2 NE/4, S/2 NW/4, NW/4 NW/4 of section 1, the E/2 NE/4, E/2 SE/4 of section 5, the E/2 NE/4, E/2 SE/4 of section 8, the N/2 NW/4, N/2 NE/4, SW/4 NW/4 of section 12, the N/2 NW/4, N/2 NE/4 of section 14, N/2 NW/4, N/2 NE/4 of section 15 and the N/2 NE/4 of section 16, Montana Prime Meridian, Glacier and Pondera Counties, Montana. Figure 1 shows the proposed UIC Permit Area.

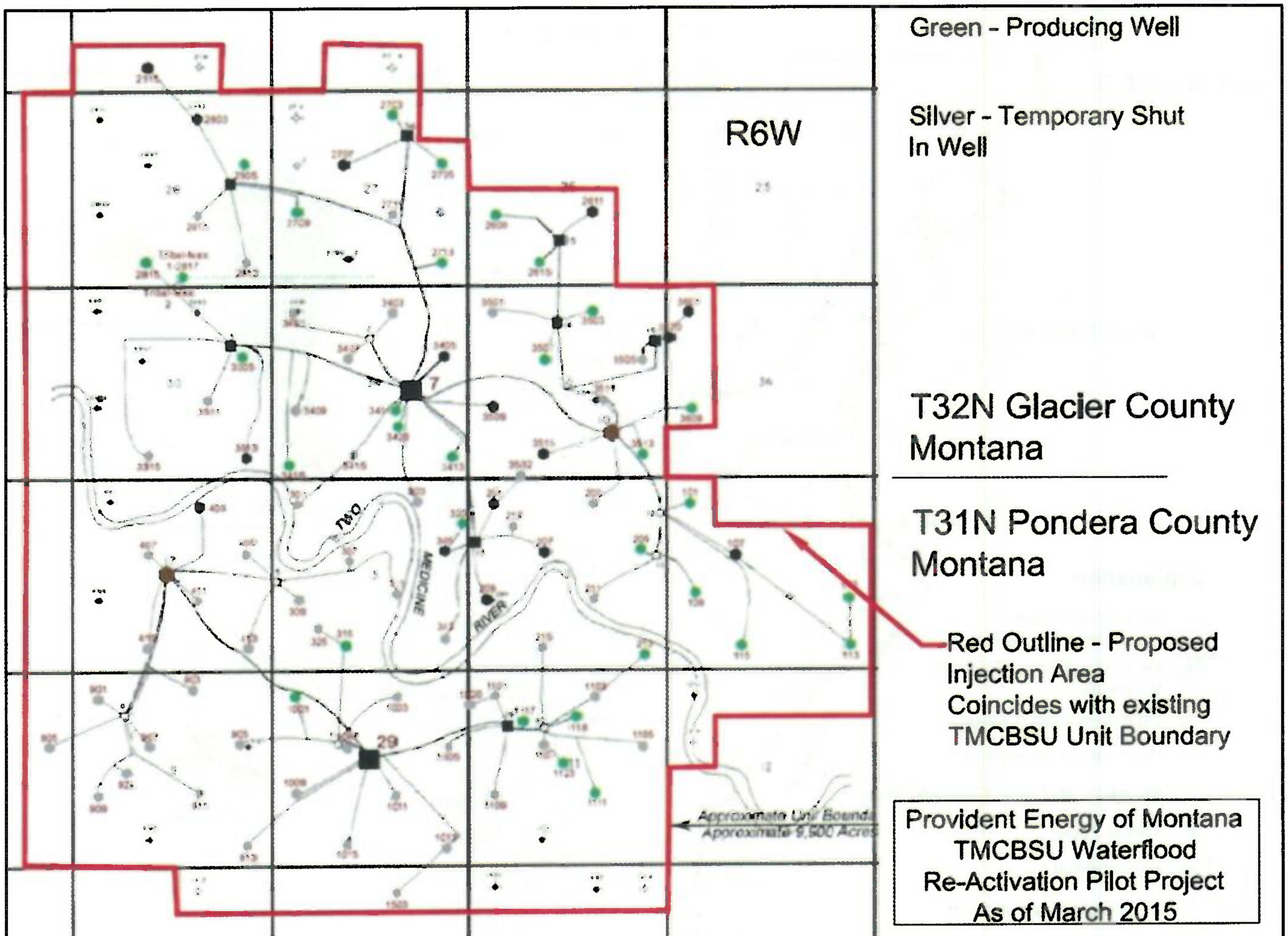

Figure 1: Map of the Two Medicine Cut Bank Sand Unit and proposed UIC permit area.

This area permit would initially authorize seven injection wells within the Authorized Permit Area and would authorize the possible further conversion of oil-gas production wells to Class II-R (enhanced recovery) water injection wells in accordance with the conditions of this permit. This permit does not limit the number of Class II-R injection wells within the Authorized Permit Area but the applicant indicates that if the pilot is successful the area could contain up to 25 injection wells. The TMCBSU is located at the southern tip of the Cut Bank Field as shown in Figure 2.

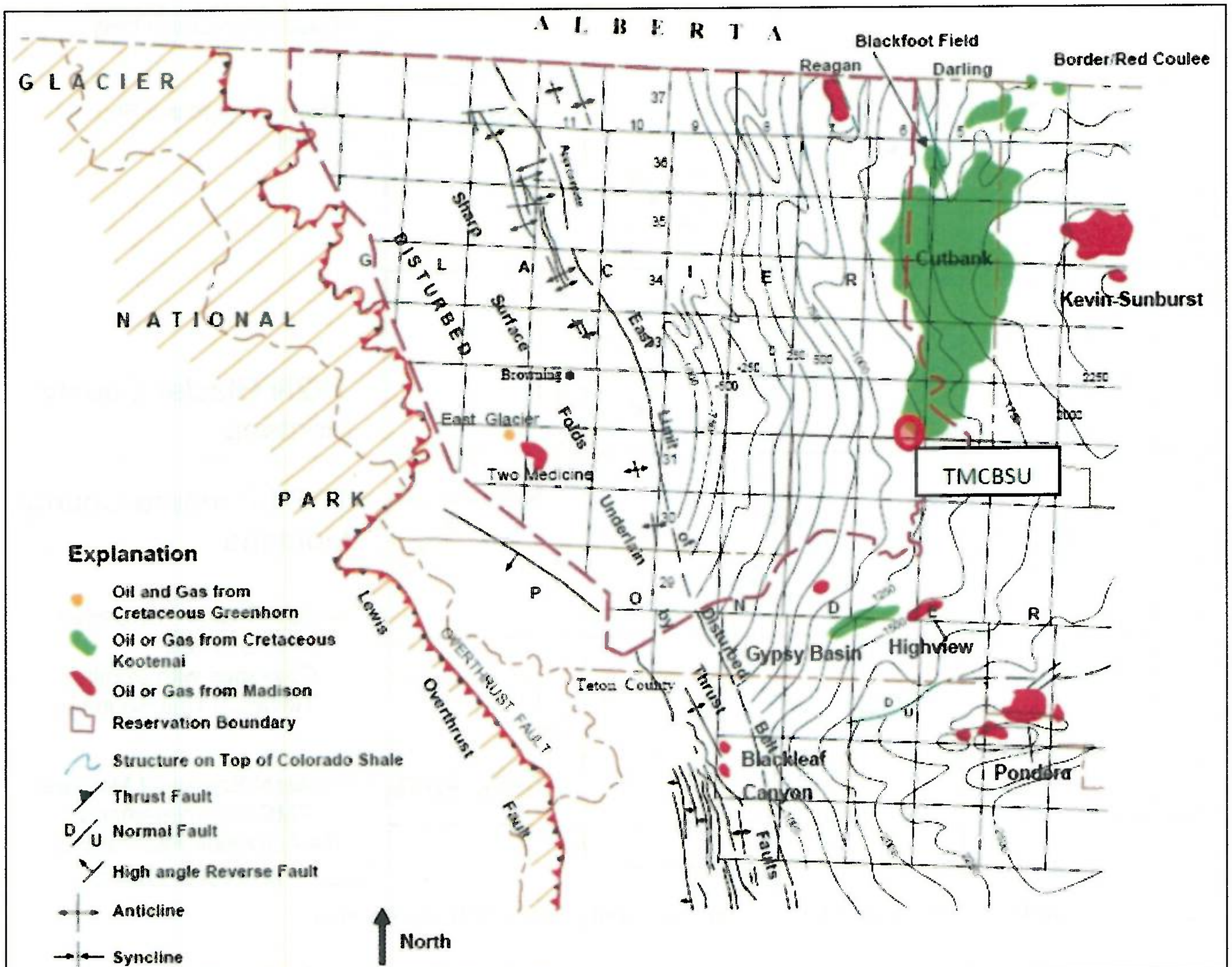

Figure 2: Map showing the location of the Two Medicine Cut Bank Sand Unit within the Cut Bank Oil Field. The TMCBSU is circled in red. Source: https://www1.eere.energy.gov/tribalenergy/guide/pdfs/blackfeet.pdf

History of the Cut Bank Oil Field

The following history of the Cut Bank Field is quoted from "Status of Mineral Resource Information for the Blackfeet Indian Reservation, Montana," Administrative Report BIA-24 1976, Balster, Sokaski, McIntyre, Berg, McClernan, Hansen:

> *The Cut Bank oil and gas field is about 30 miles long, 5 to 10 miles wide, and extends north and south of the town of Cut Bank. Most of this oil field is east of the Blackfeet Indian reservation.*
>
> *According to Perry, ES (Oil and Gas in Montana, Montana Bureau of Mines and Geology Mem, 1960, p. 38), the Cut Bank gas field was discovered in 1926 by a well drilled in sec. 1, T. 35 N., R. 5 W. Initial production was about 8 million cubic feet of gas per day from a depth of 2,780 feet. Since no pipeline was available, the well was plugged and abandoned. In 1929, a second well, 8½ miles to the southwest, found oil and gas in the same formation, although it was*

structurally 250 feet lower. Productive zones were found in the Cut Bank Sandstone at the base of the Kootenai Formation. Intensive drilling did not begin until 1931 when 20 wells were drilled northeast of Cut Bank. Only one hole was dry. Each well averaged 12,700,000 cubic feet of gas per day.

In 1932, the presence of oil in one of the wells (Drumheller-Yunck) led to downdip drilling and the Cut Bank oil field was discovered (Perry, 1960, p. 38 and 39). As of January 1936, development drilling had proven a gas-producing area 18 miles long and 3 to 5 miles wide, and an oil-producing area 20 miles long and 3 to 22 miles wide. Oil production peaked during 1942, 1943, and 1944 at about 5½ million barrels of oil annually (about 15,000 barrels daily). In December 1950, there were 1,171 oil wells and 162 gas wells.

The Carter-Brindley well No. 1 (sec. 12, T. 36 N., R. 6 W.) discovered oil and gas in the upper part of the Madison Group at a depth of about 3,090 feet in the summer of 1945. Within two years approximately one-tenth of the Cut Bank oil production was from the Madison Group (Sun River Dolomite) (Perry, 1960, p. 39).

Now that several hundred wells have been drilled, it is known that the Cut Bank field is a stratigraphic trap. The oil and gas were trapped in sandstone bodies and in limestone layers that showed distinctly limited areas of porosity and permeability. Structure contributes to the trap only because it tilts the limited sand bodies and affords a completed trapping mechanism.
The main producing zone at Cut Bank is at or near the base of the Kootenai Formation. The Kootenai has a total thickness of about 500 feet on the east side of the field and as much as 650 feet on the west, within a horizontal distance of about 10 miles. The formation is an intermingled series of river-laid, flood-plain, and near-shore deposits consisting of mudstones and shales with lenticular siltstones and sandstones. Most of the sandstones are in the lower third of the formation.

The three producing sandstone zones, in the lower 150 to 200 feet of the Kootenai Formation, are the upper Moulton, the middle Sunburst, and the basal Cut Bank zones, with the latter being the most important oil and gas reservoir (Perry, 1960, p. 40).

The Cut Bank sand zone is present throughout the field. The thickness averages about 45 feet, the porosity about 15 percent, and the permeability about 115 millidarcys. However, the characteristics of the sand vary from well to well, and dry holes and poor wells are found throughout the field. Initial production of the wells was as much as 300 barrels of oil per day (Perry, 1960, p. 40, 41)

History of the Two Medicine Cut Bank Sand Unit

The history of development of the TMCBSU is captured in the 1996 BLM Report titled "Two Medicine Cut Bank Sand Unit Analysis" Prepared by Peter J. Ditton, Dale Manchester, Aden L. Seidlitz, Petroleum Engineers, Bureau of Land Management, May 8, 1996. This document was prepared for the Blackfeet Tribe and the Bureau of Indian Affairs. The following information is quoted from the 1996 BLM report:

The Two Medicine Cut Bank Sand Unit area was originally drilled in 1959, resulting in the discovery of oil in the Cut Bank Formation at a depth of approximately 3200 feet. The discovery well was drilled by Texota in the NWSE, Sec. 27, T.32N., R.6W. The Two Medicine Area experienced three periods of development drilling. Initial development took place during the period from September 1959 through mid-1962. In December, 1962, Texota initiated a pilot water flood which resulted in a favorable response.

Development drilling remained essentially quiescent after May 1962 until late 1964. In September 1964, Continental Oil Company purchased the producing properties of Texota, et.al. and developed the purchased acreage by drilling 15 additional producing wells. Continental's development program was completed in mid-1965. During late 1964 and the first half of 1965 Amax Petroleum, E.L.K. and Austin, and C.W. Austin also continued development of the area. Then after a three or four month lull Miami Oil Producers drilled seven wells late in 1965 on acreage farmed out from Humble oil and Refining. Development drilling continued during 1966 with Miami Oil Producers operating one rotary drilling rig continuously.

Unitization of the private, Tribal and Allotted leases within the Two Medicine Cut Bank Sand Unit area was commenced by Continental Oil Company in 1965 and resulted in the Unitization, effective August 1, 1967. Operated by Miami Oil Producers, Inc., the Unit area contracted to its present configuration on May l, 1972, see attachment 1. Miami Oil Producers continued operating the unit until February 29, 1980. Conoco Inc., took over as operator of the TMCBSU effective March l, 1980, and operated the unit until S&J Operating Company assumed operations effective April 1, 1984. S&J Operating Company remained as unit operator until Wold Oil took over effective, February l, 1987. Wold Oil operated the unit through the end of October, 1989, at which time Mont-Mill Operating Company was designated as operator.

Mont-Mill Operating Company (George Montgomery and Bill Miller; Company Officers) officially assumed operations of the TMCBSU from Wold Oil Properties, Inc. on November l, 1989. Because of the depressed oil economics and water injection well bonding requirements of the Environmental Protection Agency {EPA) Mont-Mill elected to plug and abandon all water injection wells within the TMCBSU. Plugging of the nearly 100 water injection wells was completed by the end of 1994. Mont-Mill Operating Company did not drill any additional wells within the unit, however, they did successfully rework several oil producers.

Mont-Mill, in name, has remained operator of this unit through the present date. On October 6, 1995, the owners/officers of Mont-Mill changed as a result of Big Bear East, Inc. purchasing 100% of the stock from Bill Miller (George Montgomery died in December, 1994) and electing to keep the name Mont-Mill Operating Company.

Since the 1996 BLM report was published, Provident Energy Associates of Montana took over as operator on January 23, 1998. On October 2, 2008, Arkanova, Inc. purchased 100% of the working interest in Provident Energy Associates of Montana. Subsequently, the operating company name was changed to Provident Energy of Montana, LLC (Provident Energy). Provident Energy currently operates the unit as a wholly owned subsidiary of Arkanova Corporation.

Summary of ownership/operator history of the TMCBSU:

8-1-1967	Unit Formed	Case Record MTM68717X
8-1-1967	Miami Oil Producers as Unit Operator	
2-29-1980	Conoco Oil assumes Unit Operator Duties	
4-1-1984	S&J Operating becomes Unit Operator	
2-1-1987	Wold Oil Properties becomes Unit Operator	
11-1-1989	Mont-Mill Operating becomes Unit Operator	
1-23-1998	Provident Energy Associates of Montana becomes Unit Operator	
10-2-2008	Provident Energy Associates of Montana purchased by Arkanova, Inc.	
	Provident Energy of Montana, LLC (subsidiary of Arkanova, Inc.) becomes Unit Operator	

Waterflood History

Waterflood operations began in January of 1968 and ceased in August of 1986 with peak injection during 1972 at about 18,000 BWIPD. The rate just prior to the end of injection was about 2,500 BWIPD. Initially, Madison Formation water from the TMCBSU 5991, 5992, 5993 and 5994 wells was used as feed water for TMCBSU injection but as more water was produced and recycled from TMCBSU oil wells, reliance on Madison Formation water decreased. Provident Energy has not been able to recover all historical injection records but believes that the reservoir has seen cumulative injection of more than 40 million barrels of water.

On October 7, 2014, injection began into recently-drilled horizontal oil well, Tribal Max 1-2817 (referred to as “Max 1”), at a rate of about 450 BWIPD. This oil well was the first well converted as part of Provident Energy’s waterflood pilot and is authorized by EPA UIC Permit MT22274-10103, which would be revoked and replaced if the proposed Area Permit is issued final by the EPA. Feed water for the Max 1 is produced Madison Formation water from TMCBSU 5991. After providing feed water for the initial flooding of the TMCBSU, the No. 5991 was converted to Class II disposal and the EPA issued an aquifer exemption in association with this permit action. In early 2015, the EPA approved the conversion of this well back to water production to supply feed water for Max 1 and the six additionally requested wells that would be covered under the proposed Area UIC Permit.

The EPA notes that the Cut Bank Formation has been extensively water flooded since the late 1960’s using both Madison Formation water and recycled produced water from the TMCBSU, which consists of a mixture of injected Madison water and originally in place Cut Bank water. This produced mixture eventually began to be disposed of back into the Madison Formation by EPA-regulated injector TMCBSU 5991. The No. 5991 has now been placed on Madison water production to supply feed water for the Max 1 well and would supply water for the six additionally requested injectors that would be authorized by the EPA's proposed Area Permit.

Part 2. Permit Considerations (40 CFR §146.24)

Hydrogeologic Setting

The following ground water information was taken directly from the Tribal Max 1-2817 Environmental Assessment that was prepared for the drilling of a new well in the general area. This information is the most recent and most relevant in describing the current state of the local ground water information:

> *The most comprehensive and recent information regarding the groundwater resources of the Blackfeet Reservation is a report prepared by Cannon (1996) of the U.S. Geological Survey. A brief summary of the groundwater resources is presented in the following discussion. Groundwater resources for the Blackfeet Indian Reservation are provided from aquifers formed within unconsolidated materials or from bedrock. In general, bedrock aquifers in this region are located in Cretaceous age, fine grained, low permeability sandstone sedimentary rocks. Other bedrock aquifers include Jurassic age siltstones and sandstones of the Ellis Group, and Mississippian age limestones and dolomites of the Madison Group. Aquifers present in unconsolidated materials are generally characterized as Quaternary and Tertiary age, coarse-grained deposits with moderate to high permeability. Unconsolidated deposits include alluvium, gravel in terraces and pediments, glacial outwash, and sand and gravel within and beneath glacial deposits. Of the bedrock formations recognized as important water bearing units, the Virgelle Sandstone is recognized as the highest yielding and most important aquifer. Although most well yields are small, the Two Medicine Formation is also used extensively for domestic water supply. Additional near-surface aquifers such as alluvium, glacial deposits, and terrace gravel aquifers exist on top of various bedrock formations. Alluvium located above bedrock produces a high yield, but it is often too limited in extent to be a good aquifer. The glacial deposits and terrace gravels are water bearing, but are often not extensive enough to provide sufficient water yields continuously. Groundwater is generally of poorer quality than surface water on the Blackfeet Indian Reservation. Groundwater from both the Virgelle Sandstone and Two Medicine Formations is highly mineralized and of poor to fair quality with sodium as the dominant cation. Deeper aquifers, such as the Madison Group, contain water too mineralized for most uses. Groundwater from quaternary deposits is hard, but otherwise of good quality. As with surface water, most groundwater use includes agricultural irrigation, stock watering, and domestic water supply. Agricultural extraction of groundwater is limited in extent.*

Local Geologic Setting

Table 1 shows the local geology as encountered during recent drilling of the Tribal Max 1-2817 well. The "Max 1" well, a horizontally drilled well, is currently injecting and would be regulated under the proposed Area UIC Permit, if issued final by the EPA.

Table 1: Stratigraphic column representative of the local geology within the TMCBSU.

Stratigraphic Column from the Tribal Max 1-2817 Injection Well			
Formation	**Elevation relative to mean sea level (feet)**	**Formation Thickness (feet)**	**Geology/Notes**
Willow Creek Shale	3943	580	Lies at Surface, soft sandy and exhibits no hydrocarbon show
St Mary River Formation	3363	164	Dark gray gray-green blocky, firm siltstone
Horsethief Formation	3199	64	Light gray, white very fine grained sandstone, tight
Bearpaw Shale	3135	92	gray, dark gray silty shale blocky poorly sorted exhibits calcite
Eagle Sandstone	3043	264	gray salt and pepper very fine grained sandstone, moderately firm to hard
Telegraph Creek Formation	2779	14	gray to dark gray firm partly silty sandy shale
Marias River Shale	2765	714	very dark gray to black firm shale and firm sandstone
Flowers Mbr, Marias River Shale	2051	660	very dark gray to very dark brown sub-blocky firm to hard shale
Bootlegger Mbr, Blackleaf Formation	1391	124	gray salt and pepper very fine grained sub round poorly sorted sandstone embedded in firm shale
Talt Hill Mbr, Blackleaf Formation	1267	268	dark gray sub blocky firm moderated calcareous siltstone
Flood Member, Blackleaf Formation	999	30	green sub blocky firm calcareous silty shale and siltstone
Kootenai Shale	969	505	very dark gray to black sub blockey moderately firm non-calcareous silty shale
Sunburst	464	51	light gray salt and pepper coarse siltstone and extremely fine grained sandstone, firm tight
Upper Cut Bank Sand	413	32	light gray salt and peper very fine grained moderate to poorly sorted slightly calcareous sandstone. No visible porosity in silt part. Weak oil near contact with Lower Cut Bank
Lower Cut Bank Sand	381	6	Primary hydrocarbon target, clear light gray salt and pepper very fine grained sandstone. Slightly calcareous with brown oil stain in irregular porosity. Hydrocarbon quality decreases as top of underlying Ellis shale is approached
Ellis Shale	375	134	Jurasiac age, gray, very dark gray, firm to hard very calcareous shale
Swift	241	6	light gray, gray brown firm calcareous shale, sand notable absent in this well

Rierdon	235	34	gray to dark gray firm calcareous shale that grades down to light brown cream calcareous shale
Sawtooth	201	31	gray to dark gray calcareous shale grades down to white coarse soft to moderate firm calcareous siltstone with no visible porosity
Madison (Sun River Dolomite)	170	407	very light gray microcrystalline sub block firm to hard limestone
Mission Canyon Limestone	-237	335	very light gray firm to hard limestone with abundant yellow mineral florescence, Weak oil show
Lodgepole	-572	287	brown to dark brown, sub blocky firm to hard tight limestone, oil shows scattered to weak
Bakken/Exshaw Shale	-859	107	hard green glauconitic silt stone moderately calcareous sandy shale, weak rings of hydrocarbon show
Three Forks Formation	-966	61	white cream soft calcareous shale, good oil show, intergranular porosity
Potlach Mbr, Three Forks	-1027	148	white cream soft slightly calcareous shale soft anhydrite
Birdbear (Sisku)	-1175	90	cream very light tan firm to hard dolomite with abundant yellow green mineral flourescence and no hydrocarbon show
Nisku	-1265	316	white opaque soft amorphous slightly calcareous anhydrite with weak residual ring
Duperow	-1581	266	white cream very light brown firm to hard dolomite that is occasionally calcareous, common intercrystal porosity
Souris River	-1847	-	light gray, gray and light brown cryptocrystalline hard limestone exhibits no hydrocarbon shows

The following excerpts are taken directly from "Two Medicine Cut Bank Sand Unit Analysis" Prepared by Peter J. Ditton, Dale Manchester, Aden L. Seidlitz, Petroleum Engineers, Bureau of Land Management, May 8, 1996:

> *This field represents a southwest extension of the larger Cut Bank field. The geologic structure is a monocline situated on the west side of the Sweetgrass Hills Arch that dips westward at a rate of about 100 feet per mile. The primary trapping mechanism is the result of permeability pinchouts and erosional features; the monoclinic structure has little to do with the trapping of oil in this area. There are two sands identified within the Cut Bank horizon. The upper sand which is not productive ranges in thickness from 0 to 38 feet. The oil bearing lower sand varies in thickness from well to well and ranges from 0 feet to 47 feet.*

The [TMCBSU] *reservoir consists of relatively clean, porous, heterogeneous, sand with little to no clays present (<1% Montmorillic clays). Porosity ranges from 0 to 18% with an average porosity of 14.5%. 13 of the 114 wells existing at the time of unitization were cored resulting in 229 core samples taken from 1 foot intervals. These core samples were analyzed indicating an average porosity of about 12.7% and a average permeability of 44.6 md (milidarcies). Actual permeability test results ranged from less than 1 md to 897 md, with no preferential directional permeability detected. Formation water saturation was estimated at 30%, based on core tests that established the irreducible water saturation at 25%. Core analysis also established the average residual oil saturation at 33% of pore volume (test results ranged from 29-38%). Oil analysis established the gas to oil ratio at less than 300 cubic feet per barrel. The bottom hole pressure in 1965 was measured resulting in a field value of 480 psi (pound per square inch). The original oil in place was calculated at 627 barrels per acre-foot using an average porosity of 12.7%, water saturation of 30%, and a formation volume factor of 1.1 reservoir barrel per stock tank barrel. Based on a residual oil saturation value of 33%, moveable oil should approximate 330 barrels per acre-foot.*

The EPA notes that the permit applicant has discussed a 60 milidary average permeability for the TCMBSU.

Local geology is also summarized in the following Table 2 as it appears in "Water Resources of the Cut Bank Area, Glacier and Toole Counties, Montana," State of Montana, Bureau of Mines and Geology, EG Koch, Director, Bulletin 60, May 1967.

Table 2: TMCBSU geology as presented in "Water Resources of the Cut Bank Area, Glacier and Toole Counties, Montana" , State of Montana, Bureau of Mines and Geology, EG Koch, Director, Bulletin 60, May 1967.

System	Series	Stratigraphic unit		Maximum thickness (feet)	Physical characteristics	Hydrologic characteristics
Quaternary	Recent		Alluvium	25	Mainly clay, silt, and sand, some lenses of gravel.	Not extensive enough to be a good source of water. A few wells produce water from alluvium.
Quaternary	Pleistocene		Lower terrace deposits	15	Lenticular sand and gravel.	Yields water for domestic and stock use in valley of Spring Creek.
Quaternary	Pleistocene		Glacial drift undifferentiated	150	Includes: Outwash deposits, principally gravel and sand; glacial till, mostly fragments of granite and limestone in a sandy clay matrix; glacial lake deposits, consisting of laminated clay, sand, and gravel.	Generally not water yielding. Sand and gravel deposits locally will yield sufficient water for domestic and stock use.
Quaternary	Pleistocene		Higher terrace deposits	40	Gravel overlain in places by silt in unglaciated areas west of Cut Bank.	Yields water to many wells on irrigated land west of Cut Bank. Yields as much as 25 gpm. Water bearing only where fairly extensive.
Cretaceous	Upper Cretaceous	Montana Group	Two Medicine Formation	500	Mainly sandy shale and mudstone, some thin beds of sandstone; lower 250 feet is mostly massive fine-grained sandstone.	Widely used aquifer. Well yields are generally 10 gpm or less but are adequate for stock and domestic needs.
Cretaceous	Upper Cretaceous	Montana Group	Virgelle Sandstone	180	Massive gray to buff sandstone, occasional beds of shale.	One of the major aquifers in the Cut Bank area. Yields as much as 250 gpm to properly constructed, completely penetrating wells
Cretaceous	Upper Cretaceous	Montana Group	Telegraph Creek Formation	170	Gray sandy shale interbedded with thin beds of gray or buff sandstone.	Generally impermeable, but large yields have been obtained where structural deformation or gravity sliding has induced fracturing.
Cretaceous	Upper Cretaceous	Colorado Group	Marias River Shale	1,995	Mainly dark-gray shale; a few limestone concretionary layers and bentonite beds in the upper part. The lower 800 feet is mainly dark-gray calcareous shale interbedded with bentonite, sandstone, and concretionary beds.	Not an aquifer. Sandstone at the base is reported to be water bearing in oil test holes but is not exploited.
Cretaceous	? Lower Cretaceous	Colorado Group	Blackleaf Formation			
Cretaceous	Lower Cretaceous		Kootenai Formation	725	Red and green mudstone and siltstone interbedded with several beds of medium- to coarse-grained sandstone.	Not an aquifer in the study area. The sandstone beds yield oil in the oil fields of the area and some brine in some fields.
Jurassic	Upper and Middle Jurassic		Ellis Group	350	Mainly gray calcareous shale interbedded with discontinuous sandstone beds.	Not an aquifer in the Cut Bank area. Produces a small amount of brine with oil in some oil fields.
Mississippian	Upper and Lower Mississippian		Madison Group	1,060	Massive, white to cream-colored, dense crystalline limestone in upper part. Gray and dark-gray limestone and shale in alternating beds in lower part.	Fracture and cavernous porosity, erratically distributed, permits storage and movement of water. The source of most of the water used for oil-field water flood operations. Specific capacities of wells generally low and lifts great.

Regional Geology

Figures 3 and 4 are taken from https://www1.eere.energy.gov/tribalenergy/guide/pdfs/blackfeet.pdf and show the regional geologic structure. Figure 3 shows the generalized geologic structure of the Ellis Sand located at the base of the Cut Bank Sand Formation.

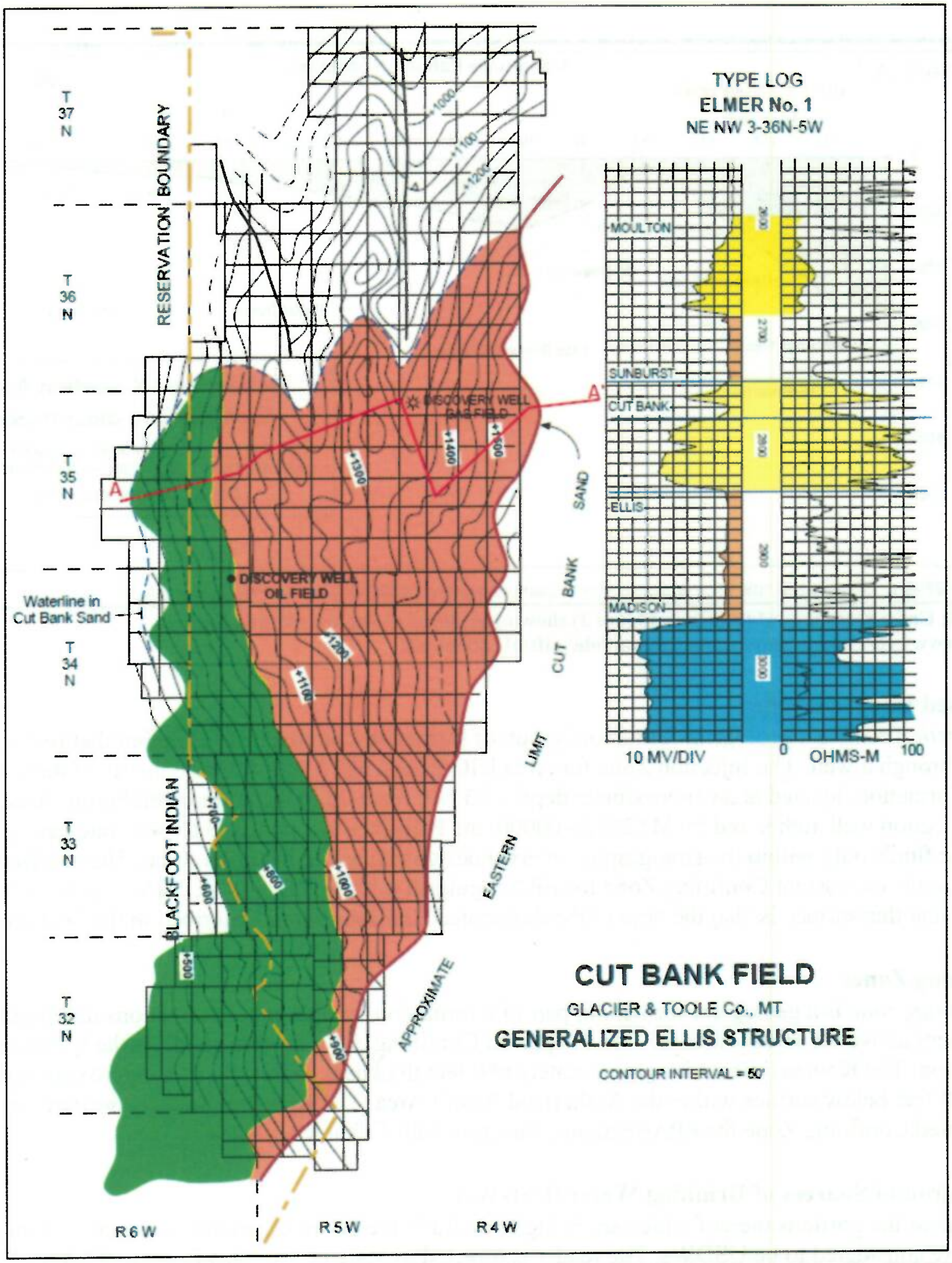

Figure 3: Generalized structure of the Ellis sand, which is the base of the Cut Bank Sand. The TMCBSU is located in the lower left of the figure. Line A-A' is shown in Figure 4 below. Source: https://www1.eere.energy.gov/tribalenergy/guide/pdfs/blackfeet.pdf

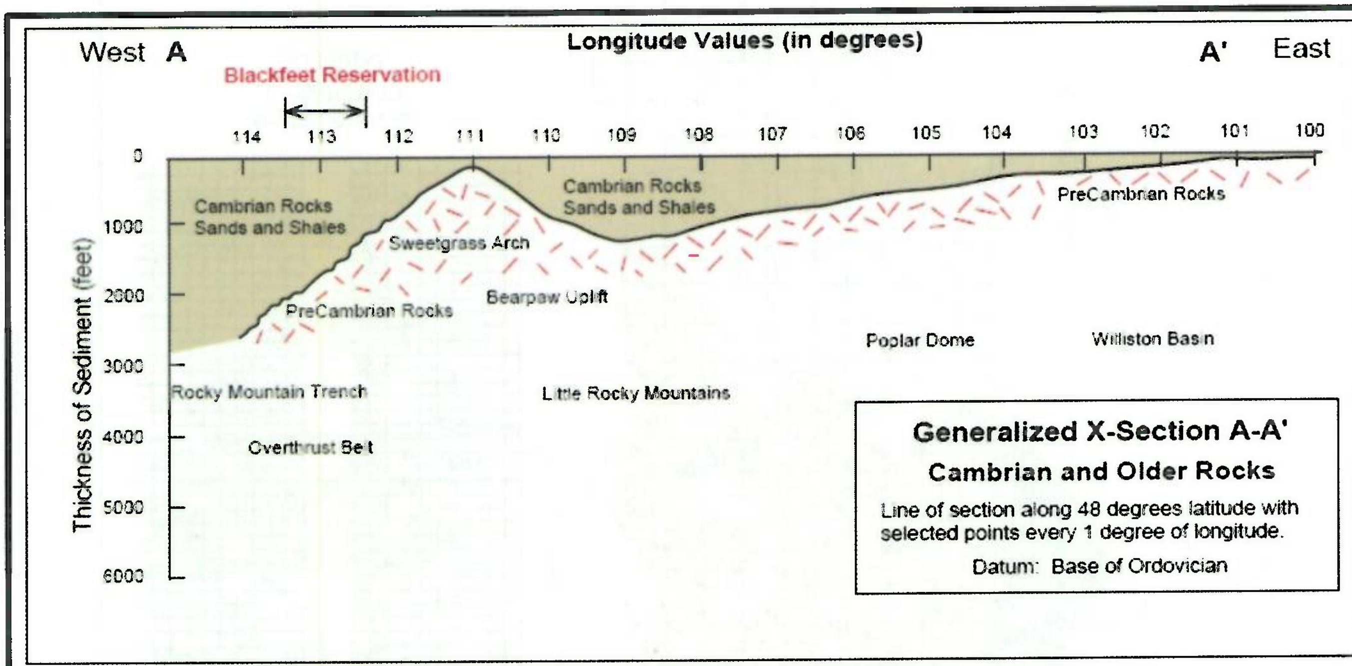

Figure BF-4.1. Generalized time slice cross-section of Cambrian paleo-topography along line of section A-A".

Figure 4: Cross Section A-A' (shown in Figure 3) showing regional geologic structure. Source: https://www1.eere.energy.gov/tribalenergy/guide/pdfs/blackfeet.pdf

Proposed Injection Zone

An *injection zone* is a geological formation, group of formations, or part of a formation that receives fluids through a well. The Injection Zone for Area UIC Permit MT22326-00000 consists of the Cut Bank Formation, located at an approximate depth of 3,500 feet within the Authorized Permit Area. For each injection well authorized by MT22326-00000, the Permittee is authorized to perforate casing and emplace fluids only within the stratigraphic interval designated as the Injection Zone. The Cut Bank Formation is the current Confining Zone for EPA-regulated injector Tribal Max 1-2817 and it is helpful to note that this surface is also the base of the designated Confining Zone described in the next section.

Confining Zones

A *confining zone* is a geological formation, part of a formation, or a group of formations that limits fluid movement above the injection zone. The designated Confining Zone for this permit is the Kootenai Formation. The Kootenai Shale is approximately 600 feet thickness and found at an approximate depth of 3,000 feet below surface within the Authorized Permit Area. The Kootenai Shale is the current designated Confining Zone for EPA-regulated injection well Tribal Max 1-2817.

Underground Sources of Drinking Water (USDWs)

Aquifers or the portions thereof which are being or could in the future be used as a source of drinking water are considered to be USDWs. The reader is directed to State of Montana Bureau of Mines Bulletin 60, "Water Resources of the Cut Bank Area", Glacier and Toole Counties Montana, by Everett A. Zimmerman, which includes the following information about USDWs:

Ground water from the Virgelle Sandstone and the Two Medicine Formation and surface water from Cut Bank Creek are the only dependable sources of fresh water in the Cut Bank area. The Virgelle is capable of yields of 250 gpm and the Two Medicine will yield 10 gpm or less. The average discharge of Cut Bank Creek at Cut Bank for 29 years of record is 192 cfs. A minimum flow of 4 cfs has been recorded. Saline water supplies of 500 gpm probably can be obtained from wells drilled to the Madison Group. The rising water levels in observation wells in the Cut Bank area during 1964 and 1965 suggest that depletion of fresh ground-water supplies in the Virgelle is not now (1966) imminent. The increased recharge from above-normal precipitation in 1964 and 1965 after a period of dry years and a reduction in the number of wells pumping water from the Virgelle for oil-field waterflood projects are the principal causes of the rising water levels. Some waterflood supply wells formerly pumping from the Virgelle have been abandoned in favor of a supply from the Madison. As the waterflood projects progress, the amount of water produced with the oil will no doubt increase. As the water is re-injected, the demand for fresh water will probably decline. As additional waterflood projects are started, no danger to the shallow aquifers is anticipated if water for flooding is obtained from the Madison. The cost of pumping water from the Madison at a depth of 1,000 feet or more may make it uneconomic for some secondary recovery operations, and shallower sources may be in demand. If more water is pumped from the Virgelle, precautions should be taken to minimize interference with existing wells. Water levels should be monitored by periodic measurements of observation wells.

Based on this information, and the information presented under Hydrogeologic Setting above, and in the absence of direct water samples from these formations, the EPA would likely consider the Virgil Sandstone, the Two Medicine Formation and the Madison Formation to be USDWs. Shallow USDWs appear to range from the surface to a depth of approximately 1,200 feet and the Madison Formation occurs roughly 200 feet below the base of the injection zone, at roughly 3,700 feet below ground surface within the Permit area. Any injection occurring under the proposed Area Permit would be evaluated to ensure that no potential conduit for fluid movement into these formations exists.

Pursuant to the UIC regulations at 40 CFR § 144.12, underground injection via a Class II well cannot cause movement of a contaminant into a USDW. If data indicates that the receiving aquifer is a USDW, an aquifer exemption would be necessary before injection could be authorized. The EPA will evaluate water quality of the injection zone within the Authorized Permit Area on a well-by-well basis to determine whether an aquifer exemption is required in conjunction with activities authorized by this permit. As discussed previously, the Cut Bank sand has been extensively flooded with an estimated 40 million barrels of Madison Formation water and this history of flooding would be considered along with any new data presented. In the event that new data indicates an aquifer exemption is required to authorize requested injection wells, the EPA would follow protocols at 40 CFR section 144.39, including notification and soliciting of comment from the public.

Part 3. Considerations Under Federal Law (40 CFR §144.4)

The EPA has determined that its permit decision authorizing injection wells is in compliance with the following applicable Federal laws:

National Historic Preservation Act (NHPA)
Section 106 of the NHPA, 16 U.S.C. § 470(f), requires that federal agencies consider the effects of federal undertakings on historic properties and afford the Advisory Council on Historic Preservation (the Council) a reasonable opportunity to comment with regard to such undertakings. Under the Council's implementing regulations (36 C.F.R. Part 800), where the federal agency determines that an undertaking is a type of activity that does not have the potential to cause effects on historic properties, there are no further obligations under section 106 or the regulations. 36 C.F.R. § 800.3(a)(1).

As discussed previously, the TMCBSU has been extensively developed over more than four decades and has seen multiple phases of drilling and waterflood activity. As a result, all necessary service roads, oil-gas wells, well pads and associated infrastructure are in place and the Permit applicant has no intention of drilling additional wells in association with a pilot or a full scale waterflood. Activities authorized by the EPA's proposed Area UIC Permit are not expected to cause any disturbance of the surface or near-surface land within the Area of Review because all activities will be conducted utilizing these existing oil field service roads, well pads, wells and pipeline rights of way. Activities resulting from the EPA's authorizations to convert existing oil wells to injection include mobilizing a well workover rig, flow back tank and hot oil truck for approximately three days to remove the existing tubing-packer assembly to then reinstall and test it per EPA permit requirements. A tractor trailer may need to be mobilized if an oil pump jack needs to be removed. Water feed lines will be installed along existing right of ways, alongside existing flow lines. No new surface-disturbing activity is required for these procedures and no surface-disturbing activity is authorized by the EPA's permit action.

Considering this information, and in accordance with 36 C.F.R. § 800.3(a)(1), the EPA has determined that issuance of an EPA Area UIC Permit to convert as few as seven and as many as 25 existing oil-gas wells to water injection wells under the terms and conditions of Area UIC Permit MT22326-00000 does not have the potential to cause effects on historic properties.

Endangered Species Act (ESA)
Section 7(a)(2) of the Endangered Species Act (ESA), 16 U.S.C. 1536 (a)(2), requires federal agencies to ensure that actions they authorize, fund, or carry out are not likely to jeopardize the continued existence of federally-listed endangered or threatened species or result in the destruction or adverse modification of designated critical habitat of such species. ESA implementing regulations at 50 C.F.R. part 402 require consultation with FWS where the action "may affect" listed species or their critical habitat. 50 C.F.R. 402.14.

Activities authorized by the EPA to convert existing oil-gas wells to enhanced recovery water injection wells will be limited in duration and are not expected to cause any disturbance within the Area of Review because all activities will be conducted utilizing existing oil service roads, well pad foot prints, oil-gas wells and pipeline right of ways. No new drilling or development is authorized by the EPA's Area UIC Permit or anticipated to occur within the Permit area. Following issuance of an EPA Authorization to Construct under the proposed Permit, Provident will mobilize a crane and tractor trailer to remove an existing oil pump jack prior to moving in a well workover rig, flow back tank and hot oil truck for approximately three days to workover the well. The existing tubing-packer assembly in the well will be removed and then reinstalled and tested per EPA permit requirements. Water feed lines will be installed along existing pipeline right of ways, adjacent to existing oil field pipelines. Because the activities occurring as a result of EPA authorizations to convert existing oil-gas wells to water injection wells under the terms and conditions of Area UIC Permit MT22326-00000 will utilize existing oil field service roads, well pad and pipeline right of ways, and because the duration of activity on site will be limited, and with no measurable impact, the EPA has concluded that its Area UIC Permit will have no effect on the following four species listed as threatened and endangered that the EPA identified as potentially present within its Area of Review:

- Piping Plover (*Charadrius melodus*)
- Grizzly Bear (*Ursus arctos horribilis)*
- Canada Lynx (*Lynx canadensis*)
- Bull Trout (*Salvelinus confluentus*)

Fish and Wildlife Coordination Act

The EPA will solicit comment on its draft permit decision from the Bureau of Land Management, Great Falls Field Office and the U.S. Fish and Wildlife Service's Montana Ecological Services Field Office in Helena.

Wild and Scenic Rivers Act

The Two Medicine River flows across the Authorized Permit Area but the EPA has determined that this river is not listed as wild or scenic by the Department of Interior. The EPA's permit authorizes the underground injection of water produced from underground and does not involve withdrawal from, or discharge to, the Two Medicine River.

Executive Order 12898

On February 11, 1994, the President issued Executive Order 12898, entitled "Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations." Based on designation of the proposed permit area as tribal land, the EPA has concluded that there may be EJ communities present. The primary potential human health or environmental effects to these communities associated with injection well operations would be to local aquifers that are currently being used or may be used in the future as USDW. The EPA's UIC program authority under the Safe Drinking Water Act is designed to protect USDWs through the regulation of underground injection wells. The EPA has concluded that the specific conditions of this area UIC permit would prevent contamination to USDWs within or proximate to the Authorized Permit Area, including USDWs that are used or may be used in the future by potential communities of environmental justice concern.

The EPA has also determined that: 1) all injection well activity will occur through the conversion of existing oil production wells utilizing existing surface oil field infrastructure (e.g., access roads, well pads, oil-gas roads and pipelines) previously authorized by the BLM; 2) conversion of oil production

wells to water injection wells will result in a decrease of volatile emissions from well heads since production of volatilizing oil at the wellhead is replaced by injection of non-volatile water; 3) conversion of oil production wells to water injection wells will result in decreased motor vehicle traffic within the Authorized Permit Area because all truck traffic associated with hauling produced oil from the converted well would stop and injection water is piped to the well; and 4) there will be no change in traffic patterns resulting from the proposed area Permit.
In reviewing the above findings, the EPA's UIC program has concluded that this permit action would not have a disproportionately high and adverse human health or environmental effect on potential communities of environmental justice concern. Nevertheless, the UIC program will conduct enhanced public outreach including notifying and soliciting input from tribal leaders, holding a public hearing if requested, and issuing a public notice announcement through local newspapers for this permit decision to solicit input from communities proximate to the injection well permit area which includes communities identified as potential environmental justice communities of concern.

Part 4. Cumulative Effects Analysis (40 CFR, Part 144.33(c)(3))

EPA has considered the cumulative effects of construction (conversion of existing production wells to injection) and operation of additional injection wells and determined that the cumulative effects of this permit action are acceptable to the EPA.

Groundwater Quality
This permit sets requirements to protect USDWs from contamination from the proposed injection activity. The established geologic confining units, well construction requirements, and injection pressure, well testing and plugging and abandonment requirements are designed to prevent fluid movement into USDWs. Based on these requirements and direct knowledge obtained by previous regulation of injection activities within the permit area, EPA has determined that the proposed underground injection will have no cumulative impact on any USDWs located beyond the injection zone.

As previously discussed, the TMCBSU has an extensive waterflood history prior to the EPA's pending area injection permit decision. The EPA recognizes that current formation fluid is not likely representative of originally in place Cut Bank Sand fluids. Especially due to the introduction of Madison Formation feed water, a formation known to contain water with Total Dissolved Solids (TDS) contents less than 10,000 mg/l, it is very likely that the current TDS content of injection zone waters may already reflect a significant degree of "aquifer freshening," or general lowering of the TDS content due to the low TDS content of feed water cycled through the reservoir. As the reservoir pressured sufficiently and more produced TMCBSU water was recycled, less Madison Formation water was required to support the waterflood. At least one Madison water supply well (TMCBSU No. 5991) was converted to disposal of produced TMCBSU water, back into the Madison Formation and this injection occurred for 28 years.

Because the injectate for this water flood is water produced from the No. 5991 well, which would be expected to reproduce previously injected TMCBSU water for a period of time comparable to the injection period of 28 years, and produced water from the TMCBSU itself, the water quality of the injection zone would not be expected to change significantly in the short term (5-15 years). If the seven well enhanced recovery pilot is successful and ramps up to the maximum number of wells over a period of 20 or more years, the cumulative effect to fluids in the injection zone as a result of this permit decision may be additional freshening, as connate (originally in place) Madison Formation water breaks back through to the No. 5991 Madison supply well. The EPA has determined that such freshening as a result of injection of relatively fresh water has occurred in other enhanced recovery permit areas and recognizes that this effect is possible in the TMCBSU, if not having already occurred as a result of injection since the late 1960's. Over geologic time scales, the salinity of injection zone water is expected to return to its original salinity as the water in the injection zone re-establishes chemical equilibrium with the geologic formations of the injection zone.

Pressure Effects

EPA has considered the cumulative effects resulting from an expected increase in reservoir pressure with time due to both the initial seven injection wells and the addition of as many as 25 injection wells to the Permit Area in the future. For Class II wells, EPA limits the injection pressure to pressures below a "fracture parting pressure" or, a threshold pressure below which existing fractures in a geologic confining zone will not be opened or extended in the subsurface, to prevent any significant fluid movement through potential pathways in the protective confining zone. These threshold pressures are obtained from injection well test data from injection wells within the permit area. The EPA has obtained representative from the Tribal Max 1-2817 well and will use this to set the initial injection pressure for all wells within the permit area.

The applicant has identified seven water supply wells within the Permit area and the deepest is 500 feet, approximately 3,000 feet vertically higher than the injection zone. Based on local and regional geology, which includes many impermeable shale units, the designated protective confining zone, the depth of the injection zone for this permit action, and history of regulating injection activities in the field, the EPA determined that there will be no effect on these shallow drinking water aquifers as a result of the changing pressure regime within the oil producing reservoir over time. The aquifers being used as a drinking water resource are hydraulically isolated from waters of the injection zone and oil-gas well cementing requirements and injection pressure limitations are set to prevent hydraulic communication between the injection zone and shallower aquifers from occurring.

In general, maintenance of existing reservoir pressure and some increase in reservoir pressure with time and injection is expected as part of an enhanced oil recovery project because this increase in pressure can help mobilize additional oil within the subsurface. As part of any enhanced recovery injection, reservoir fluid production via adjacent production wells serves to balance pressure induced by fluid injection into the reservoir. EPA is requiring the Permittee to submit reservoir pressure data before receiving authorization to place an additional well on injection. In the event that reservoir pressure was found to pose a risk to USDWs as a cumulative effect of injection under this permit, EPA would take action to require the Permittee undertake measures to reduce the reservoir pressure to acceptable levels.

Part 5. Description of Permitting Approach

Currently, EPA regulates one Class II enhanced recovery injection well within the proposed Permit Area under an individual injection well permit. Following issuance of this permit decision, a single, consolidated area Permit would apply to all existing enhanced recovery water injection wells operated by the Permittee within the Authorized Permit Area and would authorize the future conversion of as many as 25 oil-gas production wells to water injection wells.

Due to the large scope of Area UIC Permit MT22326-00000, EPA intends to record information related to this permit in a document called the List of Wells for Area UIC Permit MT22326-00000 (LW). The LW is solely intended to serve as an administrative tool to organize and communicate oil-gas well data and other information related to Area UIC Permit MT22326-00000 for the Permittee and the public. A current copy of the LW may be obtained by contacting the Provident Energy UIC Permitting Coordinator at EPA Region 8 in Denver, Colorado. Injection wells regulated by EPA and subject to the terms and conditions of this permit are listed in the LW with EPA permit number MT22326-00000 and are assigned a unique well identification number by EPA. The LW is not legally binding on any party and is simply a means to convey information to the Permittee and the public in an efficient manner. The permit specifies that any required authorizations or other EPA requirements will be conveyed by email or other written communication to the Permittee.

Part 4 of this permit describes how injection wells will be individually authorized by the EPA as they are requested by the Permittee and this process is summarized here:

1. In order to convert a production well to injection, the Permittee must first obtain an authorization to construct the injection well from the EPA. The Permittee must submit a letter requesting authorization to construct injection well(s), EPA application form(s) and all information listed under Part 4, Section 1 of the permit.

2. The EPA will review submitted materials and check the information for accuracy. The EPA will also conduct an evaluation of casing and cement in the requested injection well and ¼-mile radius Area of Review wells at that time, and record the results of its evaluation in the LW. Once the EPA has determined that the request to convert the oil-gas production well to an injection well is in accordance with permit conditions, the EPA will record a construction authorization date in the LW and notify the Permittee via written correspondence.

3. Once the EPA has authorized conversion of an oil-gas well to an injection well, the Permittee has 120 calendar days to construct the injection well before the authorization expires. If the Permittee is unable to construct the injection well within 120 days, Permittee may request an extension prior the end of 120 days and an extension may be granted at the Director's discretion. Once the packer and tubing are set, the Permittee will notify the EPA by submitting the materials required in Part 4, Section 2 of the permit within 30 calendar days.

4. Once EPA the receives materials required under Part 4, Section 2 of the permit, the EPA will review the materials to ensure the injection well was constructed in accordance with permit conditions. Upon a determination that the Permittee is in compliance with permit conditions, and

that the portion of the aquifer receiving the fluid is not a USDW, the EPA will authorize commencement of injection into the well by written correspondence and will record an injection authorization date in the LW.

5. Upon receiving authorization to inject, the Permittee has 30 calendar days to place the well on injection and must submit materials required under Part 4, Section 3 to EPA within 30 calendar days of placing that well on injection.

6. If EPA determines that a temperature log or radioactive tracer survey is required for the injection well, these must be completed within 180 calendars days of commencement of injection. Once all initial testing data is reviewed and approved by the EPA, the EPA will notify the Permittee via written correspondence and the Permittee may continue to operate the injection well according to the terms and conditions of Area UIC Permit MT22326-00000.

Part 6. Permit Conditions for Area UIC Permit UT22197-00000

Well Construction (40 CFR 146.22 and Part 7 of the permit)
Injection well construction requirements are stipulated in Part 7 of Area UIC Permit MT22326-00000 and under the Safe Drinking Water Act. The area UIC permit requires that surface casing of newly converted injection wells meet certain requirements and, in anticipation of future conversion of production wells to injection, the Permittee is advised to consider injection well construction requirements during the drilling and completion of any new production wells although no new production well drilling is anticipated at this time. The EPA does not allow the operation of any injection well that allows the movement of fluid into or between USDWs because this is prohibited in 40 CFR, Part 144.12.

If a cement bond log is available, the EPA will use EPA Region 8 Ground Water Guidance #34 to inform a determination as to the adequacy of the long string casing cement in the confining zone on a well-specific basis. Where cement bond logs are not available, which the EPA anticipates will be the majority of cases since the field is old and has changed ownership so many times, the EPA may rely on well completion records (cement tickets) to calculate the top of cement behind longstring casing. The EPA will also consider surface casing and cement although the capacity to perform corrective action on these aspects of the well are limited. The EPA would not approve injection into a well that lacks adequate casing and cement to protect USDWs.

Injection tubing is required to be installed from a packer up to the surface inside the long string well casing. The packer will be set no greater than 100 feet before (in the case of a horizontal injection well) or above the first open perforation in the well. The tubing and packer are designed to prevent injected fluid from coming in contact with the outermost well casing.

The Tubing-Casing Annulus (TCA) allows the casing, tubing and packer to be pressure-tested periodically for mechanical integrity and will allow the detection of any leaks in the casing, tubing or packer. The TCA of all injection wells will be filled with fresh water treated with a corrosion inhibitor or other fluid approved by the EPA.

The Permittee is required to install and maintain wellhead equipment that allows for monitoring pressures and provides access for sampling the injected fluid. Required equipment includes: 1) shut-off valves located at the wellhead on the injection tubing and on the TCA; 2) a flow meter that measures the cumulative volume of injected fluid; 3) fittings or pressure gauges attached to the injection tubing and the TCA for monitoring the injection and TCA pressures; and 4) a tap on the injection line, isolated by shut-off valves, for sampling the injected fluid. All sampling and measurement taken for monitoring is required to be representative of the monitored activity.

Area of Review Requirements (40 CFR 144.55 and Part 12 of the permit)
This permit requires that all oil-gas wells within a ¼-mile radius of an injection well have top of cement behind the outermost casing string at least above the designated confining zone unless that AOR well is an EPA-regulated injection well with a current demonstration of part II (external) mechanical integrity. This requirement ensures that no fluid is moved upward into USDWs through vertical channels adjacent to the wellbore of AOR wells.

Well Operation Requirements (40 CFR 146.23 and Part 10 of the permit)

Approved Injection Fluid
The approved injection fluid is limited to Class II injection well fluids as defined at 40 CFR §144.6(b). Injection of any fluid for the purpose of disposal is prohibited. Prohibited fluids include 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.

Injection Pressure Limitation (Part 11 of the permit)
Injection pressure, measured at the wellhead, shall not exceed a calculated Maximum Allowable Injection Pressure (MAIP) to assure that the pressure used during injection does not initiate new fractures or propagate existing fractures in the confining zone. The MAIP does not apply during activities the Director determines to be well stimulation such as hydraulic fracturing, the injection of polymer gel and the injection acid into the injection zone formation. The EPA does not consider the temporary filling of the wellbore with acid to descale tubing and casing to constitute well stimulation.

Injection Volume Limitation
There is no limit on the volume of approved Class II fluids that may be injected. EPA considers that in an enhanced oil recovery water flood, the production of oil and water occurs concurrently with water injection.

Mechanical Integrity (40 CFR 146.8 and Part 8 of the permit)
Part 8 of this permit describes all requirements for establishing mechanical integrity of injection wells. An injection well has mechanical integrity if:

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

well bore (Part II).

This permit prohibits injection into any well that lacks mechanical integrity. A demonstration of mechanical integrity includes both internal (Part I) and external (Part II) mechanical integrity as defined above. The methods and frequency of these demonstrations are dependent upon well-specific conditions and/or EPA's determination regarding the construction of each oil-gas well within the permit area as recorded in the LW.

Monitoring, Recordkeeping and Reporting Requirements (Part 14 of the permit)

Injection Well Monitoring Program

At least once a year the Permittee must analyze a sample of the injected fluid for Total Dissolved Solids (TDS), specific conductivity, pH and specific gravity. This analysis shall be reported to EPA annually as part of the Annual Report to the EPA. 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 Tubing-Casing Annulus (TCA) pressures must be observed on a weekly basis. A recording, at least once every 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 EPA.

Plugging and Abandonment Requirements (40 CFR 146.10 and Part 16 of the permit)

Before abandonment, injection wells shall be plugged with cement in a manner which isolates the injection zone and prevents the movement of fluids into or between underground sources of drinking water and in accordance with 40 CFR §146.10 and other applicable Federal, State or local laws or regulations.

The plugging and abandonment plan required in Part 16 of this permit accomplishes several objectives, all intended to prevent fluid movement into or between USDWs. It isolates the injection zone, both inside and outside the long string casing, preventing fluid from moving into shallower formations through the well bore. It isolates the contact between any formations known to contain a USDW, both inside and outside the long string casing. If long string casing is not cemented to surface, the Permittee is required to emplace cement behind long string casing from at least 50 feet below the base of surface casing or from at least 50 feet below the base of the lowermost USDW, back to surface. Finally, a minimum 50-foot plug is required inside the long string casing at the surface to prevent the entry of surface water runoff into the well bore.

Financial Responsibility Requirements (40 CFR 144.52 and Part 22 of the permit)

The Permittee is required to maintain financial responsibility and resources to close, plug and abandon the underground injection operation in the manner prescribed in Part 22 of the permit. The Permittee has already demonstrated financial responsibility for its existing Tribal Max 1-2817 injection well in the form of a letter of credit and intends to demonstrate financial responsibility for additional injection wells on an as required basis. The EPA will not authorize any additional injection well under area UIC Permit

MT22326-00000 until the Permittee has demonstrated sufficient financial assurance to plug and abandon the requested injection well. The EPA may, from time to time, require the Permittee to submit an estimate of the resources needed to plug and abandon injection wells governed under this permit and, if necessary, revise its demonstration of financial responsibility.

U.S. ENVIRONMENTAL PROTECTION AGENCY
ANNOUNCEMENT OF PUBLIC NOTICE
OF GROUND WATER PERMIT ACTION

Cut Bank Pioneer Press, Cut Bank, Montana
Glacier Reporter, Browning, Montana
Shelby Promoter, Shelby, Montana

The U.S. Environmental Protection Agency (EPA) intends to issue an Underground Injection Control (UIC) permit-related action, under the authority of the Safe Drinking Water Act and UIC program regulations, for wells operated by Provident Energy of Montana on the Blackfeet Indian Reservation. The EPA proposes issuance of Area UIC Permit MT22326-00000 for the Two Medicine Cut Bank Sand Unit that would initially authorize up to seven enhanced oil recovery water injection wells for a pilot waterflood project. If successful, the EPA anticipates as many as 25 water injection wells within the permit area. The public notice, which requests comments on this action within 30 days, can be found at the EPA Region 8 UIC program's website: http://www2.epa.gov/region8/underground-injection-control. Alternatively, the public may contact or call Jason Deardorff at deardorff.jason@epa.gov, 800-227-8917 extension 312-6583 or 303-312-6583 for additional information and to obtain a copy of the public notice and documentation associated with this action. Notification and details of any public comment period extension will be posted at the public comment web page address (listed above) only and will not be published in this newspaper. Interested parties on our email list will also be notified by email. If you wish to be added to our email list please notify the permitting contact listed in this Notice.

UIC Permit No.: MT22326-00000