STATEMENT OF BASIS

Middle Fork Energy Uinta, LLC
RZA 14B1-34A
Uintah County, Utah

Class II Salt Water Disposal Well
UT22420-12015

CONTACT: Christopher Brown
U. S. Environmental Protection Agency
Underground Injection Control Program, 8WD-SDU
1595 Wynkoop Street
Denver, Colorado 80202-1129
Telephone: (303) 312-6924
Email: Brown.Christopher.T@epa.gov

This Statement of Basis gives the derivation of site-specific Underground Injection Control (UIC) permit conditions and reasons for them. Referenced sections and conditions correspond to sections and conditions in UT22420-12015 (Permit).

U. S. Environmental Protection Agency (EPA) UIC permits regulate the injection of fluids into underground injection wells so that the injection does not endanger underground sources of drinking water (USDWs). EPA UIC permit conditions are based upon the authorities set forth in regulatory provisions at 40 CFR parts 2, 124, 144, 146 and 147, and address potential impacts to USDWs. In accordance with 40 CFR § 144.35, issuance of this Permit does not convey any property rights of any sort or any exclusive privilege, nor authorize injury to persons or property or invasion of other private rights, or any infringement of other federal, state or local laws or regulations. Under 40 CFR § 144 Subpart D, certain conditions apply to all UIC Permits and may be incorporated either expressly or by reference. General permit conditions for which the content is mandatory and not subject to site-specific differences (40 CFR parts 144, 146 and 147) are not discussed in this document. Regulations specific to Indian country injection wells in Utah are found at 40 CFR § 147.2253.

Upon the Effective Date when issued, the Permit authorizes the construction and operation of the injection well or wells so that the injection does not endanger USDWs. The Permit is issued for the operating life of the injection well or project unless terminated for reasonable cause under 40 CFR § 144.40 and can be modified or revoked and reissued under 40 CFR § 144.39 or § 144.41. The Permit is subject to EPA review at least once every five (5) years to determine if action is required under 40 CFR § 144.36(a).

The Permit will expire upon delegation of primary enforcement responsibility (primacy) for applicable portions of the UIC Program to an approved state or tribal program, unless the delegated agency has the authority and chooses to adopt and enforce this Permit as a tribal or state permit.

PART I. General Information and Description of Project

Middle Fork Energy Uinta, LLC
1515 Wynkoop Street, Suite 650
Denver, Colorado 80202

hereinafter referred to as the "Permittee," submitted an application for a UIC Program permit for the following injection well or wells:

RZA 14B1-34A
420' FEL & 2516' FSL, Section 33, T7S, R22E
Uintah County, Utah

The application, including the required information and data necessary to issue or modify a UIC permit in accordance with 40 CFR parts 2, 124, 144, 146 and 147, was reviewed and determined by EPA to be complete.

Project Description

The Permittee is proposing to convert the existing RZA 14B1-34A well to a Class II Salt Water Disposal (SWD) well. The well was spudded on May 24, 2019 and was completed as a deviated well to a total depth of 3,901 feet-True Vertical Depth (ft-TVD). The well has not yet been perforated. The Permittee has proposed a maximum daily injection rate of 15,000 barrels per day (bbl/d) and average daily injection rate of 7,500 bbl/d with an expected well life of 20 years. The estimated cumulative injection volume during the expected well life is 54,787,500 bbl of Class II fluids described in the fluid limitation section below.

PART II. Permit Considerations (40 CFR § 146.24)

Hydrogeologic Setting

The Uinta Basin is located in the northeastern corner of Utah and is comprised of more than 18,000 ft of sedimentary rocks at its deepest. It is bounded to the north by the Uinta Mountains, to the east by the Douglas Creek Arch, to the south by the Tavaputs Plateau, and to the west by the Wasatch Mountains. The RZA 14B1-34A well is located in the central eastern portion of the basin.

The RZA 14B1-34A well proposes injection within the Birds Nest Zone of the upper Green River Formation. The Eocene Green River Formation contains sediment deposited from an interior lake basin system (Lake Uinta) that covered a significant area of northeastern Utah, western Colorado, and southwestern Wyoming. The upper Green River Formation represents a transition to a shrinking lake basin and the formation of the saline mineral Nahcolite in deep lake sediments. After deposition, fracture zones present within Nahcolite rich intervals of the upper Green River Formation were filled with the saline mineral Shortite.

The Birds Nest Zone is a fracture rock aquifer created by the dissolution of saline minerals from groundwater flow within a predominantly impermeable oil shale matrix. The lower Green River Formation is comprised of deltaic sands interbedded with organic rich muds of lacustrine origin. Table 2.1 provides a summary of information regarding known or estimated TDS concentrations above, below, and within the proposed injection zone.

TABLE 2.1
Hydrogeologic Setting

Formation Name or Stratigraphic Unit	Top (ft)*	Base (ft)*	TDS (mg/l)	Lithology
Uinta	0	3,075	Conservatively assumed <10,000 at a transition zone occuring within this interval[1]	Calcareous shale, mudstone and sandstone; some limestone and alluvial deposits; shallow sands may be fresh-water bearing, deeper sands likely to have higher TDS with variable hydrologic continuity.
Upper Green River	3,075	3,501	>10,000[2]	Limestone, shale, sandstone. Characteristically comprised of mixed lithologies due to fluctuating lake bottom and lake-margin depositional conditions; carbonate mudstone deposition in standing water of Lake Uinta especially during evaporative conditions, including basin scale reservoir in dissolution zones of "Birds Nest" interval; kerogen rich intervals ("oil shale" of Mahogany zone); locally extensive high-TDS water bearing sands in middle Green River; local oil-bearing sandstone and ostracodal dolomitic limestone reservoirs present in lower third of the formation. The Green River formation interfingers both the overlying Uinta and underlying Wasatch formations.
Birds Nest Zone (Injection Zone)	3,501	3,901	11,296 - 21,095	Limestone, shale, dolomite. The Birds Nest zone consists almost entirely of porous and permeable sandstones interbedded with lower permeability siltstones, marlstones, and minor shale breaks. Nodular Nahcolite, approximately 0.5 to 1.5 feet in diameter, is common throughout the Birds Nest aquifer. The dissolution of

				the Nahcolite nodules creates the extensive porosity and permeability needed for significant groundwater storage and flow within the Birds Nest aquifer.
Lower Green River	3,901	4,800	>10,000[2]	See above description for Upper Green River Formation.
	4,800	6,457	<10,000[1]	

* depths are approximate values at the wellbore

[1] Additional discussion included in the Underground Sources of Drinking Water Section below.

[2] Based on a limited review of sample results within the corresponding interval in the general vicinity and identified in the United States Geologic Survey Produced Water Database v2.3.

Injection Zone

An injection zone is a geological formation, group of formations, or part of a formation that receives fluids through a well. The proposed injection zone is listed in TABLE 2.2. The injection zone is approximately 400 ft. thick with a total estimated porosity thickness of 160 to 200 ft.

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

TABLE 2.2
INJECTION ZONE

Formation Name or Stratigraphic Unit	Top (ft)*	Base (ft)*	Estimated Porosity	Exemption Status
Birds Nest Zone	3,501	3,901	2.5-10.5%	TBD[1]

* depths are approximate values at the wellbore in ft-TVD.

[1] Exemption status to be determined (TBD) following collection of a formation water quality sample.

Confining Zones

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

Both the upper and lower confining zones occur within the Green River Formation. The upper confining zone is 466 feet thick and occurs above the Birds Nest Zone to the base of the Uinta Formation occuring at 3,075 ft-TVD. This interval was estimated by the Permittee to be comprised of 69% shale with a permeability less than 0.001 millidarcies. The lower confining zone is 101 feet thick and occurs from the base of the Birds Nest Zone to the top of the Mahogany Zone. This interval was estimated by the Permittee to be comprised of 90% shale with a permeability less than 0.001 millidarcies. There are reportedly no known geologic features such as faults, fractures, or Gilsonite veins that cross-cut the upper or lower confining zones.

TABLE 2.3
CONFINING ZONES

Formation Name or Stratigraphic Unit	Top (ft)*	Base (ft)	Lithology
Green River (Upper Confining Zone)	3,075	3,501	Limestone, shale, sandstone.
Green River (Lower Confining Zone)	3,901	3,990	Shale, sandstone.

* depths are approximate values at the wellbore in ft-TVD.

Underground Sources of Drinking Water (USDWs)
Aquifers or the portions thereof which 1) currently supply any public water system or 2) contains a sufficient quantity of groundwater to supply a public water system and currently supplies drinking water for human consumption or contain fewer than 10,000 mg/l total dissolved solids (TDS), are considered to be USDWs.

The Permittee reported that there are no known USDWs above the Birds Nest Zone but indicated that shallow sands of the Uinta Formation may contain fresh water. A review of the Utah Division of Water Rights online database did not reveal any permitted shallow groundwater rights located within the AOR. Additionally, a review of geophysical logs available in the Utah Division of Oil, Gas and Mining online data explorer did not reveal any open-hole logs within the AOR logged high enough to evaluate whether shallow sands of the Uinta Formation contain fresh water. An estimate of the TDS concentration (Na-Cl equivalent) from open-hole resistivity and density porosity logs available for the OU GB 5W-17-8-22 well located approximately 3.5 miles southwest of the RZA 14B1-34A well supported that estimated TDS concentrations below 2,220 feet are greater than 10,000 mg/L. Conversely, a review of the United States Geologic Survey (USGS) Produced Water Database v2.3 revealed one (1) sample exhibiting a TDS concentrations of 2,372 mg/L collected from the Uinta Formation between 2,624 and 2,651 ft. at the Red Wash Unit No. 39 well located approximately 2.8 miles northeast of the RZA 14B1-34A well. As a result, the presence of a USDW above the injection zone within the AOR could not be confirmed; however, a transition zone to TDS concentrations less than 10,000 mg/L has been identified within the Uinta Formation in other portions of the basin and is likely present at the location of the RZA 14B1-34A well. Future Class II permitting actions for new wells in central eastern portion of the Uinta basin should require open hole resistivity and density porosity logs run to surface in order to identify and delineate such a transition zone.

Water quality analysis collected from other wells completed in the Birds Nest Zone submitted by the Permittee suggests that the proposed injection zone is not a USDW. However, the permit requires the collection of a representative formation sample from the injection zone prior to receiving authorization to inject to verify the USDW status of the Birds Nest Zone. An aquifer exemption will be necessary if the formation sample collected from the proposed injection zone exhibits a TDS concentration less than 10,000 mg/L.

The Utah Geologic Survey approximated the depth to the base of moderately saline groundwater at 4,800 feet at the location of the RZA 14B1-34A well in Special Study No. 144. Moderately saline groundwater, as defined in the report, includes groundwater with TDS concentrations between 3,000 and 10,000 mg/L. There is limited available water quality sample data below the proposed injection zone in the vicinity of the RZA 14B1-34A well. However, a sample collected at the RW 32-33A well located northwest and just outside of the AOR exhibited a TDS concentration of 8,626 mg/L; the sample was reportedly collected from a depth of 5,746 feet in the Lower (relative to the proposed injection zone) Green River Formation. This sample result is consistent with the interpretation of moderately saline groundwater occurring below ~4,800 feet made by the Utah Geologic Survey.

TABLE 2.4
UNDERGROUND SOURCES OF DRINKING WATER (USDWs)

Formation Name or Stratigraphic Unit	Top (ft)*	Base (ft)*	TDS (mg/l)	Lithology
Uinta	0	3,075	Conservatively assumed <10,000 at a transition zone occuring within this interval	Shale, mudstone, sandstone.
Lower Green River	4,800	6,457	<10,000	Shale, sandstone.

* depths are approximate values at the wellbore

PART III. Well Construction (40 CFR § 146.22)

The approved well construction plan, incorporated into the Permit as APPENDIX A, will be binding on the Permittee. Modification of the approved plan during construction is allowed under 40 CFR § 144.52(a)(1) provided written approval is obtained from the Director prior to actual modification.

Casing and Cement
The well construction plan was evaluated and determined to be in conformance with standard practices and guidelines that ensure well injection does not result in the movement of fluid containing any contaminant into USDWs. Well construction details for the injection well(s) are shown in TABLE 3.1.

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

TABLE 3.1
WELL CONSTRUCTION REQUIREMENTS

Casing Type	Hole Size (in)	Casing Size (in)	Cased Interval (ft)*	Cemented Interval (ft)*
Production	13.5	9.675	0-4,229	0-4,229
Conductor	20	16	0-150	0-150
Tubing	9.675	3.5	0-3,580	N/A

* depths are approximate values at the deviated wellbore in ft-MD.

Injection Tubing and Packer
Injection tubing is required to be installed from a packer up to the surface inside the well casing. The packer will be set within 100 feet above the uppermost perforation. The tubing and packer are designed to prevent injection fluid from coming into contact with the production casing.

Tubing-Casing Annulus
The tubing-casing annulus (TCA) allows the casing, tubing and packer to be pressure-tested periodically for mechanical integrity, and will allow for detection of leaks. The TCA will be filled with non-corrosive fluid or other fluid approved by the Director.

Sampling and Monitoring Device
To fulfill permit monitoring requirements and provide access for EPA inspections, sampling and monitoring

equipment will need to be installed and maintained. Required equipment includes but is not limited to: 1) pressure actuated shut-off device attached to the injection flow line set to shut-off the injection pump when or before the MAIP is reached at the wellhead; 2) fittings or pressure gauges attached to the injection tubing(s), TCA, and surface casing-production casing (bradenhead) annulus; 3) a fluid sampling point between the pump house or storage tanks and the injection well, isolated by shut-off valves, for sampling the injected fluid; and 4) a flow meter capable of recording instantaneous flow rate and cumulative volume attached to the injection line.

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

PART IV. Area of Review, Corrective Action Plan (40 CFR § 144.55)

Area of Review (AOR)
Permit applicants are required to identify the location of all known wells within the AOR which penetrate the lowermost confining zone, which is intended to inhibit injection fluids from the injection zone. Under 40 CFR § 146.6 the AOR may be a fixed radius of not less than one quarter (1/4) mile or a calculated zone of endangering influence. For area permits, a fixed width of not less than one quarter (1/4) mile for the circumscribing area may be used.

Since the existing well is deviated, the AOR encompasses a one quarter (1/4) mile buffer from the well surface location extending to the horizontal distance corresponding to the base of the injection zone at the bottom of the well. The well surface location is 420 ft. from the east line, 2,516 ft. from the south line of the NESE quarter-quarter in Section 33, Township 7 South, Range 22 East. The well bottom hole location at the base of the injection zone is 389 ft. from the east line, 1,850 ft. from the south line of the NWSW quarter-quarter in Section 34, Township 7 South, Range 22 East.

The permit includes a provision in Appendix C that the AOR shall be expanded to one-half (1/2) mile once a cumulative volume of 12,673,347 barrels has been injected into the well. This volume corresponds to an area of emplaced waste with a radius of one-quarter (1/4) mile. The area of emplaced waste was calculated using a simple radius-of volumetric fill-up equation using information supplied with the permit application. Additionally, this volume also corresponds to the approximate point at which the area of emplaced waste from the 14B1-34A will begin overlapping with the identical area of emplaced waste calculated for and included in the draft permit for the 14A1-33A well, which is co-located on the same well pad. The permit provides that additional corrective action may be required and appended to Appendix F if analysis of the expanded half-mile (1/2) AOR reveals additional wells, which as determined by the Director, require corrective action. The Director may subsequently request that the AOR be reevaluated and expanded further if necessary, using the criteria in 40 CFR 146.6 to ensure that fluids will remain within the injection zone.

Corrective Action Plan (CAP)
For wells in the AOR which are improperly sealed, completed, or abandoned, the applicant will develop a CAP consisting of the steps or modifications that are necessary to prevent movement of fluid into USDWs. In addition, Part II, Section B.3 of the permit states that injection is only permitted within the approved injection zone and injected fluids must remain within the injection zone. As a result, corrective action may also be necessary to ensure injected fluids remain within the approved injection zone.

No corrective action is required at this time as EPA's evaluation did not identify migration pathways within the one quarter mile AOR; however, corrective action requirements may be appended to this section following expansion of the AOR and subsequent analysis required in Appendix C of the permit. Specifically, two (2) wells (RW 34-33A and RW 32-33A) located to the northwest and outside of the current one quarter (1/4) mile AOR may necessitate corrective action upon expansion of the AOR to one half (1/2) mile.

TABLE 4.1 lists the wells in the AOR and shows the well type, operating status, depth, uncemented interval from well records and CAP required for the well. The CAP is incorporated into the Permit as APPENDIX F and becomes binding on the Permittee.

TABLE 4.1
CAP TABLE

AOR Well Name	Well Type	Operating Status	Total Depth (ft)*	Uncemented Interval (ft)*	Corrective Action
N/A					

PART V. Well Operation Requirements (40 CFR § 146.23)

Mechanical Integrity (40 CFR § 146.8)
An injection well has mechanical integrity (MI) if:

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

The Permit requires MI to be maintained at all times. The Permittee must demonstrate MI prior to injection and periodically thereafter, as required in APPENDIX B Logging and Testing Requirements. A demonstration of well MI includes both internal (Part I) and external (Part II). The methods and frequency for demonstrating internal (Part I) and external (Part II) MI are dependent upon well and are subject to change. Should well conditions change during the operating life of the well, additional requirements may be specified and will be incorporated as minor modifications to the Permit.

A successful internal Part I Mechanical Integrity Test (MIT) is required prior to receiving authorization to inject and repeated no less than five years after the last successful MIT. A demonstration of internal MI is also required following any workover operation that affects the tubing, packer, or casing or after a loss of MI. In such cases, the Permittee must complete work and restore MI within 90 days following the workover or within the timeframe of the approved alternative schedule. After the well has lost mechanical integrity, injection may not recommence until after internal MI has been demonstrated and the Director has provided written approval.

Internal (Part I) MI is demonstrated by using the maximum permitted injection pressure or 1,000 psi, whichever is less, with a ten percent or less pressure loss over thirty minutes. Additional guidance for Internal (Part I) MI can be found at https://www.epa.gov/uic/underground-injection-control-epa-region-8-co-mt-nd-sd-ut-and-wy#guidance.

External (Part II) MIT may be demonstrated by evaluation of the cement bond log to show that adequate cement exists to prevent significant movement of fluid out of the approved injection zone through the casing annular cement (i.e., 80% bond index cement bond across the confining zone.) Guidance on the logging and interpretation of the cement bond log (CBL) can be found at https://www.epa.gov/uic/underground-injection-control-epa-region-8-co-mt-nd-sd-ut-and-wy#guidance.

Should the CBL analysis show inadequate external Part II MI, additional periodic tests will be required at a frequency no less than every five years after the last successful test. These requirements are found in APPENDIX B Logging and Testing Requirements of the Permit.

Injection Fluid Limitation
Injected fluids are limited to those identified in 40 CFR § 144.6(b) as fluids (1) which are brought to the surface in connection with conventional oil or natural gas production that may be commingled with waste waters from gas plants which are an integral part of production operations unless those waters are classified as a hazardous waste

at the time of injection, (2) used for enhanced recovery of oil or natural gas, and (3) used for storage of hydrocarbons which are liquid at standard temperature and pressure. Non-exempt wastes, including unused fracturing fluids or acids, gas plant cooling tower cleaning wastes, service wastes and vacuum truck wastes, are not approved for injection. This well is not approved for commercial brine injection or other fluid disposal operations.

Prior to adding a new source, a fluid analysis sample must be provided for any new source that was not previously characterized. A new source may include fluids from a new formation, a new portion of the field, non-commercial fluids from another operator, or that are chemically dissimilar from fluids that are already injecting into the well. The list of analytes is found in APPENDIX D of the Permit "WITHIN 30-DAYS OF AUTHORIZATION TO INJECT AND PRIOR TO INTRODUCTION OF A NEW SOURCE". As a result of the new sample analysis, the MAIP may need to be recalculated.

Volume Limitation

There is no limitation on the fluid volume permitted to be injected into this well. However, the AOR shall be expanded to one half (1/2) mile once the cumulative injection volume reaches 12,673,347 barrels. The results of the expanded AOR shall be submitted with the annual report and include the information required in Part II, D.4, and if determined necessary, an updated corrective action plan shall be appended to Appendix F. In no case shall injection pressure exceed the MAIP.

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

Injection Pressure Limitation

40 CFR § 146.23(a)(1) requires that the injection pressure at the wellhead must not exceed a maximum calculated to ensure that the pressure during injection does not initiate new fractures or propagate existing fractures in the confining zone adjacent to the USDWs. In lieu of testing the fracture pressure of the confining zone, which may be impractical, the pressure in the injection formation provides a conservative surrogate.

The calculated Maximum Allowable Injection Pressure (MAIP) described below is the pressure that will initiate fractures in the injection zone and that the Director has determined satisfies the above condition.

Except during stimulation, the injection pressure must not exceed the MAIP. Furthermore, under no circumstances shall injection pressure cause the movement of injection or formation fluids into a USDW.

The **MAIP** allowed under the permit, as measured at the surface, will be calculated according to the equations below. The Permit itself does not contain a specific MAIP value but instead requires that a MAIP be calculated using these equations. The Permit also specifies where the input values are derived from. Prior to authorization to commence injection, the Permittee must submit for review the necessary information to calculate the MAIP. After review of the submitted documents, the Director will notify the Permittee of the MAIP in the written authorization to commence injection.

The formation fracture pressure (**FP**) is the pressure above which injection of fluids will cause the rock formation to fracture. This equation, as measured at the surface, is defined as:

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

Where, FG is the fracture gradient in psi/ft
SG is the specific gravity
D is the depth of the top perforation in feet

The **FG** value for each well will be determined by conducting a step rate test. The results of the test will be reviewed and approved by the Director. As appropriate, the FG may be determined by one of these other following methods:

- Representative **FG** values determined previously from valid tests in nearby wells.
- Established **FG** values found in reliable sources approved by the Director. These could include journal articles, scientific studies, etc.
- An alternative method approved by the Director.

The value for **SG** must be obtained from the fluid analysis of a representative sample of the injection fluid.

The value for **D** is the depth of the top perforation of the as-built well.

When a step rate test is conducted, bottom-hole and surface gauges are required. This requirement may be waived by the Director, but may result in a final MAIP that does not include adjustment for friction loss.

The MAIP can also be adjusted for friction loss if the friction loss can be adequately demonstrated. To account for friction loss, the **MAIP** is equal to **FP** adjusted for friction loss, or:

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

An acceptable method to determine friction loss is to measure it directly. Friction can be calculated when surface and bottom-hole pressures are known. When conducting a step rate test, a surface and bottom-hole gauge at depth **D** are necessary to calculate friction loss.

During the operational life of the well, the depth to the top perforation, fracture gradient, and specific gravity may change. When well workover records, tests, or monitoring reports indicate one of the variables in the FP equation has changed, the MAIP calculation will be reviewed. EPA is incorporating the MAIP equations into this Permit instead of identifying a specific MAIP value because it will result in a more efficient application of the true MAIP, as these changes occur over the life of the well to provide greater protection for nearby USDWs.

When additional perforations are added to the injection zone, the Permittee must provide the appropriate workover records and also demonstrate that the fracture gradient value to be used is representative of the portion of the injection interval proposed for perforation. It may be necessary to run a step rate test to provide representative data, such as when a new formation (within the approved injection zone) or a geologically distinct interval (based on core data or well logs) in the same formation is proposed for injection.

When the fracture gradient or depth to top perforation changes, the formation fracture pressure will be recalculated. The Permittee will also submit fluid analysis that reports SG annually. In the above, a factor of 0.05 has been added to the SG. This adjustment factor allows for the MAIP to be recalculated only if the newly submitted SG is greater than 0.05 from the previous year's SG, without exceeding the fracture pressure of the formation. A MAIP due to the SG change will only be recalculated if the absolute difference of the newly submitted SG and that of the previous year is greater than 0.05.

The new permitted MAIP will become effective when the Director has provided written notification. The Permittee may also request a change to the MAIP by submitting the necessary documentation to support a recalculation of the MAIP.

As discussed above, the formation fracture pressure calculation sets the MAIP to assure that the pressure used during injection does not initiate new fractures or propagate existing fractures in the confining zones adjacent to USDWs. However, it may be that the condition of the well may also limit the permitted MAIP. When external (Part II) MIT demonstrations (such as a temperature survey or radioactive tracer test) are required, the tests required to make this demonstration must be conducted at the permitted MAIP based on the calculations described above. If during testing, the Permittee is unable to achieve the pressure at the permitted MAIP, the new permitted MAIP will be set at the highest pressure achieved during a successful external (Part II) MIT and not the calculated MAIP.

TABLE 5.1 provides an estimated formation fracture pressure based on the information submitted with the application. A step rate test is required in Appendix B of the permit prior to receiving authorization to inject, the permitted MAIP will be recalculated with the information submitted to obtain the authorization to commence injection.

TABLE 5.1
Injection Zone Fracture Pressure

Formation Name or Stratigraphic Unit	Depth (ft)	Specific Gravity	Fracture Gradient (psi/ft)	Friction Loss (psi)	Estimated Formation FP (psi)
Birds Nest Zone	3,501	1.062	0.58	N/A	420

PART VI. Monitoring, Recordkeeping and Reporting Requirements

Injection Well Monitoring Program
At least once a year the Permittee must analyze a sample of the injected fluid for parameters specified in APPENDIX D of the Permit. This analysis must be reported to EPA annually as part of the Annual Report to the Director. Any time a new source is added, a fluid analysis must be provided of the injection fluid that includes the new source as discussed above, in PART V Injection Fluid Limitation.

Instantaneous injection pressure, injection flow rate, injection volume, cumulative fluid volume, bradenhead and TCA pressures must be observed on a weekly basis. A recording, at least monthly, must be made of that month's injected volume and cumulative fluid volume to date, the maximum and average value for injection tubing pressure and rate, maximum and minimum annulus and bradenhead pressures. This information is required to be reported annually as part of the Annual Report to the Director.

PART VII. Plugging and Abandonment Requirements (40 CFR § 146.10)

Plugging and Abandonment Plan
Prior to abandonment, the well must be plugged in a manner that isolates the injection zone and prevents movement of fluid into or between USDWs, and in accordance with any applicable federal, state or local law or regulation. General requirements applicable to all wells include:

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

Within thirty (30) days after plugging the owner or operator must submit Plugging Record (EPA Form 7520-19) to the Director. The Plugging Record must be certified as accurate and complete by the person responsible for the plugging operation. The plugging and abandonment plan is described in APPENDIX E of the Permit.

PART VIII. Financial Responsibility (40 CFR § 144.52(a)(7))

Demonstration of Financial Responsibility
The Permittee is required to maintain financial responsibility and resources to close, plug, and abandon the underground injection operation in a manner prescribed by the Director. The Permittee will show evidence of such financial responsibility to the Director by the submission of 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) a financial test and corporate guarantee.

The Director may, on a periodic basis, require the holder of a lifetime permit to submit a revised estimate of the resources needed to plug and abandon the well to reflect inflation of such costs, and a revised demonstration of financial responsibility, if necessary. The Permittee may also, upon written request, provide an alternative demonstration of financial responsibility.

If a financial test is provided, evidence of continuing financial responsibility is required to be submitted to the Director annually.

PART IX. Considerations Under Other Federal Law (40 CFR § 144.4)

EPA will ensure that issuance of this Permit will be in compliance with the laws, regulations, and orders described at 40 CFR § 144.4, including the National Historic Preservation Act, the Endangered Species Act, and Executive Order 12989 (Environmental Justice), before a final permit decision is made.

National Historic Preservation Act (NHPA)
Section 106 of the National Historic Preservation Act, 54 U.S.C. § 306108, requires federal agencies to consider the effects on historic properties of actions they authorize, fund or carry out. EPA has determined that a decision to issue a Class II injection well permit for authorization of injection into the RZA 14B1-34A well constitutes an undertaking subject to the National Historic Preservation Act and its implementing regulations at 36 CFR part 800.

Prior to construction, Aros Archaeology, L.L.C. completed a literature review and Class III cultural resource survey of the Red Wash 33-7-22 Well Pad, Access Road, Powerline and Pipeline Corridors on Deadman Bench associated with the 14B1-34A and 15A1-33A wells in Uintah County, Utah. A total of 39.8 acres were examined on land administered by the Vernal Field Office Bureau of Land Management. No previously recorded sites were revisited or new cultural resource sites were recorded within the project's Area of Potential Effects (APE). A total of eight isolated artifacts were observed. The isolated artifacts are not significant. No further work or adjustment to well or infrastructure location is recommended for this project. A finding of No Historic Properties Affected was recommended pre-construction, and EPA correspondingly finds that no historic properties will be affected during the well conversions.

Based on this information, EPA is proposing to find that no historic properties will be affected as a result of issuing this UIC Permit.

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. EPA has determined that a decision to issue a Class II permit for authorization of injection into the RZA 14B1-34A well would constitute an action that is subject to the Endangered Species Act and its implementing regulations (50 CFR part 402). Accordingly, EPA will comply with these regulations by determining what, if any, effects this action will have on any federally-listed endangered or threatened species or their designated critical habitat and by following any required ESA procedures. EPA's determination will be documented as part of the administrative record supporting this decision.

Mitigation measures were undertaken for the subject well pad during the construction phase that included the RZA 14B1-34A and RZA 15A1-33A wells. During the well's conversion to a UIC Class II well, the Permittee will follow the mitigation measures as documented in the following Environmental Assessment (EA):

DOI-BLM-UT-G010-2019-0005-EA
February 2019
Vernal Field Office
170 South 500 East
Vernal, Utah 84078

Based on this information, EPA is proposing a no effect finding as a result of issuing this UIC Permit.

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." EPA has concluded that there may be potential EJ communities proximate to the Authorized Permit Area. 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 USDWs. EPA's UIC program authority under the Safe Drinking Water Act is designed to protect USDWs through the regulation of underground injection wells. EPA has concluded that the specific conditions of UIC Permit UT22420-12015 will prevent contamination to USDWs, including USDWs which either are or will be used in the future by communities of EJ concern. These USDWs could include the aquifer within the proposed injection zone in which case injection would only commence if the aquifer is exempted and thereby no longer protected under the SDWA. The UIC program will be conducting enhanced public outreach to EJ communities by publishing a public notice announcement in local newspapers and holding a public hearing, if requested, or if public interest in the proposed permit is high.