MODIFICATIONS AND STATEMENT OF BASIS
MAJOR MODIFICATION 1

INTRODUCTION

In 2014 the Berry Petroleum Company, LLC (Berry) obtained a final Underground Injection Control (UIC) Area Permit for Class II enhanced recovery injection wells located on the portion of the Brundage Canyon Oil Field located within the Uintah and Ouray Indian Reservation. In recent years Berry has produced excess natural gas and has recently requested to inject produced natural gas, in the form of a liquid (Natural Gas Liquid, or NGL), into injection wells to enhance oil production from Brundage Canyon oil wells. Along with produced NGL, Berry has requested to inject produced water, gas and produced water condensate. While produced water comes from Berry's oil and gas production wells, NGL and gas will come solely from Berry's natural gas production wells. This Statement of Basis provides a discussion of the modified portions of the Permit that will allow for the Area Permit's continued protection of Underground Sources of Drinking Water (USDWs) during all enhanced recovery injection operations.

MAJOR PERMIT MODIFICATIONS
Underground Injection Control (UIC) Permit No. UT22195-00000
Brundage Canyon Area Permit

Pursuant to Title 40 of the Code of Federal Regulations, Sections 124.5 and 144.39 of the above referenced Class II UIC permit, a major modification to this Permit is proposed. The proposed changes are as follows:

Original Permit Language (July 2, 2014), from Part 4. Requirements for Adding Injection Wells to Area UIC Permit UT22195-00000, Section 2 of Area Permit:

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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 UT22195-00000. If EPA is satisfied that all Permit conditions have been met, EPA Region 8 will authorize injection by email or by another means of written correspondence. In addition, the injection authorization date will be recorded in the LW, which is described below in Part 5.

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is hereby modified as:

Brundage Canyon Area Permit - Major Permit Modification 1

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). If the 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.

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 UT22195-00000. If EPA is satisfied that all Permit conditions have been met, EPA Region 8 will authorize injection by email or by another means of written correspondence.

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<u>The basis for the modification to Part 4, Section 2</u>: The added sentence in the first paragraph ensures the permittee follows the specific CFR requirements for seeking authorization to inject into an aquifer, which is a USDW less than 10,000 mg/l Total Dissolved Solids (TDS). The second paragraph removes the injection authorization date from being included in the List of Wells. The List of Wells documents the injection-authorized area permit wells and their respective MAIP, specific gravity, fracture gradient, and depth of top perforation.

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Original Permit Language (July 2, 2014), from Part 5. List of Wells (LW) for Area UIC Permit UT22195-00000 of Area Permit:

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PART 5. LIST OF WELLS (LW) FOR AREA UIC PERMIT UT22195-00000

Due to the large scope of Area UIC Permit UT22195, the EPA intends to record information related to this permit in a document called the LW. The LW is intended to serve the administrative functions of organizing and communicating oil-gas well data, EPA requirements and EPA authorizations related to Area UIC Permit UT22195-00000 for the Permittee. Injection wells regulated by EPA and subject to the terms and conditions of this Permit are listed in the LW with EPA Permit number UT22195 and are assigned a unique well identification number by EPA.

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is hereby modified as:

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PART 5. LIST OF WELLS (LW) FOR AREA UIC PERMIT UT22195-00000

Due to the large scope of Area UIC Permit UT22195, EPA intends to record information related to this permit in a document called the List of Wells for the Area UIC Permit UT22195-00000. The LW is intended to serve as an administrative tool to organize and communicate oil-gas well data and other information related to Area UIC Permit UT22195-00000 for the Permittee. It is maintained by EPA Region 8 and available to the public upon request. Injection wells regulated by EPA and subject to the terms and conditions of this Permit are listed in the LW with EPA Permit number UT22195 and are assigned a unique well identification number by EPA.

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<u>The basis for the modification to Part 5</u>: The modified paragraph furnishes background information regarding the reason this list is maintained in the area permit. The List of Wells documents the injection-authorized area permit wells and their respective MAIP, specific gravity, fracture gradient, and depth of top perforation.

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Original Permit Language (July 2, 2014), from Part 8. Mechanical Integrity of Injection Wells, Section 4 of Area Permit:

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PART 8. MECHANICAL INTEGRITY OF INJECTION WELLS

4. **Notification of Mechanical Integrity Testing:** Prior notification of mechanical integrity testing is not required under Area Permit UT22195-00000. It is the Permittee's responsibility to ensure that mechanical integrity demonstration on all wells is conducted in accordance with Area UIC Permit UT22195-00000 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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is hereby modified as:

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PART 8. MECHANICAL INTEGRITY OF INJECTION WELLS

4. **Notification of Mechanical Integrity Testing:** At least once each year, the Permittee is to report to the UIC Enforcement Coordinator a list of planned mechanical integrity tests during each of the next 52 week-long periods; this annual notification shall delineate 52 Monday through Friday periods. This list shall have EPA well numbers and well names that the Permittee anticipates testing for mechanical integrity during each week of the designated 52-week period. Example: Permittee submits the planned tests for each week of the period from March 1, 2021 through February 28, 2022. (List must be submitted no later than 30-days in advance of the beginning of this period, which in this example is January 29.) It is the Permittee's responsibility to ensure that mechanical integrity demonstration on all wells is conducted in accordance with Area UIC Permit UT22195-00000 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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<u>The basis for the modification to Part 8, Section 4</u>: The modified paragraph furnishes clarification as to when the operator must notify EPA of planned mechanical integrity tests. This gives the EPA the option to plan inspection dates in the Uinta Basin with these tests in mind.

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Original Permit Language (July 2, 2014), from Part 8. Mechanical Integrity of Injection Wells, Section 5 of Area Permit:

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PART 8. MECHANICAL INTEGRITY OF INJECTION WELLS

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[1] pressure in the Tubing-Casing Annulus (TCA), water flowing at the surface, etc.), the Permittee shall notify the Director within 24 hours (see Part 22, 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 test results, repairs undertaken or a proposed remedial action plan. Injection operations shall not be resumed until after the well has successfully been repaired and demonstrated mechanical integrity and has received written notification from the Director.

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

is hereby modified as:

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PART 8. MECHANICAL INTEGRITY OF INJECTION WELLS

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 22, 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 test results, repairs undertaken or a proposed remedial action plan. Injection operations shall not be resumed until after the well has successfully been repaired and demonstrated mechanical integrity and 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 EPA.

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<u>The basis for the modification to Part 8, Section 5</u>: The modified paragraph adds this sentence to the end: "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 EPA." This establishes a time frame in which mechanical integrity must be restored.

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Original Permit Language (July 2, 2014), from Part 10. Requirements for Operating Injection Wells, Sections 4 and 5 of Area Permit:

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PART 10. REQUIREMENTS FOR OPERATING INJECTION WELLS

4. **Injection Fluid Limitation:** Area UIC Permit UT22197-00000 authorizes the injection of produced Green River Formation water commingled with water from the Green River and/or municipal water from the Johnson Water District. The Permittee shall provide an annual listing of sources of injected fluids in accordance with the reporting requirements in Part 15, Paragraph 4 of this Permit. Injection of any fluid for the purpose of disposal is prohibited. Prohibited fluids

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[2] Abnormal pressure on the tubing-casing annulus is less than 0 psig or greater than 100 psig

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."

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is hereby modified as:

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4. **Injection Fluid Limitation:** Area UIC Permit UT22195-00000 authorizes the injection of produced Green River and Wasatch Formation water, natural gas liquids and condensate, and gas, commingled with water from the Green River and/or municipal water from the Johnson Water District for the purpose of enhanced recovery. 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 between the range of 0-100 psi. If TCA pressure cannot be maintained between this range, 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."

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<u>The basis for the modification to Part 10, Section 4</u>: The modified paragraph allows for the injection of natural gas liquids and gas, in addition to produced water.

<u>The basis for the modification to Part 10, Section 5</u>: The modified paragraph allows for a tubing-casing annulus pressure range of 0-100 psi, which reflects actual EPA field observations of

operations, and a normal occurrence with deep injection wells. Therefore, requiring the permittee to maintain a zero pressure in the annulus is unrealistic.

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Original Permit Language (July 2, 2014), from Part 11. Maximum Allowable Injection Pressure, of Area Permit:

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PART 11. MAXIMUM ALLOWABLE INJECTION PRESSURE

Previously established Maximum Allowable Injection Pressures (MAIP) for wells under existing Federal UIC Permits in the Brundage Canyon Field are transferred to UIC Permit UT22195-00000 and are incorporated as enforceable conditions of this permit. Requested changes to these pressures shall follow the same procedure as described here. For requested changes to these previously established MAIPs and for all other wells covered under this permit, the Permittee shall calculate the MAIP based on the following equation:

$$\text{MAIP} = [\text{FG} - (0.433)(\text{SG})] * \text{Depth}$$

"Depth" is the depth in feet from the Kelly Bushing to the top of the injection zone.
"FG" is the fracture gradient.

As part of the permit application, the Permittee supplied the FG value for each existing well. (See Book 2, well data, of permit application.) Each respective well FG value identified in Book 2 shall be used unless the Director approves a more accurate value, as determined by the results of a Step Rate Test.

If the Permittee learns by results of a new Step Rate Test that there is a change to the FG value, it shall submit the most current value to EPA, as determined by the current Step Rate Test. If the Director approves the new FG derived from the Step Rate Test, then that value will be plugged into the MAIP formula above, and a new MAIP will be derived based on the FG change.

The SG (specific gravity) is 1.015 throughout T5S-R4-5W and shall be used unless the Director determines otherwise through a permit modification.

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is hereby modified as:

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PART 11. MAXIMUM ALLOWABLE INJECTION PRESSURE

(a) Except during stimulation, injection pressure at the wellhead shall not exceed the MAIP which shall be calculated to assure that the pressure in the injection zone does not initiate new fractures or propagate existing fractures in the injection zone. In no case shall injection pressure initiate fractures in the confining zone or cause the movement of injection or formation fluids into a USDW.

(b) The **MAIP** allowed under the Permit, as measured at the surface, shall equal the formation fracture pressure (FP**)** plus friction loss.

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

This MAIP is calculated using the equations found in this section and data submitted with the permit application.

For liquids (produced water or NGL) injection, the **FP** (measured at the surface) must be calculated using the following equation:

$$FP = [\mathbf{FG} - (0.433)(\mathbf{SG} + 0.025)] * D$$

The values used in the equation are defined as:
"FG" is the fracture gradient of the injection zone in pounds per square inch/feet (psi/ft). The **FG** value for each well shall be determined by conducting a valid step rate test, reviewed and approved by the Director. Alternative methods to determine a representative **FG** may be used, if approved by the Director, such as previously submitted FGs from Book 2 of the application.
"SG" is the specific gravity of the injection fluid obtained from a representative water sample. Based on the average SG, taken from monitoring reports from the eleven area permit wells shown in the List of Wells, the SG is 1.000. Any exceedance becomes the updated SG for all wells. The Director may also determine otherwise, or a permit modification may change this approach.

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

For gas injection:

$$FP = [\mathbf{FG} - P_g] * \mathbf{D}$$

P_g = gas gradient in psi/ft = 0.433 [psi/ft]/1 [g/cc] *ρ_f [g/cc]
ρ_g = gas density in g/cc = 0.043*p*γ_g/(zT) [g/cc]

Where,
γ_g = specific gravity of gas = 0.75 (constant)
z = gas deviation factor = 0.569 (constant)
T = temperature in ˚R = 479.67 ˚R (constant)
p = pressure in psi = **FG * D**

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

When the D or FG value changes, a new MAIP shall be recalculated.

To approve an increase to the MAIP as a result of changes to the D or FG values, the Director may also require an external (Part II) mechanical integrity demonstration at the increased MAIP.

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

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

<u>The Basis for the modification to Part 11:</u>
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. 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 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:

Produced Water and NGL Injection

$$\mathbf{FP} = [\mathbf{FG} - (0.433 * (\mathbf{SG} + 0.025)] * \mathbf{D}$$

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. When conducting a step rate test, a surface and bottom-hole gauge at depth **D** is required. 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, such as Book 2 of the application.

The value for **SG** must be obtained from the fluid analysis of a representative sample of the injection fluid. The SG for NGL will be treated as produced water, which also conservatively lowers the MAIP from a potentially higher level to that of water.

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

Gas Injection

$FP = [FG – P_g] * D$

P_g = gas gradient in psi/ft = 0.433 [psi/ft]/1 [g/cc] *ρ_f [g/cc]
ρ_g = gas density in g/cc = $0.043*p*\gamma_g/(zT)$ [g/cc]

Where,
γ_g = specific gravity of gas = 0.75 (constant)
z = gas deviation factor = 0.569 (constant)
T = temperature in ˚R = 479.67 ˚R (constant)
p = pressure in psi = FG * Depth

The values for γ_g, z-factor and temperature used to calculate the FP will varies depending upon operational and environmental conditions. The γ_g varies with the gas composition and this value ranges between 0.6 to 0.75. The z or gas deviation factor is dependent upon γ_g, temperature and pressure, determined using an analytical model. For the different permutations of γ_g, temperature and pressure, the z varies from 0.569 to over 1.2. Berry provided a history of the gas temperature over the last year. The temperature experienced during this time period ranged from 20˚ to over 100˚ F.

As discussed above, these parameters are interdependent when determining the FP value. To simplify the calculation of the FP for gas injection, the constant values incorporated in this permit are the values the result in the most conservative FP.

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 to the injection zone are added, 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 for liquid injection, a factor of 0.025 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 0.025 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 0.025.

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 injection zone(s). 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.

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PART 13. Requirements for Stimulating the Injection Zone Using Injection Wells has been deleted. All subsequent part numbers have been reduced by one. Example, Part 14. Requirements for Workovers and Alterations now becomes Part 13, Part 15 becomes Part 14, etc.

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Original Permit Language (July 2, 2014), from Part 14. Requirements for Workovers and Alterations of Area Permit:

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PART 14. REQUIREMENTS FOR WORKOVERS AND ALTERATIONS

Workovers and alterations shall meet all conditions of Area UIC Permit UT22195-00000. Prior to beginning any addition or physical alteration to an injection well that may significantly affect the tubing, packer, or casing, the Permittee shall give advance notice to the Director. The Permittee shall record all changes to well construction on a Well Rework Record (EPA Form 7520-12) and provide an updated well bore diagram and shall provide this and any other record of well workover, including logging or test data to the EPA 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.

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is hereby modified as:

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PART 13. REQUIREMENTS FOR WORKOVERS AND ALTERATIONS

1. **Definition**: Any addition, physical alteration or activity that may affect tubing, packer or casing is a well rework activity covered under Part 13 of this Permit. Workovers also include well stimulation activities such as hydraulic fracturing, polymer gel injection and the delivery of acid to the injection zone formation. EPA Region 8 does not consider the temporary filling of the wellbore with acid to descale tubulars, or the use of biocides to prevent algal growth, to constitute a well rework.

2. **Procedures**: Workovers and alterations to the injection well shall meet all conditions of Area UIC Permit UT22195-00000. Prior to beginning any well rework activity, 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 7520-19) 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.

3. **Re-establishing Mechanical Integrity**: A successful demonstration of mechanical integrity is required following the completion of any well workover, well stimulation or alteration which affects the casing, tubing, or packer, or exceeds the MAIP for the well. Injection operations shall not be resumed until the Permittee has successfully demonstrated mechanical integrity of the well, and if the well lost mechanical integrity or the well rework results in a change in the MAIP, the Director has provided written notice. 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 EPA.

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<u>The Basis for the modification to Part 13 (formerly Part 14):</u>
The last sentence of paragraph 3 is added: "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 EPA." This establishes a time frame in which mechanical integrity must be restored. Paragraph 2 provides clarification for use of the well rework record and provides the updated form number.

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Original Permit Language (July 2, 2014), from Part 15. Monitoring, Recordkeeping and Reporting of Results, Table 2 of Area Permit:

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PART 15. MONITORING, RECORDKEEPING AND REPORTING OF RESULTS

Table 2: Monitoring and reporting requirements for each injection well authorized by Area UIC Permit UT22195-00000.

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 Both produced water and NGL	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

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is hereby modified as:

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PART 14. MONITORING, RECORDKEEPING AND REPORTING OF RESULTS

Table 1: Monitoring and reporting requirements for each injection well authorized by Area UIC Permit UT22195-00000. Include separate produced water, NGL and gas reports.

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 Both produced water and NGL	Injected fluid total dissolved solids (mg/l)
	Injected fluid specific gravity
	Injected fluid specific conductivity
	Injected fluid pH
Annually	
Report	Each month's maximum injection pressure (psig)
	Each month's maximum annulus pressure (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

<u>Produced water, natural gas liquid (NGL) and gas are to be submitted independently for each well</u>.

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<u>The Basis for the modification to Part 14 Table 1 (formerly Part 15 Table 2):</u>
The following statement is added immediately after Table 1: “Produced water, natural gas liquid

(NGL) and gas are to be submitted independently for each well." This requirement is a direct result of the modification allowing the additional option of injecting NGL and gas. The EPA requires the information from Table 1 in all permits, which typically only permits the injection of produced water. Records for each type of liquid or gas must be submitted independently.

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The Basis for the modification to Part 15 (formerly Part 16): The following sentence was added at the end of this section for the purpose of clarifying that the EPA must be notified each time a well resumes injection after a period of not operating the well: "The Permittee shall notify the Director prior to resuming operation of the well." The original and modified paragraphs are not shown here, since the only change is the addition of this sentence.

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NOTES

- The current facility for water injection will not be modified for NGL as the NGL will be trucked to the injection well.
- The existing gas plant is separate from the existing produced water plant. Berry's gas plant chills and compresses produced gas to be pumped into pipelines which transports it to the marketplace. A byproduct of chilling the gas is NGL. Currently NGL is stored at the gas plant and is later trucked.