STATEMENT OF BASIS

BP America Production Company
Barnes Water Disposal Well No. 1
La Plata County, Colorado

Class II Salt Water Disposal Well
CO20939-04673

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This Statement of Basis gives the derivation of site-specific UIC permit conditions and reasons for them. Referenced sections and conditions correspond to sections and conditions in CO20939-04673 (Permit).

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 underground sources of drinking water. 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 Colorado injection wells are found at 40 CFR § 147 Subpart G.

Upon the Effective Date when issued, the Permit authorizes the construction and operation of 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

BP America, Inc
BPX Energy
1199 Main Avenue, Suite 101
Durango, Colorado 81301

hereinafter referred to as the “Permittee,” submitted an application for an Underground Injection Control (UIC) Program permit for the following injection well or wells:

Barnes Water Disposal Well No. 1
2210’ FEL & 1105’ FSL, Section 4, T33N, R9W
La Plata County, Colorado

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

BP America Production Company (BP) was issued a Class II permit on November 19, 2002 that allowed injection only into the Entrada Sandstone with an injection volume limit of 79,354,840 barrels. Subsequently, in the modified permit of October 14, 2004, both the Bluff and Entrada Sandstones were permitted as injection zones, with allowable injection volumes of 105,949,400 barrels and 85,789,010 barrels respectively. Additionally, to permit injection above the fracture pressure in the injection zones, BP was required to run temperature surveys and radioactive tracer tests annually, due to the potential of out of zone migration of fluids. BP has requested to reduce the frequency for these two tests after having run them 16 years and continuously demonstrating external mechanical integrity. In addition, the Dakota and Burro Canyon Formations (possible USDWs) were previously considered in earlier permits as possible injection zones. Since there has been no request by the operator to provide an aquifer exemption application for these formations they are not included as injection zones at this time. Due to the age of the Permit, BP has agreed to have their Permit revoked and reissued to reduce their external MIT testing frequencies and bring the Permit conditions up to current EPA standards.

The Permit allows for the disposal of produced water from Coal Bed Methane wells drilled to the Fruitland Formation in the Ignacio Blanco Field. The disposal well was originally drilled starting on November 29, 2002, and completed to a depth of 8,931 feet to near the base of the Entrada Formation. Authorization to inject was approved on April 26, 2004, and injection continues at the present time. As of April 1, 2019, approximately 9,976,858 barrels of approved Class II fluids have been injected into this well. Analytical results of injected fluids reported in October 2018 indicated a total dissolved solids concentration of 3,760 mg/l and a specific gravity of 1.003.

PART II. Permit Considerations (40 CFR § 146.24)

Hydrogeologic Setting

The San Juan Basin encompasses approximately 21,600 square miles in southwestern Colorado, northwestern New Mexico and south eastern Utah and northeastern Arizona. The San Juan structural basin is an approximate circular asymmetric structural depression located primarily in the east-central part of the Colorado Plateau. The majority of the Basin is within New Mexico and is bounded on the north by the San Juan Mountains in Colorado. The geologic bedrock dips more steeply to the south from the northern boundary into the basin and more gently from south to north in New Mexico. The bedrock geologic units of the Colorado portion of the basin dip to the south and strike in a generally easterly direction.

Groundwater bearing units in the vicinity of the well consists of generally thin shallow alluvium that have well yields averaging 15 (gallons/minute) gpm with generally low TDS concentrations reported in the basin. The next recognized water bearing unit is the Tertiary Animas Formation that is about 300 feet thick at a depth of 1,670 feet.

The Animas Formation has reported yields of 1-10 gpm with TDS values ranging from 312-1350 mg/L in the basin.

The underlying USDWs consist of the Mesaverde Group that includes the Cliff House Sandstone and the Menefee Formation. The top of the Mesaverde Group is at 4480 feet and the base of the Menefee is at 5,173 feet. The next recognized USDW is the Dakota Formation that is found between 7,494 and 7,678 feet (KB). The Morrison is a USDW that occurs between 7,712 feet to 8,190 feet in depth immediately above the upper injection Zone (Bluff Sandstone). There are several sandstone units between the Mesa Verde and Dakota Sandstones could be considered USDWs, but they are generally considered hydrocarbon bearing.

Multiple upper confining zones consisting primarily of impermeable shale units including the Lewis, Mancos, Greenhorn and Graneros with a combined thickness of 2,812 feet. A 225-foot thick confining zone consisting of the Middle Morrison Formation isolates the injection zones from the shallower units in the well. A recent Radioactive Tracer Survey indicates that there is no apparent fluid migration occuring above the Lower Morrison Formation.

TABLE 2.1
Geologic Setting

Formation Name or Stratigraphic Unit	Top (ft)*	Base (ft)*	TDS (mg/l)	Lithology
Animas	20	923	<10,000	Tuffaceous sandstone with some variegated shale
Lower Animas	923	1,083	<10,000	Tuffaceous sandstone with some variegated shale
Kirtland	1,083	1,913	1,120-4,450	Sandy Shale
Lower Kirtland	1,913	2,249	1,120-4,450	Sandy Shale
Fruitland Coal	2,249	2,660	7,150	Carbonaceous shale and coal
Pictured Cliffs SS	2,660	2,823	3,285-4,660	Sandstone
Lewis Shale	2,823	4,480		Grey & black Marine Shale
Mesaverde	4,480	4,961	1,120-4,450	Sandstone
Menefee	4,961	5,173	210~3,350+	Silty Shale
Point Lookout	5,173	5,606	18,000	Sandy Shale
Mancos SH	5,606	6,595	207~4,820+	Shale
Gallup SS	6,595	7,328		Sandstone
Greenhorn SSH	7,328	7,380		Calcareous shale argillaceous limestone
Graneros	7,380	7,494		Marine Shale
Dakota SS	7,494	7,678	5,297-7,361	Sandstone
Burro Canyon	7,678	7,712	5,960	Sandstone
Upper Morrison	7,712	7,835	4,000	Sandstone
Middle Morrison	7,835	8,060		Shale and Sandstone
Lower Morrison	8,060	8,190	4,000	Sandstone
Bluff SS	8,190	8,437	7,580	Sandstone

Wanakah	8,437	8,557		Sandstone
Todilto	8,557	8,584		Limestone / Anhydrite
Entrada SS	8,584	8,784	4,580-18,735	Sandstone
Chinle	8,784			Shale

*formation top and bottom depths (KB) at the Barnes WDW 1 well
+Groundwater Atlas of Colorado, San Juan Basin, Colorado Geological Survey, Special Publication 53

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(s) are listed in TABLE 2.2.

The injection zone in this well consists of three USDWs, two of which (Bluff Sandstone and Entrada Sandstone) already have Aquifer Exemptions (AE). The third USDW (Lower Morrison Formation) above the Bluff Sandstone is the subject of an additional AE associated with this action.

The USDW above the lower Morrison Formation is a sequence of sandstones in the Dakota and Burro Canyon Formations from 7494 to 7712 feet. These sandstones are isolated from the lower Morrison Formation by upper and middle Morrison Formation units consisting of 76 feet of shaley rock units from 7712 to 7788 feet a thin sandstone unit (38 feet) from 7788 feet to 7926 feet and a 128-foot thick shale unit from 7926 feet to the top of the lower Morrison Formation sandstones at 8060 feet. These shale units are acting as a confining zone from the migration of fluids from the lower Morrison Formation and the underlying Bluff Sandstone injection zone. In addition, the Cement Bond Log indicates satisfactory cement bonding through the upper confining zone between the lower Morrison and the Burro Canyon.

The Lower Morrison Formation consists of a 130-foot thick sandstone. The sandstone unit is a recognized USDW and in direct contact and hydrologically connected with the underlying Bluff Sandstone. Since the well is perforated into the Bluff Sandstone and is directly receiving produced water, Lower Morrison Formation requires an Aquifer Exemption as part of the Permitting process.

The Bluff Sandstone from 8,190 to 8,437 feet (KB) is 247 feet thick and is separated from the lower injection zone (Entrada Sandstone) by the Wanaka and the Todilto Limestone that have a total thickness of 147 feet. The lower injection zone is the Entrada Sandstone that is encountered from 8,584 to 8,784 feet (KB) is 200 feet thick overlying the lower confining Chinle Formation consisting primarily of shale.

Table 2.2
Injection Zones

Formation Name or Stratigraphic Unit	Top (ft)*	Base (ft)*	Porosity	Exemption Status
Lower Morrison	8,060	8,190	11%	Proposed
Bluff SS	8,190	8,437	11%	Yes
Entrada SS	8,584	8,784	11%	Yes

* depths are approximate values at the wellbore

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.

The Lewis Shale consists of about 1,657 feet of relatively impermeable grey and black marine shale. The next major confining zone is the Mancos Shale that consists of about 949 feet of shale that is 1,126 feet below the base of the Lewis Shale. The next major confining zone consists of the Greenhorn Shale that is 52 feet thick and is 733 feet below the base of the Mancos Shale.

An additional confining zone occurs at the top of the Lower Morrison/Bluff Sandstone injection zone. Notably, a 225-foot thick shaley unit (Middle Morrison Formation).

The Wanakah and Todilto Limestone act as a confining zone between the Lower Morrison/Bluff Sandstone injection zone and the Entrada Sandstone injection zone. The Wanaka is 120 feet of relatively impermeable interbedded shales and sandstones that overly the Todilto Limestone that consists of 27 feet of impermeable Limestone and anhydrite.

The Chinle Formation is the lower confining zone below the Entrada Sandstone injection zone. The Chinle Formation consists of a minimum of 147 feet of shale as the Chinle Formation is not fully penetrated by the well.

TABLE 2.3
CONFINING ZONES

Formation Name or Stratigraphic Unit	Top (ft)	Base (ft)	Lithology
Kirtland	1,083	1,913	Sandy Shale
Lower Kirtland	1,913	2,249	Sandy Shale
LewisShale	2,823	4,480	Grey & black Marine Shale
Mancos SH	5,606	6,595	Shale
Greenhorn SSH	7,328	7,380	Calcareous shale argillaceous limestone
Graneros	7,380	7,494	Marine Shale
Middle Morrison	7,835	8,060	Shale and Sandstone
Wanakah	8,437	8,557	Sandstone
Todilto	8,557	8,584	Limestone / Anhydrite
Chinle	8,784		Shale

* depths are approximate values at the wellbore

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 upper injection zone in the Barnes WDW #1 well consists of approximately 130 feet of sandstone of the Lower Morrison Formation and 247 feet of the underlying Bluff Sandstone. The Bluff Sandstone is a massive medium-grained eolian sandstone. The total thickness of the upper injection zone is therefore 377 feet. The Lower Morrison Formation/Bluff Sandstone (upper injection zone) is above the Wanakah Sandstone and the Todilto Limestone, that are considered tight, low porosity rock. The lower injection zone is the Entrada Sandstone that occurs below the Todilto Limestone. The Entrada Sandstone consists of 200 feet of a massive medium-grained eolian sandstone.

Aquifer exemptions were approved for the two injection zones, the Entrada Sandstone on November 19, 2002 and the Bluff Sandstone within the Barnes WDW #1 well with the Major Modification dated October 14, 2004, respectively. It should be noted that the Morrison Formation was designated as a potential injection zone in the original Permit. A part of the Lower Morrison Formation immediately above and in direct contact with the Bluff

Sandstone is a recognized USDW and an aquifer exemption will be required as part of this action. The Lower Morrison Formation from 8,060-8,190 feet (130 feet) is hydrologically connected with the Bluff Sandstone (upper injection zone). This part of the Morrison Formation is not perforated but is considered part of the upper injection zone.

TABLE 2.4
UNDERGROUND SOURCES OF DRINKING WATER (USDWs)

Formation Name or Stratigraphic Unit	Top (ft)*	Base (ft)*	TDS (mg/l)	Lithology
Alluvium	0	100	300-1,000#	Silt, sand, gravel, and boulders
San Jose Formation	100	1,500	800-1,600#	Sandstone, shale and conglomerate
Farmington Sandstone	1,610	2,225	1,120-4,450	Sandstone
Fruitland Formation	2249	2660	7,150	Carboniferous Shale and Coal – CBM producing
Pictured Cliffs Sandstone	2660	2823	3,285-4,660	Sandstone – Hydrocarbon Producing
Cliff House Sandstone	4480	4961	1,120-4,450	Sandstone – Hydrocarbon Producing
Menefee+	4961	5,173	210-3,350	Silty Shale
Dakota	7,494	7,678	5,297-7,361	Sandstone
Burro Canyon	7,678	7,712	5,960	Sandstone
Lower Morrison	**8,060**	**8,190**	**4,000**	**Sandstone**
Bluff Sandstone	**8,190**	**8,437**	**7,580**	**Sandstone**
Entrada Sandstone	**8,584**	**8,784**	**4,580-18,735**	**Sandstone**

*Formation top and bottom depths at the Barnes WDW #1
#Groundwater Resources of the Florida Mesa Area, La Plata County, Colorado
+Groundwater Atlas of Colorado, San Juan Basin, Colorado Geological Survey, Special Publication 53

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.

To protect shallow USDWs when drilling the surface hole, the Permittee is limited to drilling with air or mud made with water containing no additives and no more than 3,000 mg/l TDS, unless waived by the Director.

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)
Surface	17.5	13.375	0-478	0-478
Intermediate	12.25	9.625	0-3,094	0-3,094
Intermediate	8.75	7	0-7,561	950-7,561
Liner		4.5	7,251-8,931	7,296-8,931

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.

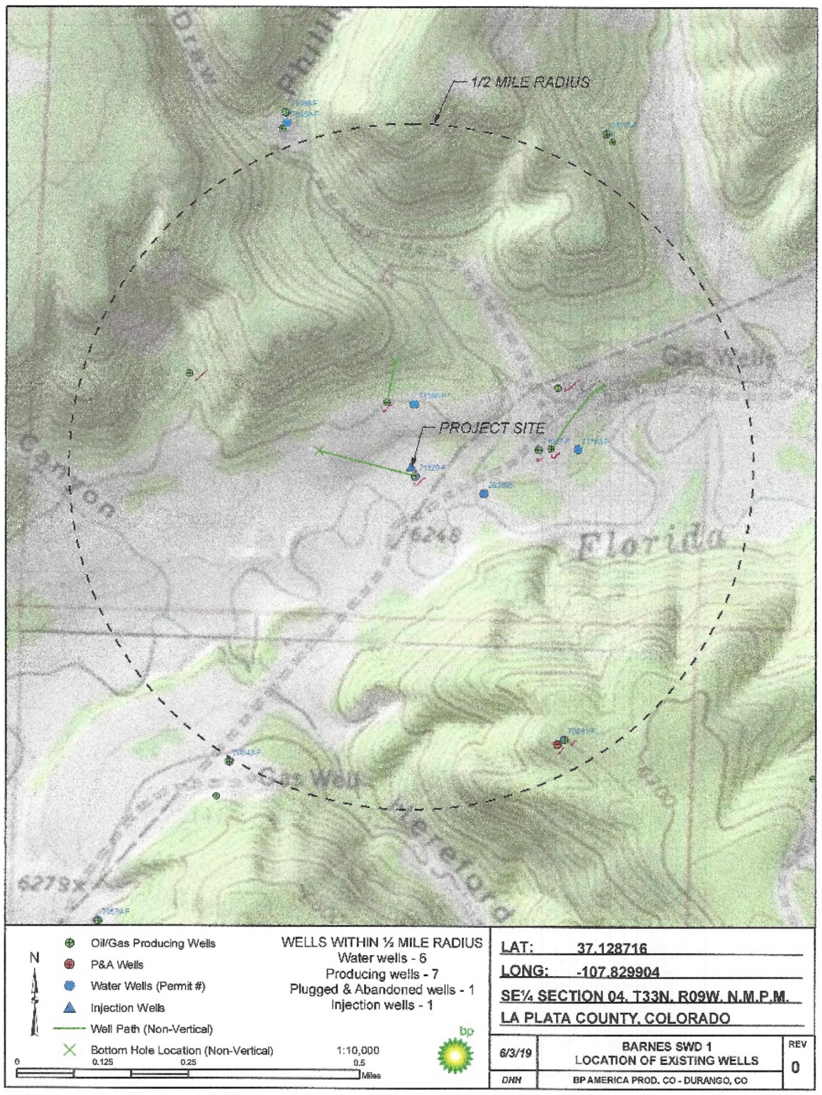
All sampling and measurement taken for monitoring must be representative of the monitored activity.

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.

The AOR is a ½ mile radius from the Barnes WDW #1 well. Within the ½ mile radius there are eight (8) producing wells. All of these wells are shallower than the injection zones of the Barnes WDW #1 injection well. Two of the wells are Mesaverde Formation producers, one is a plugged and abandoned Mesaverde producer and the remaining 5 wells are Fruitland Formation producers. Of the eight total producing wells, the following four (4) wells were drilled after the construction of the Barnes WDW #1.

- John Barnes A 2, API# 05-067-08860
- FC Southern Ute com 001, API# 05-067-08891



- John Barnes A 4, API# 05-067-09683
- John Barnes A 3, API# 05-067-09764

The following four wells were evaluated as part of the previous permitting process. These wells are completed in more shallow units, as noted above, than the injection well.

- Southern Ute 33-9;9-4, API# 05-067-06217
- Southern Ute 33-9;4-1, API# 05-067-05514
- Southern Ute 33-9;4-2, API# 05-067-06213
- John Barnes A 1, API# 05-067-07027

A single domestic well is located within the AOR. According to State records, this well is only 12 feet in depth.

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.

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

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.

The original Permit (November 19, 2002) allowed for injection into the Entrada Sandstone with the following Testing requirements:

• Hall Plot – Injection flow analysis	After 36 months of injection service
• Hall Plot – Injection flow analysis	After 12 months of injection service
• Pressure Fall-off Test	After 12 months of injection service
• Injection Zone Water Sample	Prior to Injection
• Pore Pressure	Prior to Injection
• Permeability	Prior to Injection
• Cement Records	Prior to Injection

On July 6, 2004, a minor modification was requested to increase the MAIP from 1160 psi to 2360 psi because the result of the June 23, 2004, injection testing of the Entrada did not satisfy the disposal requirements of the operator. In order to satisfy the disposal requirements of the operator, the request included adding injection to the Bluff Sandstone in addition to the Entrada Sandstone with the required an aquifer exemption for the Bluff with volume limitations. The injection test included running a RATS test at pressures up to 2400 psi. The RATS test indicated that there was no flow out of the injection zone adjacent to the casing as a result of the injection at pressures exceeding the original MAIP (1160 psi).

On October 14, 2004, EPA approved increasing the MAIP to 2300 psi with the additional requirement of conducting a RATS test and temperature log annually to ensure that upward migration of injection fluids do not occur.

None of the tests from 2004 to 2020 indicated upward movement near the wellbore based upon the RATS and temperature logging.

This Permit reduces the requirement to conduct a RATS and temperature log to once every five (5) years based upon the results of previous testing and at the request of the operator.

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

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

The maximum total volume permitted to be injected during the life of the well is 191,738,410 barrels based upon the previous aquifer exemptions approved for the Bluff Sandstone and Entrada Sandstone injection zones. This volume is intended to ensure fluids remain within the aquifer exemption boundary. The volume limitation is calculated using the formula below using thicknesses for the Bluff and Entrada Sandstones:

$$\mathbf{V} = (\pi\, \mathbf{r}^2 \mathbf{t} \phi)/\mathbf{5.615}$$

Where, **V** = maximum cumulative volume to be injected (bbl)
r = radial distance away from the wellbore that fluids have traveled, 2640 ft
t = thickness of injection zone, 447 ft
ϕ = porosity of injection zone, 11%
π = 3.14159265
5.615 = conversion factor (barrels and ft^3)

An aquifer exemption is required for this Permit (Lower Morrison). However, no additional volume limitation will be enforced as the Lower Morrison is not perforated by this well, but is hydrologically connected with the underlying Bluff Sandstone, a recognized injection zone with a volume limitation.

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.

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

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:

FP = [**FG** - (0.433 * **SG**)] * **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

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)

Bluff SS	8,190	1.003	0.58	650	1843
Entrada SS	8,584	1.003	0.57	650	1814

The fracture gradient of the Entrada Sandstone (0.57 psi/ft) is the average of the fracture gradients from the following offset wells.

- Florida River SWD No.1-0.656 psi/ft based on Instantaneous Shut In Pressure (ISIP) after fracking
- Simon SWD No. 1-0.575 psi/ft based on ISIP after fracking
- Simon SWD No. 1 – 0.478 psi/ft. based on step rate test

The fracture gradient of the Bluff Sandstone (0.58 psi.ft) is the average of the fracture gradients from the following offset wells.

- Florida River SWD No. 1 – 0.696 psi/ft on ISIP after fracking
- Simon SWD No. 1- o.475 psi/ft based on step rate test

Friction loss was provided by the operator and consists of the following:

- The tubing is divided into 3 segments
- 7207 feet of 3.5 inch = 473psi
- 916 feet of 2.875 = 162 psi
- 32 feet of 2.375 = 15 psi
- For a total of 650 psi

The Major Modification provided on October 14, 2004, allowed the operator to inject above formation fracture pressure. The operator requested an increase in MAIP from 1160 to 2360 psi to dispose of the targeted 10 barrels per minute in the Bluff and Entrada injection zones. The request was based on the results of a June 23, 2004, injection test. The well test involved the running of a RTS while injecting at pressures up to 2400 psi. The test results indicated that there was no flow out of the injection zone via flow adjacent to the casing as a result of injection at pressures exceeding the MAIP of 1160 psi. As a condition of the permit to allow injection above fracture pressure the operator was required to demonstrate through periodic RTS and temperature logs that injection fluids remain within the injection zone. An MAIP of 2300 psi was approved as part of this Major Modification.

With the permit modification, BP was required to run temperature surveys and radioactive tracer tests annually. BP has requested to reduce the frequency for these two tests after having run them for 16 years and continuously demonstrating fluids have remained within the injection zone. Upon permit reissuance, the RTS and temperature log requirement will be reduced from annual to at least every 5 years after the last successful demonstration.

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. Tubing, packer and other downhole apparatus must be removed. Cement with additives such as accelerators and retarders that control or enhance cement properties may be used for plugs; however, volume-extending additives and gel cements are not approved for plug use. Plug placement must be verified by tagging. A minimum 50 ft. surface plug must be set inside and outside of the surface casing to seal pathways for fluid migration into the subsurface.

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.

Since the Barnes Water Disposal Well No. 1 is an existing constructed well, the P&A plan may need to be reassessed when the plug and abandonment is proposed.

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.

In this case a letter of credit is being used for Financial Responsibility.

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.

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. The EPA has determined that a decision to re-issue a Class II injection well permit for authorization of injection into the Barnes Water Disposal Well No. 1 well constitutes an undertaking subject to the National Historic Preservation Act and its implementing regulations at 36 CFR part 800. The Barnes Water Disposal Well #1 drill pad and well has been constructed and operating since 2002. There is no expectation that additional ground disturbances will occur as a result of implementing the current reissuance of this Permit. It is expected that if the operator encounters historic properties as a result of future operations as described in the NHPA, they will document the finding and report the finding to the Southern Ute Tribe and the State Historical Preservation Office (SHPO) for guidance as how to proceed.

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 re-issue a Class II permit for authorization of injection into the Barnes Water Disposal Well No. 1 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. Since the well has been in operation since 2002, no effect is anticipated to threatened and endangered species that are found in the area. Based on this information, EPA is proposing a no effect finding as a result of re-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 CO20939-04673 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.