UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
UNDERGROUND INJECTION CONTROL PROGRAM

DRAFT PERMIT (RENEWAL)
CO10787-00053

Class I Non-Hazardous Waste Disposal Well
HWD-1 (Hovenweep 1)
Montezuma County, Colorado

Issued To

Kinder Morgan CO_2 Company LP
17801 U.S. Hwy 491
Cortez, Colorado 81321

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PART I. AUTHORIZATION TO CONSTRUCT AND OPERATE

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

Kinder Morgan CO_2 Company LP
17801 U.S. Hwy 491
Cortez, Colorado 81321

hereinafter referred to as the "Permittee," is authorized to operate the following Class I well:

HWD-1 (Hovenweep 1)
515' FEL & 300' FNL, Section 9, T38N, R18W
Montezuma County, Colorado

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

Where a state or tribe is not authorized to administer the UIC program under the SDWA, EPA regulates underground injection of fluids into wells so that injection does not endanger Underground Sources of Drinking Water (USDWs). EPA UIC permit conditions are based on authorities set forth at 40 CFR parts 144 and 146 and address potential impacts to USDWs. Under 40 CFR part 144, subpart D, certain conditions apply to all UIC permits and may be incorporated either expressly or by reference. Regulations specific to Colorado injection wells are found at 40 CFR § 147 Subpart G.

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

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

This Permit is issued for 10 (ten) years from the Effective Date, until it expires under the terms of the Permit, or unless modified, revoked and reissued, or terminated under 40 CFR §§ 124.5, 144.12, 144.39, 144.40 or 144.41.

Issue Date: **DRAFT** Effective Date: **DRAFT**

DRAFT

Sarah Bahrman, Chief*
Safe Drinking Water Branch

* Throughout this Permit the term "Director" refers to the Safe Drinking Water Branch Chief or the Water Enforcement Branch Chief.

PART II. SPECIFIC PERMIT CONDITIONS

Section A. WELL CONSTRUCTION REQUIREMENTS

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

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

1. Well Siting

Under 40 CFR § 146.12(a), the wells shall be sited, such that injection occurs into a formation which is beneath the lowermost formation containing, within one quarter mile of the well bore, a USDW.

2. Casing and Cement

The well or wells shall be cased and cemented to prevent the movement of fluids into or between USDWs and shall be in accordance with 40 CFR § 146.12. Remedial construction measures may be required if the well is unable to demonstrate mechanical integrity.

3. Injection Tubing and Packer

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

4. Sampling and Monitoring Devices

The Permittee shall install and maintain in good operating condition:

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

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

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

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

(d) a flow meter capable of recording instantaneous flow rate and cumulative volume attached to the injection line; and

(e) continuous recording devices to monitor injection pressure, flow rate, volume, pressure on the annulus between the tubing and the long string of casing, and the bradenhead pressure.

Section B. WELL OPERATION

1. Outermost Casing Injection Prohibition

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

2. Injection Zone and Fluid Movement

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

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

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

3. Injection Pressure Limitation

(a) Except during stimulation approved by the Director, injection pressure at the wellhead shall not exceed the MAIP which shall be calculated to assure that the pressure in the injection zone during injection 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, as measured at the surface, shall equal the formation fracture pressure (FP**)** plus friction loss, provided the pressure loss due to friction can be adequately documented through a direct measurement.

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

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

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

The values used in the equation are defined as:

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

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

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

The current permitted Maximum Allowable Injection Pressure (MAIP) is found in APPENDIX C. This MAIP is calculated using the equation above and data submitted with the permit application.

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

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

To approve an increase to the MAIP, as a result of changes to the D or FG value, 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.

4. Injection Volume Limitation

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

5. Injection Fluid Limitation

Injected fluids are limited to non-hazardous industrial fluids. The Permittee is authorized to inject field and gas plant waste streams and other associated waste streams generated at the Permittee's McElmo Dome and Doe Canyon facilities. The present list of waste stream items is limited to:

a) spent sulfamic acid (2-8%) neutralized to a pH of 5 to 9 with soda ash or baking soda. This solution will also include a surfactant, a corrosion inhibitor and ammonium bifluoride;

b) acetic acid;

c) diethanolamine (DEA);

d) coolant drain-off (50% water, 50% diethylene glycol);

e) associated treatment chemicals, (e.g., antifreeze, corrosion inhibitor, and bacteria inhibitor);

f) potassium permanganate in potable water;

g) diethylene glycol;

h) produced/processed fluids; and

i) any non-hazardous fluids associated with field and plant development, operation and maintenance.

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

6. Tubing–Casing Annulus

The tubing-casing annulus (TCA) shall be filled with a non-corrosive fluid or other fluid approved by the Director. The TCA valve shall remain closed during normal operations and the TCA pressure shall be maintained between 0 (zero) and 30 psig.

If TCA pressure cannot be achieved, the Permittee shall report to EPA the actions taken to determine the cause of the excessive pressure and the proposed remedy. If a loss of MI has been determined, the Permittee shall comply with the *Loss of Mechanical Integrity* requirements found in Part II, Section C.5.

7. Alteration, Workover, and Well Stimulation

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

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

The Permittee shall record all alterations, workovers, and well stimulations on a Well Rework Record (EPA Form 7520-19) and submit a revised well construction diagram, when the well construction has been modified. The Permittee shall provide this and any other record of well workover, logging, or test data to EPA within thirty (30) days of completion of the activity.

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

8. Well Logging and Testing

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

9. Annual Pressure Falloff Test

The Permittee must perform a pressure falloff test at least once every twelve months (40 CFR § 146.13(d)(1)). The pressure falloff test is required for Class I operations to monitor pressure buildup in the injection zone, to monitor reservoir parameters, to identify any fracturing, and to identify any boundaries within the injection formations.

The Permittee is required to prepare a plan for running the falloff test. *EPA Region 6 UIC Pressure Falloff Testing Guideline* should be used by the Permittee when developing a site-specific plan. This document can be found at: https://www.epa.gov/sites/production/files/2015-07/documents/guideline.pdf.

The test plan shall be submitted to EPA for review at least 30 days prior to conducting the initial annual pressure falloff test. Subsequent test plan is required only if it is not identical to the previous year’s plan. It is important that the initial and subsequent tests follow the same or similar test procedure, so that valid comparisons of reservoir pressure, permeability, and porosity can be made.

The report shall also compare the test results with previous years test data, unless it is the first test performed at that well. A falloff test that fails to adhere to these requirements may be subject to retest.

The Permittee shall analyze test results and provide a report with an appropriate narrative interpretation of the test results, including an estimate of reservoir parameters, information of any reservoir boundaries, and estimate of the well skin effect and reservoir flow conditions. The report shall be prepared by a knowledgeable analyst, comparing the test results with previous years test data, unless it is the first test performed for the well.

10. Well Injection and Seismicity

The U.S. Geological Survey (USGS) Earthquake Hazards Program operates an email notification service which reports real-time earthquake events for any area specified by the user. The Permittee is required to subscribe to this service, known as the Earthquake Notification Service (ENS) to monitor seismic activity within fifty (50) miles from the area permit boundary. Details for the ENS can be found at: https://earthquake.usgs.gov/ens/.

For any seismic event reported within two miles of the permit boundary, the Permittee shall immediately cease injection and report to EPA within twenty-four (24) hours according to Part III, Section E.11. Injection shall not resume until the Permittee has obtained approval to recommence injection from EPA. For any seismic event occurring between two (2) and fifty (50) miles of the permit boundary, that event will be recorded and reported to EPA on a quarterly basis.

Section C. MECHANICAL INTEGRITY

1. Requirement to Maintain Mechanical Integrity

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

An injection well has MI if:

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

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

2. Demonstration of Mechanical Integrity

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

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

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

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

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

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

3. Mechanical Integrity Test Methods and Criteria

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

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

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

4. Notification Prior to Testing

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

5. Loss of Mechanical Integrity

If the well fails to demonstrate MI during a test or a loss of MI becomes evident during operation (such as presence of pressure in the tubing-casing annulus, bradenhead annulus, water flowing at the surface, etc.), the Permittee shall notify the Director within twenty-four (24) hours (see Part III, Section D.11(e) of this Permit), cease injection and shut-in the well within forty-eight (48) hours unless the Director requires immediate shut-in.

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

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

Section D. MONITORING, RECORDKEEPING, AND REPORTING OF RESULTS

1. Monitoring Parameters and Frequency

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

Records of monitoring information shall include:

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

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

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

(d) the analytical technique or method used; and

(e) the results of such analyses.

2. Monitoring Methods

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

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

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

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

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

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

3. Records Retention

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

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

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

4. Quarterly Reports

Regardless of whether or not the well is operating, the Permittee shall submit Quarterly Reports to the Director that:

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

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

(c) includes any additional wells within the area of review that have not previously been submitted. For those wells that penetrate the injection zone, a well construction diagram, cement records and cement bond log are also required. This evaluation is only required annually and shall be submitted with the fourth quarter report.

The Quarterly Report shall cover the period from January 1 through March 31, April 1 through June 30, July 1 through September 30, and October 1 through December 31. Quarterly Reports shall be submitted by the fifteenth day of the month following the end of the data collection period. EPA Form 7520-8 may be used or adapted to submit the Quarterly Report. An electronic form may also be obtained from EPA to satisfy reporting requirements.

Section E. PLUGGING AND ABANDONMENT

1. Notification of Well Abandonment

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

2. Well Plugging Requirements

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

3. Approved Plugging and Abandonment Plan

The approved P&A Plan and required tests are incorporated into this Permit as APPENDIX E. Changes to the approved P&A Plan will be incorporated into the Permit as a modification prior to beginning plugging operations and shall be submitted using EPA Form 7520-19. The Director also may require revision of the approved P&A Plan at any time prior to plugging the well.

4. Plugging and Abandonment Report

Within sixty (60) days after plugging a well, the Permittee shall submit a report (EPA Form 7520-19) to the Regional Administrator or his/her authorized representative. The plugging report shall be certified as accurate by the person who performed the plugging operation. Such report shall consist of either:

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

or

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

5. Wells Not Actively Injecting

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

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

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

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

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

PART III. CONDITIONS APPLICABLE TO ALL PERMITS

Section A. CHANGES TO PERMIT CONDITIONS

1. Modification, Revocation and Reissuance, or Termination

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

2. Conversion to Non-UIC Well

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

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

3. Transfer of Permit

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

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

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

4. Permittee Change of Address

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

Section B. CONTINUATION OF EXPIRING PERMITS

1. Duty to Reapply

If the Permittee wishes to continue an activity regulated by this Permit after the expiration date of this Permit, the Permittee must submit a complete application for a new permit at least 180 days before this Permit expires.

2. Permit Extensions

The conditions of an expired permit continue in force in accordance with 5 U.S.C. 558(c) until the effective date of a new permit, if:

(a) The Permittee has submitted a timely application, which is a complete application for a new permit; and

(b) The Regional Administrator or his/her authorized representative, through no fault of the Permittee, does not issue a new permit with an effective date on or before the expiration date of the previous permit.

3. Enforcement

When the Permittee is not in compliance with the conditions of the expiring or expired permit, the Regional Administrator or his/her authorized representative may choose to do any or all of the following:

(a) Initiate enforcement action based upon the permit which has been continued.

(b) Issue a notice of intent to deny the new permit. If the permit is denied, the owner or operator would then be required to cease the activities authorized by the continued permit or be subject to enforcement action for operating without a permit.

(c) Issue a new permit under 40 CFR part 124 with appropriate conditions.

(d) Take other actions authorized by these regulations.

4. State or Tribal Continuation

An EPA issued permit does not continue in force beyond its expiration date under Federal law if at that time a State or Tribe has primary enforcement authority. A State or Tribe authorized to administer the UIC program may continue EPA issued permits until the effective date of the new permits, if State or Tribal law allows. Otherwise, the facility or activity is operating without a permit from the time of expiration of the old permit to the effective date of the State or Tribal-issued new permit.

Section C. SEVERABILITY

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

Section D. CONFIDENTIALITY

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

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

Section E. ADDITIONAL PERMIT REQUIREMENTS

1. Prohibition on Movement of Fluid Into a USDW

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

2. Duty to Comply

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

3. Need to Halt or Reduce Activity Not a Defense

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

4. Duty to Mitigate

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

5. Proper Operation and Maintenance

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

6. Permit Actions

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

7. Property and Private Rights; Other Laws

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

8. Duty to Provide Information

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

9. Inspection and Entry

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

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

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

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

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

10. Signatory Requirements

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

11. Reporting Requirements

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

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

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

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

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

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

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

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

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

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

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

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

(f) *Other Noncompliance.* The Permittee shall report all instances of noncompliance not reported under Paragraphs 11(a), 11(b), 11(d), or 11(e) of this Section at the time the monitoring reports are submitted. The reports shall contain the information listed in Paragraph 11(e) of this Section.

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

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

Section F. FINANCIAL RESPONSIBILITY

1. *Method of Providing Financial Responsibility*

The Permittee, including the transferor of a permit, is required to demonstrate and maintain financial responsibility and resources to close, plug, and abandon the underground injection operation in a manner prescribed by the Director until:

- The well has been plugged and abandoned in accordance with an approved plugging and abandonment plan pursuant to 40 CFR §§144.51(o) and 146.10, and the Permittee has submitted a plugging and abandonment report pursuant to 40 CFR §144.51(p); or
- The well has been converted in compliance with the requirements of 40 CFR §144.51(n); or
- The transferor of a permit has received notice from the Director that the owner or operator receiving transfer of the permit, the new Permittee, has demonstrated financial responsibility for the well.

No substitution of a demonstration of financial responsibility shall become effective until the Permittee receives notification from the Director that the alternative demonstration of financial responsibility is acceptable. The Director may, on a periodic basis, require the holder of a permit to revise the estimate of the resources needed to plug and abandon the well to reflect changes in such costs and may require the Permittee to provide a revised demonstration of financial responsibility.

2. *Types of Adequate Financial Responsibility.*

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

(a) a surety bond with a standby trust agreement,

(b) a letter of credit with a standby trust agreement,

(c) a fully funded trust agreement, or

(d) a financial test and corporate guarantee.

A standby trust agreement acceptable to the Director shall contain wording identical to model language provided to the Permittee by EPA and must accompany any surety bond or letter of credit. Annual reports from the financial institution managing the standby trust account shall be submitted to the Director showing the available account balance.

A surety bond acceptable to the Director shall contain wording identical to model language provided to the Permittee by EPA and shall be issued by a surety bonding company found to be acceptable to the U.S. Department of Treasury, which can be determined by review of that Department's Circular #570, currently available on the internet at https://fiscal.treasury.gov/surety-bonds/circular-570.html.

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

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

An independently audited financial test with a corporate guarantee acceptable to the Director shall contain wording identical to model language provided to the Permittee by EPA and shall demonstrate that the Permittee meets or exceeds certain financial ratios. The Permittee must meet EPA's requirements including, but not limited to, total net worth to be able to use this method. If this financial instrument is used, it must be resubmitted annually, within ninety (90) calendar days after the close of the Permittee's fiscal year, using the financial data available from the most recent fiscal year. If at any time the Permittee does not meet the financial ratios, notice to EPA must be provided within 90 days and a new demonstration of financial responsibility must be submitted within 120 days.

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

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

3. Determining How Much Coverage is Needed

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

4. Insolvency

In the event of:

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

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

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

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

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

APPENDIX A

WELL CONSTRUCTION REQUIREMENTS

The well(s) shall be cased and cemented to prevent the movement of fluids into or between USDWs, and in accordance with 40 CFR § 146.12 and other applicable federal, state or local laws and regulations. General requirements include:

- The well shall be completed with injection tubing set on at least one packer.
- The uppermost packer must be set within 130 feet of the top of the injection zone at 8220 feet.

WELL CONSTRUCTION:

HWD-1 well, API No. 05-083-06240
Non-Hazardous Water Disposal Well
300 feet from the south line & 515 feet from the east line
Section 9, Township 37 North, Range 18 West
Montezuma County, Colorado

Operator Name: Kinder Morgan CO_2 Company
Elevation: 6889 ft.
Measured TD: 8583 ft.
Measured PBTD: 8535 ft.
Top of Cement: 4845 ft.

CASING OR OTHER EQUIPMENT TYPE	HOLE SIZE, in.	CASING SIZE, in.	CASING LENGTH, ft.	CEMENTED INTERVAL ft.
Conductor	17-1/2	13-3/8	surface to 50	surface to 50
Surface	12 ¼	9-5/8	Surface to 2873	Surface to 2873
Production	8 ¾	7	Surface to 8020	4845 - 8020
Liner	6-1/8	4 ½	7827 - 8581	7827 - 8581
Squeezed Perforations Depths, ft.	8298-8300; 8326-8332; 8336-8348; 8354-8370; 8386-8442; 8444-8448			
Open Perforations Depths, ft.	8480 – 8534			
Packer Depth, ft	8090			

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

INJECTION WELL CONSTRUCTION DIAGRAM

Current Well Schematic for HWD-1

Well Name: Hovenweep Water Disposal 1 (HWD-1) **Original Name:** *Yellow Jacket #2*
Pilot API # : 05-083-06240-00
S/T API # : N/A
Section: 26 **Township** 28N **Range** 18W
Surface Hole: 300' FSL, 515' FEL Section 9, T38N R18W NMPM KB Elevation: 6,889 ft. (GL: 6,877 ft.)

Spud Date: 11/21/1978
Pilot Completion Date: 1/16/1979
S/T Completion Date: N/A

FILE: HWD-1 Schematic 2018 v2 - Updated:10/31/18 WEA

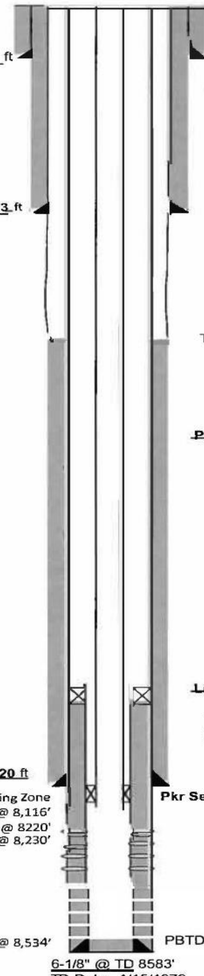
Conductor Casing
Size 13-3/8 in
Set at 50 ft

Surface Casing
Size 9-5/8 in
Set at 2873 ft
Wt. 36 ppf Grade K-55 from surface to 2520 ft
Wt. 30 ppf Grade K-55 from 2520 to 2873 ft
Hole Size 12-1/4 in
Est. T.O.C. surface ft

Production Casing
Size 7 in
Wt. 23 ppf Grade K-55 from surface to 291 ft
Wt. 23 ppf Grade N-80 from 291 to 5349 ft
Wt. 29 ppf Grade S-95 from 5349 to 8020 ft
Hole Size 8-3/4 in
Est. T.O.C. 4845 ft

Tubing (Run Date: 3/13/86)	Top	Bottom
KB	0	22
TUBING HANGER	22	23
PUP JT 3.5" IPC 8RD 9.3# J-55 TBG	23	25
X/O SUB 3.5" X 2.875" 8RD IPC TBG	25	26
1 JTS 2.875" IPC 8RD 6.5# J-55 TBG	26	56
1 JT 10' Sub 2.875" (10')	56	66
256 JTS 2.875" IPC 8RD 6.5# J-55 TBG	66	7785
X/O SUB 2.875" 8RD X HYDRIL A-95 TBG (13CR)	7785	7786
BAKER ON/OFF TOOL 2.312" ID "FL"	7786	7788
10 JTS 2.375"13CR 8RD J-55 4.7# TBG	7788	8089
X/O SUB 2.375" 8RD X 2.375" HYDRIL TBG	8089	8090
BAKER A-3 LOK-SET PACKER (2.44" ID)	**8090**	**8094**
PUP JT 2.375" L-80 4.7# HYDRIL TBG	8094	8104
BAKER "F" NIPPLE 1.81" HYDRIL	8104	8105
SLOTTED JT 2.375" L-80 4.7# HYDRIL TBG	8105	8136
JT 2.375" L-80 4.7# HYDRIL TBG	8136	8167
"R" NIPPLE 1.81" HYDRIL	8167	8168
WL REENTRY GUIDE HYDRIL	8168	8169

Production Liner
Size 4-1/2 in
Wt. 11.6 ppf Grade K-55 from 7827 to 8581 ft



Conductor Pipe Cement:
Cemented with ready-mix to surface

Surface Casing Cement:
Date Cemented: 1979
Lead: 600 sx Howco Lt. Wt. Cmt, w/ 1/4# flocele, 2% CaCl,
Tail: 200 sx Class D Cmt, w/ 2% CaCl
Note: Circulated 150 sxs to surface

Production Casing Cement:
Date Cemented: 1/7/1979
Lead: 600 sx Howco Lt. Wt. Cmt, w/ 18# salt, 1/4# FC
Tail: 350 sx Class B Cmt, w/ 18# salt, 1/4# FC, 2% CaCl
Note: TOC @ 4,845 ft. from CBL (7-3-84)

Liner Cement:
Date Cemented: 1/16/1979
Lead: 150 SXS Howco Class B
Note: w/ 1% CFR2 + .25% FC

Perf Intervals	Status
8298 - 8448 ft.	squeezed
8480 - 8534 ft.	OPEN

Completion Activity
2/5/1979 - Perferated Liner with 2 JSPF 8444-8448 (10 shots)
2/7/1979- Acidized perforations (8444'-8448') w/ 1000 gal 15% HCL
2/11/1979 - Acidized perforations (8444'-8448') w/ 500 gal 15% HCL
2/17/1979 - Perforated with 1 shot every other foot (49 Shots Total)
2/17/1979 (cont) - intervals 8442-8386, 8354-8370, 8336-8348, 8326-8332
2/18/1979 - Acidized perforations w/ 10,000 gal 15% HCL +100 RCN Ball Sealers
11/11/1983 - Cmt retainer set @ 8030', Pump 150 sxs Class H w/ 0.6% Halad-9
11/22/1983 - Perforated liner with 4 JSPF from 8480' to 8534' (216 Shots)
11/30/1983 - Acidize perforations (8480'-8534') with 100 gal 15% HCl
12/1/83 - Acidize perforations (8480'-8534') with 4200 gal 15% HCl

NOT TO SCALE - Schematic Only

APPENDIX B

LOGGING AND TESTING REQUIREMENTS

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

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

LOGS AND TESTS

TYPE OF LOG OR TEST	DATE DUE
Well logs and test results shall be submitted to the Director within sixty (60) calendar days of completion of the logging or testing activity.	
Injectate Water Analysis A representative water sample of the injectate shall be analyzed for the constituents found in APPENDIX D. **A representative sample shall be obtained at a location nearest the point of injection.**	1. Quarterly 2. Prior to the introduction of a new source
Injection Zone Water Quality Information Devonian Elbert and Cambrian Formations (water quality data from the nearby MWD-1 wells or alternative representative data).	1. Within sixty (60) days following the effective date of the Final Permit for the HWD-1 well. 2. Within sixty (60) days following the completion and/or addition of perforations to the Devonian Elbert and/or Cambrian Formations in the HWD-1, if such construction should occur in the future.
Sump Tank Sample & Analysis Obtain a sample from the sump drain. Analyze the sample for • Reactivity, Corrosivity, Ignitability (RCI) • Volatile Organic Compounds (VOCs) via the Toxicity Characteristic Leaching Procedure (TCLP) Method 1311 • Semi-volatile Organic Compounds (SVOCs) via TCLP Method 1311 • RCRA 8 metals: • Additional Metals: Arsenic, Barium, Cadmium, Chromium, Lead, Selenium, Mercury and Silver	Perform within one hundred eighty (180) days of the effective date of this permit.

Injection Zone Interpretation of Logs A summary of interpretations of available well logs to refine the estimated bottom and top of the Devonian Elbert Formation and Undifferentiated Cambrian Formation(s) described in Appendix C.	Within sixty (60) days following the effective date of the Final Permit for the HWD-1 well.
Standard Annulus Pressure (internal Part I MI) If the well has not received authorization to inject and does not have tubing installed, in lieu of the Standard Annulus Pressure test, a Casing Pressure Test can be performed.	1. Prior to recommencing injection after any well rework that compromises the internal mechanical integrity of the well or a loss of MI. 2. At least once every five (5) years after the last successful demonstration of internal (Part I) Mechanical Integrity.
Surface and Production Casing and Cemented Liner Cement Evaluation Logs (CBL or CET) The log shall cover the area of the cementing to verify the adequacy and location of the cement placement.	Shall be performed within sixty (60) days after the completion of any workover involving remedial cementing. Not required for surface casing.
Temperature Log (external Part II MI)	Subsequent logs will be repeated no less than five (5) years after the last successful external (Part II) MI demonstration.
Step Rate Test Perform with both surface pressure and bottom hole pressure gauges. Obtain friction loss estimate. Pressures tested should range between near 0 psig up to approximately 1000 psig or an alternate pressure approved by the Director.	Shall be performed in 2021 at the time the annual 2021 Pressure Falloff Test is scheduled.
Pressure Falloff Test A report shall be provided with appropriate narrative interpretation, including an estimate of reservoir parameters, information of any reservoir boundaries, and estimate of the well skin effect and reservoir flow conditions. Refer to Part II.10. Annual Pressure Fall-off Test for additional requirements.	At least once every twelve (12) months. Subsequent years' test plans, if different than the previous year's plan, shall be submitted for review at least 30 days prior to conducting the annual pressure fall-off test.

APPENDIX C

OPERATING REQUIREMENTS

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

APPROVED INJECTION ZONE (GL, ft.)

FORMATION NAME or STRATIGRAPHIC UNIT	TOP (ft.) *	BOTTOM (ft.) *
Leadville - Ouray	8220	8630
Devonian Elbert	8630	8980
Cambrian	8980	9400

*estimated top and bottom depths of formations. These depths may be adjusted following the receipt of well interpretation data required in Appendix B.

MAXIMUM ALLOWABLE INJECTION PRESSURE:

The parameters below are the values used to calculate the initial authorized MAIP issued with this Permit. These parameters may be updated throughout the life of well, pursuant to the conditions and formula at Part II.B.4 of this Permit. Documentation to support a change shall be provided and approved by the Director prior to recalculation of the MAIP.

MAIP Parameters

fracture gradient	specific gravity*	depth (ft.)	friction loss (PSI)	Calculated MAIP (PSI)	**Authorized MAIP (PSI)**
0.56	1.010	8220	NA	856	856

**From the MAIP equation in Part II, Section B.4(b), SG+0.05*

MAXIMUM INJECTION VOLUME:

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

APPENDIX D

MONITORING, AND REPORTING PARAMETERS

MONITORING, AND REPORTING PARAMETERS

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

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

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

<table>
<tr><td colspan="2">PRIOR TO INTRODUCTION OF A NEW SOURCE AND
QUARTERLY (if injection occurred during reporting period)
Analytical methods used must comply with the methods cited in Table 1 of 40 CFR 136.3, Appendix II of 40 CFR 261, or those methods listed below.</td></tr>
<tr><td>ANALYZE</td><td>Analyze a sample of injection fluids for the following constituents:
• Total Dissolved Solids (mg/L) via Method 2540 C-97
• pH via Method 4500-H+ B-00
• Specific gravity via Method SM 2710 F
• Conductivity/Specific Conductance (S/m) via Method 2510 B-97
• Corrosivity Index (Langelier Saturation Index)
• Nitrate (as N) (mg/L)
• Nitrite (as N) (mg/L)
• Cations: Na, Fe, Mg, Ca (mg/L)
• Anions: Cl and SO_4 (mg/L)
• Strontium (mg/L)
• Gross Alpha and Beta Radiation (pCi/L) via Method 900.0
• Uranium-234 and Uranium-238 (pCi/L) via Method 907.0
• Radium-226 (pCi/L) via Method 903.0
• Radium-228 (pCi/L) via Method 904.0
• Potassium-40 (pCi/L) via Method 901.1
• Barium (mg/L)
• Chromium (mg/L)
• Nitrite + Nitrate (as N) (mg/L)
• Total Alkalinity
Alternative analysis methods may be used, if pre-approved.</td></tr>
</table>

QUARTERLY	
REPORT	Each month’s minimum, maximum and average injection tubing pressures (psi)
	Each month’s minimum, maximum and average annulus pressures (psi)
	Each month’s minimum, maximum and average bradenhead pressures (psi)
	Each month’s minimum, maximum and average injection rate (bbl/day)
	Each month’s injected volume (bbl)
	Fluid volume injected since the well began injecting (bbl)
	Written results of quarterly injected fluid analysis
	Sources of all fluids injected during the year, including any wellfield and formation, noting any major changes in characteristics of injected fluid.
	Summary of monthly reviews of seismic event(s), within a fifty (50) mile radius of the area permit boundary, gathered from the USGS Earthquake Hazard Program website or personal communication.

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

APPENDIX E

PLUGGING AND ABANDONMENT (P&A) REQUIREMENTS

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

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

At a minimum, the following plugs are required:

1. **PLUG NO. 1:** (Leadville interval, 7" shoe, and 4.5" liner top, 7777 ft. - 8430 ft.) – **Isolate the Injection Zone**: Remove down hole apparatus from the well and perform necessary clean out; displace well fluid with plugging gel.

Squeeze injection zone perforations. Set a 4.5" cast iron bridge plug (CIBP) or Cement Retainer (CR) at approximately 8430 ft. Set a cement plug atop of the CIBP or CR to at least 7777 ft.

2. **PLUG NO. 2:** (Paradox Salt and Desert Creek tops, 5956 ft. - 6180 ft.) – Set a balanced plug at a minimum from 5956 ft. to 6180 ft.

3. **PLUG NO. 3:** (Hermosa top, 4432 ft. – 4532 ft.) – Set a balanced plug at a minimum from 4432 ft. to 4532 ft. inside and behind the long string casing.

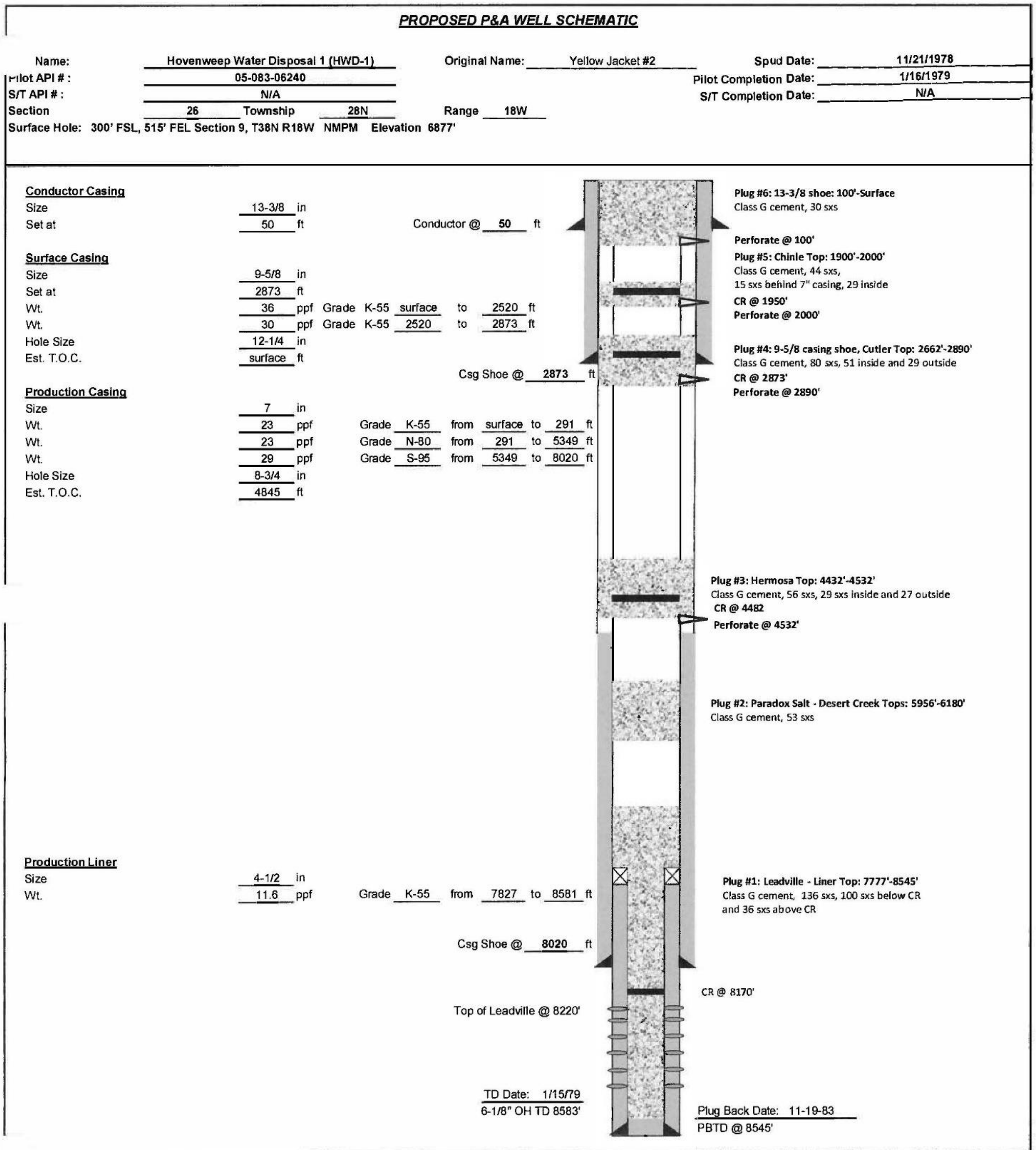
4. **PLUG NO. 4:** (Cutler top, 2662 ft. - 2890 ft., 9.625" shoe) – **Isolate Shallow USDWs from the Injection Zone**: Set a 7" cement retainer at approximately 2873 ft. Set a cement plug above the retainer at a minimum from 2662 ft. to 2873 ft. Set a cement plug below the retainer at a minimum from 2873 ft. and 2890 ft. Squeeze cement behind 7" casing from at least 2662 ft. to 2890 ft.

5. **PLUG NO. 5:** (Chinle top, 1900 ft. - 2000 ft.) – Set a 7" cement retainer at approximately 1950 ft. Set a cement plug above the retainer at a minimum from 1900 ft. to 1950 ft. Set a cement plug below the retainer at a minimum from 1950 ft. to 2000 ft. Squeeze cement behind the 7" casing from at least 1900 ft. to 2000 ft.

6. **PLUG NO. 6:** (Surface - 100 ft., 13.375" shoe) – **Isolate Surface Fluid Migration Paths**: Set a cement plug at a minimum from 0 to 100 ft. Squeeze cement behind casing from at least the surface to 100 ft.

Cut off the wellhead below the surface casing. Install P&A marker .

INJECTION WELL P&A DIAGRAM



Proposed Well Completion Schematic After Plugging and Abandonment

APPENDIX F

CORRECTIVE ACTION PLAN

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