UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
UNDERGROUND INJECTION CONTROL PROGRAM

DRAFT AREA PERMIT
CO12143-00000

Class I Non-Hazardous Waste Disposal Well
East Cherry Creek Valley Area Permit
Adams County, Colorado

Issued To

East Cherry Creek Valley Water & Sanitation District
6201 South Gun Club Road
Aurora, Colorado 80016

TABLE OF CONTENTS

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),

East Cherry Creek Valley Water & Sanitation District
6201 South Gun Club Road
Aurora, Colorado 80016

hereinafter referred to as the "Permittee," is authorized to construct and operate the following Class I wells located in Adams County, Colorado:

CO12143-08425
ECCV DI-1
649' FWL & 517' FSL, S1, T1S, R66W

CO12143-08426
ECCV DI-2
51' FEL & 610' FNL, S1, T1S, R66W

CO12143-08427
ECCV DI-3
TBD

located wholly within the area permit boundary as shown in Appendix A-1 and described by (commencing from the northeast corner and continuing clockwise):

190 feet FNL, 650 feet FWL, S6, T1S, R65W
1080 feet FNL, 1510 feet FWL, S12, T1S, R66W
2180 feet FNL, 1510 feet FWL, S12, T1S, R66W
2180 feet FNL, 0 feet FWL, S12, T1S, R66W
2900 feet FNL, 775 feet FEL, S11, T1S, R66W
2690 feet FNL, 960 feet FEL, S11, T1S, R66W
1890 feet FNL, 0 feet FEL, S11, T1S, R66W
640 feet FSL, 0 feet FWL, S1, T1S, R66W
190 feet FNL, 0 feet FEL, S1, T1S, R66W

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, the EPA regulates underground injection of fluids into wells so that injection does not endanger Underground Sources of Drinking Water (USDWs). The EPA UIC permit conditions are based on authorities set forth at 40 CFR parts 144 and 146 and address potential impacts to USDWs. Under 40 CFR part 144, subpart D, certain conditions apply to all UIC permits and may be incorporated either expressly or by reference. 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 Regional Administrator or an authorized representative in either the Water Division or the Enforcement and Compliance Assurance Division.

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 plans are incorporated into this Permit as APPENDIX A. Changes to the approved construction plans prior to authorization to inject 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.

All wells in the area permit must be located wholly within the area permit boundary described in Part I. Authorization to Construct and Operate.

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);
- (iii) on the surface casing-production casing annulus (bradenhead); and

(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.

5. Pre-Injection Logs and Tests

Well logging and testing requirements prior to receiving authorization to inject are found in APPENDIX B. Well logs and tests shall be performed according to current EPA-approved procedures, or alternate procedures approved by the Director. The Director may stipulate specific test methods and criteria best suited for a specific well construction and injection operation. Limited injection is permissible prior to receiving authorization to inject only for the purposes of conducting the initial well logs and tests required in APPENDIX B.

6. Postponement of Construction to Injection Wells

For wells that have begun construction, if authorization to inject has not been provided within two years of spud date, the Permittee is subject to the conditions found in Part II, Section E.5. *Wells Not Actively Injecting* or may elect to convert the well to a non-UIC well found in Part III, Section A.2 *Conversion to Non-UIC Well.*

Section B. WELL OPERATION

1. Outermost Casing Injection Prohibition

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

2. Requirements Prior to Receiving Authorization to Inject

Well injection may commence only after all well construction and pre-injection requirements have been met and a written authorization to commence injection has been obtained from the Director.

In order to obtain written authorization to inject, the following must be satisfied:

(a) The Permittee has:

(i). submitted to the Director a notice of completion of construction and a completed EPA Form 7520-18 and required attachments. If the well construction is different than the approved construction found in APPENDIX A, the Permittee shall also provide a revised well diagram and a description of the modification to the well construction;

(ii). conducted all applicable logging and testing requirements found in APPENDIX B and submitted required records to the Director. The logging and testing requirements include demonstration of mechanical integrity pursuant to 40 CFR § 146.8, in accordance with the conditions found in Part II, Section C of this permit; and

(iii). satisfied requirements for corrective action in APPENDIX F, if applicable.

(b) The Director has received and reviewed the documentation associated with the requirements in Paragraph 2(a) of this section and finds it is in compliance with the conditions of the Permit.

(c) The Director has inspected the injection well and finds it is in compliance with the conditions of the Permit. If the Permittee has not received notice from the Director of his or her intent to inspect the injection well within 13 days of the date of the notice in Paragraph 2(a)(i) above, then prior inspection is waived.

3. 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.

4. *Injection Pressure Limitation*

(a) Except during stimulation, injection pressure at the wellhead shall not exceed the MAIP which shall be calculated to assure that the pressure in the injection zone 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 values, the Director may also require an external (Part II) mechanical integrity demonstration at the increased MAIP.

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

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

5. *Injection Volume Limitation*

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

6. Injection Fluid Limitation

Approved injected fluids are limited to non-hazardous waste fluid generated by the East Cherry Creek Valley Water and Sanitation District from their reverse osmosis plant and products injected for well workover and maintenance of the wells.

7. 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 the lesser of either 100 psi or 10 percent of the tubing pressure.

If TCA pressure cannot be achieved, the Permittee shall report to the 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.

8. 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 the 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.

9. 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.

10. 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 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.

11. 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 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. All seismic event within fifty miles of the permit boundary shall be recorded and reported to EPA on a quarterly basis, as specified in APPENDIX D.

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:

1. 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.
2. 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 results 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 the 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 the 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 the EPA to witness the MIT or the 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, 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, 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; 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 the 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.

Section F. CONSTRUCTION NOTIFICATION REQUIREMENTS FOR ECCV DI-3

The Permittee may construct and operate ECCV DI-3 within the permitted area, provided that all conditions as set forth in the permit are met. Additional requirements beyond those described in this Permit may be required.

Prior to construction of ECCV DI-3, the Permittee shall submit a plan consisting of:

(a) Final well location and suitability of proposed location. This would include a summary of DI-1 and DI-2 injection volumes and analysis of pressure interference from these wells.

(b) If different from the approved well construction plan in APPENDIX A, a well schematic and construction details to meet the well construction requirements described in Section A of this Permit;

(c) If different from the approved plugging and abandonment plan in APPENDIX E, submit a completed EPA Form 7520-14 injection well plugging and abandonment plan that includes a well schematic and description of type, number, and placement of the plugs and method used to place the plugs. The plan should demonstrate adequate protection of USDWs;

(d) A topographic map extending to at least ¼-mile radius Area of Review (AOR) from the well and information on all wells within a 1/4 mile of the injection well location. If an AOR review well penetrates the confining zone and has not been previously identified, this information shall also include the completion report including casing and cementing details, CBL (if available), depths to top and bottom of any USDWs, formation depths, and P&A record (if applicable); and

(e) Demonstration of financial responsibility and resources to close, plug, and abandon the well.

The plan must first be approved by the Director and the Permittee shall not begin construction or conversion of the well until after receiving written authorization from the Director.

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 the 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 the 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, the 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 includes effective performance, adequate funding, adequate operator staffing and training, and adequate laboratory and process controls, including appropriate quality assurance procedures. This provision requires the operation of back-up or auxiliary facilities or similar systems only when necessary to achieve compliance with the conditions of this Permit.

6. Permit Actions

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

7. Property 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 the EPA:

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

All correspondence should reference the well name and location and include the 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 the EPA Region 8 Emergency Operations Center at (303) 293-1788.

In addition, a follow up written report shall be provided to the Director within five (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 the 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 the 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 the 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 the 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 the EPA and shall demonstrate that the Permittee meets or exceeds certain financial ratios. The Permittee must meet the 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 the 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-W-SD
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

PERMIT AREA & WELL CONSTRUCTION REQUIREMENTS

PERMIT AREA

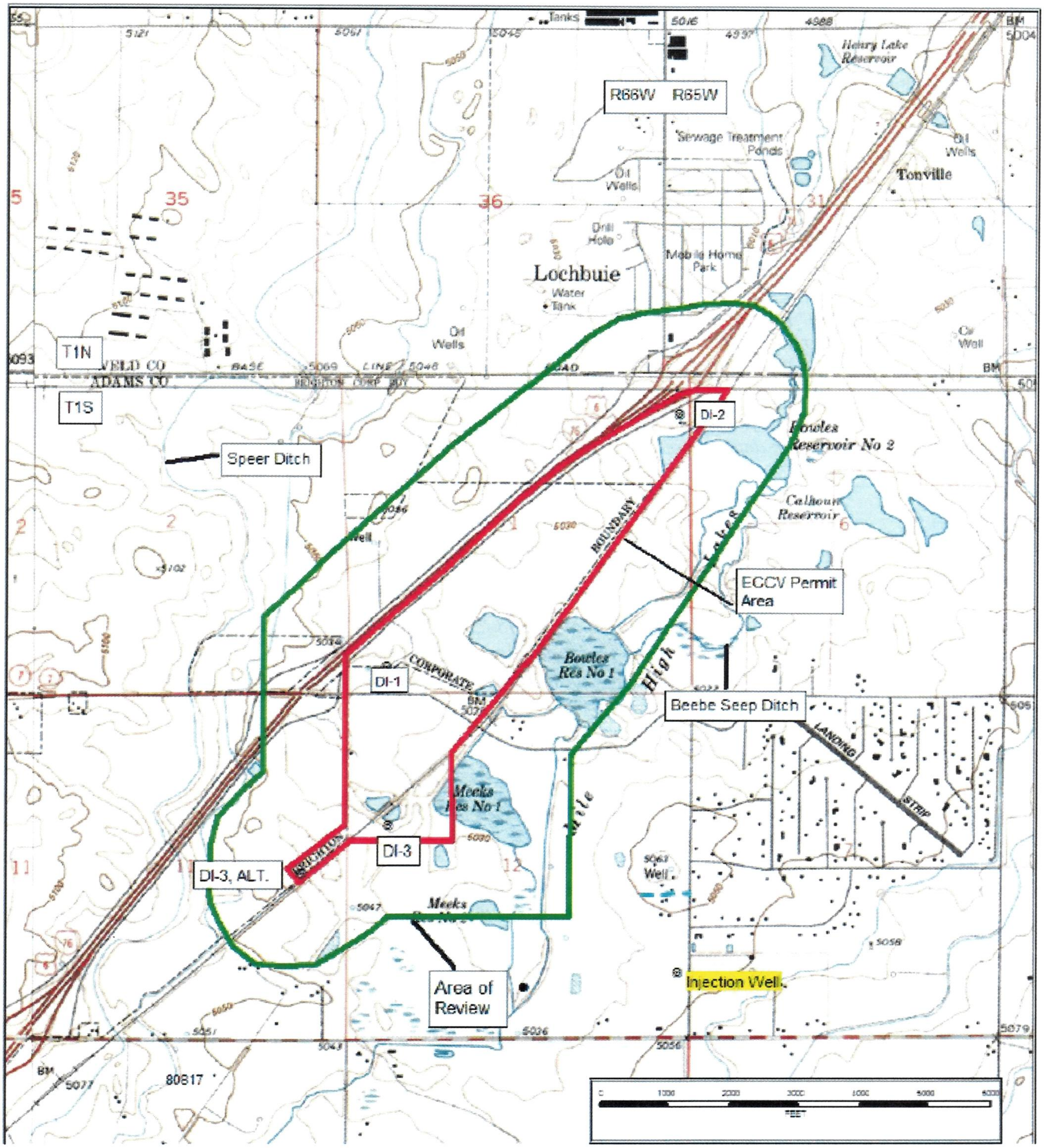


Figure A-1

WELL CONSTRUCTION REQUIREMENTS

All wells 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 at least two cemented casing strings set within a drilled hole.
- Cemented casing shall be cemented from the casing shoe to the surface and care shall be taken to maximize cement fill and bond in the annulus behind the casing.
- The casing and cement used in the construction of the well shall be designed for the life expectancy of the well, including the natural and applied pressures expected during the life of the well.
- When drilling the surface hole, unless waived by the Director, air or mud made with water containing no additives and no more than 3,000 mg/L TDS shall be used. At no time shall the permittee conduct any activity that endangers any USDW, as prohibited by 40 CFR § 144.12.
- The well shall be completed with injection tubing set on at least one packer.
- The uppermost packer must be set within 100 feet of the uppermost open perforation.

The well construction plans for DI-1 and DI-2 have been approved. Either plan is approved the for DI-3 well. The casing, tubing and liner weight, grades, and sizes may be modified with Director approval prior to well construction. The depths of the well, will vary based on the geology found at the DI-3 location. A final well construction diagram shall be provided with updated depths, prior to authorization to inject.

Multi-stage cementing is not required; however, demonstration of competent cement must be shown prior to authorization to inject. If such demonstration cannot be made, remedial cement or additional monitoring may be required.

DI-1

Surface Casing: A 9-5/8" 36# J-55 STC casing set at a depth of 1,473' (Laramie-Fox Hills) in a 12-1/4" hole and cemented to surface with 875 sx 15.8#/gal. Class G + 2%Ca.

Production Casing: A 7" 26# N-80 LTC casing set at 10,248 feet in an 8-3/4" hole and cemented to surface in three stages. The first stage involved 456 sx of 15.8#gal. Class G cemented to DV tool set at 7,750'. The second stage above the DV tool included 920 sx of 11.0#/gal., 415 sx 15.8#/gal. Class G to DV tool set at 2,382'. 3rd stage cement to surface with 739 sx 15.3#/gal. Class G.

Tubing Packer: The packer is set at 9,052' with a 4-1/2" 11.6# tubing N-80 LTC R3 Internal Coating TK-805.

The current well construction, including perforations are show in Figure A-2.

DI-2

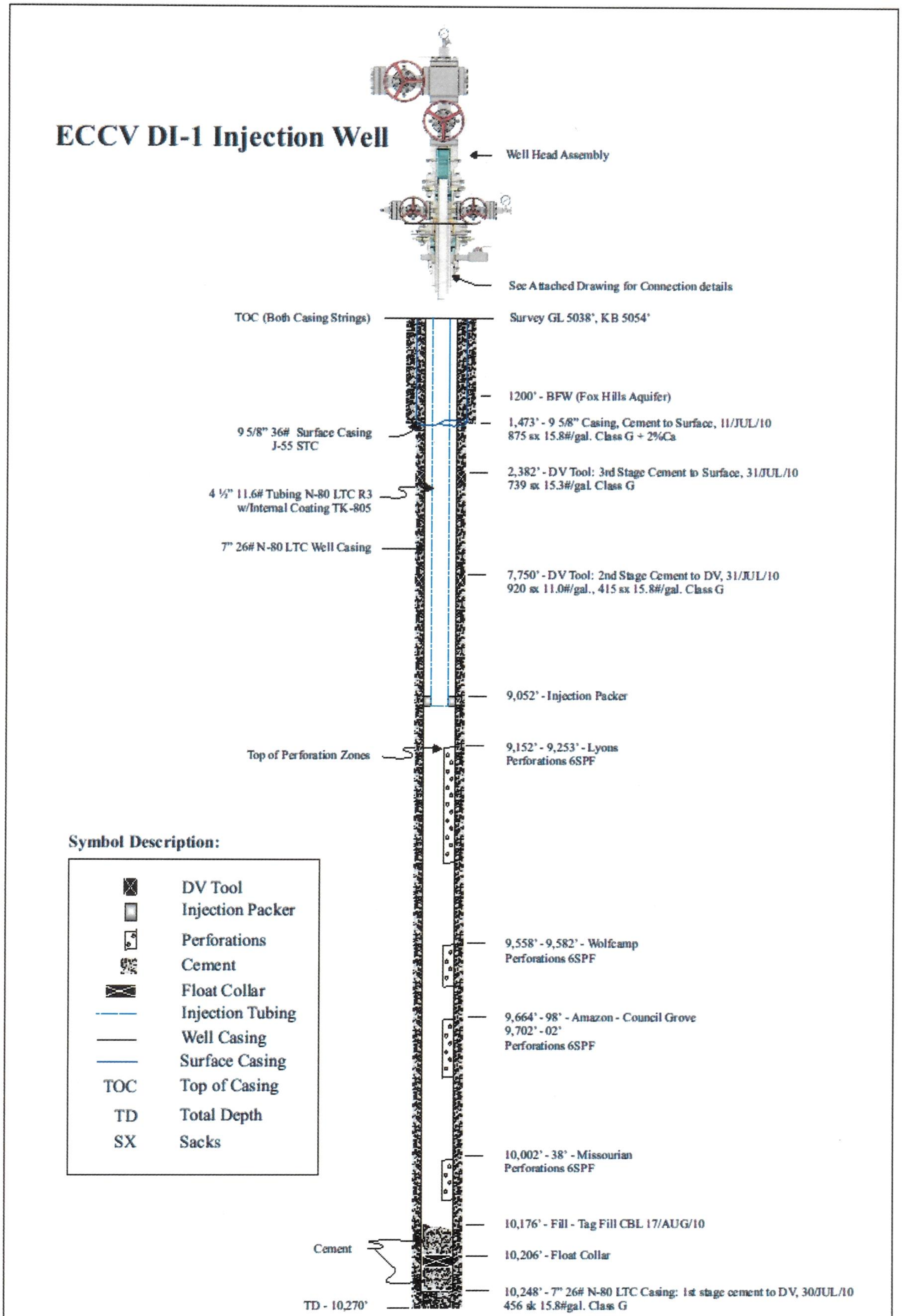
Surface Casing: A 10-3/4", 40.5# J-55 STC casing set at a depth of 1,743' (Laramie-Fox Hills) in a 14-3/4" hole and cemented to surface with 670 SX 13.5# Swift Cement, 110 SX 14.2# Swift Cement.

Production Casing: A 7-5/8" 26.4# P-110 LTC casing set at 9,071' in an 9-7/8" hole and cemented to surface in three stages. The first stage involved 302 SX 13.8# ExpandaCem cemented to DV tool set at 7,714'. The second stage above the DV tool included 1,900 SX 13.2# Elasticem, 90 SX 15.8# Halcem to DV tool set at 2,374'. 3rd Stage cement to surface with 670 SX 13.5# Swift Cement, 110 SX 14.2# Swift Cement.

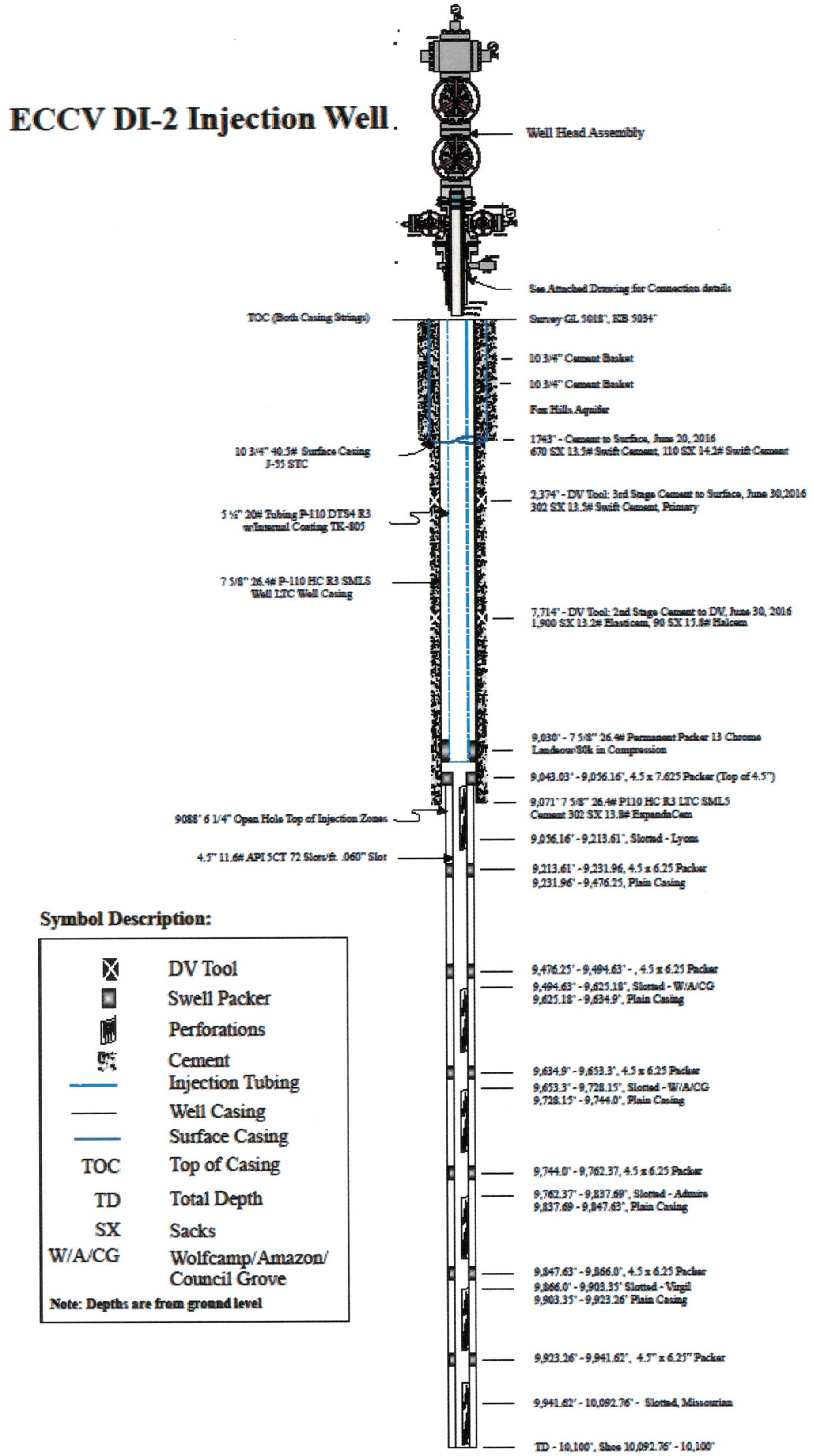
Tubing Packer: The packer is set at 9,031' with a 5-1/2" 20# tubing N-80 LTC R3 Internal Coating TK-805.

Slotted Liner: From 9,071' to 10,100', a borehole with diameter 6-1/4" was drilled to accommodate a 4.5" 11.6# API 5CT 72 Slots/ft. .060" slotted liner.

The current well construction, including locations of the slotted casing are show in Figure A-3.



Hydro Resources - Rocky Mountain, Inc.	Client: East Cherry Creek Valley WSD	View: Elevation Drawing (As Built)
Job #RKYR00652	Project: ECCV DI-1 Injection Well	Description: Not to Scale
Date: 10/21/10	Drawing By: Randy Parsons	Figure A-2



Hydro Resources - Rocky Mountain, Inc. Job #RKYR03808	Client: East Cherry Creek Valley WSD	View: Elevation Drawing R4 (As Built)
	Project: ECCV DI - 2 Injection Well	
Date: 11/08/16	Drawing By: Randy Parsons	Not to Scale Figure A-3

APPENDIX B

LOGGING AND TESTING REQUIREMENTS

Well logging and tests shall be performed according to the 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.	Annually
Injection Zone Water Sample A representative water sample from each discrete injection zone shall be analyzed. After a minimum of three successive pore volumes, a representative sample shall be determined by stabilized specific conductivity. The sampling procedure should follow immediately after perforating an interval in order to prevent wellbore fluids from contaminating the naturally occurring injection formation water.	1. Prior to receiving Authorization to Inject (DI-3) 2. Prior to injection into any new formation not previously sampled after Authorization to Inject has been provided.
Injection Formation Fluid Pressure	Prior to receiving Authorization to Inject (DI-3)
Mud logging record	Prior to receiving Authorization to Inject (DI-3)
Caliper, Resistivity, Spontaneous Potential, Gamma Ray, and any combination of logs to provide formation porosity The logs shall provide information from ground level to total depth.	Prior to receiving Authorization to Inject (DI-3)
Deviation Checks	Prior to receiving Authorization to Inject (DI-3)
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.	1. Prior to receiving Authorization to Inject (DI-3) 2. Shall be performed within sixty (60) days after the completion of any workover involving remedial cementing. Not required for surface casing.

Cement Records	Prior to receiving Authorization to Inject (DI-3)
Step Rate Test (SRT) The SRT shall be performed following current EPA guidance. The SRT shall be conducted with both surface and bottom-hole pressure gauges. This requirement may be waived with a written approval from the Director.	1. Prior to receiving Authorization to Inject (DI-3) 2. Prior to approval of new fracture gradient value to calculate MAIP.
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 receiving Authorization to Inject. (DI-3) 2. Prior to recommencing injection after any well rework that compromises the internal mechanical integrity of the well or a loss of MI. 3. At least once every five (5) years after the last successful demonstration of internal (Part I) Mechanical Integrity.
Radioactive Tracer Survey (RTS) ECCV DI-2	If ECCV requests a MAIP greater than 2982 psi, a RTS at the higher requested MAIP will be required.
Radioactive Tracer Survey (RTS) If the Director's review of the cement bond log does not show 80% bond index, an RTS is required. ECCV DI-3	1. Prior to receiving Authorization to Inject
Temperature Log (external Part II MI) ECCV DI-1	1. Logs will be repeated no less than five (5) years after the last successful external (Part II) MI demonstration.
Temperature Log (external Part II MI) ECCV DI-2	1. Logs will be repeated no less than three (3) years after the last successful external (Part II) MI demonstration.
Temperature Log (external Part II MI) ECCV DI-3 (1 through 3 are applicable)	1. Baseline temperature log required prior to receiving Authorization to Inject. 2. Initial temperature log will be conducted between 6 to 12 months after Authorization to Inject. 3. Subsequent logs will be repeated no less than five (5) years after the last successful external (Part II) MI demonstration.
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.	First test shall be run 6 to12 months after Authorization to Inject. Subsequent tests shall be conducted at least once every year thereafter. The test plan, if different than the previous years' 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.) *
Lyons	9,150	9,268
L. Satanka	9,268	9,525
Wolfcamp	9,525	9,663
Amazon	9,663	9,702
Council Grove	9,702	9,758
Admire	9,802	9,934
Virgil	9,934	10,002
Missouri(an)	10,002	10,220

* formation top and bottom depths at the ECCV DI-1 well

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.

ECCV well	fracture gradient*	specific gravity**	depth (ft)	friction loss (PSI)	Calculated MAIP (PSI)	**Authorized MAIP (PSI)**
DI-1	0.559	1.000 [+ 0.05]	9150	1800	2755	2755
DI-2	0.559	1.000 [+ 0.05]	9056	1800	2745	2745
DI-3***	0.559	1.000 [+ 0.05]	9056	1800	2745	2745

**The fracture gradient listed here is for the uppermost Lyons formation.*
***From the MAIP equation in Part II, Section B.4(b), SG+0.05 or 1.050.*
****The DI-3 well has not been drilled. The initial MAIP is estimated based on DI-2 parameters.*

Note: The CBL for DI-2 did not demonstrate adequate cement bond. Should ECCV run an additional SRT for DI-2 to increase their authorized MAIP, the highest MAIP is limited to 2982 psi (pressure at which the initial RATS was conducted), unless an additional RATS or approved test is run at the higher MAIP.

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.

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

APPENDIX D

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 the 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)

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.	
ANALYZE	Analyze a sample of injection fluids for the following constituents: • Total Dissolved Solids (mg/L) • Total Suspended Solids (mg/L) • pH • Specific gravity • Conductivity/Specific Conductance (S/m) • Corrosivity Index (Langelier Saturation Index) • Nitrate (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 Alternative analysis methods may be used, if pre-approved.

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 annual 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/liter difference of TDS between individual exposed USDWs, they must be isolated from each other.

At a minimum, the following plugs are required (Figure E-1 and E-2):

PLUG NO. 1: Set a cement retainer at most 50 feet above permanent packer. Squeeze sufficient quantity of cement through the retainer to squeeze the perforations and plug the well from the base of the well to the cement retainer. Place a minimum of 100 feet of cement on top of cement retainer. This must extend a minimum 50 feet above the base of the Lykins confining zone.

PLUG NO. 2: Set a minimum 100' balanced plug across the lowermost DV tool.

PLUG NO. 3: Set a minimum 100' balanced plug across the surface casing.

PLUG NO. 4: Set a minimum 100' surface plug to surface.

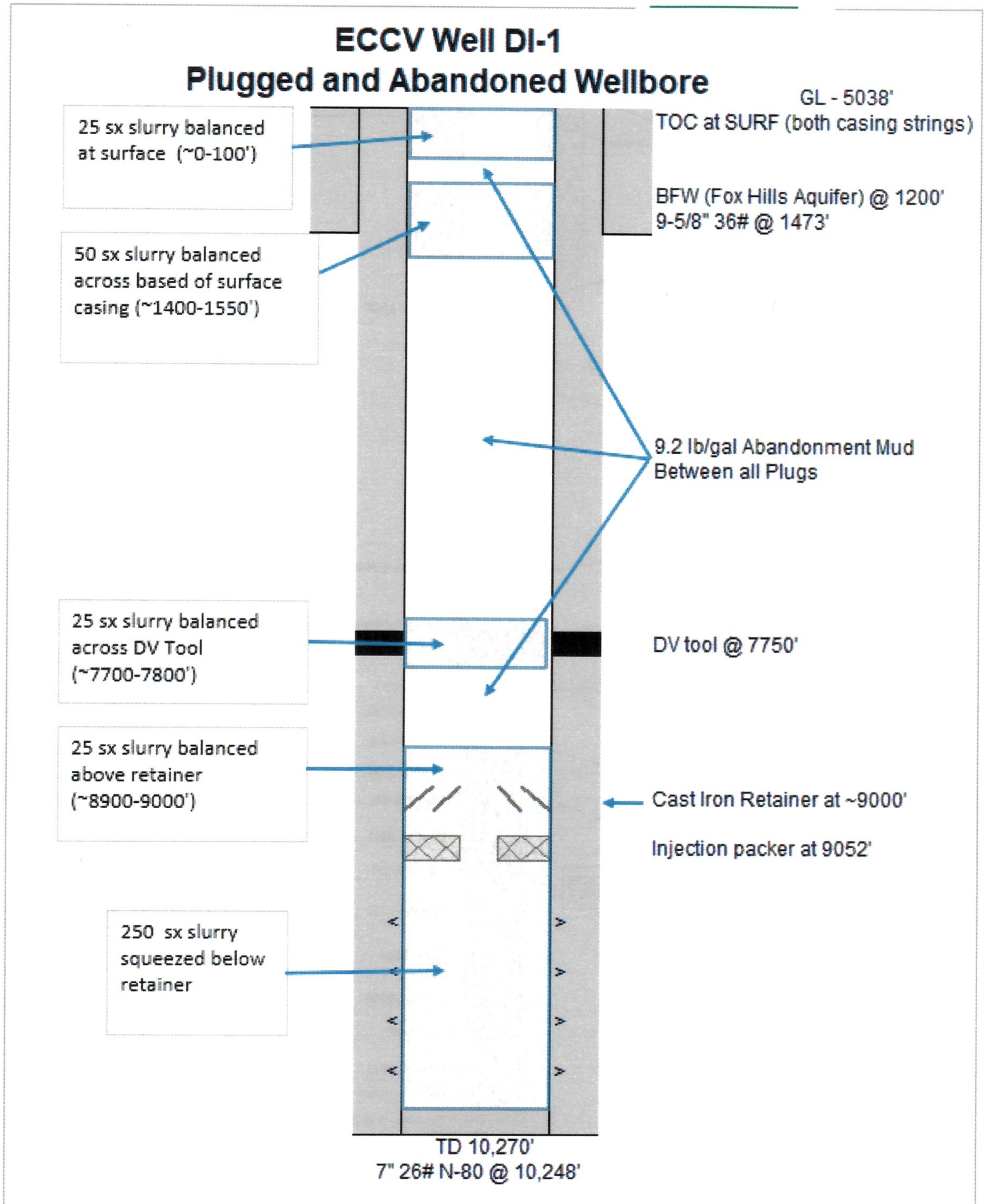
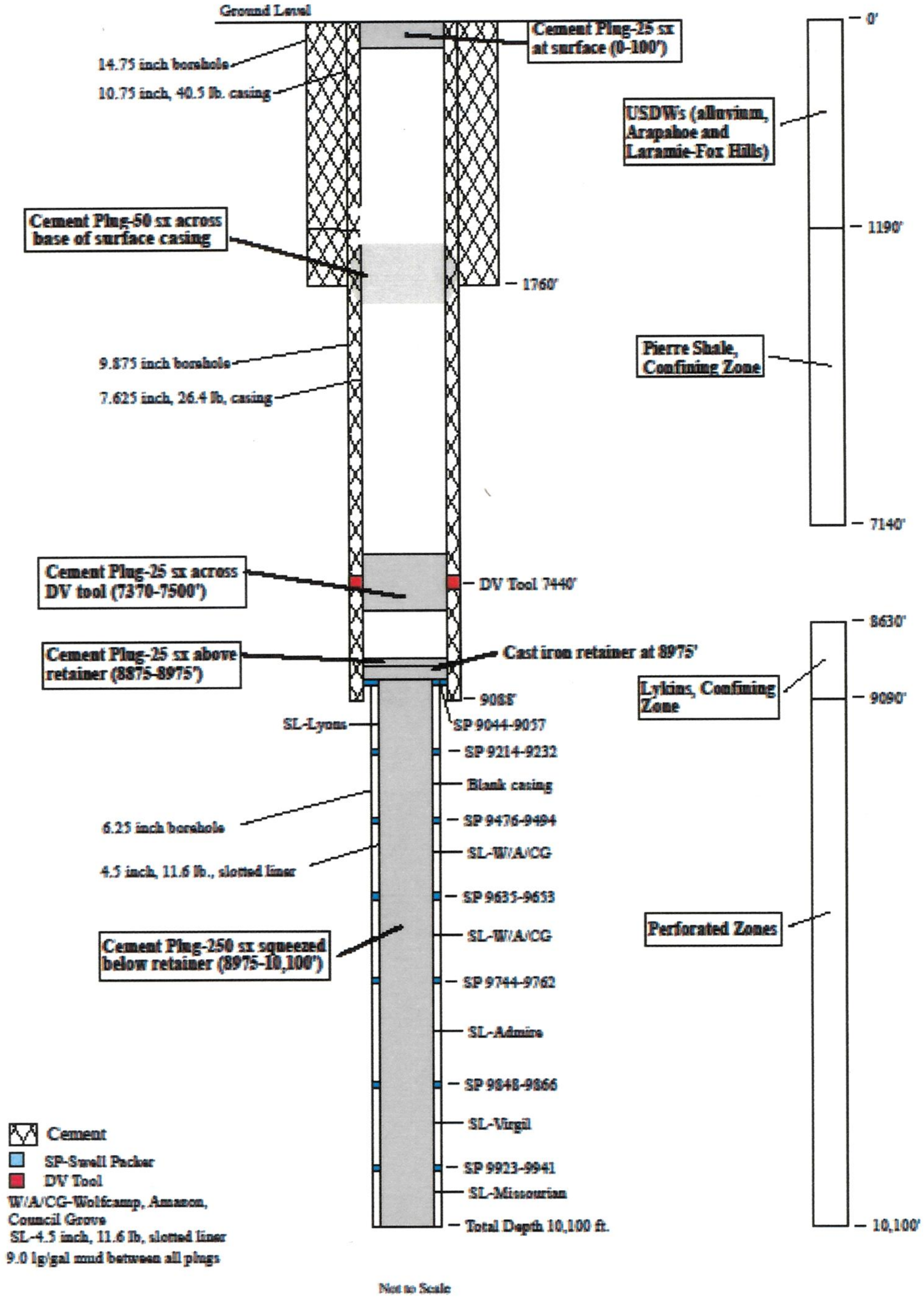

ECCV Well DI-1
Plugged and Abandoned Wellbore
GL - 5038'
TOC at SURF (both casing strings)
25 sx slurry balanced at surface (~0-100')
BFW (Fox Hills Aquifer) @ 1200'
9-5/8" 36# @ 1473'
50 sx slurry balanced across based of surface casing (~1400-1550')
9.2 lb/gal Abandonment Mud Between all Plugs
25 sx slurry balanced across DV Tool (~7700-7800')
DV tool @ 7750'
25 sx slurry balanced above retainer (~8900-9000')
Cast Iron Retainer at ~9000'
Injection packer at 9052'
250 sx slurry squeezed below retainer
TD 10,270'
7" 26# N-80 @ 10,248'

Figure E-1



ECCV DI- 2 Well Plugged and Abandoned Design.

Figure E-2

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.

STATEMENT OF BASIS

East Cherry Creek Valley Water & Sanitation District
Class I Non-Hazardous Waste Disposal Well
CO12143-00000

CONTACT: Wendy Cheung
U. S. Environmental Protection Agency
Underground Injection Control Program, 8WD-SDU
1595 Wynkoop Street
Denver, Colorado 80202-1129
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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 CO12143-00000 (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. 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.

PART I. General Information and Description of Project

East Cherry Creek Valley Water & Sanitation District
6201 South Gun Club Road
Aurora, Colorado 80016

hereinafter referred to as the "Permittee," submitted an application for an Underground Injection Control (UIC) Program permit for the following injection wells located in Adams County, Colorado:

CO12143-08425
ECCV DI-1
649' FWL & 517' FSL, S1, T1S, R66W

CO12143-08426
ECCV DI-2
51' FEL & 610' FNL, S1, T1S, R66W

CO12143-08427
ECCV DI-3
TBD

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.

General Info

The East Cherry Creek Valley Water and Sanitation District (ECCV) has requested renewal of their Class I Non-hazardous Disposal Well Area Permit (Permit) for the purpose of disposing reverse osmosis (RO) brine that is generated as a result of treating ground water to drinking water standards. Two of the wells have been constructed. The location of the third well has been proposed, including an alternate location. The proposed injection zones are over 8000 feet below the Laramie/Fox Hill, the deepest aquifer presently used as a water resource and below all known underground sources of drinking water (USDWs). The water quality of the formations below the Laramie/Fox Hill is greater than 10,000 mg/L total dissolved solids (TDS), based on data from the drilled DI-1 and DI-2.

ECCV provides water and sanitation services to approximately 55,000 users in the eastern portion of Centennial and unincorporated Arapahoe County, Colorado. ECCV operates the Beebe Draw wellfield, which consists of nearly over a dozen shallow wells ranging in depth from 75 to 100 feet. This wellfield allows ECCV to reduce its reliance on their depleting deep (over 1000 feet in depth) drinking water aquifers. Rather these wells are replenished by surface water from the South Platte River that flows through a series of ditches and seeps into the Beebe Draw. Prior to distribution, the water undergoes reverse osmosis (RO) treatment in their nearby Northern Water Treatment Plant (NWTP)[1]. It is the concentrate from their RO treatment that is injected into the UIC wells. The Beebe Draw wellfield and NWTP are located approximately one mile south of Lochbuie, Colorado.

The water produced from the Beebe Draw has elevated levels of gross alpha, TDS, fluoride, and iron. Levels of uranium and nitrates may also be elevated and may require treatment. The water quality run through the NWTP will vary depending upon the ratio of water used from the high quality deep drinking water wells. This will affect the injectate water quality along with whether it is a single or double pass (additional treatment) through the RO system.

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[1] https://www.eccv.org/sites/default/files/uploads/policy/northoverview.pdf

The DI-1 well began injection in March 2012 and DI-2 began injection in September 2017. The second injection well allowed ECCV to expand their facility to deliver 14.74 million gallons of water, nearly doubling their capacity in 2012[2]. To accommodate future service needs and further expansion of the NWTP, ECCV has sited two locations where a third injection well can be constructed. The full extent of the area permit along with the location of the Beebe Draw and injections wells are shown in Figure A-1 in the permit.

PART II. Permit Considerations (40 CFR § 146.14)

Hydrogeologic Setting

The Denver Basin encompasses more than 70,000 square miles and underlies the eastern portion of Colorado along the Front Range, extending into southeast Wyoming, western Nebraska, and western Kansas. The basin is bounded on the west by the Front Range of the Rocky Mountains, on the northwest by the Hartville Uplift, on the northeast by the Chadron Arch, and on the southwest and southeast by the Apishapa Uplift and Las Animas Arch, respectively. The Denver basin is an asymmetrical elongated bowl-shaped Laramide-age foreland-style structural basin with the sag deepest near Denver, where it reaches a depth of approximately 13,000 feet below the surface.

The Denver Basin contains four principal water supply aquifers that are confined systems. From deepest to shallowest, these are the Laramie-Fox Hills, Arapahoe, Denver and Dawson.

More than 1.05 billion barrels of oil and 3.67 trillion cubic feet of natural gas have been produced from wells across the Denver Basin. Currently producing sandstone reservoirs range in age from Permian through Cretaceous, with the majority producing from the latter. Minor amounts have also been produced from the Pennsylvania in the Nebraska Panhandle. Depths of production vary from less than 900 feet at the Florence field in Fremont County to about 9,000 feet at the Pierce field in Weld County.

TABLE 2.1
Geologic Setting

Formation Name or Stratigraphic Unit	Top (ft)*	Base (ft)*	TDS (mg/l)	Lithology
Alluvium	0	60	750	Unconsolidated sand, silt, clay and gravel
Arapahoe	60	616	800	Tan to gray sandstone and conglomerate, some shale and coal.
Laramie - Fox Hills	616	1,728	550	Tan to gray sandstone, with dark shale and thin coal
Pierre SH	1,728	7,130	18,700	Gray to brown shale. Some sandstone layers.
Niobrara	7,130	7,556	-	Gray to brown shale
Fort Hays LS (in Niobrara)	7,530	7,556	-	White limestone interbedded with shale
Greenhorn	7,556	7,925	-	Gray-black shale and limestone

[2] https://www.eccv.org/sites/default/files/uploads/policy/northoverview.pdf

Dakota GP	7,925	8,325	10,504 - 23,371	Tan, gray, white sandstone, siltstone and shale
Morrison	8,325	8,488	-	Tan and maroon sandstone and siltstone
Entrada SS	8,488	8,683	17,400	White sandstone, some anhydrite and shale
Lykins	8,683	9,150	-	Red shale and siltstone, with anhydrite at base
Lyons	9,150	9,268	17,700 – 59,000[#]	White to pink sandstone
L. Satanka	9,268	9,525	-	Red shale and sandstone with blue-white dolomite layers
Wolfcamp	9,525	9,663	16,900 - 17,900	Gray to red sandstone, shale, and anhydrite
Amazon	9,663	9,702	15,800 – 16,900	White limestone, dolomite and anhydrite
Council Grove	9,702	9,758	15,800 – 16,900	White to red limestone and dolomite with some sandstone, anhydrite and shale layers
Admire	9,802	9,934	76,500[#]	White to red limestone and dolomite with some shale
Virgil	9,934	10,002	-	White to red limestone, sandstone and anhydrite
Missouri(an)	10,002	10,220	21,000	White to red sandstone, limestone, shale and anhydrite
Fountain	10,220	10,271	13,526	Red sandstone and dolomite

*formation top and bottom depths at the ECCV DI-1 well

[#] may not be a representative sample

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

The proposed injection zones are the Permian and Pennsylvanian sandstones at an estimated depth of 9,000 to 10,000 feet in this area. The Pennsylvanian Missouri(an) is interbedded cream to dark brown, locally cherty and oolithic limestones and dark gray to black shales with some light gray to buff dolomite and occasional traces of tan sandstone. Increasing sandstone and red shales westward. The Virgil is composed of limestone and thin shale. The Admire is described as white to light gray dolomite on top and white limestone and chalk on bottom.

Both the Permian Council Grove and Amazon are described as white to light gray dolomite. The Wolfcamp is gray to pink limestone, dolomite, anhydrite with interbedded pink to gray or black shale and siltstone. The L Santanka is interbedded shale, siltstone, dolomite, and anhydrite. The Lyons is fine-grained orange to tan sandstone. The top of the Lyons is composed of fine-grained quartz sandstones, siltstones and maroon shales which act as a confining unit.

TABLE 2.2
INJECTION ZONE

Formation Name or Stratigraphic Unit	Top (ft)*	Base (ft)*
Lyons	9,150	9,268
L. Satanka	9,268	9,525
Wolfcamp	9,525	9,663
Amazon	9,663	9,702
Council Grove	9,702	9,758
Admire	9,802	9,934
Virgil	9,934	10,002
Missouri(an)	10,002	10,220

* formation top and bottom depths at the ECCV DI-1 well

After the DI-1 and DI-2 wells were drilled, the injection formations were sampled. Some of the injection formations were sampled together if they were of similar lithological characteristics. For the formations that were open for injection and sampled, TABLE 2.3 provides the results of the formation TDS. In some formations, samples from DI-2 were suspected to have been contaminated due to unexpected high values, so TDS values for all the formations were also estimated using open hole logs. The direct samples from the two wells and the estimated TDS all suggest these injection zones are not USDWs.

Not all approved injection zones are currently used for injection. Should additional zones be opened for injection, they will need to be sampled prior to injection. Water sample from the discrete formations will also be isolated and sampled individually prior to authorization to inject for DI-3. If the water sample indicates that any portion of the injection zone is a USDW, an application for an aquifer exemption will need to be submitted and/or the approved injection zone(s) may need to be reconsidered.

TABLE 2.3
INJECTION ZONE TDS

Injection Formation	DI-1 (mg/L)	DI-2 (mg/L)	Estimated TDS DI-2 (mg/L)
Lyons	17,700	59,000#	28,000
Wolfcamp	17,900	16,900 (Wolfcamp/Amazon/CG	19,000
Amazon/Council Grove	15,800	16,900	20,000 – 34,000
Admire	Not Perfed	76,500#	12,500
Virgil	Not Perfed	Didn't sample	24,000
Missourian	21,000	Unable to obtain water sample due to low yield.	57,000

may not be a representative sample

Confining Zones
A confining zone is a geological formation, part of a formation, or a group of formations that limits fluid movement above and below the injection zone. The confining zone or zones are listed in TABLE 2.4.

Immediately below the Laramie-Fox Hills is the Pierre Shale that serves as a confining layer for the shallow aquifers. The Pierre Shale is a black to dark gray shale estimated to be 5500 feet thick.

Directly above the uppermost injection zone is the Lykins, a red shale and siltstone with interbedded persistent units of dolomite and anhydrite approximately 400 feet thick.

TABLE 2.4
CONFINING ZONES

Formation Name or Stratigraphic Unit	Top (ft)	Base (ft)	Lithology
Pierre SH	1,728	7,130	Gray to brown shale. Some sandstone layers.
Niobrara	7,130	7,556	Gray to brown shale
Fort Hays LS (in Niobrara)	7,530	7,556	White limestone interbedded with shale
Greenhorn	7,556	7,925	Gray-black shale and limestone
Lykins	8,683	9,150	Red shale and siltstone, with anhydrite at base

*formation top and bottom depths at the ECCV DI-1 well

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 Laramie-Fox Hills is a fine to very fine-grained sandstone and siltstone interbedded with shale and occasional coal layers.

The Arapahoe consists of interbedded layers of conglomerate, sandstone, siltstone, and shale.

The Quaternary alluvium makes up the first 60 feet of surface and consists of stream-deposited layers of clay, silt, sand and gravel.

In this part of the basin, the Denver and Dawson aquifers do not exist.

TABLE 2.5
UNDERGROUND SOURCES OF DRINKING WATER (USDWs)

Formation Name or Stratigraphic Unit	Top (ft)*	Base (ft)*	TDS (mg/l)	Lithology
Alluvium	0	60	750	Unconsolidated sand, silt, clay and gravel
Arapahoe	60	616	800	Tan to gray sandstone and conglomerate, some shale and coal.
Laramie - Fox Hills	616	1,728	550	Tan to gray sandstone, with dark shale and thin coal

*formation top and bottom depths at the ECCV DI-1 well

PART III. Well Construction (40 CFR § 146.12)

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 wells are shown in TABLE 3.1 and 3.2.

To protect shallow USDWs when drilling the surface hole for the new well, 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 DI-1

Casing Type	Hole Size (in)	Casing Size (in)	Cased Interval (ft)	Cemented Interval (ft)
Surface	12.25	9.625	0-1,473	0-1,473
Production	8.75	7	0-10,248	0-10,248
Tubing		4.5	0-9,052	-

TABLE 3.2
WELL CONSTRUCTION DI-2

Casing Type	Hole Size (in)	Casing Size (in)	Cased Interval (ft)	Cemented Interval (ft)
Surface	14.75	10.75	0-1,743	0-1,743
Production	9.875	7.625	0-9,071	0-9,071
Tubing		5.5	0-9,031	-
Slotted Casing	6.25	4.5	9,056-10,100	-

Well Siting
By definition, Class I wells must inject beneath the lowermost formation containing, within one-quarter mile of the well bore, an underground source of drinking water.

DI-3 Well Location
Prior to construction of DI-3, the Permittee will notify the EPA of the final well location. A summary of DI-1 and DI-2 injection volumes and analysis of pressure interference from these wells will be provided to support the suitability of the location proposed.

The well must be sited wholly within the permit area. If the DI-3 well location is sited outside of the permit area, a major modification to the permit will be required to expand the permit area.

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; 4) a flow meter capable of recording instantaneous flow rate and cumulative volume attached to the injection line; and 5) 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.

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

Well Injection and Seismicity

During the public comment period for the initial ECCV area permit, a commenter had expressed concerns for induced seismicity due to the ECCV's proposed injection activity, citing the Rocky Mountain Arsenal (RMA) which operated a deep injection well that was implicated to have induced earthquakes in the early sixties. The RMA is located approximately 15 miles southwest of the ECCV facility.

The RMA deep well injection occurred into the Precambrian crystalline bedrock, at a depth of 12,045 feet. The high pressure injection, induced earthquakes as high as a magnitude 5.

For seismic activity to occur, there needs to be the presence of a fault(s) and sufficient pore pressure to change the tectonic stress field. Based on existing information, there are no known major faults within the area of review. Additional, ECCV injection pressure cannot exceed the injection formation fracture pressure. As discussed below in the Injection Pressure Limitation section, based on the step rate test results, the wells will be subject to maximum allowable injection pressures that prevent the injection formations from fracturing. For the period since injection commenced to end of year 2018, the highest injection pressure has been 2137 psi, well below their MAIP. Furthermore, inherent to ECCV's operation and reflected in their injection volume data, the volume injected varies seasonal, based on their customers' water demand. Each year since injection, there is at least one winter month when the injection well usage is reduced 70% or more when compared to that year's peak summer usage. This practice also mitigates the potential for seismic activity by allowing the fluids to dissipate into the pore space and alleviating the pressure built up in the formation.

In May 2014, induced seismic activity was detected approximately 30 miles to the north of the permit area. It was thought that three wells contributed to these seismic events. The wells were initially drilled to the lower Fountain and Precambrian. After the operators plugged back to the upper Fountain and injection rates were reduced, the seismic activity dissipated. Similar to the RMA case, these injection wells were injecting near the Precambrian bedrock. The lowest injection zone in the ECCV wells is the Missourian, which lies above the Fountain.

ECCV is required to monitor seismic activity by receiving automatic updates from U.S. Geological Survey (USGS) Earthquake Hazards Program's seismic network. At a magnitude ~2, seismic activity will be picked up by the USGS Advanced National Seismic System network and at ~2.5, the location can be determined. USGS has the ability to readily determine the location of a magnitude 3 and above. There is low risk of structural damage for a magnitude between 2.5 and 3.

If an event is detected within two miles of the permit boundary, ECCV will immediately cease injection and report the event to EPA within 24 hours. Two miles is just beyond the distance of the closest known wrench fault. There are five documented wrench faults in the vicinity of the area permit that influence present-day reservoir production in the shallower D and Muddy (J) Sandstone in the Wattenberg oil and gas field. The ECCV wells lies on a block between two of these faults, the Lafayette Wrench Fault Zone (LWFZ), and the Cherry Gulch Wrench Fault Zone (CCWFZ). Based on maps in Robert Weimer's Guide to the Petroleum Geology and Laramide Orogeney, the ECCV Area Permit is approximately 1 to 1.5 mile away from the LWFZ and approximately 8 miles from the CCWFZ.

ECCV will report all events within 50 miles radius of the are permit boundary. The 50-mile extent will capture most of the area in the DJ basin, including the Wattenberg Oil and Gas Field. ECCV will provide a summary in the seismic events in the quarterly reports.

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 has been increased from ¼ to ¾ mile around the permit boundary. As reported in their pressure fall-off test results, since October 9, 2019, DI-1 has injected 14,832,318 bbls and based on the volume fill-up model, the fluids are estimated to have reached 1,539 feet. As of September 16, 2019, DI-2 has injected 3,024,101 bbls.

There are no AOR wells in the ¾-mile AOR that penetrate below the Lykins confining layer other than the two ECCV wells. There are numerous water wells within the ¾-mile AOR including the twelve wells that are part of the Beebe Draw wellfield. The majority of the wells are into the alluvium, with the deepest wells drilled into the Laramie-Fox Hills at approximately 1200 feet, well above the 5,500-foot thick Pierre shale.

There are no known or identifiable faults in the AOR.

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 the EPA's evaluation did not identify migration pathways that would impact USDWs within the area of review.

PART V. Well Operation Requirements (40 CFR § 146.13)

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 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.

Demonstration of External (Part II) MI is required and will be repeated no less than five years after the last successful MIT. The External MIT will be demonstrated by using the results of a temperature log. A baseline temperature log will be required prior to authorization to inject, a temperature log will be run within six to twelve months after injection has commenced, and subsequent temperature logs will be run at least once every five (5) years after the last successful demonstration of Part II MI.

In addition to the required temperature log discussed above, should the analysis of the cement bond log show inadequate cement behind pipe to prevent significant movement of fluid out of the approved injection zone of the annulus cement, i.e. less than 80% bond index cement bond across the confining zone, a Radioactive Tracer Survey (RTS) will be required prior to authorization to inject along with additional tests as required by the Director.

DI-1: *The CBL was evaluated and was shown to have greater than 80% bond index. The well was also tested for its mechanical integrity soon after construction and has been repeated two additional times. Since it began injection in 2012, the well has successfully passed both Part I (standard annulus pressure test) and Part II (temperature log). The frequency for standard annulus pressure test and temperature log are every 5 years after the last successful demonstration.*

DI-2: *The DI-2 well was also evaluated for its mechanical integrity soon after construction. The standard annulus pressure test demonstrated internal mechanical integrity prior to authorization to inject and is required every 5 years after the last successful demonstration.*

The cement records show that the cement job was performed according to plan, however, evaluation of the CBL showed that the bond index across the confining zone was poor and possibly absent. As a result, a minor modification to the permit required an RTS prior to authorization to inject and a temperature survey to be performed annually. The results of the tracer survey did not indicate fluid movement behind the casing. In addition to the initial temperature survey conducted within 6 to 12 months after authorization to inject, ECCV ran a temperature survey the following year. Both temperature surveys did not show temperature anomalies.

Although the CBL did not show adequate cement, the external MI tests performed (RTS and temperature surveys) did not indicate movement of fluids behind the casing. With this reissuance, the frequency of the temperature survey is now required at least every 3 years after the last successful demonstration.

Injection Fluid Limitation
Approved injected fluids are limited to non-hazardous waste fluid generated by the East Cherry Creek Valley Water and Sanitation District from their reverse osmosis plant and products injected for well workover and maintenance of the wells.

The waste stream is the concentrate or permeate from treating water from their drinking water supply wells through a reverse osmosis process to meet National Primary and Secondary Drinking Water Standards. The source water is also high in radionuclides and may be considered radioactive waste as defined by the UIC program.

In 40 CFR §144.3, the UIC definition of radioactive waste is any waste which contains radioactive material in concentrations which exceed those listed in 10 CFR part 20, Appendix B, Table II, Column 2. The concentrations referenced are protective dose limits for individual members of the public that the Nuclear Regulatory Commission has set. These concentration limits for liquid effluents when released to the general environment is equivalent to the radionuclide concentrations which, if inhaled or ingested continuously over the course of a year, would produce a total effective dose equivalent of 50 mrem. To put this into context, according to the National Council on Radiation Protection (1987), the average radiation dose to an individual in the United States is about 360 mrem/yr. On average, 80 percent of that exposure comes from natural sources including cosmic radiation (30 mrem/yr); terrestrial radiation from natural radioactive materials in rocks, soil, and minerals (230 mrem/yr); and radiation inhaled or ingested from food and water (40 mrem/yr).

The concentrate of the injectate will vary depending upon whether it is a single or double pass through the RO plant. To date, the injectate has not exceeded the threshold of radioactive waste as defined by UIC regulation 40 CFR §144.3.

The Permittee has provided annual sample results for the analytes in APPENDIX D. Lead 210 and Thorium 230 concentrations were consistently low and well below the UIC radioactive waste threshold. These two analytes have been removed from the list in APPENDIX D of the Permit.

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

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

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

Injection Pressure Limitation
40 CFR § 146.13(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 injection zone.

The calculated Maximum Allowable Injection Pressure (MAIP) described below is the pressure that will initiate fractures in the injection zone and that the Director has determined satisfies the above condition. Except during stimulation, the injection pressure must not exceed the MAIP. Furthermore, under no circumstances shall injection pressure cause the movement of injection or formation fluids into a USDW.

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

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

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

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

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

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

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

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

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

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

$$\mathbf{MAIP} = \mathbf{FP} + \text{friction loss (if applicable)}$$

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

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

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

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

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

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

When the ECCV was first permitted, there were very few wells that injected into the Lyons and below. A number of disposal wells have since been constructed for disposal of Class II fluids. Of nearly a dozen wells reviewed in the Colorado Oil and Gas Conservation Commission's database, only two wells included a bottom-hole gauge during the SRT, to most accurately determine the fracture gradient value. In these tests the FGs were 0.571 and 0.465 for wells 27 and 12 miles away, respectively. This information is consistent with the FG determined at DI-2 well and will be the permit FG used to perform the calculations. To date, the highest pressure attained is 2035 and 2137 psi in DI-1 and DI-2, respectively. In the reissuance of the ECCV area permit, the proposed MAIP for both DI-1 and DI-2 wells use the formulaic equation as described above.

In Table 5.1, the MAIP parameters determined from the DI-1 and DI-2 Step Rate Tests (SRTs) are provided. These value were used to calculate the permitted MAIP with the reissuance of this permit.

TABLE 5.1
Injection Zone Fracture Pressure

ECCV well	fracture gradient	specific gravity	depth (ft)	friction loss (PSI)	Calculated MAIP (PSI)	**Authorized MAIP (PSI)**
DI-1	0.559	1.000 [+ 0.05]	9150	1800	2755	2755
DI-2	0.559	1.000 [+ 0.05]	9056	1800	2745	2745
DI-3	0.559	1.000 [+ 0.05]	9056	1800	2745	2745

The specific gravity range of the injected fluid over the period of injection is between 0.996 and 1.018, well within the 0.05 variability built into the equation. The MAIP equation uses SG+0.05, therefore 1.050 is used in the equation. As discussed above, the MAIP is determined using an equation, rather than a constant value. The MAIP may be recalculated, if the injection fluid specific gravity submitted annually differs by 0.05.

DI-1:
ECCV performed two Step Rate Tests (SRTs). The first test was inconclusive and when run a second time (with all formations open), the bottom-hole gauge could not be retrieved. Based on the available surface pressure data and calculated friction loss, the formations did not appear to fracture at the injection flowrates achieved during the test. The final step of the second SRT achieved a flowrate of 38.9 bbl/min at a surface injection pressure of 4723 psi. In the absence of a bottom-hole gauge and uncertainty in the contribution of friction loss, the operator requested a conservative Maximum Allowable Injection Pressure (MAIP) of 3200 psi. EPA approved this request.

To calculate the authorized MAIP, the fracture gradient from DI-2 will be used (FG = 0.559) as well as friction loss. This is a conservative value, as tubing is smaller in the DI-1 than that DI-2, and friction loss would be expected to be greater.

DI-2:
The SRT test performed on all the injection formation opened showed a break at approximately 5635 psi (downhole) or 3070 psi (surface). This test was run with a bottom-hole gauge and friction loss was determined

directly from the test. The gauge was located at 10,080 feet. This resulted in a fracture gradient of 0.559. Individual SRTs were also performed on each of the formations, with some of these SRTs run with bottom-hole gauges. These individual datasets were not conclusive, as pressure data uncharacteristically rose and dropped over the course of the test.

While the well was shut-in overnight prior to the SRT, the DI-2 well became over-pressured. Brine was added to "kill the well" or keep the pressure down in the well by filling the wellbore with heavier fluids. The SRT was conducted with fresh water. The fresh cold water was pumped down the tubing and out into the formation over the course of the SRT (3.5 hours). The Permittee believes that the drop in downhole temperature due to the cold water caused the salt to precipitate out, however, the low salinity of the fresh water caused the salt deposits to dissolve downhole. The interaction of these two processes, which changes with time and location, appears to be what is causing the unexpected pressure fluctuations during the SRTs.

The SRT conducted with all the formations open provided the only set of results that appeared to be valid. The test result from this SRT was used to determine the fracture pressure for all 3 wells.

Since the CBL of the production casing suggested poor cement behind pipe, the MAIP will be limited to the pressure achieved during the RTS. The operator was required to demonstrate Part II MI with a RATS (refer to MIT section). The average pressure during the RATS test was conducted at 2982 psi. A minor permit modification on September 18, 2017, set the MAIP to 2982 psi.

DI-3:
Initially, the parameters to calculate the MAIP will utilize the data from the DI-2. If, and when this well is constructed, the data from the required SRT will be used to calculate a new MAIP.

PART VI. Monitoring, Recordkeeping and Reporting Requirements

Annual Pressure Falloff Test (40 CFR § 146.13(d)(1))

The pressure falloff test is required for Class I operations and must be performed at least once every twelve months for the purposes of monitoring pressure buildup in the injection zone, to monitor reservoir parameters, to identify any fracturing, and to identify any boundaries within the injection formations.

Annual monitoring of the pressure buildup in the injection zone includes a shutdown of the well for a time sufficient to conduct a valid observation of the pressure falloff curve.

Injection Well Monitoring Program

Continuous monitoring of injection pressure, injection flow rate, injection volume, cumulative fluid volume, bradenhead and TCA pressures shall be at the wellhead. If the continuous monitoring is carried out with digital equipment, the instrumentation shall be capable of recording at least one value for each of the parameters at least every thirty (30) seconds. If the continuous monitoring is carried out with a continuous chart recorder: 1) to monitor the injection, annulus, and bradenhead pressures the chart shall be of a scale that allows changes in pressure of 5 psi to be detected and 2) to monitor the injection volume and injection rate the chart shall be of a scale that allows changes in pressure of 5 barrels or barrels per day to be detected. Monthly averaged, maximum, and minimum values for injection pressure, flow rate and volume, and bradenhead and annular pressure is required to be reported as part of the Quarterly Report to the Director.

Reporting Requirements

Quarterly, 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 the EPA as part of the Quarterly Report to the Director.

Instantaneous injection pressure, injection flow rate, injection volume, bradenhead and TCA pressures must be recorded continuously. Each month's minimum, maximum and averaged values of these parameters and the cumulative fluid volume is required to be reported as part of the Quarterly 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 7520-14) to the Director. The Plugging Record must be certified as accurate and complete by the person responsible for the plugging operation. The plugging and abandonment plan is described in APPENDIX E of the Permit.

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

Demonstration of Financial Responsibility
The Permittee is required to maintain financial responsibility and resources to close, plug, and abandon the underground injection operation in a manner prescribed by the Director. The Permittee will show evidence of such financial responsibility to the Director by the submission of completed original versions of one of the following:

(a) a surety bond with a standby trust agreement,
(b) a letter of credit with a standby trust agreement,
(c) a fully funded trust agreement, OR
(d) a financial test and corporate guarantee.

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

A financial test is provided to demonstrate financial responsibility. Evidence of continuing financial responsibility is required to be submitted to the Director annually.