UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 8
1595 Wynkoop Street
Denver, CO 80202-1129
Phone 800-227-8917
http://www.epa.gov/region8

Ref: 8WD-SDU

SENT VIA EMAIL
DIGITAL READ RECEIPT REQUESTED

AJ Krieger, Town Manager
akrieger@firestoneco.gov

Re: Draft Permit – CO12413-00000, Town of Firestone Class I Area Permit

Dear Mr. Krieger:

Enclosed is a copy of the draft U.S. Environmental Protection Agency Region 8 Underground Injection Control (UIC) permit (Permit) for the above referenced well or project area. Also enclosed are copies of the statement of basis for the proposed action and the public notice provided on EPA's website at https://www.epa.gov/uic/underground-injection-control-epa-region-8-co-mt-nd-sd-ut-and-wy.

EPA regulations and procedures for issuing UIC permit decisions are found in Title 40 of the Code of Federal Regulations (40 CFR) part 124. These regulations and procedures require a public notice and the opportunity for the public to comment on this proposed Permit decision. The public comment period will run for at least 30 days and a courtesy announcement of the comment period, also enclosed, was published in the following newspapers(s):

Longmont Times - Prairie Mountain Publishing

A final decision will not be made until after the close of the comment period. All relevant comments will be taken into consideration. If any substantial comments are received, the effective date of the final Permit will be delayed for an additional 30 days, as required by 40 CFR § 124.15(b), to allow for any potential appeal of the final Permit decision.

If you have any questions or comments about the above action, please contact Omar Sierra-Lopez at (303) 312-7045 or Sierra-Lopez.Omar@epa.gov.

Sincerely,

8/3/2020

X Douglas Minter for

Sarah Bahrman
Chief, Safe Drinking Water Branch, Water Divisi...
Signed by: DOUGLAS MINTER

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
UNDERGROUND INJECTION CONTROL PROGRAM

DRAFT AREA PERMIT
CO12413-00000

Class I Non-Hazardous Waste Disposal Well
Town of Firestone Area Permit
Weld County, Colorado

Issued To

Town of Firestone
151 Grant Avenue
Firestone, Colorado 80520

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PART I. AUTHORIZATION TO CONSTRUCT AND OPERATE

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

Town of Firestone
151 Grant Avenue
Firestone, Colorado 80520

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

CO12413-11959
Town of Firestone SWD#1
SW ¼ SW ¼
Section 31 T3N R67W

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

1459 feet FSL and 1093 feet FWL, S31, T3N, R67W;
608 feet FSL and 1055 feet FWL, S31, T3N, R67W;
606 feet FSL and 1316 feet FWL, S31, T3N, R67W;
30 feet FSL and 1315 feet FWL, S31, T3N, R67W;
37 feet FNL and 2456 feet FWL, S6, T2N, R67W;
1759 feet FNL and 2418 feet FWL, S6, T2N, R67W;
2281 feet FNL and 2094 feet FWL, S6, T2N, R67W;
2329 feet FNL and 1236 feet FWL, S6, T2N, R67W:
34 feet FNL and 1269 feet FWL, S6, T2N, R67W
30 feet FSL and 30 feet FWL, S31, T3N, R67W;
1469 feet FSL and 30 feet FWL, S31, T3N, R67W.

This Area Permit will authorize to construct and operate up to two Class I wells in the permit area. This Permit is based on representations made by the applicant and on other information contained in the administrative record. Misrepresentation of information or failure to fully disclose all relevant information may be cause for termination, revocation and reissuance, or modification of this Permit and/or formal enforcement action. It is the Permittee's responsibility to read and understand all provisions of this Permit. Where a state or tribe is not authorized to administer the UIC program under the SDWA, EPA regulates underground injection of fluids into wells so that injection does not endanger Underground Sources of Drinking Water (USDWs). EPA UIC permit conditions are based on authorities set forth at 40 CFR parts 144 and 146 and address potential impacts to USDWs. Under 40 CFR part 144, subpart D, certain conditions apply to all UIC permits and may be incorporated either expressly or by reference. Regulations specific to Colorado injection wells are found at 40 CFR § 147 Subpart G.

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

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

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

Issue Date: DRAFT Effective Date DRAFT

DRAFT

Sarah Bahrman, Chief*
Safe Drinking Water Branch
Water Division

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

PART II. SPECIFIC PERMIT CONDITIONS

Section A. WELL CONSTRUCTION REQUIREMENTS

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

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, and volume, injectate fluid temperature, 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.

(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 Town of Firestone - St. Vrain Water Treatment Plant from their reverse osmosis plant and products injected for well workover and maintenance of the well.

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 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 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. For any seismic event occurring between two and fifty miles of the permit boundary, that event will be recorded and reported to EPA on a quarterly basis.

Section C. MECHANICAL INTEGRITY

1. Requirement to Maintain Mechanical Integrity

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

An injection well has MI if:

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

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

2. Demonstration of Mechanical Integrity

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

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 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 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, injection fluid temperature, 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) Injection fluid temperatures are to be measured in degrees Fahrenheit (deg F).

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

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

(f) 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 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 ADDITIONAL WELL

The Permittee may construct and operate at most, one additional well 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 SWD #2, the Permittee shall submit a plan consisting of:

(a) Final well location and suitability of proposed location. This would include a summary of SWD #1 injection volume and analysis of pressure interference.

(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 7520-19 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 EPA issued permits until the effective date of the new permits, if State or Tribal law allows. Otherwise, the facility or activity is operating without a permit from the time of expiration of the old permit to the effective date of the State or Tribal-issued new permit.

Section C. SEVERABILITY

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

Section D. CONFIDENTIALITY

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

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

Section E. ADDITIONAL PERMIT REQUIREMENTS

1. Prohibition on Movement of Fluid Into a USDW

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

2. Duty to Comply

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

3. Need to Halt or Reduce Activity Not a Defense

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

4. Duty to Mitigate

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

5. Proper Operation and Maintenance

The Permittee shall at all times properly operate and maintain all facilities and systems of treatment and control (and related appurtenances), which are installed or used by the Permittee to achieve compliance with the conditions of this Permit. Proper operation and maintenance 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-WSD
U.S. Environmental Protection Agency
1595 Wynkoop Street
Denver, Colorado 80202-1129

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

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

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

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

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

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

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

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

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

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

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

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

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

Section F. FINANCIAL RESPONSIBILITY

1. Method of Providing Financial Responsibility

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

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

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

2. Types of Adequate Financial Responsibility.

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

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

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

(c) a fully funded trust agreement, or

(d) a financial test and corporate guarantee.

A surety bond acceptable to the Director shall contain wording identical to model language provided to the permittee by EPA and shall be issued by a surety bonding company found to be acceptable to the U.S. Department of Treasury, which can be determined by review of that Department's Circular #570, currently available on the internet at https://www.fiscal.treasury.gov/fsreports/ref/suretyBnd/c570.htm.

A letter of credit acceptable to the Director shall contain wording identical to model language provided to the permittee by EPA (40 CFR 144.70) and be issued by a bank or other institution whose operations are regulated and examined by a State or Federal agency.

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

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

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

UIC Financial Responsibility Coordinator
Mail Code: 8ENF-ROR
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

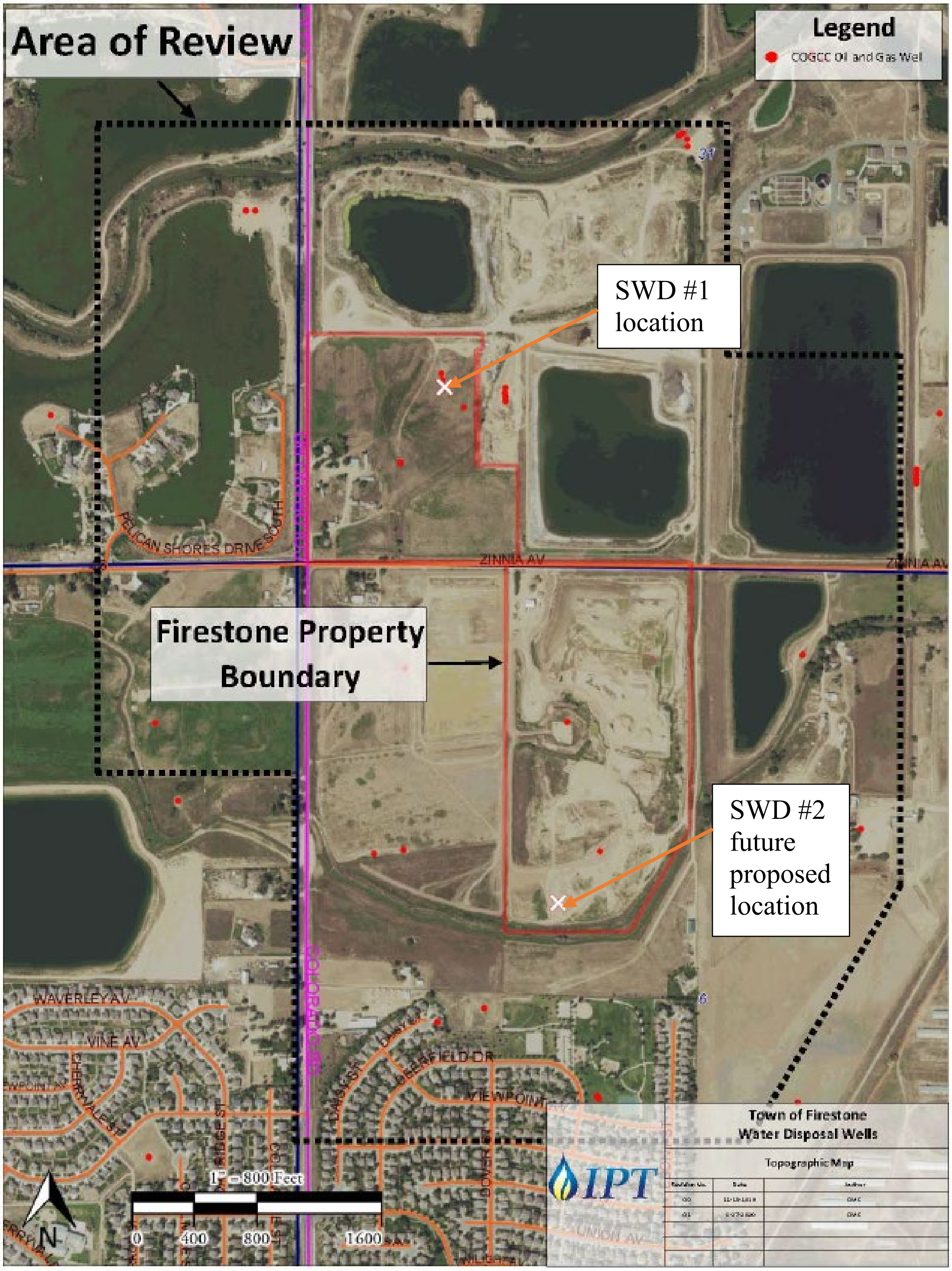

Figure A-1

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 wells 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 plan for SWD #1 has been approved. The casing, tubing and liner weight, grades, and sizes may be modified with Director approval prior to well construction. The depths will vary based on the geology found at the well's location. A final well construction diagram shall be provided with updated depths, prior to authorization to inject. The cementing plan is provided in Table A-1. The Firestone well depth is 10,855'. If during the well construction the Atoka formation is penetrated, the well will be cemented back as illustrated on Figure A-2 of this Permit, as the Atoka will not be used for injection.

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.

Town of Firestone SWD #1

Cementing Plan																						
Casing Interval	Type	Hole Size (in)	Casing OD (in)	Wt (ppf)	Casing ID (in)	Cement Top (ft)	Cement Bottom (ft)	Interval (ft)	Caliper Vol ft3	% Excess	Cement Vol ft3	Pumped Volume bbls	Blend	Yield (ft3/sx)	Sacks Cmt	Sacks Cum Cmt	Water		Density	Bbbls Pumped	TT 70 BC (min)	Cumm Bbls
																	Gal/SX	Bbls				
Surface	Spacer	12.25	9.625	36.0	8.921							20	Water Based Spacer 2.50 lbm/bbl WG-36					20	8.4	20.0		20
	LEAD					0	814	814	255	30%	331	59.0	Type III Portland Cement	2.13	156	156	12.08	45	12.5	59.0	300	79
	TAIL					814	1,200	386	121	30%	157	28.0	Type III Portland Cement	1.9	83	101	10.38	20	13	28.0	180	107
	Shoe							80	35	0%	35	6.2	Type III Portland Cement	1.9	18		10.38	5	13	6.2		113
	Displacement											90	Fresh Water						8.3	90		203
																					JOB TOTAL TIME @ 5 BPM [min]	41
Intermediate Stage 1 DV Tool	Spacer	8.75	7.000	26	6.276							30	Water						8.3	30		30
	Spacer											10	Water						8.3	10		40
	Tail					7514	8876	1,362	205	30%	266	47	Class G Cement; Pozzolan	1.8	148	148	8.73	31	13.5	47	247	135
	Displacement					Brine Mud													10.2	340		474
																					JOB TOTAL TIME @ 5 BPM [min]	119
Intermediate Stage 2	Spacer	8.75	7.000	26	6.276							30	Water						8.3	30		30
	Spacer											10	Water						8.3	10		40
	Lead - Casing					0	1164	1,164	272	20%	327	58	Class G Cement; Pozzolan	2.13	153	689	11.04	181	12.5	261	350	301
	Lead - OH					1164	7000	5,836	877	30%	1141	203			536							
	Tail					7000	7514	514	77	30%	100	18	Class G Cement; Pozzolan	1.8	56	65	8.73	12	13.5	18	222	319
	Shoe							80	17	0%	17	3		1.8	10		8.73	2	13.5	3		322
	Displacement					Brine Mud													10.2	288		610
																					JOB TOTAL TIME @ 5 BPM [min]	152

Table A-1

The current well construction, including the slotted liner are show in Figure A-2.

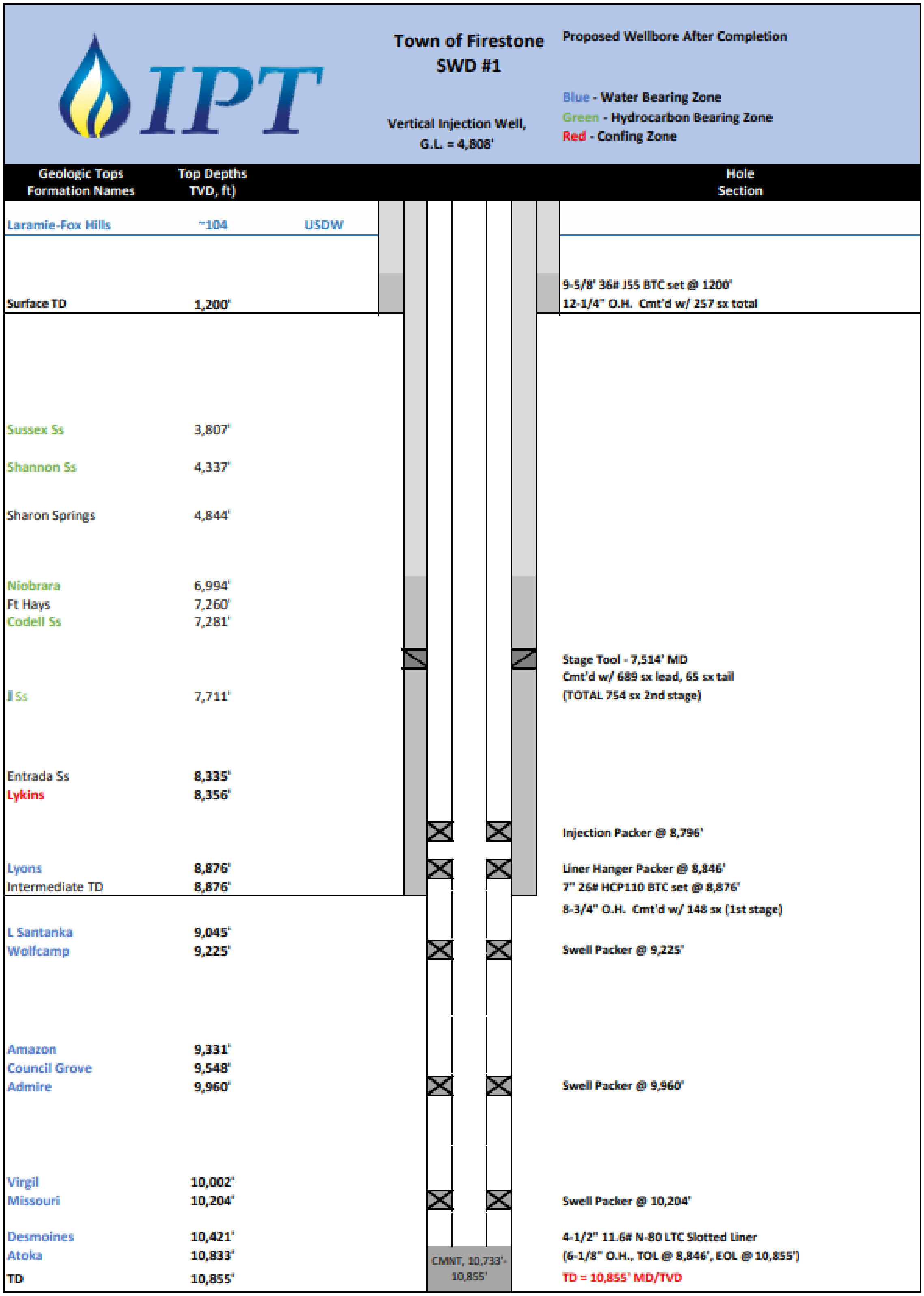
Town of Firestone
SWD #1
Vertical Injection Well,
G.L. = 4,808'
Proposed Wellbore After Completion
Blue - Water Bearing Zone
Green - Hydrocarbon Bearing Zone
Red - Confing Zone
Geologic Tops
Formation Names
Top Depths
TVD, ft)
Hole
Section
Laramie-Fox Hills ~104 USDW
Surface TD 1,200'
9-5/8' 36# J55 BTC set @ 1200'
12-1/4" O.H. Cmt'd w/ 257 sx total
Sussex Ss 3,807'
Shannon Ss 4,337'
Sharon Springs 4,844'
Niobrara 6,994'
Ft Hays 7,260'
Codell Ss 7,281'
Stage Tool - 7,514' MD
Cmt'd w/ 689 sx lead, 65 sx tail
(TOTAL 754 sx 2nd stage)
J Ss 7,711'
Entrada Ss 8,335'
Lykins 8,356'
Injection Packer @ 8,796'
Lyons 8,876'
Intermediate TD 8,876'
Liner Hanger Packer @ 8,846'
7" 26# HCP110 BTC set @ 8,876'
8-3/4" O.H. Cmt'd w/ 148 sx (1st stage)
L Santanka 9,045'
Wolfcamp 9,225'
Swell Packer @ 9,225'
Amazon 9,331'
Council Grove 9,548'
Admire 9,960'
Swell Packer @ 9,960'
Virgil 10,002'
Missouri 10,204'
Swell Packer @ 10,204'
Desmoines 10,421'
Atoka 10,833'
TD 10,855'
4-1/2" 11.6# N-80 LTC Slotted Liner
(6-1/8" O.H., TOL @ 8,846', EOL @ 10,855')
TD = 10,855' MD/TVD
CMNT, 10,733'-
10,855'

Figure A-2

APPENDIX B

LOGGING AND TESTING REQUIREMENTS

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

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

LOGS AND TESTS

TYPE OF LOG OR TEST	DATE DUE
Well logs and test results shall be submitted to the Director within sixty (60) calendar days of completion of the logging or testing activity.	
Injectate Water Analysis A representative water sample of the injectate shall be analyzed for the constituents found in APPENDIX D.	Within 30 days after Authorization to Inject Annually Prior to the introduction of a new source
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.	Prior to receiving Authorization to Inject 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
Mud logging record	Prior to receiving Authorization to Inject
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
Deviation Checks	Prior to receiving Authorization to Inject
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 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
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.	Prior to receiving Authorization to Inject
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 or within two (2) years of the permit effective date. 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) If the Director's review of the cement bond log does not show 80% bond index, an RTS is required	1.Prior to receiving Authorization to Inject 2. If an RTS is required, subsequent 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)	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. Refer to Part II.10. Annual Pressure Falloff Test for additional requirements.	First test shall be run 6 to12 months after Authorization to Inject. Subsequent tests shall be conducted at least once every year thereafter. The initial and subsequent years' test plans, if different than the previous year's plan, shall be submitted for review at least 30 days prior to conducting the annual pressure fall-off test.

APPENDIX C

OPERATING REQUIREMENTS

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

APPROVED INJECTION ZONE (GL, ft.)

FORMATION NAME or STRATIGRAPHIC UNIT	TOP (ft.) *	BOTTOM (ft.) *
Lyons	8,876	9,055
L. Satanka	9,055	9,235
Wolfcamp	9,235	9,341
Amazon	9,341	9,558
Council Grove	9,558	9,970
Admire	9,970	10,012
Virgil	10,012	10,214
Missouri(an)	10,214	10,431
Desmoines	10,431	10,833

* formation top and bottom depths at the SWD #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.

MAIP Parameters

fracture gradient*	specific gravity**	depth (ft)	friction loss (PSI)	Calculated MAIP (PSI)	**Authorized MAIP (PSI)**
0.559	1.000[+0.05]	8,876	TBD***	926	TBD

**The fracture gradient listed here is for the uppermost Lyons formation. This value was taken from the nearest UIC Class I well injecting in the same formation.*

*** From the MAIP equation in Part II, Section B.4(b), SG+0.05 or 1.050.*

**** Friction loss may be added after a valid step rate test prior to authorization to inject.*

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 EPA to satisfy reporting requirements.

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

WITHIN 30 DAYS AFTER AUTHORIZATION TO INJECT **PRIOR TO INTRODUCTION OF A NEW SOURCE AND** **QUARTERLY (if injection occurred during reporting period)** Analytical methods used must comply with the methods cited in Table 1 of 40 CFR 136.3, Appendix II of 40 CFR 261, or those methods listed below.	
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) • Lead-210 (pCi/L) via Method 905.0 Mod. • Gross Alpha and Beta Radiation (pCi/L) via Method 900.0 • Uranium-234 and Uranium-238 (pCi/L) via Method 907.0 • Thorium-230 (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 minimum, maximum and average injection fluid temperature (deg F)
	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:

1. **Isolate the Injection Zone**: Remove down hole apparatus from the well and perform necessary clean out; displace well fluid with plugging gel.
   PLUG 1: Squeeze injection zone perforations. Set a cast iron bridge plug (CIBP) within the innermost casing string no more than 50 feet above the top of the liner with a minimum 20-foot cement plug on the top of the CIBP. Alternatively, the Permittee may install a cement retainer no more than 50 feet above the top of the liner, squeeze the open perforations and then place a minimum 20-foot cement plug on top of the cement retainer.

2. **Isolate Shallow USDWs from the Injection Zone**:
   PLUG 2: Set a minimum 200-foot cement plug approximately 50 feet above the bottom of the surface casing to 150 feet below the bottom of the surface casing. This plug also covers the surface casing shoe.

3. **Isolate Surface Fluid Migration Paths**:
   PLUG 3: Set a cement plug inside the innermost casing string from 200 feet to the surface.

The SWD #1 is a new proposed well, the P&A plan may need to be modified after construction.

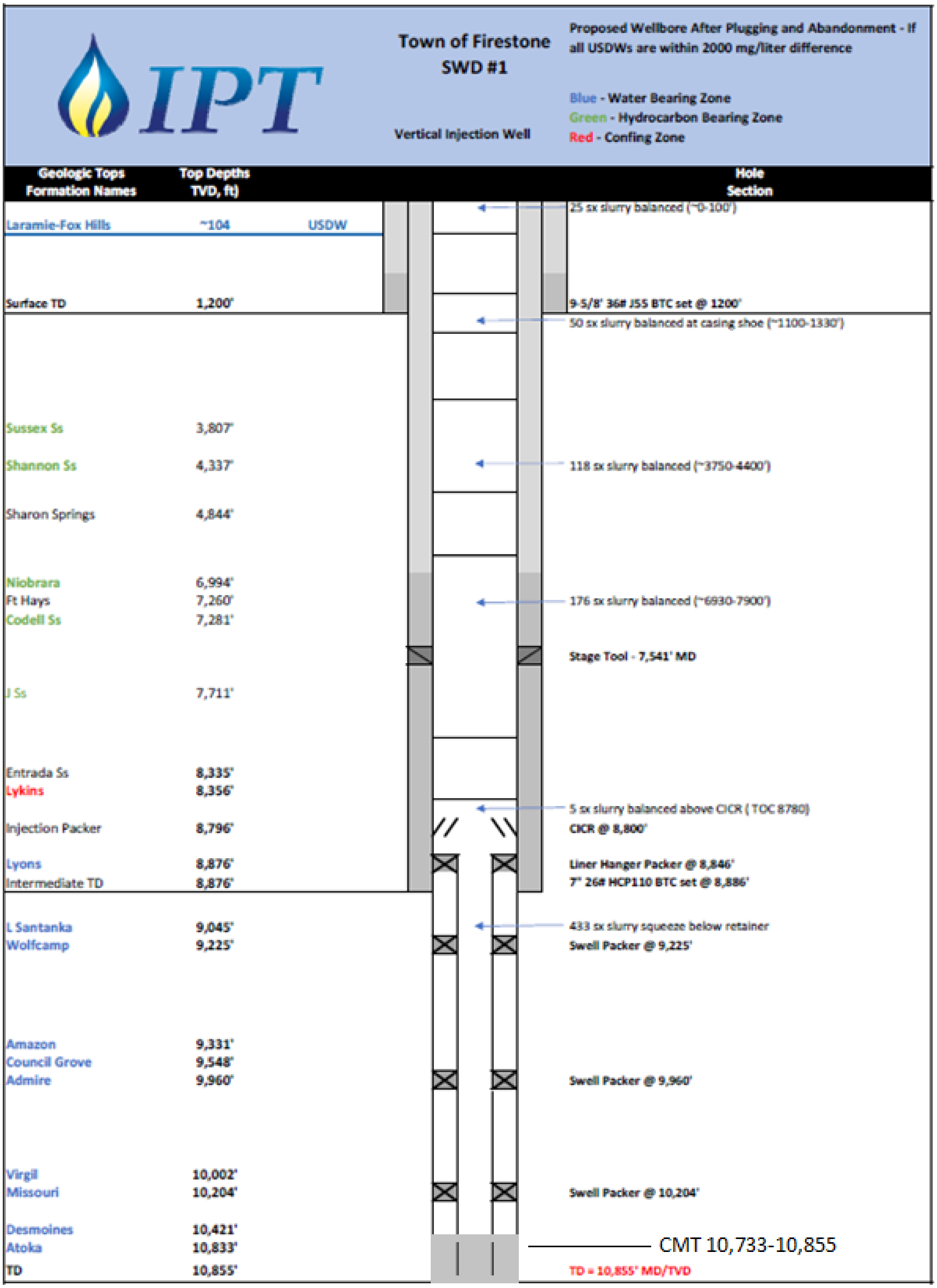
IPT
Town of Firestone
SWD #1
Vertical Injection Well
Proposed Wellbore After Plugging and Abandonment - If all USDWs are within 2000 mg/liter difference
Blue - Water Bearing Zone
Green - Hydrocarbon Bearing Zone
Red - Confing Zone
Geologic Tops Formation Names
Top Depths TVD, ft)
Hole Section
Laramie-Fox Hills ~104 USDW
Surface TD 1,200'
Sussex Ss 3,807'
Shannon Ss 4,337'
Sharon Springs 4,844'
Niobrara 6,994'
Ft Hays 7,260'
Codell Ss 7,281'
J Ss 7,711'
Entrada Ss 8,335'
Lykins 8,356'
Injection Packer 8,796'
Lyons 8,876'
Intermediate TD 8,876'
L Santanka 9,045'
Wolfcamp 9,225'
Amazon 9,331'
Council Grove 9,548'
Admire 9,960'
Virgil 10,002'
Missouri 10,204'
Desmoines 10,421'
Atoka 10,833'
TD 10,855'
25 sx slurry balanced (~0-100')
9-5/8' 36# J55 BTC set @ 1200'
50 sx slurry balanced at casing shoe (~1100-1330')
118 sx slurry balanced (~3750-4400')
176 sx slurry balanced (~6930-7900')
Stage Tool - 7,541' MD
5 sx slurry balanced above CICR (TOC 8780)
CICR @ 8,800'
Liner Hanger Packer @ 8,846'
7" 26# HCP110 BTC set @ 8,886'
433 sx slurry squeeze below retainer
Swell Packer @ 9,225'
Swell Packer @ 9,960'
Swell Packer @ 10,204'
CMT 10,733-10,855
TD = 10,855' MD/TVD

Figure E-1

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

Town of Firestone
Town of Firestone SWD#1
Weld County, Colorado

Class I Non-Hazardous Waste Disposal Well
CO12413-00000

CONTACT: Omar Sierra-Lopez
U. S. Environmental Protection Agency
Underground Injection Control Program, 8WD-SDU
1595 Wynkoop Street
Denver, Colorado 80202-1129
Telephone: (303) 312-7045
Email: Sierra-Lopez.Omar@epa.gov

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 CO12413-00000 (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.

Upon the Effective Date when issued, this Area Permit will authorize construction and operation of up to two Class I wells in this Permit area. 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

Town of Firestone
151 Grant Avenue
Firestone, CO 80520

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

CO12413-11959
Town of Firestone SWD#1
SW ¼ SW ¼
Section 31 T3N R67W

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

1459 feet FSL and 1093 feet FWL, S31, T3N, R67W;
608 feet FSL and 1055 feet FWL, S31, T3N, R67W;
606 feet FSL and 1316 feet FWL, S31, T3N, R67W;
30 feet FSL and 1315 feet FWL, S31, T3N, R67W;
37 feet FNL and 2456 feet FWL, S6, T2N, R67W;
1759 feet FNL and 2418 feet FWL, S6, T2N, R67W;
2281 feet FNL and 2094 feet FWL, S6, T2N, R67W;
2329 feet FNL and 1236 feet FWL, S6, T2N, R67W:
34 feet FNL and 1269 feet FWL, S6, T2N, R67W
30 feet FSL and 30 feet FWL, S31, T3N, R67W;
1469 feet FSL and 30 feet FWL, S31, T3N, R67W

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

Project Description

The Town of Firestone is in the process of designing and constructing a reverse osmosis (R.O.) procedure water treatment plant ("St. Vrain Water Treatment Plant") with the input water obtained from a nearby alluvial well field. This plant will operate at either 85% or 92% recovery with the system reject requiring disposal. It is The Town's intent to dispose of this reject via underground injection into one deep disposal well at rates which vary in time. A second well (SWD #2) will be proposed in the future by the Town of Firestone. Projected injection rates for years one (1) – three (3) are 30 – 60 gpm (1,029 – 2,057 BPD) at 85% R.O. recovery, and 15 – 30 gpm (514 – 1,029 BPD) at 92% R.O. recovery. Rates are expected to reach 90 – 180 gpm (3,086 – 6,171 BPD) in years five (5) – ten (10) and stabilize at 200 gpm (6,857 BPD) by year ten (10). The Town of Firestone SWD #1 ("SWD #1"), located in SW ¼ SW ¼ Sec. 31 T3N R67W, will be drilled first. The Town of Firestone will work with EPA Region 8 in the future to add a possible second well inside the proposed permit area.

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
Laramie-Fox Hills	0	104	550	USDW, sandstone, siltstone
Pierre Shale	104	7,004	28,235	Gray to brown shale. Some sandstone layers
Niobara	7,004	7,260	-	Gray to brown shale
Ft Hays	7,260	7,281	-	shale and sandstone
Codell	7,281	7,711	-	shale and sandstone
J S	7,711	8,335	-	shale and sandstone
Entrada	8,335	8,356	17,400	shale and sandstone
Lykins	8,356	8,876	-	sandstone, shale and siltstone
Lyons	8,876	9,055	17,600	sandstone
L Santanka	9,055	9,235	15,480	shale, siltstone, anhydrite and shale
Wolf Camp	9,235	9,341	15,480	limestone, dolomite, anhydrite, shale and siltstone
Amazon	9,341	9,558	15,980	dolomite
Council Grove	9,558	9,970	15,980	dolomite, limestone and chalk
Admire	9,910	10,012	15,980	sandstome and limestone
Virgil	10,012	10,214	15,960	sandstome and limestone
Missouri	10,214	10,431	15,960	sandstome and limestone
Desmoines	10,431	10,833	-	limestone
Atoka	10,833	11,400	-	limestone

* depths are approximate values at the wellbore

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 injection zone for the Firestone SWD well is constrained to the Lyons Formation and older sediments, which is approximately 1,200 feet below the top of the conventional "Muddy" J Sand. The injection interval will likely be located between approximately 8,876 and 10,833 feet, pending confirmation of the top of the Lyons Formation. Because approximately 8,777 feet of rock is expected to occur between the Laramie-Fox Hills aquifer and the injection interval, it is extremely unlikely that disposal fluid will affect the Laramie-Fox Hills USDW.

TABLE 2.2
INJECTION ZONE

Formation Name or Stratigraphic Unit	Top (ft)*	Base (ft)*
Lyons	8,876	9,055
L. Satanka	9,055	9,235
Wolfcamp	9,235	9,341
Amazon	9,341	9,558
Council Grove	9,558	9,970
Admire	9,970	10,012
Virgil	10,012	10,214
Missouri(an)	10,214	10,431
Desmoines	10,431	10,833

* depths are approximate values at the wellbore

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

There are no known outcrops of the confining and receiving formations or hazardous waste treatment, storage, or disposal facilities. 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 6,880 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 520 feet thick.

TABLE 2.3
CONFINING ZONES

Formation Name or Stratigraphic Unit	Top (ft)	Base (ft)	Lithology
Pierre Shale	104	7,004	Gray to brown shale. Some sandstone layers

Lykins	8,356	8,876	sandstone, shale and siltstone

* depths are approximate values at the wellbore

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

The Laramie-Fox Hills is a fine to very fine-grained sandstone and siltstone interbedded with shale and occasional coal layers. The drinking water wells in the AOR produce water from the Laramie-Fox Hills aquifer. The Laramie-Fox Hills is the lowermost aquifer in the Denver Basin aquifer system. The formations below the Laramie-Fox Hills contain water of poor quality and are not used for municipal or agricultural purposes. The Laramie-Fox Hills aquifer is present at the surface elevation of 4,818 feet to a measured depth of approximately 104 feet below surface.

TABLE 2.4
UNDERGROUND SOURCES OF DRINKING WATER (USDWs)

Formation Name or Stratigraphic Unit	Top (ft)*	Base (ft)*	TDS (mg/l)	Lithology
Laramie-Fox Hills	0	104	550	USDW, sandstone, siltstone

* depths are approximate values at the wellbore

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 well(s) are shown in TABLE 3.1.

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

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

The Firestone well depth is 10,855'. If during the well construction the Atoka formation is penetrated, the well will be cemented back as illustrated on Appendix A, Figure A-2 of the Permit, as the Atoka will not be used for injection.

TABLE 3.1
WELL CONSTRUCTION SWD #1

Casing Type	Hole Size (in)	Casing Size (in)	Cased Interval (ft)	Cemented Interval (ft)
Surface	12.25	9.625	0-1,200	0-1,200
Intermediate	8.75	7	0-8,876	0-8,876
Liner	6.125	4.5	8,846-10,855	

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.

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, injection fluid temperatures, 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

If an event is detected within two miles of the wellbore, the Permittee will immediately cease injection and report the event to EPA within 24 hours. The Permittee will report all events within 50 miles radius of the wellbore and provide a summary in the seismic events in the quarterly reports.

There is a history in the D-J basin of induced seismicity most notably demonstrated by earthquakes linked to injection at the Rock Mountain Arsenal (RMA) in the 1960s where contaminated water was injected into highly fractured Precambrian gneiss basement rock resulting in earthquakes. In the Denver basin in eastern Colorado, the Precambrian basement is about 13,000 ft below the surface between Denver and Colorado Springs, and about 6,000 ft below the surface near the Kansas border. The Precambrian Basement is about 12,000 ft below the surface in the Rocky Mountain Arsenal area. The Rocky Mountain Arsenal is approximately 16 miles south of the proposed SWD #1 well.

On December 29, 2015, a seismic event was detected approximately 21.5 miles northeast of the proposed SWD #1 well, near Evans, Colorado. This earthquake had a recorded magnitude of 2.1. This may have been induced by an injection well drilled to approximately 10,500 feet below the surface, found southeast of the epicenter of this event. This well has since been isolated from the basement rock via bailed cement.

The Firestone well depth is 10,855'. If during the well construction the Atoka formation is penetrated, the well will be cemented back as illustrated on Appendix A, Figure A-2 of the Permit, as the Atoka will not be used for injection. The Atoka is approximately 570' thick at the location of this well. The Firestone well will be constructed to provide sufficient distance from the top of the Precambrian basement rock in order to prevent induced seismicity.

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 boundary was determined by extending a one-quarter mile fixed radius around the permit boundary. There are no known outcrops of the confining and receiving formations or hazardous waste treatment, storage, or disposal facilities.

Colorado Division of Water Resources (CDWR) records show all permitted water wells within the AOR except for one (1) are designated as alluvial wells. Thirteen (13) wells are constructed and are used for monitoring, sampling, household, domestic, stock, and other purposes. Three (3) have permit issued statuses and are intended for household, domestic, monitoring, and sampling purposes with one (1) being permitted to the Laramie-Fox Hills aquifer. One (1) well was intended for domestic use but its permit has expired.

The oil and gas wells target the "Muddy" J Sand, Niobrara, Codell, Sussex, and Shannon formations. Ten (10) wells are plugged and abandoned (PA), five (5) are abandoned locations (AL), and two (2) are currently shut-in (SI). None of the oil and gas wells penetrate the upper confining formation of the proposed injection zone and thus are not hydraulic conduits for out-of-zone injectate migration.

Additionally, four (4) Division of Reclamation, Mining and Safety (DRMS) surface mines are included within the AOR. Two (2) hold terminated statuses and the other two (2) mines are active. The active surface mines are owned by Varra Companies, Incorporated and L.G. Everist, Incorporated and primarily produce sand and gravel. The Last Chance Ditch traverses across the AOR in section 6, south of the permit area.

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

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

Initial demonstration of External (Part II) MI will be required within six (6) to 12 months of injection and repeated no less than five (5) years after the last successful MIT. The External MIT will be demonstrated by using the results of a temperature log.

Additionally, the cement bond logs will also be required to evaluate the quality and location of cement to show that adequate cement exists to prevent significant movement of fluid out of the approved injection zone through the casing annular cement (i.e., 80% bond index cement bond across the confining zone.) Guidance on the logging and interpretation of the cement bond log (CBL) can be found at https://www.epa.gov/uic/underground-injection-control-epa-region-8-co-mt-nd-sd-ut-and-wy#guidance.

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

Injection Fluid Limitation

Approved injected fluids are limited to non-hazardous waste fluid generated by the Town of Firestone - St. Vrain Water Treatment Plant from their reverse osmosis plant and products injected for well workover and maintenance.

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 loss.

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

When additional perforations 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.

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 fluid temperature, 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 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 7520-19) to the Director. The Plugging Record must be certified as accurate and complete by the person responsible for the plugging operation. The plugging and abandonment plan is described in APPENDIX E of the Permit.

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

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 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://www.fiscal.treasury.gov/fsreports/ref/suretyBnd/c570.htm.

A letter of credit acceptable to the Director shall contain wording identical to model language provided to the permittee by EPA (40 CFR 144.70) and be issued by a bank or other institution whose operations are regulated and examined by a State or Federal agency.

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

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

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

UIC Financial Responsibility Coordinator
Mail Code: 8ENF-ROR
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.

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

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

National Historic Preservation Act (NHPA)
Section 106 of the National Historic Preservation Act, 54 U.S.C. § 306108, requires federal agencies to consider the effects on historic properties of actions they authorize, fund or carry out. EPA has determined that a decision to issue a Class II injection well permit for authorization of injection into the Town of Firestone SWD#1 well constitutes an undertaking subject to the National Historic Preservation Act and its implementing regulations at 36 CFR part 800. EPA's determination will be documented as part of the administrative record supporting the final Class I decision.

Endangered Species Act (ESA)
Section 7(a)(2) of the Endangered Species Act (ESA), 16 U.S.C. § 1536 (a)(2), requires federal agencies to ensure that actions they authorize, fund, or carry out are not likely to jeopardize the continued existence of federally-listed endangered or threatened species or result in the destruction or adverse modification of designated critical habitat of such species. EPA has determined that a decision to issue a Class I area permit for authorization of injection into the proposed Town of Firestone SWD #1 well would constitute an action that is subject to the Endangered Species Act and its implementing regulations (50 CFR part 402). Accordingly, EPA will comply with these regulations by determining what, if any, effects this action will have on any federally-listed endangered or threatened species or their designated critical habitat and by following any required ESA procedures. EPA's determination will be documented as part of the administrative record supporting the final Class I decision.

Executive Order 12898
On February 11, 1994, the President issued Executive Order 12898, entitled "Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations." EPA has concluded that there may be potential EJ communities proximate to the Authorized Permit Area. The primary potential human health or environmental effects to these communities associated with injection well operations would be local aquifers that are currently being used or may be used in the future as USDWs. EPA's UIC program authority under the Safe Drinking Water Act is designed to protect USDWs through the regulation of underground injection wells. EPA has drafted specific conditions in UIC Draft Area Permit CO12413-00000 to prevent contamination of USDWs which either are being used or will be used in the future by communities of EJ concern. These USDWs could

include the aquifer within the proposed injection zone in which case injection would only commence if the aquifer is exempted and thereby no longer protected under the SDWA. The UIC program will be conducting enhanced public outreach to EJ communities including publication of a public notice announcement in local newspapers and holding a public hearing, if requested, or if public interest in the proposed permit is high.