Southern Utah Wilderness Alliance
Petition for Review
UIC Permit UT22291-10328

Exhibit Three

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 8
1595 Wynkoop Street
DENVER, CO 80202-1129
Phone 800-227-8917
http://www.epa.gov/region08

NOV 17 2014

Ref: 8P-W-UIC

CERTIFIED MAIL
RETURN RECEIPT REQUESTED

Michael Decker
Gasco Energy, Inc.
7979 Tufts Avenue
Denver, Colorado 80202

RE: FINAL Permit
EPA UIC Permit UT22291-10328
Well: RBU 1-10D
NENE Sec. 10-T10S-R18E
Uintah County, Utah
API No.: 43-047-34312

Mr. Decker:

Enclosed is your copy of the FINAL Underground Injection Control (UIC) Permit for the proposed RBU 1-10D injection well. A Statement of Basis that discusses the conditions and requirements of this Environmental Protection Agency (EPA) UIC Permit is also included.

The public comment period ended on August 15, 2014. We received comments from one commenter on the Draft Permit. Also included with this letter is a copy of the Response to Comments. Because comments were received during the public comment period, the Final Permit becomes effective 30 days from the date of issuance per 40 CFR 124.15, to provide a 30-day window for the commenter to appeal the Final Permit decision.

Please note that under the terms of the Final Permit, you are authorized only to construct the proposed injection well, and must fulfill the "Prior to Commencing Injection" requirements of the Permit and obtain written Authorization to Inject prior to commencing injection. It is your responsibility to be familiar with and to comply with all provisions of the Final Permit.

If you have any questions on the enclosed Final Permit, please call Bruce Suchomel of my staff at (303) 312-6001, or toll-free at (800) 227-8917, extension 312-6001.

Sincerely,

Callie A. Videtich
Acting Assistant Regional Administrator
Office of Partnerships and Regulatory Assistance

Enclosures: Final UIC Permit
Statement of Basis
Response to Comments

cc letter only:

Uintah & Ouray Business Committee
Gordon Howell Jr., Chairman
Ronald Wopsock, Vice-Chairman
Tony Small, Councilman
Phillip Chimburas, Councilman
Stewart Pike, Councilman
Bruce Ignacio, Councilman

Lelilah Duncan, Acting Superintendent
BIA - Uintah & Ouray Indian Agency

cc with enclosures:

Bart Powaukee
Environmental Director
Ute Indian Tribe

Minnie Grant
Air Quality Coordinator
Ute Indian Tribe

Manual Myore
Director of Energy & Minerals Dept.
Ute Indian Tribe

Brad Hill
Utah Division of Oil, Gas, and Mining

Robin Hansen
Fluid Minerals Engineering Office
BLM - Vernal Office

Brad Woodard
Kleinfelder

Hollis Bairrington
Wapiti Energy

Morgan Anderson
QEP

Jim Davis
SITLA

Steve Bloch
Southern Utah Wilderness Alliance

Landon Newell
Southern Utah Wilderness Alliance

EPA

UNDERGROUND INJECTION CONTROL PROGRAM

PERMIT

PREPARED: November 2014

Permit No. UT22291-10328

Class II Enhanced Oil Recovery Injection Well

RBU 1-10D
Uintah County, UT

Issued To

Gasco Energy, Inc.
7979 E. Tufts Avenue
Suite 1150
Denver, CO 80237

Part I. AUTHORIZATION TO CONSTRUCT AND OPERATE

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

Gasco Energy, Inc. 7979 E. Tufts Avenue Suite 1150 Denver, CO 80237

is authorized to construct and to operate the following Class II injection well or wells:

RBU 1-10D 826' FNL and 642' FEL, NENE S10, T10S, R18E Uintah County, UT

EPA regulates the injection of fluids into injection 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. General permit conditions for which the content is mandatory and not subject to site-specific differences are not discussed in this document. Issuance of this Permit does not convey any property rights of any sort or any exclusive privilege, nor does it authorize injury to persons or property or invasion of other private rights, or any infringement of other Federal, State or local laws or regulations. (40 CFR §144.35) An EPA UIC Permit may be issued for the operating life of the injection well or project unless terminated for reasonable cause under 40 CFR §144.39, 144.40 and 144.41, and may be reviewed at least once every five (5) years to determine if action is required under 40 CFR §144.36(a).

This Permit is issued for the life of the well(s) unless modified, revoked and reissued, or terminated under 40 CFR §144.39 or 144.40. This EPA Permit may be adopted, modified, revoked and reissued, or terminated if primary enforcement authority for a UIC Program is delegated to an Indian Tribe or State. Upon the effective date of delegation, reports, notifications, questions and other correspondence should be directed to the Indian Tribe or State Director.

Issue Date: NOV 17 2014 Effective Date NOV 17 2014

Callie A. Videtich
Acting Assistant Regional Administrator
Office of Partnerships and Regulatory Assistance

*NOTE: The person holding this title is referred to as the "Director" throughout this Permit.

PART II. SPECIFIC PERMIT CONDITIONS

Section A. WELL CONSTRUCTION REQUIREMENTS

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

Details of the approved well construction plan are incorporated into this Permit as APPENDIX A. Changes to the approved plan that may occur during construction must be approved by the Director prior to being physically incorporated.

1. Casing and Cement.

The well or wells shall be cased and cemented to prevent the movement of fluids into or between underground sources of drinking water. The well casing and cement shall be designed for the life expectancy of the well and of the grade and size shown in APPENDIX A. Remedial cementing may be required if shown to be inadequate by cement bond log or other attempted demonstration of Part II (External) mechanical integrity.

2. Injection Tubing and Packer.

Injection tubing is required, and shall be run and set with a packer at or below the depth indicated in APPENDIX A. The packer setting depth may be changed provided it remains below the depth indicated in APPENDIX A and the Permittee provides notice and obtains the Director's approval for the change.

3. Sampling and Monitoring Devices.

The Permittee shall install and maintain in good operating condition:

(a) a "tap" at a conveniently accessible location on the injection flow line between the pump house or storage tanks and the injection well, isolated by shut-off valves, for collection of representative samples of the injected fluid; and

(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 Maximum Allowable Injection Pressure specified in APPENDIX C:

  (i) on the injection tubing; and

  (ii) on the tubing-casing annulus (TCA); and

(c) 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) specified in APPENDIX C is reached at the wellhead; and

(d) a non-resettable cumulative volume recorder attached to the injection line.

4. 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. Well log and test results shall be submitted to the Director within sixty (60) 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 test or log results.

5. Postponement of Construction or Conversion

The Permittee shall complete well construction within one year of the Effective Date of the Permit, or in the case of an Area Permit within one year of Authorization of the additional well. Authorization to construct and operate shall expire if the well has not been constructed within one year of the Effective Date of the Permit or Authorization and the Permit may be terminated under 40 CFR 144.40, unless the Permittee has notified the Director and requested an extension prior to expiration. Notification shall be in writing, and shall state the reasons for the delay and provide an estimated completion date. Once Authorization has expired under this part, the complete permit process including opportunity for public comment may be required before Authorization to construct and operate may be reissued.

6. Workovers and Alterations

Workovers and alterations shall meet all conditions of the Permit. Prior to beginning any addition or physical alteration to an injection well that may significantly affect the tubing, packer or casing, the Permittee shall give advance notice to the Director and obtain the Director's approval. The Permittee shall record all changes to well construction on a Well Rework Record (EPA Form 7520-12), and shall provide this and any other record of well workover, logging, or test data to EPA within sixty (60) days of completion of the activity.

A successful demonstration of Part I MI is required following the completion of any well workover or alteration which affects the casing, tubing, or packer. Injection operations shall not be resumed until the well has successfully demonstrated mechanical integrity and the Director has provided written approval to resume injection.

Section B. MECHANICAL INTEGRITY

The Permittee is required to ensure each injection well maintains mechanical integrity at all times. The Director, by written notice, may require the Permittee to comply with a schedule describing when mechanical integrity demonstrations shall be made.

An injection well has mechanical integrity if:

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

(b) There is no significant fluid movement into an underground source of drinking water through vertical channels adjacent to the injection well bore (Part II).

1. Demonstration of Mechanical Integrity (MI).

The operator shall demonstrate MI prior to commencing injection and periodically thereafter. Well-specific conditions dictate the methods and the frequency for demonstrating MI and are discussed in the Statement of Basis. The logs and tests are designed to demonstrate both internal (Part I) and external (Part II) MI as described above. The conditions present at this well site warrant the methods and frequency required in Appendix B of this Permit.

In addition to these regularly scheduled demonstrations of MI, the operator shall demonstrate internal (Part I) MI after any workover which affects the tubing, packer or casing.

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 injection activity. Results of MI tests shall be submitted to the Director as soon as possible but no later than sixty (60) days after the test is complete.

2. Mechanical Integrity Test Methods and Criteria

EPA-approved methods shall be used to demonstrate mechanical integrity. Ground Water Section Guidance No. 34 "Cement Bond Logging Techniques and Interpretation", Ground Water Section Guidance No. 37, "Demonstrating Part II (External) Mechanical Integrity for a Class II injection well permit", and Ground Water Section Guidance No. 39, "Pressure Testing Injection Wells for Part I (Internal) Mechanical Integrity" are available from EPA and will be provided upon request.

The Director may stipulate specific test methods and criteria best suited for a specific well construction and injection operation.

3. Notification Prior to Testing.

The Permittee shall notify the Director at least seven calendar days prior to any mechanical integrity test unless the mechanical integrity test is conducted after a well construction, well conversion, or a well rework, in which case any prior notice is sufficient. The Director may allow a shorter notification period if it would be sufficient to enable EPA to witness the mechanical integrity test. Notification may be in the form of a yearly or quarterly schedule of planned mechanical integrity tests, or it may be on an individual basis.

4. Loss of Mechanical Integrity.

If the well fails to demonstrate mechanical integrity during a test, or a loss of mechanical integrity becomes evident during operation (such as presence of pressure in the TCA, water flowing at the surface, etc.), the Permittee shall notify the Director within 24 hours (see Part III Section E Paragraph 11(e) of this Permit) and the well shall be shut-in within 48 hours unless the Director requires immediate shut-in.

Within five days, the Permittee shall submit a follow-up written report that documents test results, repairs undertaken or a proposed remedial action plan.

Injection operations shall not be resumed until after the well has successfully been repaired and demonstrated mechanical integrity, and the Director has provided approval to resume injection.

Section C. WELL OPERATION
INJECTION BETWEEN THE OUTERMOST CASING PROTECTING UNDERGROUND SOURCES OF DRINKING WATER AND THE WELL BORE IS PROHIBITED.

Injection is approved under the following conditions:

1. Requirements Prior to Commencing Injection.
Well injection, including for new wells authorized by an Area Permit under 40 CFR 144.33 (c), may commence only after all well construction and pre-injection requirements herein have been met and approved. The Permittee may not commence injection until construction is complete, and

(a) The Permittee has submitted to the Director a notice of completion of construction and a completed EPA Form 7520-10 or 7520-12; all applicable logging and testing requirements of this Permit (see APPENDIX B) have been fulfilled and the records submitted to the Director; mechanical integrity pursuant to 40 CFR 146.8 and Part II Section B of this Permit has been demonstrated; and

(i) The Director has inspected or otherwise reviewed the new injection well and finds it is in compliance with the conditions of the Permit; or

(ii) The Permittee has not received notice from the Director of his or her intent to inspect or otherwise review the new injection well within 13 days of the date of the notice in Paragraph 1a, in which case prior inspection or review is waived and the Permittee may commence injection.

2. Injection Interval.
Injection is permitted only within the approved injection interval, listed in APPENDIX C. Additional individual injection perforations may be added provided that they remain within the approved injection interval and the Permittee provides notice to the Director in accordance with Part II, Section A, Paragraph 6.

3. Injection Pressure Limitation

(a) The permitted Maximum Allowable Injection Pressure (MAIP), measured at the wellhead, is found in APPENDIX C. Injection pressure shall not exceed the amount the Director determines is appropriate to ensure that injection does not initiate new fractures or propagate existing fractures in the confining zone adjacent to USDWs. In no case shall injection pressure cause the movement of injection or formation fluids into a USDW.

The initial MAIP authorized by EPA is contained in Appendix C. The MAIP may be changed by EPA following a step-rate-test according to the formula and procedures discussed in the Statement of Basis.

(b) The Permittee may request a change of the MAIP, or the MAIP may be increased or decreased by the Director in order to ensure that the requirements in Paragraph (a) above are fulfilled. The Permitee may be required to conduct a step rate injection test or other suitable test to provide information for determining the fracture pressure of the injection zone. Change of the permitted MAIP by the Director shall be by modification of this Permit and APPENDIX C.

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

5. Injection Fluid Limitation.
Injected fluids are limited to those identified in 40 CFR 144.6(b)(2) as fluids used for enhanced recovery of oil or natural gas, including those which are brought to the surface in connection with conventional oil or natural gas production that may be commingled with waste waters from gas plants which are an integral part of production operations unless those waters are classified as a hazardous waste at the time of injection, pursuant to 40 CFR 144.6(b). Non-exempt wastes, including unused fracturing fluids or acids, gas plant cooling tower cleaning wastes, service wastes and vacuum truck wastes, are NOT approved for injection. This well is NOT approved for commercial brine injection, industrial waste fluid disposal or injection of hazardous waste as defined by CFR 40 Part 261. The Permittee shall provide a listing of the sources of injected fluids in accordance with the reporting requirements in Part II Section D Paragraph 4 and APPENDIX D of this Permit.

6. Tubing-Casing Annulus (TCA)
The tubing-casing annulus (TCA) shall be filled with water treated with a corrosion inhibitor, or other fluid approved by the Director. The TCA valve shall remain closed during normal operating conditions and the TCA pressure shall be maintained at zero (0) psi.

If TCA pressure cannot be maintained at zero (0) psi, the Permittee shall follow the procedures in Ground Water Section Guidance No. 35 "Procedures to follow when excessive annular pressure is observed on a well."

Section D. MONITORING, RECORDKEEPING, AND REPORTING OF RESULTS

1. Monitoring Parameters, Frequency, Records and Reports.
Monitoring parameters are specified in APPENDIX D. Pressure monitoring recordings shall be taken at the wellhead. The listed parameters are to be monitored, recorded and reported at the frequency indicated in APPENDIX D even during periods when the well is not operating.

Monitoring records must include:

(a) the date, time, exact place and the results of the observation, sampling, measurement, or analysis, and;

(b) the name of the individual(s) who performed the observation, sampling, measurement, or analysis, and;

(c) the analytical techniques or methods used for analysis.

2. *Monitoring Methods.*

(a) Monitoring observations, measurements, samples, etc. taken for the purpose of complying with these requirements shall be representative of the activity or condition being monitored.

(b) Methods used to monitor the nature of the injected fluids must comply with analytical methods cited and described in Table 1 of 40 CFR 136.3 or Appendix III of 40 CFR 261, or by other methods that have been approved in writing by the Director.

(c) Injection pressure, annulus pressure, injection rate, and cumulative injected volumes shall be observed and recorded at the wellhead under normal operating conditions, and all parameters shall be observed simultaneously to provide a clear depiction of well operation.

(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).

(f) Fluid rates are to be measured in barrels per day (bbl/day).

3. *Records Retention.*

(a) Records of calibration and maintenance, and all original strip chart recordings for continuous monitoring instrumentation, copies of all reports required by this permit, and records of all data used to complete the application for this permit shall be retained for a period of AT LEAST THREE (3) YEARS from the date of the sample, measurement, report, or application. This period may be extended anytime prior to its expiration by request of the Director.

(b) Records of the nature and composition of all injected fluids must be retained until three (3) years after the completion of any plugging and abandonment (P&A) procedures specified under 40 CFR 144.52(a)(6) or under Part 146 Subpart G, as appropriate. The Director may require the Permittee to deliver the records to the Director at the conclusion of the retention period. The Permittee shall continue to retain the records after the three (3) year retention period unless the Permittee delivers the records to the Director or obtains written approval from the Director to discard the records.

4. *Annual Reports.*

Whether the well is operating or not, the Permittee shall submit an Annual Report to the Director that summarizes the results of the monitoring required by Part II Section D and APPENDIX D.

The first Annual Report shall cover the period from the effective date of the Permit through December 31 of that year. Subsequent Annual Reports shall cover the period from January 1 through December 31 of the reporting year. Annual Reports shall be submitted by February 15 of the year following data collection. EPA Form 7520-11 may be copied and shall be used to submit the Annual Report, however, the monitoring requirements specified in this Permit are mandatory even if EPA Form 7520-11 indicates otherwise.

Section E. PLUGGING AND ABANDONMENT

1. Notification of Well Abandonment, Conversion or Closure.

The Permittee shall notify the Director in writing at least forty-five (45) days prior to: 1) plugging and abandoning an injection well, 2) converting to a non-injection well, and 3) in the case of an Area Permit, before closure of the project.

2. Well Plugging Requirements

Prior to abandonment, the injection well shall be plugged with cement in a manner which isolates the injection zone and prevents the movement of fluids into or between underground sources of drinking water, and in accordance with 40 CFR 146.10 and other applicable Federal, State or local law or regulations. Tubing, packer and other downhole apparatus shall 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 shall be verified by tagging. Plugging gel of at least 9.2 lb/gal shall be placed between all plugs. A minimum 50 ft surface plug shall be set inside and outside of the surface casing to seal pathways for fluid migration into the subsurface. The Plugging Record must be certified as accurate and complete by the person responsible for the plugging operation. Prior to placement of the cement plug(s) the well shall be in a state of static equilibrium with the mud weight equalized top to bottom, either by circulating the mud in the well at least once or by a comparable method prescribed by the Director.

3. Approved Plugging and Abandonment Plan.

The approved plugging and abandonment plan is incorporated into this Permit as APPENDIX E. Changes to the approved plugging and abandonment plan must be approved by the Director prior to beginning plugging operations. The Director also may require revision of the approved plugging and abandonment plan at any time prior to plugging the well.

4. Forty Five (45) Day Notice of Plugging and Abandonment.

The Permittee shall notify the Director at least forty-five (45) days prior to plugging and abandoning a well and provide notice of any anticipated change to the approved plugging and abanonment plan.

5. Plugging and Abandonment Report.

Within sixty (60) days after plugging a well, the Permittee shall submit a report (EPA Form 7520-13) to the Director. 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 plugging and abandonment plan; or

(b) Where actual plugging differed from the approved plugging and abandonment plan, an updated version of the plan, on the form supplied by the Director, specifying the differences.

6. Inactive Wells.

After any period of two years during which there is no injection the Permittee shall plug and abandon the well in accordance with Part II Section E Paragraph 2 of this Permit unless the Permittee:

(a) Provides written notice to the Director;

(b) Describes the actions or procedures the Permittee will take to ensure that the well will not endanger USDWs during the period of inactivity. These actions and procedures shall include compliance with mechanical integrity demonstration, Financial Responsibility and all other permit requirements designed to protect USDWs; and

(c) Receives written notice by the Director temporarily waiving plugging and abandonment requirements.

PART III. CONDITIONS APPLICABLE TO ALL PERMITS

Section A. EFFECT OF PERMIT

The Permittee is allowed to engage in underground injection in accordance with the conditions of this Permit. The Permittee shall not construct, operate, maintain, convert, plug, abandon, or conduct any other activity in a manner that allows the movement of fluid containing any contaminant into underground sources of drinking water, if the presence of that contaminant may cause a violation of any primary drinking water regulation under 40 CFR 142 or may otherwise adversely affect the health of persons. Any underground injection activity not authorized by this Permit or by rule is prohibited. Issuance of 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. 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 Safe Drinking Water Act (SDWA) or any other law governing protection of public health or the environment, for any imminent and substantial endangerment to human 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.

Section B. CHANGES TO PERMIT CONDITIONS

1. Modification, Reissuance, or Termination.

The Director may, for cause or upon a request from the Permittee, modify, revoke and reissue, or terminate this Permit in accordance with 40 CFR 124.5, 144.12, 144.39, and 144.40. Also, this Permit is subject to minor modification for causes as specified in 40 CFR 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. Conversions.

The Director may, for cause or upon a written request from the Permittee, allow conversion of the well from a Class II injection well to a non-Class II well. Conversion may not proceed until the Permittee receives written approval from the Director. Conditions of such conversion may include but are not limited to, approval of the proposed well rework, follow up demonstration of mechanical integrity, well-specific monitoring and reporting following the conversion, and demonstration of practical use of the converted configuration.

3. Transfer of Permit.

Under 40 CFR 144.38, this Permit is transferable provided the current Permittee notifies the Director at least thirty (30) days in advance of the proposed transfer date (EPA Form 7520-7) and provides a written agreement between the existing and new Permittees containing a specific date for transfer of Permit responsibility, coverage and liability between them. The notice shall adequately demonstrate that the financial responsibility requirements of 40 CFR 144.52(a)(7) will be met by the new Permittee. The Director may require modification or revocation and reissuance of the Permit to change the name of the Permittee and incorporate such other requirements as may be necessary under the Safe Drinking Water Act; in some cases, modification or revocation and reissuance is mandatory.

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 30 days.

5. Construction Changes, Workovers, Logging and Testing Data

The Permittee shall give advance notice to the Director, and shall obtain the Director's written approval prior to any physical alterations or additions to the permitted facility. Alterations or workovers shall meet all conditions as set forth in this permit. The Permittee shall record any changes to the well construction on a Well Rework Record (EPA Form 7520-12), and shall provide this and any other record of well workovers, logging , or test data to EPA within sixty (60) days of completion of the activity.

Following the completion of any well workovers or alterations which affect the casing, tubing, or packer, a successful demonstration of mechanical integrity (Part III, Section F of this Permit) shall be made, and written authorization from the Director received, prior to resuming injection activities.

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.

Section D. CONFIDENTIALITY

In accordance with 40 CFR Part 2 and 40 CFR 144.5, information submitted to EPA pursuant to this Permit 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 validity of the claim will be assessed 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. GENERAL PERMIT REQUIREMENTS

1. Duty to Comply.

The Permittee must comply with all conditions of this Permit. Any noncompliance constitutes a violation of the Safe Drinking Water Act (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 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.

2. *Duty to Reapply.*

If the Permittee wishes to continue an activity regulated by this Permit after the expiration date of this Permit, under 40 CFR 144.37 the Permittee must apply for a new permit prior to the expiration date.

3. *Need to Halt or Reduce Activity Not a Defense.*

It shall not be a defense for a Permittee 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 Rights.*

This Permit does not convey any property rights of any sort, or any exclusive privilege.

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. The Permittee is required to submit any information required by this Permit or by the Director to the mailing address designated in writing by the Director.

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 purpose 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 Director 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.

(a) 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 facility, and prior to commencing such changes.

(b) 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.

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

(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 30 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 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 VIII UIC Program Compliance and Technical Enforcement Director, or by contacting the EPA Region VIII Emergency Operations Center at (303) 293-1788.

In addition, a follow up written report shall be provided to the Director within five (5) 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) Oil Spill and Chemical Release Reporting: The Permittee shall comply with all reporting requirements related to the occurence of oil spills and chemical releases by contacting the National Response Center (NRC) at (800) 424-8802, (202) 267-2675, or through the NRC website http://www.nrc.uscg.mil/index.htm.

(g) Other Noncompliance. The Permittee shall report all instances of noncompliance not reported under paragraphs Part III, Section E Paragraph 11(b) or Section E, Paragraph 11(e) at the time the monitoring reports are submitted. The reports shall contain the information listed in Paragraph 11(e) of this Section.

(h) Other information. Where the Permittee becomes aware that it failed to submit any relevant facts in the permit application, or submitted incorrect information in a permit application or in any report to the Director, the Permittee shall promptly submit such facts or information to the Director.

Section F. FINANCIAL RESPONSIBILITY

1. Method of Providing Financial Responsibility.

The Permittee shall maintain continuous compliance with the requirement to maintain financial responsibility and resources to close, plug, and abandon the underground injection well(s). No substitution of a demonstration of financial responsibility shall become effective until the Permittee receives written 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. Insolvency.

In the event of:

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

(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) days after any event specified in (a), (b), or (c) above.

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

APPENDIX A

WELL CONSTRUCTION REQUIREMENTS

The well is an existing production well. The well is proposed to be converted to an Enhanced Oil Recovery injection well. A summary of the pertinent well construction and conversion information is as follows:

Surface casing: 8-5/8" steel casing set at a total depth of 2,414' in a 12-1/4" hole and cemented to surface using 750 sacks of Class G cement.

Longstring casing ("production casing"): 5-1/2" steel casing set to a total depth of 9,383' in a 7-7/8 hole and cement using 1,125 sacks of cement (combination of HiFil and Type V cement). The top of cement (TOC) is at at a depth of 2,980'.

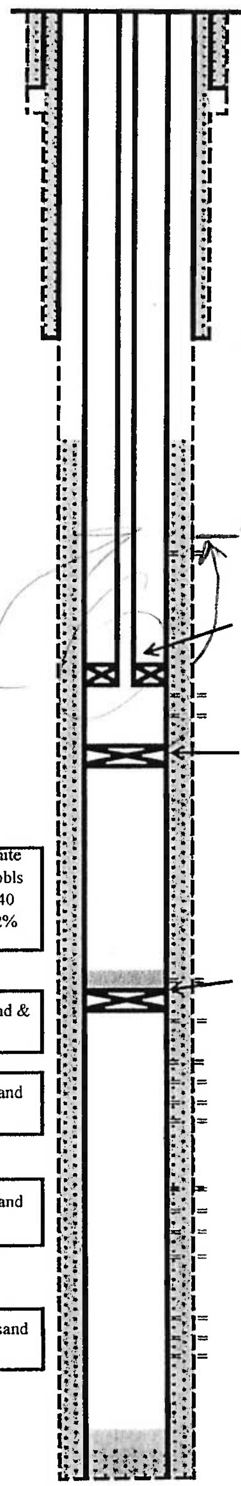
Existing Perforations: 4,861'-4,880'

Tubing: 2-7/8" set at a depth of 4,840'. The end of tubing must be within 100' of the top perforation.

The wellbore diagram on page A-2 contains the additional well construction information (note:all depths are approximate and are based on an approximate KB elevation of 5,041 ft.).

Gasco Energy, Inc.
UT22291-10328

RBU 1-10D: Proposed Injection Configuration



5,023	Ground Elevation
	Uinta Frm.
1,186	Green River Frm.
2414	
2523	**BMSW**
2980	**TOC**
4346-4704	Upper Confining Layer (Black Shale)
4650'	
4,704	Top of Injection Zone
	Uteland Butte Member

2 7/8" 6.50# J-55 8rd Internally Coated Tubing
Packer Set @ ~~4840'~~ 4650'

4861-69, 4874-78	Stage 5	C-Shoal (Uteland Butte Limestone)
4,880		Bottom of Injection Zone

CIBP Set @ 5000'

4880-5480	Lower Confining Layer (Wasatch Frm.)

CIBP Set @ 7800' w/ 100' Cement

7846-57	Stage 4	Wasatch
8805-09, 8813-21, 8864-69	Stage 3	Mesaverde
8911-15, 8937-42, 8978-84, 9004-11	Stage 2	Mesaverde
9149-55, 9241-50, 9260-64	Stage 1	Mesaverde

CONDUCTOR

SIZE:	13 3/8"
WT/GRD:	K-55
WT/GRD:	54.5#
CSA:	84'
SX:	Ready mix
CIRC:	Y
TOC:	Surface
HOLE SIZE:	17 1/2"

SURFACE CASING

SIZE:	8 5/8"
WT/GRD:	J-55
WT/GRD:	32#
CSA:	2,414
SX:	500 sx Class G
	250 sx Class G
CIRC:	Y
TOC:	Surface
HOLE SIZE:	12 1/4"

PRODUCTION CASING

SIZE:	5 1/2"
WT/GRD:	N-80
WT/GRD:	17#
CSA:	9,383
SX:	100 sx HiFil
	1025 sx Type V
CIRC:	Y
TOC:	2980'
HOLE SIZE:	7 7/8"

Stimulation

Stage 5: 12/17/2013	Hybrid frac well w/75,140# 20/40 white sand, 47 bbls 15% HCL acid, 1,255 bbls FR slick water, 903 bbls 15# Delta 140 gelled fluid, and flushed w/112 bbls 2% KCL
Stage 4: 1/23/2005	N2 Frac w/ 38891# 20/40 Ottawa sand & 211 MCF N2
Stage 3: 1/22/2005	N2 Frac w/ 31566# 20/40 PR 6000 sand & 314 MCF N2
Stage 2: 1/22/2005	N2 Frac w/ 58972# 20/40 PR 6000 sand & 400 MCF N2
Stage 1: 1/22/2005	N2 Frac w/ 44,837# 20/40 PR 6000 sand & 313 MCF N2

MD:	9400
TD:	9400

APPENDIX B

LOGGING AND TESTING REQUIREMENTS

Logs.

Logs will be conducted according to current UIC guidance. It is the responsibility of the Permittee to obtain and use guidance prior to conducting any well logging required as a condition of this permit.

WELL NAME: RBU 1-10D

TYPE OF LOG	DATE DUE
CBL/VDL/GAMMA RAY	Prior to receiving authorization to inject
Porosity	Prior to receiving authorization to inject
RATS	The CBL does not show Part II MI. Therefore, a RATS is required prior to authorization to inject and at least once every 5 years after the last successful demonstration of Part II MI.

Tests.

Tests will be conducted according to current UIC guidance. It is the responsibility of the Permittee to obtain and use guidance prior to conducting any well test required as a condition of this permit.

WELL NAME: RBU 1-10D

TYPE OF TEST	DATE DUE
Standard Annulus Pressure	Prior to authorization to inject and at least once every five (5) years after the last successful demonstration of Part I Mechanical Integrity.
Pore Pressure	Prior to receiving authorization to inject
Step Rate Test	Prior to receiving authorization to inject. The SRT shall be performed following current EPA guidance.
Cement Records	Prior to receiving authorization to inject
Injection Zone Water Sample	Prior to receiving authorization to inject, a representative sample (stabilized specific conductivity from three successive swab runs) from the injection zone will be analyzed for TDS, pH, Specific Gravity and Specific Conductivity

APPENDIX C

OPERATING REQUIREMENTS

MAXIMUM ALLOWABLE INJECTION PRESSURE:

Maximum Allowable Injection Pressure (MAIP) as measured at the surface shall not exceed the pressure(s) listed below.

WELL NAME	MAXIMUM ALLOWED INJECTION PRESSURE (psi) ZONE 1 (Upper)
RBU 1-10D	1,945

INJECTION INTERVAL(S):

Injection is permitted only within the approved injection interval listed below. Injection perforations may be altered provided they remain within the approved injection interval and the Permittee provides notice to the Director in accordance with Part II, Section A, Paragraph 6. Specific injection perforations can be found in Appendix A.

WELL NAME: RBU 1-10D

FORMATION NAME	APPROVED INJECTION INTERVAL (KB, ft) TOP	BOTTOM	FRACTURE GRADIENT (psi/ft)
Uteland Butte	4,704.00 -	4,880.00	0.860

ANNULUS PRESSURE:

The annulus pressure shall be maintained at zero (0) psi as measured at the wellhead. If this pressure cannot be maintained, the Permittee shall follow the procedures listed under Part II, Section C. 6. of this permit.

MAXIMUM INJECTION VOLUME:

There is no limitation on the number of barrels per day (bbls/day) of water that shall be injected into this well, provided further that in no case shall injection pressure exceed that limit shown in Appendix C.

APPENDIX D

MONITORING AND REPORTING PARAMETERS

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

OBSERVE MONTHLY AND RECORD AT LEAST ONCE EVERY THIRTY DAYS	
OBSERVE AND RECORD	Injection pressure (psig)
	Annulus pressure(s) (psig)
	Injection rate (bbl/day)
	Fluid volume injected since the well began injecting (bbls)

ANNUALLY	
ANALYZE	Injected fluid total dissolved solids (mg/l)
	Injected fluid specific gravity
	Injected fluid specific conductivity
	Injected fluid pH

ANNUALLY	
REPORT	Each month's maximum and averaged injection pressures (psig)
	Each month's maximum and minimum annulus pressure(s) (psig)
	Each month's injected volume (bbl)
	Fluid volume injected since the well began injecting (bbl)
	Written results of annual injected fluid analysis
	Sources of all fluids injected during the year

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 REQUIREMENTS

Following the operating life of the well as an injection well, the well must be properly plugged and abandoned in accordance with permit Section II.E. and with the approved Plugging and Abandoment (P&A) Plan. The operator must use appropriate grades of cement for all plugging and abandonment procedures. The P&A Plan is summarized below.

Cement Plugs:

Plug 1: 7,700'-7,800' -This plug was previously installed during conversion of well from a production well to an injection well.

Plug 2: 4,654'-5,000' -This plug isolates the injection zone.

Plug 3: 2,050'-2,650' -This plug covers the base of the surface casing, the base of the deepest USDW, and the Mahogany Bench Formation.

Plug 4: 1,130'-1,230' -This plug covers the top of the Green River Formation.

Plug 5: Surface to 100' -This plug isolates the well at the surface.

Additional P&A Plan information is contained on pages E-2 (P&A wellbore diagram) and E-3 (narrative of specific P&A procedures).

Gasco Energy, Inc.
UT22291-10328

RBU 1-10D: Proposed P&A Configuration

CONDUCTOR

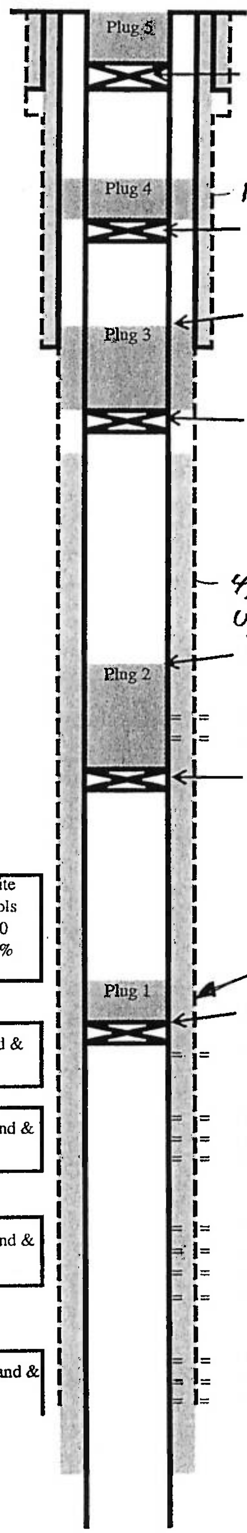
SIZE:	13 3/8"
WT/GRD:	K-55
WT/GRD:	54.5#
CSA:	84'
SX:	Ready mix
CIRC:	Y
TOC:	Surface
HOLE SIZE:	17 1/2"

SURFACE CASING

SIZE:	8 5/8"
WT/GRD:	J-55
WT/GRD:	32#
CSA:	2,414
SX:	500 sx Class G
	250 sx Class G
CIRC:	Y
TOC:	Surface
HOLE SIZE:	12 1/4"

PRODUCTION CASING

SIZE:	5 1/2"
WT/GRD:	N-80
WT/GRD:	17#
CSA:	9,383
SX:	100 sx HiFil
	1025 sx Type V
CIRC:	Y
TOC:	2980'
HOLE SIZE:	7 7/8"



CIBP Set @ 100' w/ Cement to Surface — Uinta Fm

1,186' Top of Green River Fm

CIBP Set @ 1230' w/ 100' Cement

Cement to 2050'

2523 BMSW — Mahogany Bench Fm 2,597' - 2,661'

CIBP Set @ 2650'

2980 TOC

4,346' Top of Upper Confining Zone

Upper Confining Zone: 4,346' - 4,704'

Cement to ~~4750'~~ 4,654'

Injection Zone: 4,704' - 4,880'

4861-69 4874-78	Stage 5	C-Shoal (Uteland Butte Limestone)	

CIBP Set @ 5000' — Lower Confining Zone: 4,880' - 5,480'

Top of Wasatch Fm: 4,880'

Previously installed (during well conversion)

CIBP Set @ 7800' w/ 100' Cement

7846-57	Stage 4	Wasatch
8805-09 8813-21 8864-69	Stage 3	Mesaverde
8911-15 8937-42 8978-84 9004-11	Stage 2	Mesaverde
9149-55 9241-50 9260-64	Stage 1	Mesaverde

Stimulation

Stage 5: 12/17/2013	Hybrid frac well w/75,140# 20/40 white sand, 47 bbls 15% HCL acid, 1,255 bbls FR slick water, 903 bbls 15# Delta 140 gelled fluid, and flushed w/112 bbls 2% KCl.
Stage 4: 1/23/2005	N2 Frac w/ 38891# 20/40 Ottawa sand & 211 MCF N2
Stage 3: 1/22/2005	N2 Frac w/ 31566# 20/40 PR 6000 sand & 314 MCF N2
Stage 2: 1/22/2005	N2 Frac w/ 58972# 20/40 PR 6000 sand & 400 MCF N2
Stage 1: 1/22/2005	N2 Frac w/ 44,837# 20/40 PR 6000 sand & 313 MCF N2

MD: 9400
TD: 9400

Revised by EPA

APPENDIX F

CORRECTIVE ACTION REQUIREMENTS

No corrective action is deemed necessary for this project.

STATEMENT OF BASIS

GASCO ENERGY, INC.
RBU 1-10D
UINTAH COUNTY, UT

EPA PERMIT NO. UT22291-10328

CONTACT: Tom Aalto
U. S. Environmental Protection Agency
Ground Water Program, 8P-W-GW
1595 Wynkoop Street
Denver, Colorado 80202-1129
Telephone: 1-800-227-8917 ext. 312-6949

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 the 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. EPA UIC permit conditions are based upon the authorities set forth in regulatory provisions at 40 CFR Parts 144 and 146, and address potential impacts to underground sources of drinking water. Under 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 of 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, the Permit authorizes the construction and operation of injection wells so that the injection does not endanger underground sources of drinking water, governed by the conditions specified in the Permit. The Permit is issued for the operating life of the injection well or project unless terminated for reasonable cause under 40 CFR 144.39, 144.40 and 144.41. The Permit is subject to EPA review at least once every five (5) years to determine if action is required under 40 CFR 144.36(a).

PART I. General Information and Description of Facility

Gasco Energy, Inc. 7979 E. Tufts Avenue Suite 1150 Denver, CO 80237

on

February 4, 2014

submitted an application for an Underground Injection Control (UIC) Program Permit or Permit Modification for the following injection well or wells:

RBU 1-10D 826' FNL and 642' FEL, NENE S10, T10S, R18E Uintah County, UT

Regulations specific to Uintah-Ouray Indian Reservation injection wells are found at 40 CFR 147 Subpart TT.

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

Considerations Under Federal Law (40 CFR Part 144.4): The well is proposed to be converted from a producing well to an injection well using the same perforations in the Uteland Butte Member of the Green River Formation. There will be no new land disturbances. As such, there are not expected to be any impacts related to the National Historic Preservation Act (NHPA), or the Endangered Species Act (ESA).

NEPA Environmental Impact Study (EIS) Area: The project area is located in the U.S. BLM Gasco Energy, Inc. Final EIS Project Area (2012).

The Permit will expire upon delegation of primary enforcement responsibility (primacy) for applicable portions of the UIC Program to the Ute Indian Tribe or the State of Utah unless the delegated agency has the authority and chooses to adopt and enforce this Permit as a Tribal or State Permit.

TABLE 1.1 shows the status of the well or wells as "New", "Existing", or "Conversion" and for Existing shows the original date of injection operation. Well authorization "by rule" under 40 CFR Part 144 Subpart C expires automatically on the Effective Date of an issued UIC Permit.

TABLE 1.1 WELL STATUS / DATE OF OPERATION		
CONVERSION WELLS		
Well Name	**Well Status**	**Date of Operation**
RBU 1-10D	Conversion	N/A

PART II. Permit Considerations (40 CFR 146.24)

Hydrogeologic Setting

See Statement of Basis Attachment 1: "Overview of Project Area Hydrogeology and Geology"

Geologic Setting (TABLE 2.1)

TABLE 2.1
GEOLOGIC SETTING
RBU 1-10D

Formation Name	Top (ft)	Base (ft)	TDS (mg/l)	Lithology
Uinta	0	1,186		mudstones, siltstones and sandstones
Uinta/Green River (GR)	0	2,523	< 10,000	mudstones, siltstones and sandstones
Upper Green River	1,186	2,097		mudstones, siltstones and sandstones
Mahogany Oil Shale Unit	2,097	2,661		shales
Middle GR/Garden Gulch	2,661	3,550		shales and very fine grained sandstones
Upper Douglas Creek	3,550	4,082		calcareous sandstones, shales, and limestones
Lower Douglas Creek	4,082	4,270		calcareous sandstones, shales, and limestones
Castle Peak Carbonate	4,270	4,346		carbonate
Black Shale	4,346	4,704		shales
Uteland Butte	4,704	4,880	62,276	porous and permeable Interbedded limestones and sandstones
Wasatch/Colton	4,880	5,480		shales, limestones and sandstones
Wasatch/Colton	5,480	7,800		shales, limestones and sandstones
Mesaverde	7,800	9,400		sandstones, shales and minor coals

Proposed Injection Zone(s) (TABLE 2.2)

An injection zone is a geological formation, group of formations, or part of a formation that receives fluids through a well. The proposed injection zones 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.

TABLE 2.2
INJECTION ZONES
RBU 1-10D

Formation Name	Top (ft)	Base (ft)	TDS (mg/l)	Fracture Gradient (psi/ft)	Porosity	Exempted?*
Uteland Butte	4,704	4,880	62,276	0.860		N/A

*** C - Currently Exempted**
E - Previously Exempted
P - Proposed Exemption
N/A - Not Applicable

Confining Zone(s) (TABLE 2.3)

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

TABLE 2.3
CONFINING ZONES
RBU 1-10D

Formation Name	Formation Lithology	Top (ft)	Base (ft)
Black Shale	shales	4,346	4,704
Wasatch/Colton	shales, limestones and sandstones	4,880	5,480

Underground Sources of Drinking Water (USDWs) (TABLE 2.4)

Aquifers or the portions thereof which contain less than 10,000 mg/l total dissolved solids (TDS) and are being or could in the future be used as a source of drinking water are considered to be USDWs. The USDWs in the area of this facility are identified in TABLE 2.4.

TABLE 2.4
UNDERGROUND SOURCES OF DRINKING WATER (USDW)
RBU 1-10D

Formation Name	Formation Lithology	Top (ft)	Base (ft)	TDS (mg/l)
Uinta/Green River (GR)	mudstones, siltstones and sandstones	0	2,523	< 10,000

PART III. Well Construction (40 CFR 146.22)

TABLE 3.1
WELL CONSTRUCTION REQUIREMENTS
RBU 1-10D

Casing Type	Hole Size (in)	Casing Size (in)	Cased Interval (ft)	Cemented Interval (ft)
Other	17.50	13.38	0 - 20	0 - 20
Surface	12.25	8.63	0 - 2,414	0 - 2,414
Longstring	7.88	5.50	0 - 9,383	0 - 2,980

The approved well completion plan will be incorporated into the Permit as APPENDIX A and will be binding on the Permittee. Modification of the approved plan is allowed under 40 CFR 144.52(a)(1) provided written approval is obtained from the Director prior to actual modification.

Casing and Cementing (TABLE 3.1)
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 fluids into USDWs. Well construction details for this "new" injection well is shown in TABLE 3.1.

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

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 above the uppermost perforation. The tubing and packer are designed to prevent injection fluid from coming into contact with the outermost casing.

Tubing-Casing Annulus (TCA)
The 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 fresh water treated with a corrosion inhibitor or other fluid approved by the Director.

Monitoring Devices
The permittee will be required to install and maintain wellhead equipment that allows for monitoring pressures and providing access for sampling the injected fluid. Required equipment may include

but is not limited to: 1) shut-off valves located at the wellhead on the injection tubing and on the TCA; 2) a flow meter that measures the cumulative volume of injected fluid; 3) fittings or pressure gauges attached to the injection tubing and the TCA for monitoring the injection and TCA pressure; and 4) a tap on the injection line, isolated by shut-off valves, for sampling the injected fluid.

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

PART IV. Area of Review, Corrective Action Plan (40 CFR 144.55)

TABLE 4.1

AOR AND CORRECTIVE ACTION

Well Name	Type	Status (Abandoned Y/N)	Total Depth (ft)	TOC Depth (ft)	CAP Required (Y/N)
RBU 8-10D	Producer	No	4,900	850	No

TABLE 4.1 lists the wells in the Area of Review ("AOR") and shows the well type, operating status, depth, top of casing cement ("TOC") and whether a Corrective Action Plan ("CAP") is required for the well.

Area Of Review

Applicants for Class I, II (other than "existing" wells) or III injection well Permits are required to identify the location of all known wells within the injection well's Area of Review (AOR) which penetrate the injection zone, or in the case of Class II wells operating over the fracture pressure of the formation, all known wells within the area of review that penetrate formations which may be affected by increased pressure. 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.

Corrective Action Plan

For wells in the AOR which are improperly sealed, completed, or abandoned, the applicant shall develop a Corrective Action Plan (CAP) consisting of the steps or modifications that are necessary to prevent movement of fluid into USDWs.

The CAP will be incorporated into the Permit as APPENDIX F and become binding on the permittee.

PART V. Well Operation Requirements (40 CFR 146.23)

TABLE 5.1 INJECTION ZONE PRESSURES RBU 1-10D			
Formation Name	**Depth Used to Calculate MAIP (ft)**	**Fracture Gradient (psi/ft)**	**Initial MAIP (psi)**
Uteland Butte	4,704	0.860	1,945

Approved Injection Fluid

The approved injection fluid is limited to Class II injection well fluids pursuant to 40 CFR § 144.6(b). For disposal wells injecting water brought to the surface in connection with natural gas storage operations, or conventional oil or natural gas production, the fluid may be commingled and the well used to inject other Class II wastes such as drilling fluids and spent well completion, treatment and stimulation fluid. Injection of non-exempt wastes, including unused fracturing fluids or acids, gas plant cooling tower cleaning wastes, service wastes, and vacuum truck and drum rinsate from trucks and drums transporting or containing non-exempt waste, is prohibited.

Injection Pressure Limitation

Injection pressure, measured at the wellhead, shall not exceed a maximum calculated to assure that the pressure used during injection does not initiate new fractures or propagate existing fractures in the confining zones adjacent to the USDWs.

The initial Maximum Allowable Injection Pressure (MAIP) approved by EPA is contained in Appendix C. The MAIP may be changed by EPA following the completion of a more recent step-rate-test by the operator. After review of any newly submitted step-rate-test data the EPA will notify the operator in writing of any change in the approved MAIP. In no case would the approved MAIP be at or above pressures that could result in the fracturing of the upper confining zone.

The applicant submitted injection fluid density and injection zone data which was used to calculate a formation fracture pressure and to determine the maximum allowable injection pressure (MAIP), as measured at the surface, for this Permit.

TABLE 5.1 lists the fracture gradient for the injection zone and the approved MAIP, determined according to the following formula:

$$FP = [fg - (0.433 * sg)] * d$$

FP = formation fracture pressure (measured at surface)
fg = fracture gradient (from submitted data or tests)
sg = specific gravity (of injected fluid)
d = depth to top of injection zone (or top perforation)

Injection Volume Limitation

Cumulative injected fluid volume limits are set to assure that injected fluids remain within the boundary of the exempted area. Cumulative injected fluid volume is limited when injection occurs into an aquifer that has been exempted from protection as a USDW.

Mechanical Integrity (40 CFR 146.8)
An injection well has mechanical integrity if:

1. there is no significant leak in the casing, tubing, or packer (Part I); and
2. there is no significant fluid movement into a USDW through vertical channels adjacent to the injection well bore (Part II).

The Permit prohibits injection into a well which lacks mechanical integrity.

The Permit requires that the well demonstrate mechanical integrity prior to injection and periodically thereafter. A demonstration of mechanical integrity includes both internal (Part I) and external (Part II). The methods and frequency for demonstrating Part I and Part II mechanical integrity are dependent upon well-specific conditions as explained below.

PART VI. Monitoring, Recordkeeping and Reporting Requirements

Injection Well Monitoring Program
At least once a year the permittee must analyze a sample of the injected fluid for total dissolved solids (TDS), specific conductivity, pH, and specific gravity. This analysis shall be reported to EPA annually as part of the Annual Report to the Director. Any time a new source of injected fluid is added, a fluid analysis shall be made of the new source.

Instantaneous injection pressure, injection flow rate, cumulative fluid volume and TCA pressures must be observed on a weekly basis. A recording, at least once every thirty (30) days, must be made of the injection pressure, annulus pressure, monthly injection flow rate and cumulative fluid volume. This information is required to be reported annually as part of the Annual Report to the Director.

PART VII. Plugging and Abandonment Requirements (40 CFR 146.10)

Plugging and Abandonment Plan
Prior to abandonment, the well shall 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 shall 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 shall be verified by tagging. Plugging gel of at least 9.2 lb/gal shall be placed between all plugs. A minimum 50 ft surface plug shall be set inside and outside of the surface casing to seal pathways for fluid migration into the subsurface. Within sixty (60) days after plugging the owner or operator shall submit Plugging Record (EPA Form 7520 13) 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)

Demonstration of Financial Responsibility
The permittee is required to maintain financial responsibility and resources to close, plug, and abandon the underground injection operation in a manner prescribed by the Director. The

permittee shall show evidence of such financial responsibility to the Director by the submission of a surety bond, or other adequate assurance such as financial statements or other materials acceptable to the Director. The Regional Administrator may, on a periodic basis, require the holder of a lifetime permit to submit a revised estimate of the resources needed to plug and abandon the well to reflect inflation of such costs, and a revised demonstration of financial responsibility if necessary. Initially, the operator has chosen to demonstrate financial responsibility with:

The EPA approved the operator's demonstration of financial responsibility for the estimated cost of plugging and abandonment of the injection well on the following date (see EPA file for specific instrument and supporting documentation): Financial Responsibility Approved by EPA on: June 17, 2014.

Surety Bond, received February 6, 2013

Evidence of continuing financial responsibility is required to be submitted to the Director annually.

Response To Public Comments

On

EPA Permit Number: UT22291-10328

for

RBU 1-10D Class II Enhanced Oil Recovery Well

in the

River Bend Unit

Uintah County, Utah

Issued to

Gasco Energy, Inc.

Background

In July 2014, staff of the U. S. Environmental Protection Agency (EPA) prepared Underground Injection Control (UIC) Draft Permit Number UT22291-10328. The Final Permit will authorize the construction and operation of the RBU 1-10D Class II UIC well to inject produced waters underground for the purpose of contributing to an enhanced oil recovery project in the River Bend Unit as proposed by Gasco Energy, Inc. (Gasco). In accordance with the federal public notice regulations, public notice of the EPA's Draft UIC Permit was posted in the Uinta Basin Standard and the Vernal Express, with the public notification period ending August 15, 2014.

EPA received comments from one commenter regarding water quality descriptions and determination, well construction description, and the project description considerations. The comments, attached to this document as Attachment A, were the only public comments received by the EPA.

The EPA provided public notice of its intent to issue a permit to Gasco for a Class II injection well. EPA did not receive any comments during the comment period but received comments from the Southern Utah Wilderness Alliance 11 days after the formal deadline of August 15, 2014. While EPA is not required to consider comments received outside of the comment period, in this instance, EPA decided to consider the comments in its decision-making process. Although EPA chose to consider these comments received outside the comment period, EPA makes these determinations on a case-by-case basis, and there should be no expectation that this will occur for future permit decisions. A summary of the issues presented in these comments and EPA's responses to those concerns, are discussed below:

Well Construction

Comment #1: The commenter expressed concern that the design and construction of the proposed injection well and nearby offset wells are not sufficient to protect USDWs. More specifically, the commenter is concerned that a portion of the annular space adjacent to the USDW is uncemented because of the lack of cement between the estimated top of cement between the Production casing and the formation wall and the bottom of cement behind the Surface casing.

The commenter further states that:

> Failing to extend surface casing in any well to below the base of the lowest USDW puts those USDWs below the base of the surface casing at significant risk of contamination. Cross flows may occur between the USDW and other formations, potentially leading to contamination of the USDW. Leaving a potential flow zone uncemented can also result in overpressurization of the annulus and/or result in casing corrosion, both of which may lead to a well integrity failure, further putting drinking water at risk. Properly constructed wells typically have at least two barriers between USDWs and fluids contained in the well: 1) the surface casing and 2) the production casing. These redundant barriers are necessary to ensure that if one barrier fails USDWs are still protected. The proposed injection well and offset wells lack redundant barriers, putting USDWs at serious risk in the case of a well integrity failure.
>
> The American Petroleum Institute recommends that "surface casing be set at least 100 feet below the deepest USDW encountered while drilling the well." Both UIC Class I and Class VI well rules require surface casing to extend below the base of the lowest USDW, indicating that EPA clearly recognizes this as an important standard to protect groundwater.

EPA Response: It appears that the commenter is concerned with a potential for mechanical integrity issues to arise due to the way this well will be cemented. Mechanical integrity is defined at 40 CFR 146.8. The commenter's concerns are in regard to the second prong of this definition. This says that "an injection well has mechanical integrity if: there is no significant fluid movement into an underground source of drinking water through vertical channels adjacent to the injection well bore." 40 CFR 146.8(a)(2). The regulations further describe the methods that must be used to determine the absence of significant fluid movement. 40 CFR 146.8(c). In this case, EPA has determined that the applicant has adequately demonstrated mechanical integrity via 40 CFR 146.8(c)(2).

EPA Region 8 Groundwater Section Guidance Number 34 (http://www2.epa.gov/sites/production/files/documents/R8UIC-GUIDE34.pdf), in the evaluation of well Mechanical Integrity, instructs permit reviewers to review the well's Cement Bond Log (CBL) to determine the adequacy of the cement to prevent fluid migration under 40 CFR 146.8(c). The CBL must show a Cement Bond Index (CBI) of at least 80% for a span of 18 consecutive feet (for 5 ½ inch pipe) in the injection zone's overlying confining zone. This will verify that seepage is unlikely to occur, between the injection zone and any adjacent USDWs. The top of cement is above the confining zone, and there is no requirement for it to go above the bottom of the surface casing. The base of the USDW is covered under Appendix E, Plugging and Abandonment Requirements.

Since a greater than 80% CBI could not be confirmed by the analysis of the CBL in this case, the operator is additionally required, as part of the permit, to determine the absence of significant fluid movement into a USDW through vertical channels adjacent to the injection well bore by conducting a Radioactive Tracer Test (RTS) as a procedure to identify the presence or absence of vertical fluid movement behind the casing near injection perforations. The RTS is used to supplement data from approved Part II demonstrations. If channeling behind casing is detected, the RTS can also be used to evaluate the vertical extent of fluid movement. In addition, if the results of the radioactive tracer test were to fail, additional testing would need to be performed. If those tests indicate that an adequate seal still could not be confirmed, the permit (authorization to inject) would be denied and the operator would be allowed to rework the well to achieve the acceptable criteria, if the operator desires, or otherwise plug and abandon the well as per the permit requirements.

The USEPA considers this approach to be protective of USDWs and complies with CFR requirements concerning permitting of Class II injection wells.

Injection Pressure

Comment #2: The commenter expressed concern that the MAIP is set too high and may allow the injection to fracture the confining zone. The commenter stated that "the MAIP should not be equal to, but rather should be less than, the fracture pressure of the confining zone and incorporate an appropriate safety factor."

EPA Response: We agree. The conservative equation we use calculates formation fracture pressure (FFP) using the top of the injection interval as the value for depth, which is a more conservative value than the already conservative value of the FFP at the top perforation. Using the top perforation would account for a larger depth value in the following equation:

$$\text{MAIP} = \text{MSIP} = [\text{FG} - (0.433 * \text{SG})] * (\text{Depth to Top of Injection Interval})$$

MSIP = Maximum Surface Injection Pressure
SG = Specific Gravity
FG = Fracture Gradient of injection interval

Therefore, using the Depth to the Top Perforation would allow for a higher MAIP. While this is also an acceptable method of calculating the MAIP, we are using the more conservative "top of the injection interval" depth. Furthermore, the perforations are in the injection zone only and fracturing in this interval is allowed. There is no danger of fracturing in the above confining layer comprised primarily of black shale.

The equation meets the requirement stipulated in 40 CFR 146.23(a)(1) that reads:

> Injection pressure at the wellhead shall not exceed a maximum which shall be calculated so as to assure that the pressure during injection does not initiate new fractures or propagate existing fractures in the confining zone adjacent to the USDWs.

While the commenter proposes a method that is even more conservative, EPA's conservative approach allows for the protection of USDWs and complies with the UIC regulations.

Reservoir Stimulation

Comment #3: The commenter is concerned about a potential discrepancy in the application. The commenter indicates that while the permit application states that no additional stimulation is anticipated for the proposed well, attached Exhibit L-1 indicates that they may perforate and frack the shown intervals. The commenter wants to ensure that the discrepancy is resolved and any potential hydraulic fracturing or other reservoir stimulation be disclosed for public review and comment and approved by EPA.

EPA response: As stated on Page 9, Section F of the permit application no stimulation is *expected* to be required. However, formation fracturing is allowed in the injection zone in accordance with log and test requirements stipulated in the permit. This is different than fracturing the confining zone, which is not authorized by the permit. If fracturing of the injection zone occurs and meets the conditions of the permit, adjacent USDWs will be protected.

Area of Review

Comment #4: The commenter believes that a fixed ¼ mile area of review is not sufficient to protect USDWs and asserts that EPA must require the applicant to more accurately determine where injected fluids will flow. They also suggest that the EPA should have considered using the "zone of endangering influence" or "ZEI" to determine the area of review.

EPA Response: As the commenter points out, the UIC regulation at 40 CFR 146.6 allows for the area of review to be determined by either a fixed radius *or* by calculating the zone of endangering influence. 40 CFR 146.6 states "the Director may solicit input from the owners of operators of injection wells within the State as to which method is most appropriate for each geographic area or field." In this case, Gasco submitted a ZEI calculation to EPA, and it was 747 feet. However, Gasco proposed a ¼ mile AOR. EPA agrees that a fixed ¼ mile AOR is appropriate because it is more conservative and protective than the 747 foot ZEI. Gasco's ZEI calculation and explanation is attached as Attachment B.

The USEPA considers this approach to be protective of USDWs and complies with CFR requirements concerning permitting of Class II injection wells.

Attachment A

August 25, 2014

To: Landon Newell, Staff Attorney, Southern Utah Wilderness Alliance
Steve Bloch, Attorney, Southern Utah Wilderness Alliance

From: Briana Mordick, Staff Scientist, Natural Resources Defense Council

Subject: Comments on Draft Underground Injection Control Permit UT22291-10328, Class II Enhanced Oil Recovery Well, RBU 1-10D, API No.: 43-047-34312, Uintah County, UT

This report responds to the request of the Southern Utah Wilderness Alliance ("SUWA") for a technical review of the Draft Underground Injection Control Permit UT22291-10328, Class II Enhanced Oil Recovery Well, RBU 1-10D, API No.: 43-047-34312, Uintah County, UT. I have reviewed the draft permit and supporting documents and detailed my comments below. My CV detailing my qualifications to provide this technical review is attached.

The permit applicant, Gasco, and the Environmental Protection Agency ("EPA") have not sufficiently demonstrated that the proposed injection well will not endanger Underground Sources of Drinking Water ("USDWs").[1] Specifically, as discussed in greater detail in the comments that follow:

- The proposed injection well and offset wells are not properly designed and constructed and may currently be endangering USDWs
- The proposed maximum allowable injection pressure ("MAIP") in the draft permit may result in fracturing of the injection or confining zone, potentially creating pathways that may allow injected fluids to reach USDWs
- The Area of Review ("AoR") evaluation is not sufficient and neither the applicant nor EPA has demonstrated that the proposed ¼-mile fixed radius is appropriate to protect USDWs.

Consequently, the draft permit should not be approved unless and until these deficiencies are addressed.

Well Construction

The design and construction of the proposed injection well, the RBU 1-10D, and nearby offset wells are not sufficient to protect USDWs.

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[1] As noted in the draft permit, the Base of Moderately Saline Water (BWSW) corresponds with the base of the USDWs in the area. However, no analyses of water from this interval were provided in the permit application.

In the permit application, the base of the deepest USDW in the proposed injection well is estimated at 2523 feet. However, the surface casing, which is intended to isolate and protect usable groundwater, is set at 2414 feet. Furthermore, the top of cement behind the production casing is estimated to be at 2980 feet. In other words, the surface casing does not extend below the base of the USDW and the production casing cement does not extend above the base of either the USDW or the surface casing. This means that a portion of the annular space adjacent to the USDW is uncemented. Leaving this annular space uncemented puts both the USDW and well integrity at risk.

The surface casings for the wells identified in the permit application as being within or near the ¼-mile AoR are set significantly shallower than the surface casing in the proposed injection well. The permit application does not specify the depths to the base of the USDW for these wells. However, a review of the map of the Base of Moderately Saline Ground Water ("BMSW")[2], which, as stated in the draft permit, "corresponds to the base of the USDWs in the area," indicates that the BMSW in these offset wells is likely to be at similar depths as the BMSW in the RBU 1-10D, or approximately 2500 feet. The surface casing in all five listed offset wells does not extend below the base of the USDW.

As with the RBU 1-10D, in three of the five offset wells, the top of the production casing cement does not extend above the base of the surface casing. In one such well, the RBU 5-11D, the top of the production cement also does not extend above the base of the USDW. In this well, the base of the surface casing is at 500′, the base of the USDW is at approximately 2500′, and the top of the production casing cement is at 4160′, meaning that almost 1650 feet of wellbore behind the production casing is uncemented.

Failing to extend surface casing in any well to below the base of the lowest USDW puts those USDWs below the base of the surface casing at significant risk of contamination. Cross flow may occur between the USDW and other formations, potentially leading to contamination of the USDW. Leaving a potential flow zone uncemented can also result in overpressurization of the annulus and/or result in casing corrosion, both of which may lead to a well integrity failure, further putting drinking water at risk. Properly constructed wells typically have at least two barriers between USDWs and fluids contained in the well: 1) the surface casing and 2) the

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[2] Anderson, P. B., Vanden Berg, M. B., Carney, S., Morgan, C., & Heuscher, S. (2012). *Moderately Saline Groundwater in the Uinta Basin, Utah, Special Study 144.* Utah Geological Survey.

production casing.[3] These redundant barriers are necessary to ensure that if one barrier fails USDWs are still protected. The proposed injection well and offset wells lack redundant barriers, putting USDWs at serious risk in the case of a well integrity failure.

The American Petroleum Institute recommends that "surface casing be set at least 100 feet below the deepest USDW encountered while drilling the well."[4] Both UIC Class I and Class VI well rules require surface casing to extend below the base of the lowest USDW, indicating that EPA clearly recognizes this as an important standard to protect groundwater.[5]

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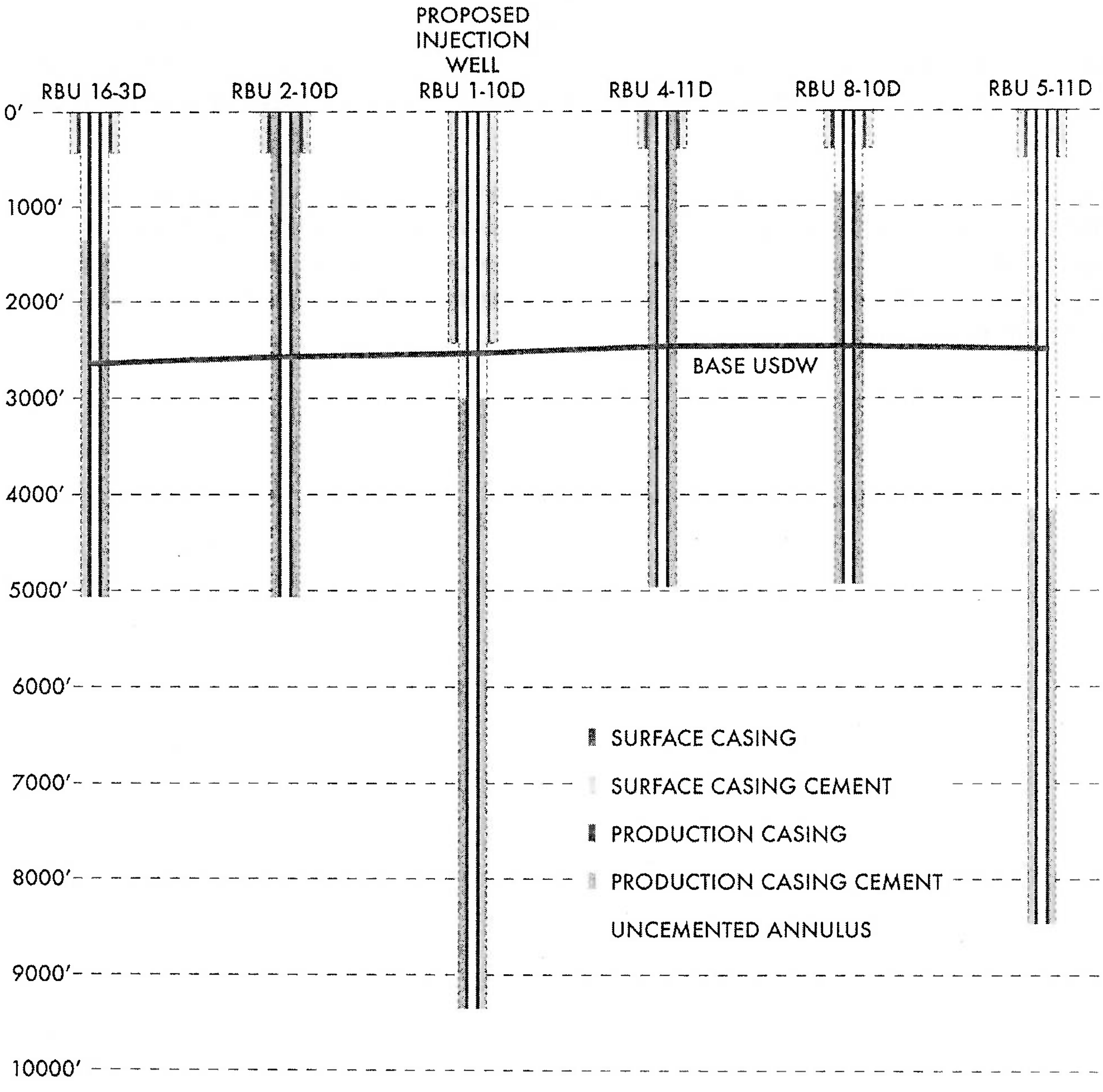
[3] Smith, J. B., & Browning, L. A. (1993, January). Proposed Changes to EPA Class II Well Construction Standards and Area of Review Procedures. In SPE/EPA Exploration and Production Environmental Conference. Society of Petroleum Engineers.

[4] American Petroleum Institute. 2009. Hydraulic Fracturing Operations – Well Construction and Integrity Guidelines. API Guidance Document HF1. First Edition, October 2009.

[5] 40 CFR 146.86(b)(2) and 40 CFR 146.65(c)(2)


PROPOSED INJECTION WELL
RBU 16-3D
RBU 2-10D
RBU 1-10D
RBU 4-11D
RBU 8-10D
RBU 5-11D
0'
1000'
2000'
3000'
4000'
5000'
6000'
7000'
8000'
9000'
10000'
BASE USDW
SURFACE CASING
SURFACE CASING CEMENT
PRODUCTION CASING
PRODUCTION CASING CEMENT
UNCEMENTED ANNULUS

While Class II rules do not explicitly require surface casing to extend below the base of the lowest USDW,[6] they do require that, "all Class II wells shall be cased and cemented to prevent movement of fluids into or between underground sources of drinking water,"[7] and that the depth to the bottom of all USDWs be considered in determining and specifying casing and cementing requirements.[8]

The permit application and draft permit state that corrective action is not anticipated to be necessary for either the proposed injection well or wells within or near the AoR. However, a review of the construction details indicates that, due to inadequate casing and cementing practices, both the proposed injection well and nearby offset wells may *currently* be endangering USDWs, not even taking into account the additional risks associated with converting the RBU 1-10D into an injection well. In sum, the current construction of the proposed injection well and nearby offset wells is insufficient to protect USDWs and the permit should not be granted unless and until these deficiencies are corrected.

The applicant and EPA must demonstrate that contamination is not currently occurring in the proposed injection well and offset wells, including but not limited to water sampling and analyses from the USDW interval in these wells. This information must also be provided to the public for additional review before the permit is granted.

Injection pressure

Federal Class II regulations require that,

"Injection pressure at the wellhead shall not exceed a maximum which shall be calculated so as to assure that the pressure during injection does not initiate new fractures or propagate existing fractures in the confining zone adjacent to the USDWs."[9]

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[6] A report by the General Accounting Office, an internal EPA Mid-Course Evaluation of the UIC program, and a federally chartered advisory committee found that Class II well construction rules were insufficient to protect drinking water and recommended that the rules be changed to require surface casing to extend below the base of protected water. EPA proposed to make these changes in the early 1990s, but they were never finalized. Nevertheless, these improvements are still needed in order to adequately protect USDWs and should be implemented in permitting decisions. *See* Smith, J. B., & Browning, L. A. (1993, January). Proposed Changes to EPA Class II Well Construction Standards and Area of Review Procedures. In *SPE/EPA Exploration and Production Environmental Conference.* Society of Petroleum Engineers.

[7] 40 CFR 146.22(b)(1)

[8] 40 CFR 146.22(b)(1)(ii)

[9] 40 CFR 146.23(a)(1)

The MAIP calculated in the draft permit does not meet this requirement. The proposed MAIP is too high and may endanger USDWs by allowing injected fluids to fracture the confining zone, which may create pathways through which injected fluids can migrate into the USDW.

The proposed MAIP in the draft permit is equal to EPA's estimated fracture pressure at the base of the confining zone/top of the injection zone. The MAIP should not be equal to, but rather should be less than, the fracture pressure of the confining zone and incorporate an appropriate safety factor. Class VI rules require that the maximum injection pressure be no greater than 90% of the fracture pressure of the injection zone.[10] For Class II wells, EPA Region 5 recommends adding a safety factor of 0.05 to the specific gravity of the injectate.[11]

In the draft permit, EPA states that the MAIP calculation was performed using injection fluid density and injection zone data submitted by the applicant. Despite repeated requests, EPA declined to make this information available.[12] It is therefore very difficult to evaluate the adequacy of EPA's MAIP calculation in the draft permit because EPA does not include all the inputs used to derive the MAIP, notably the specific gravity ("SG") of the injectate. By back calculating from the available information, it appears that EPA is using a SG of approximately 1.025. This is the value of SG commonly assumed for seawater due to the average density of seawater being equal to 1.025 g/ml. Seawater is commonly assumed to have an average total dissolved solids ("TDS") concentration of 35,000 mg/L. The permit application submitted by Gasco indicates that the TDS concentration of a representative sample of injection fluid is 158,679 mg/L, or approximately 4.5 times the average TDS concentration of seawater. As such, the density and therefore specific gravity of the injection fluid will be significantly higher. Assuming a standard ambient pressure and temperature of 25° C and 100 kPA, the density of water with a TDS concentration of 158,679 mg/L would be approximately 1.125 g/ml, or a SG of 1.125. Using this value of SG and the following equation to determine MAIP, which includes a safety factor:

$$MAIP_{surface} = \{[FG - 0.433 * (SG + 0.05)] * D\} - 14.7$$

where:
FG = fracture gradient (assume value used in draft permit, 0.860 psi/ft)
0.433 = density of water in psi/ft
SG = specific gravity
0.05 = safety factor
D = depth

[10] 40 CFR 146.88(a)
[11] "Requirements for Commercial Underground Injection Control Class II Wells." *EPA Region 5 Water*. Environmental Protection Agency, n.d. Web. 20 Aug. 2014.
[12] *See* e-mail correspondence between Landon Newell, SUWA, and Tom Aalto, EPA.

14.7 = conversion factor from absolute pressure to gauge pressure

the MAIP for the RBU 1-10D would be 1637 psig, or approximately 16% lower than the EPA's proposed MAIP.

Additionally, the fracture gradient of the injection and confining zones must be confirmed with field data from the proposed well, and the MAIP must be adjusted to reflect any difference between the actual and estimated FG.

In sum, the proposed MAIP in the draft permit may be too high[13] and injecting at this pressure may endanger USDWs. The operator and EPA must:

- Resolve the apparent discrepancy between the reported salinity and density of the injectate;
- Accurately determine the density and specific gravity of the injectate;
- Use an accurate value for the specific gravity of the injectate and incorporate a safety factor in the MAIP calculation, and;
- Provide all inputs to the MAIP calculation, including the salinity and density/specific gravity of the injectate, to the public for additional review before the permit is granted.

Reservoir Stimulation

The permit application states that no additional stimulation is anticipated for the proposed well. However, Exhibit L-1 submitted by the applicant states that, "Plan call for perforating and fracking the shown intervals..." [sic]. This discrepancy must be resolved and any plan to hydraulically fracture or use other reservoir stimulation techniques must be disclosed for public review and comment and approved by EPA.

Area of Review

Under federal UIC Class II rules, the AoR may be determined using one of two methods: either a fixed radius of not less than ¼ mile or by calculating the zone of endangering influence ("ZEI"). Neither the permit application nor the draft permit consider the use of the ZEI or include a discussion of the merits of the different methods.

In 2004 the UIC National Technical Workgroup ("NTW") prepared a report entitled, "Does a Fixed Radius Area of Review meet the statutory mandate and regulatory

[13] We again note that this is difficult to evaluate due to EPA's refusal to provide the necessary data.

requirements of being protective of USDWs under 40 CFR §144.12?"[14] The purpose of the report was to summarize available information on the use of a ¼-mile fixed radius as opposed a ZEI to designate the AoR around Class II injection wells. The researchers summarized the process that led to the development of the two different AoR approaches, stating, "The final AoR regulation at 40 CFR §146.6 was adopted even though much existing evidence showed that the actual pressure influence of any authorized underground injection operation is not limited to any pre-determined radius around any proposed or existing injection well, but is a function of specific physical parameters (including initial pore pressures in both the injection zone and in the lowermost USDW and actual injection rate)."

The researchers noted incidents where injected fluids contacted improperly abandoned wells beyond a ¼-mile radius, including one case on the Texas/Louisiana border where injected fluids flowed out of orphan wells located more than a mile from the injection well, impacting a local public water supply.

Accordingly, the researchers recommended that EPA develop and adopt technical guidance regarding the AoR determination, and that every UIC program reevaluate the area of review of all authorized injection activities, stating, "The majority of EPA UIC National Technical Workgroup members understands the magnitude of the suggested action and consider this proposal as a long-term solution to *a long-standing inadequate permitting practice*." (emphasis added) The researchers went further to state, "A majority of the UIC National Technical Workgroup members believe that enough evidence exists to challenge the assumption that a fixed radius AOR is sufficient to assure adequate protection of USDWs from upward fluid migration through artificial penetrations within the pressure influence of authorized injection operations."

The isopachs provided as Exhibits J and K indicate that the injection interval does not have a uniform thickness in the vicinity of the proposed injection well, meaning that injected fluids may flow preferentially in one or more directions rather than flowing radially as the ¼-mile AoR implies. This may allow injected fluids to contact wells beyond the ¼-mile AoR. Gasco's exhibits show that many existing wells fall just outside the ¼-mile AoR. As noted above, the construction practices used in the identified offset wells are insufficient to protect groundwater. EPA lists "vertical movement of fluids through improperly abandoned and improperly completed

[14] Frazier, M., Platt, S., & Osborne, P. (2004) Does a Fixed Radius Area of Review meet the statutory mandate and regulatory requirements of being protective of USDWs under 40 CFR §144.12?. *Final Work Product from the National UIC Technical Workgroup.*

wells," as one of six key pathways of contamination through which injected fluids may reach USDWs.[15]

The fixed ¼-mile AoR is not sufficient to protect USDWs. EPA must require the applicant to more accurately determine where injected fluids will flow, in order to more thoroughly identify pathways through which injected fluids may reach groundwater.

Conclusion

The proposed injection project presents significant risks to USDWs. The draft permit should not be approved unless and until the deficiencies discussed are addressed.

[15] U.S. Environmental Protection Agency, Office of Drinking Water. (1980, May). *Statement of Basis and Purpose, Underground Injection Control Regulations.*

Attachment B

Evaluation of the Zone of Endangering Influence for the RBU 1-10D Injector

When water is injected into a reservoir, the reservoir pressure increases. The maximum pressure increase is seen at the injection wellbore and decreases with the log of distance. The zone of endangering influence surrounding an injection well is the area where this pressure increase from fluid injection could potentially cause migration of injection or reservoir fluids into an underground source of drinking water, should a path be available.

As described in Regulation 40 CFR, Part 146.6, the radius r of this zone can be determined using the modified Theis equation:

$$r = \left(\frac{2.25\ KHt}{S\ 10^{x}}\right)^{\frac{1}{2}}$$

where

$$x = \frac{4\pi\ KH\ (h_w - h_{bo}S_pG_b)}{2.3\ Q}$$

and K is the hydraulic conductivity of the injection zone, H is the injection zone thickness, t is total injection time, S is the dimensionless storage coefficient, Q is the injection rate, S_pG_b is the specific gravity of the injection fluid, h_{bo} is the initial hydrostatic head of the injection zone, and h_w is the hydrostatic head at the base of the usable water zone.

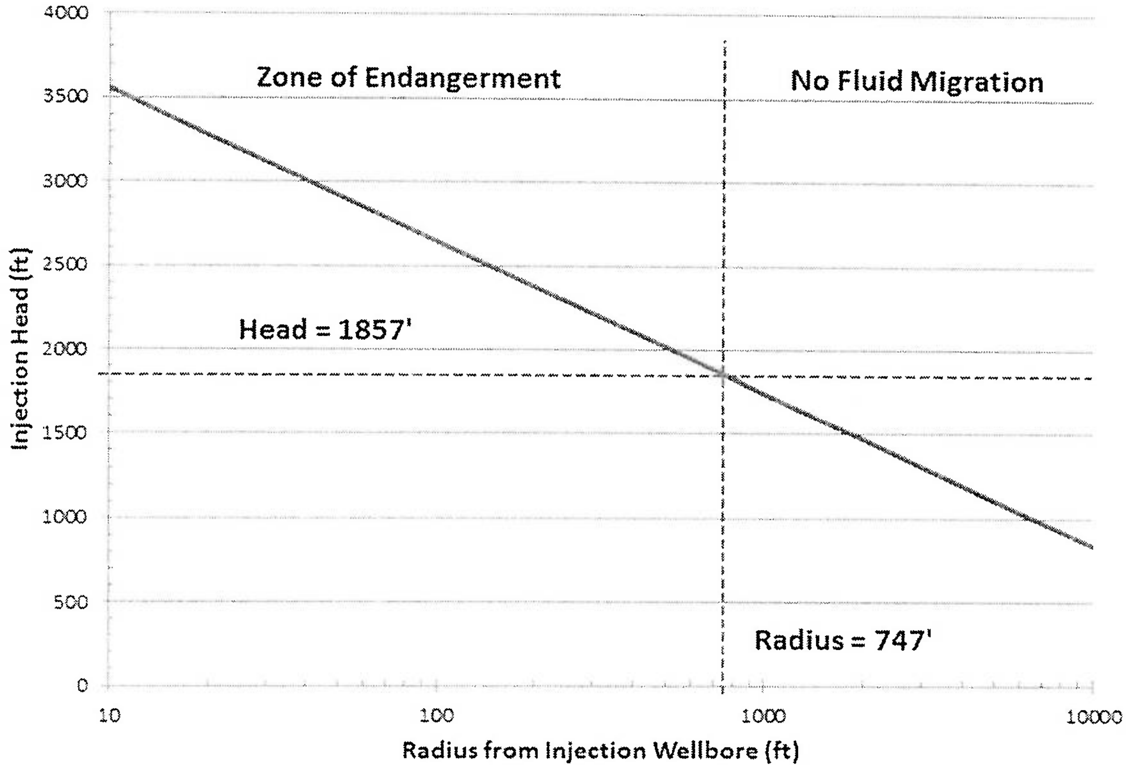
The term $(h_w - h_{bo}\ S_pG_b)$ is the difference in pressure between the injection zone and the base of the usable water zone, expressed as a hydrodynamic head. The average injection water will have a TDS of 27,000 mg/L, corresponding to a specific gravity of 1.02. According to the analysis by the USGS, the base of the usable water zone is 2523' below the surface at the RBU 1-10D. The initial injection reservoir pressure was determined from a series of fluid level measurements in surrounding wells, which were performed by Gasco in August to October 2010 (see table below).

Before measuring these levels, the wells had been shut in for periods of one month or more.

Well Name	Fluid Level (ft below surface)
RBU 2-10D	4380'
RBU 4-11D	4489'
RBU 8-10D	4649'
RBU 15-3D	4808'
RBU 16-3D	4692'

The Uteland Butte zone is very depleted; the fluid level in the RBU 2-10D showed the highest reservoir pressure. Using this value, we get a conservative measure of the hydraulic head difference $h_w - h_{bo} S_p G_b$ = (-2523 – (-4380)) = 1857 feet.

The Theis equation can be rearranged to determine the hydraulic head increase in the injection zone as a function of radius from the injection wellbore. For the specific case of the RBU 1-10D, the radius of the zone of endangerment is the radius where the hydrostatic head increase from injection exceeds 1857 feet. Results of this calculation are shown in the accompanying figure. This figure assumes an injection rate Q of 2000 bbls/day, an injection time t of 30 years, an injection zone thickness H of 12' (the height of the C-shoal member of the Uteland Butte formation in the RBU 1-10D), and a storage coefficient S of 1.2×10^{-5}. The Uteland Butte injection reservoir is naturally fractured and has had additional fracture stimulation. The hydraulic conductivity was assumed to be 1×10^{-6} m/s, corresponding to fractured reservoir with 200 micron fracture openings spaced every 16 feet. With these assumptions, the radius of the zone of endangerment is calculated to be 747'.



Conservative assumptions were used to determine the radius of 747'; relaxing these assumptions will decrease the radius of the possibly affected area. First, the reservoir thickness of 12' assumes that injection will occur only in the C-shoal formation; injecting into the entire Uteland Butte will increase the thickness to 41'. Second, the injection head of 1857' was determined using the maximum measured reservoir pressure. Using the lower average value would increase the injection head needed for possible fluid migration, decrease the radius. Third, the reservoir pressure measurements were conducted four years ago. In this time, more than 40,000 bbls of oil have been produced from the wells near the RBU 1-10D, further depleting the reservoir pressure. Finally, this calculation assumes that no liquids will be produced from the injection zone. Since the RBU 1-10D will be used as an injector for secondary oil recovery, fluid will be continuously removed from the reservoir, decreasing the rate of pressure build-up.

Item				
Formation Thickness	12	*ft*		
Permeability	106	*mDarcy*		
Specific Gravity	1.02			
Viscosity	1.06	*cP*		
Injection Rate	2000	*bbls/day*		
Time	30	*yrs*		
Formation Thickness	3.6576	*m*		
Permeability	1.06E-13	*m2*		
Density	1020	*kg/m3*		
Viscosity	0.00106	*Pa s*		
Injection Rate	0.00276019	*m3/s*		
Time	946728000	*s*		
S	1.20E-05			
K	1.00E-06	*m/s*	1.00E-06	*m/s*
UDSW	2523	*ft below surf*		
UB Head	4380	*ft below surf*		
ho - h	1857	*ft below surf*		

Radius (ft)		Radius (m)	ho - h (m)	ho - h (ft)
	10	3.048	1.08E+03	3554.71
	20	6.096	1.00E+03	3281.89
	50	15.24	8.90E+02	2921.23
	100	30.48	8.07E+02	2648.41
	200	60.96	7.24E+02	2375.58
	500	152.4	6.14E+02	2014.92
	747	**227.6856**	**5.66E+02**	**1856.91**
	1000	304.8	5.31E+02	1742.10
	1320	402.336	4.98E+02	1632.82
	2000	609.6	4.48E+02	1469.27
	5000	1524	3.38E+02	1108.62
	10000	3048	2.55E+02	835.79