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

AUG 05 2011

Ref: 8P-W-GW

Andrew Nicholas
U.S. Bureau of Reclamation
Paradox Valley Unit
P.O. Box 20
Bedrock, Colorado 81411

RE: UNDERGROUND INJECTION CONTROL (UIC)
Permit Reauthorization
Paradox Salinity Control Well No. 1
EPA Permit No.CO50108-00647

Dear Mr. Nicholas:

Enclosed is the UIC Program Reauthorization for the Paradox Salinity Control Well No. 1 Permit. Also, enclosed are the Statement of Basis and Fact Sheet that discuss development of the Reauthorization.

The Environmental Protection Agency regulations and procedures for issuing UIC Permit decisions are found in Title 40 of the Code of Federal Regulations Part 124 (40 CFR §124). These regulations and procedures require a Public Notice and the opportunity for the public to comment on the proposed UIC Permit decision. The EPA received comments on the draft documentation of the reauthorization. Those comments and the EPA's response are also included with this letter. Minor revisions to the draft documents have been made based on the comments.

The Final Permit was issued on AUG 03 2011. Because comments were received during the public comment period, the Final Permit will not become effective until thirty (30) days after the issue date, per Title 40 Code of Federal Regulations (40 CFR) Section 124.18, to provide a 30-day window for commenters to appeal the Final Permit decision. The procedures for appealing a Final Permit decision are outlined under 40 CFR Section 124.19, which is enclosed.

DISCUSSION OF THIS REAUTHORIZATION

The EPA has reviewed your request of March 2006 to renew the injection for the Paradox Salinity Control Well No. 1 Permit, EPA Permit No. CO50108-00647, and has decided to reauthorize the UIC Permit. This reauthorization will fully replace the March 1997 Permit and its subsequent modifications.

This reauthorization proposes no changes to the existing Permit with the previously approved modifications to it.

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UNDERGROUND INJECTION CONTROL PROGRAM

PERMIT FOR REAUTHORIZATION

CO50108-00647

Class V Brine Disposal Well
PARADOX SALINITY CONTROL WELL NO. 1
Montrose County, Colorado

issued to:

U.S. Bureau of Reclamation
Upper Colorado Regional Office
Post Office Box 11568
Salt Lake City, Utah 84147

DATE PREPARED: FEBRUARY 2011

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PART I - REAUTHORIZATION TO INJECT

Pursuant to the Underground Injection Control Regulations of the U.S. Environmental Protection Agency (EPA) codified at Title 40 of the Code of Federal Regulations (40 CFR), Parts 124, 144, 146 and 147,

United States Bureau of Reclamation (USBR)
Upper Colorado Regional Office
Post Office Box 11568
Salt Lake City, Utah 84147

is hereby reauthorized to continue operation of the Class V injection well, commonly known as the Paradox Salinity Control Well No. 1 located in the SE NW SE of Section 30, Township 47 North, Range 18 West of Montrose County, Colorado. Injection is for the purpose of disposing of brine captured from springs near Bedrock, Colorado, presently discharging into the Dolores River. The injection zone is limited to the Leadville Formation, the Ouray Formation, the McCracken Formation, the Ignacio Formation, and the Precambrian fractured granite in accordance with conditions set forth herein. The maximum authorized surface injection pressure is 5,350 pounds per square inch at gauge (psig).

This is the third permit issued to the USBR for this injection well. The operator has fulfilled any application requirements for a new Permit. "Transition from Expired Permit to Permit Reauthorization" requirements are set forth in Part II, Section E. 2. of this Permit.

All conditions set forth herein refer to 40 CFR Parts 144, 146, and 147 and are regulations that are in effect on the date that this Permit is effective.

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

This reauthorized Permit and the authorization to continue injection are issued for ten (10) years from the date this permit becomes effective unless terminated as provided in Part III, Section B. 1.

The Permit shall expire after ten (10) years, or upon delegation of primary enforcement responsibility for the UIC-1422 Program to the State of Colorado, unless Colorado has adequate authority and chooses to adopt and enforce this Permit as a State Permit.

Please be advised that this permit pertains solely to UIC and does **not** preclude any other federal, state, or local regulations that may apply.

Issue Date AUG 05 2011

Effective Date AUG 05 2011

Stephen S. Tuber
Assistant Regional Administrator
Office of Partnerships and Regulatory Assistance

PART II. SPECIFIC PERMIT CONDITIONS

A. GENERAL

Copies of all reports and notifications required by this area permit shall be signed and certified in accordance with the requirements under Part III, Section E.9 of this area permit and shall be submitted to the EPA:

U.S. Environmental Protection Agency - Region 8
Shallow Well Compliance Lead, Mailcode: 8ENF-UFO
1595 Wynkoop Street
Denver, CO 80202-2699

The EPA permit number the UIC Program Director (hereafter referred to as the "Director") has assigned to this area permit is CO50108-00647. All correspondence should reference the site name, address, and include the EPA area permit number.

B. WELL CONSTRUCTION AND INJECTION.

1. Casing and Cementing. The construction details previously submitted are hereby incorporated into this Permit as Appendix A and shall be binding on the permittee unless changes are approved. The permittee has cased and cemented the well to prevent the movement of fluids into or between underground sources of drinking water (USDWs) and into or between formations other than those designated as the injection zone in Part I and Part II, Section E.3. The casing and cementing used in the construction of the well have been designed for the life expectancy of the well and shall be maintained throughout the operating life of the well.

2. Tubing and Packer Specifications. The applicant has submitted details on the tubing, and these are incorporated into the Permit as Appendix A and shall be binding on the permittee. Injection between the outermost casing protecting underground sources of drinking water and the wellbore is prohibited. Injection directly through the long string casing is also prohibited.

3. Monitoring Devices. The permittee has installed continuous recording devices which monitor the operation of the well. These devices shall be maintained for the operating life of the well.

   a) The well site instruments shall be capable of continuously monitoring the following with an accuracy of 95%, or greater:
      (i) injection pressure,
      (ii) flowrate,
      (iii) cumulative volume, and
      (iv) casing/tubing annulus pressure.

   b) The operator shall provide and maintain in good operating condition two (2) ½-inch fittings isolated by a needle valve or equivalent, and located:

(i) at the wellhead on the tubing and
(ii) on the tubing/casing annulus.

These valves shall be positioned to allow the attachment of ½-inch maximum injection pressure gauges of an appropriate rating.

c) USBR operates a 16-station earthquake monitoring network to record both natural and induced earthquakes in the Paradox Valley Area. In addition, USBR operates a 3-station strong-motion accelerograph network to measure strong ground shaking that may occur from induced earthquakes that are large enough to be felt. Historically, injection activity in the Paradox Valley area induces earthquakes in the subsurface in the vicinity of the injection well. These earthquakes are analyzed with respect to date and time of occurrence, focal depth, geographic location, magnitude, type of faulting, and relation to injection operations. A monthly status report on the Paradox Valley Seismic Network is submitted to the operator as required under Part II, Section E.1.

4. Proposed Changes and Workovers. The permittee shall give advance notice to the Director as soon as possible and no later than thirty (30) days **before** any planned physical alterations or additions to the permitted injection well system. Alterations of the permitted injection system shall meet all conditions as set forth in this permit. An alteration or addition shall be considered any work performed that affects the quantity or quality of the fluid being injected.

After approval by the Director, the permittee shall provide plans, as-built schematics, sketches, or other test data to EPA within sixty (60) days of completion of the alteration or addition that took place.

C. CORRECTIVE ACTION

No corrective action is required prior to issuance of this permit.

D. MECHANICAL INTEGRITY

The permittee is required to ensure that the injection well maintains mechanical integrity at all times. 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 USDW through vertical channels adjacent to the injection well bore (Part II).

1. Continuous Demonstration of Mechanical Integrity

Method of Demonstrating Absence of Casing Leaks. 40 CFR 144.51(8) requires that the well have mechanical integrity at all times. Adherence to all requirements under 40 CFR Parts 144, 146, and 147, including construction, has been verified for this well.

Demonstration of mechanical integrity was performed on February 10, 2011 as part of reauthorization of injection activities for this well. The absence of significant leaks in the casing, tubing, and/or packer has been and shall be demonstrated on a continuing basis by monitoring the pressure on the casing/tubing annulus. This monitoring procedure was formalized in adopting a Standard Operating Procedure (SOP) for the Well Annulus Monitoring System (WAMS) on March 2, 2009 (Appendix D). The permittee shall place sufficient pressure on the annular space such that the range of pressure fluctuations caused by injection operations, such as temperature variations of the injected fluids, shall be maintained in the positive range. Abnormal increases in annulus pressure shall be reported to the Director, and the cause of the increase shall be investigated. If the increase is determined to be related to leaks in either tubing or packer, the well shall be shut-in until repairs have been completed. This test is to be performed every year as part of the requirements of this permit, the results of which will be included in the 3rd quarter report as specified in Section F.4.below.

2. Modification of Mechanical Integrity Requirements. Any new criteria developed during the review for establishing that the well has continuing mechanical integrity shall be made part of this Permit by Minor Modification. No further opportunity for public comment shall be required.

3. Loss of Mechanical Integrity. If the well fails to demonstrate mechanical integrity during a test, or a loss of mechanical integrity as defined by 40 CFR Section 146.8 becomes evident during operation, the permittee shall notify the Director in accordance with Part III, Section E. 10. of this Permit. Furthermore, injection activities shall be terminated immediately; and operation shall not be resumed until the permittee has taken necessary actions to restore integrity to the well and has obtained approval to recommence injection from EPA.

E. WELL OPERATION

1. Well Injection and Seismicity.
   a. Response to Felt Seismicity. Injection activity shall be temporarily halted to inspect for damage, according to the USBR Emergency Action Plan, and the permittee shall notify EPA within twenty-four (24) hours according to Part III, Section E.10, if either of the following occur:
      i. A seismic event is felt in the Brine Injection Facility Control Room.
      ii. A seismic event is recorded on the strong-motion instrument located at the Brine Injection Facility, and the instrument measures a peak horizontal acceleration of 0.1 g or greater.

   b. Response to Other Potentially Significant Seismicity. If a significant seismic event is reported in the Paradox Valley area, but is not felt in the Brine Injection Facility Control Room, then within 72 hours of the report the USBR shall notify EPA and perform an inspection if any of the following occur:

i. A seismic event is recorded on the strong-motion instrument located at the Brine Injection Facility, and the instrument measures a peak horizontal acceleration of 0.05 g or greater.
ii. A magnitude 3 or greater earthquake is recorded by PVSN or the U.S. Geological Survey, and is predicted to have produced a median peak horizontal acceleration of 0.05 g or greater at the Brine Injection Facility, based on empirical ground motion attenuation curves.
iii. A seismic event is reported by the news media as being widely felt in the Paradox Valley area.

c. Seismic Monitoring Monthly Evaluation. A monthly evaluation shall be performed to summarize the operating status of the Paradox Valley Seismic Network (PVSN) and local seismicity recorded during the previous month. The evaluation shall assess induced and natural seismicity located within 30 km of the injection well and its potential relation to injection operations. The evaluation shall also include an assessment of the operation of the seismic instrumentation, data telemetry, data recording, and earthquake notification systems. Based on this evaluation, USBR will schedule preventative and remedial maintenance needed to maintain compliance with the Seismic Monitoring Plan. Should immediate maintenance be needed to comply with the minimum standards of the Seismic Monitoring Plan, EPA will be notified within 72 hours. Within two weeks, the needed maintenance shall either be performed or, if circumstances prevent immediate action, a proposed corrective action plan shall be submitted to EPA.

2. Transition from Expired Permit to Permit Reauthorization. The Paradox Salinity Control Well No. 1 has been operating by Permit since July 1991. Adherence to all requirements under 40 CFR Parts 144, 146, and 147, including construction, has been verified for this well. Demonstration of mechanical integrity is continuous, as provided in Part II, Section D.1., and no further conditions are required for reauthorization.

3. Injection Interval. Injection shall be limited to the gross interval between the top Leadville perforation (14,080 feet) in well casing and the plug back total depth (PBTD) (15,827 feet) in Precambrian granite. The net perforated intervals are:

Upper Leadville: 14,080 feet - 14,185 feet
Middle Leadville: 14,215 feet - 14,350 feet
Lower Leadville/Ouray: 14,380 feet - 14,504 feet
McCracken: 14,651 feet - 14,719 feet
Ignacio: 15,376 feet - 15,489 feet
Precambrian: 15,489 feet - 15,827 feet

4. Injection Pressure Limitation.
a) Injection pressure, measured at the surface, shall not exceed 5,350 psig.

b) The pressure limit in paragraph (a) may be increased by the Director if the fracture pressure of the confining formation shall not be exceeded; and the permittee demonstrates that the proposed increase in surface injection pressure is necessary to overcome friction losses in the injection system, including the reservoir losses. This demonstration shall include:

(i) an analysis of the adequacy of the injection equipment, well head and downhole tubulars to withstand the proposed maximum allowable surface injection pressure (MASIP);

(ii) an analysis of the potential for adverse seismic activity if injections pressures are increased;

(iii) an analysis of the continued adequacy of the confining zones, including information on the potential vertical fracture growth in the confining layers as a result of an increase in injection pressure;

(v) and a demonstration made by performing a step rate injection test, using fluid normally injected, to determine both the instantaneous shut-in pressure and the formation breakdown pressure.

The Director shall determine any allowable increase based upon the results of these analyses.

c) The permittee shall give thirty (30) days advance notice to the Director if an increase of injection pressure shall be sought.

5. <u>Injection Volume-rate Limitation</u>. There shall be no limit on the number of gallons per minute of produced brine wastes that shall be injected into this well provided that in no case shall injection pressure exceed that limit shown in Part II, Section E. 4. of this Permit.

6. <u>Injection Fluid Limitation</u>. The permittee shall not inject any hazardous wastes, as defined under 40 CFR Part 261, at any time during the operation of the facility. And further, no substances shall be injected other than those noted in the Permit application, such as, additives needed to ensure injection fluid compatibility and corrosion control. The applicant has identified that the waste stream is to be brine intercepted from springs near the Dolores River with or without fresh water and containing a corrosion inhibitor. The quality of the brine is expected to vary, but the total dissolved solids (TDS) content is stated to be between 250,000 - 260,000 mg/liter. Any additional additives needed to insure compatibility of injected fluids with those in the reservoir shall be identified for review and approval by the EPA. The use of these additives shall be incorporated into the Permit as a Minor Modification. The use of fluids, such as hydrochloric acid (HCL) for acid stimulation, is under Part II. Section B.4. dealing with proposed changes and workovers.

7. <u>Annular Fluid</u>. The annulus between the tubing (5 ½-inch) and the 9 5/8-inch/10.98-inch casing, from 13,092 feet (below-ground level) to the surface is filled with corrosion inhibited fresh water. Below 13.092 feet to the PBTD (15,827 feet) the annulus is filled with cement.

F. MONITORING, RECORDKEEPING, AND REPORTING OF RESULTS

1. Injection Well Monitoring Program. The description of the planned monitoring indicating the minimum injection parameters to be monitored, which was submitted by the permittee, is incorporated into this Permit as specified below. Samples and measurements shall be representative of the monitored activity. The permittee shall utilize the applicable analytical methods described in Table I of 40 CFR Part 136.3, or in Appendix III of 40 CFR Part 261, or in certain circumstances, by other methods that have been approved by the EPA Administrator. Monitoring shall consist of:

    a) Analyses of the injection fluids shall be performed:
        (i) annually for TDS, pH, conductivity, and specific gravity; and
        (ii) whenever there is a change in the source or type of the injection fluids as specified in Part II, E.6. Analysis of the constituents above, plus all major ions and corrosivity, shall be submitted to the Director within thirty (30) days of the change in injection fluids.

    b) Continuous recordings of the injection pressure, flow rate, cumulative volume, and annulus pressure shall be averaged daily. Daily averages shall be averaged monthly. A paired reading of the annulus and injection pressures shall be taken at the same time on a weekly basis. Both daily and monthly averages along with the weekly paired readings shall be reported quarterly to the EPA Denver Office as specified in Section F.4.below.

    c) Continuous monitoring of earthquakes potentially induced by well operations. The operator shall provide a yearly report that is due on June 1 as described in Part II, Section F.4. Any abnormal seismic activity that may indicate problems shall be reported within five (5) days. Operations shall follow the Paradox Valley Unit's standard operating procedure for the seismic monitoring.

2. Monitoring Information. Records of any monitoring activity required under this permit shall include:
    a) the date, exact place, the time of sampling or field measurements;
    b) the name of the individual(s) who performed the sampling or measurements;
    c) the exact sampling method(s) used to take samples;
    d) the date(s) laboratory analyses were performed;
    e) the name of the individual(s) who performed the analyses;
    f) the analytical techniques or methods used by laboratory personnel; and
    g) the quality assurance procedures used by the laboratory; and
    h) the result of such analysis.

3. Records to Retain and Retention Time

a) All data required to complete the Permit Application for this permit for a period of at least five (5) years from the effective date of this permit. This period may be extended by request of the Director at any time.
b) Copies of all reports required by this permit for a period of at least three (3) years after the reports were submitted.
c) Records regarding the nature and composition of all injected fluids. The permittee shall continue to retain these records for a period of three (3) years after the closure of the injection well system unless the records are delivered to the Director or written approval to discard the records is obtained from the Director. This period may be extended by request of the Director at any time.
d) Records of monitoring information as specified under Part II, Section F.2.

4. Reporting of Results. The permittee shall submit a Quarterly Report to the Director summarizing the results of the monitoring information required by Part II, Section F. 1. of this permit. Copies of all records on injected fluids, and any major changes in characteristics or sources of injected fluid shall be included in the Quarterly Report. Quarterly Reports shall cover the periods of:January 1 through March 31;
   - April 1 through June 30;
   - July 1 through September 30; and,
   - October 1 through December 31.

   Each Quarterly Report shall be submitted to the Denver Office by the fifteenth of the following month. EPA form 7520-8 (Appendix B) may be used to submit the quarterly summary of monthly averages of monitoring data. Daily and monthly averages shall be submitted in a tabular form developed by the permittee. Also, assurance that the annulus is filled with approved fluid shall be submitted at this date.

   The annual report describing all monitored local seismic events, whether induced or not, shall be submitted to the EPA by June 1 of the following year.

G. PLUGGING AND ABANDONMENT

The method for plugging and abandonment of any injection well shall not allow the movement of a fluid containing any contaminant into any USDW if the presence of that contaminant may cause a violation of the primary drinking water standards under 40 CFR Part 141, other health based standards, or may otherwise adversely affect the health of persons.

1. Notice of Plugging and Abandonment. The permittee shall notify the Director forty-five (45) days before conversion, workover, or abandonment of the well.

2. Plugging and Abandonment Plan. The permittee shall plug and abandon the well

as provided in the Plugging and Abandonment Plan, Appendix C. EPA reserves the right to change the manner in which the well shall be plugged if the well is modified during its permitted life, if the well is not maintained consistently with EPA requirements for construction and mechanical integrity, or if it is deemed that the designated closure method is not protective of any USDW.

The Director may ask the permittee to update the estimated plugging cost periodically. Such estimates shall be based upon costs that a third party would incur to plug the well according to the plan.

3. Cessation of Injection Activities. After a cessation of injection for two (2) years, the permittee shall plug and abandon the well in accordance with the Plugging and Abandonment Plan unless the permittee:

   a) provides notice to the Director, and

   b) demonstrates that the well shall be used in the future, and
   c) describes actions or procedures, satisfactory to the Director that shall be taken to ensure that the well shall not endanger USDWs during the period of temporary abandonment.

4. Plugging and Abandonment Report. Within sixty (60) calendar days after plugging the well, the permittee shall submit a report on Form 7520-13 to the Director. The report shall be certified as accurate by the person who performed the plugging operation and the report shall consist of either: (1) a statement that the well was plugged in accordance with the plan, or (2) where actual plugging differed from the plan, a statement that specifies the different procedures followed.

H. FINANCIAL RESPONSIBILITY

The permittee is required to maintain financial responsibility and resources to operate, close, plug, and abandon the injection well as provided in the Plugging and Abandonment Plan. This demonstration is made by the permittee's participation in the U.S. Budgetary process.

1. The permittee shall provide information annually to demonstrate that sufficient funds are budgeted to adequately operate or abandon the facility.

2. The permittee shall have sufficient contingency funds available in any given year to adequately abandon the facility, if operating funds are cut out of the Budget for the following years.

PART III. GENERAL PERMIT CONDITIONS

A. EFFECT OF PERMIT

The permittee is allowed to engage in underground injection in accordance with the conditions of this permit. The permittee, as authorized by this permit, shall not construct, operate, maintain, convert, plug, abandon, or conduct any other injection activity in a manner that allows the movement of fluid containing any contaminant into any USDW, if the presence of that contaminant may cause a violation of any primary drinking water regulation under 40 CFR Part 141 or otherwise adversely affect the health of persons. Any underground injection activity not authorized in this permit, or otherwise authorized by permit or 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 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.

B. PERMIT ACTIONS

1. Modification, Reissuance, or Termination. This permit may be modified, revoked and reissued, or terminated either at the request of any interested person (including the permittee) or upon the Director's initiative. However, permits may only be modified, revoked and reissued, or terminated for the reasons specified in 144.39 or 144.40. All requests shall be in writing and shall contain facts or reasons supporting the request. Also, the permit is subject to minor modifications for cause as specified in 40 CFR Section 144.41. The filing of a request for a permit modification, revocation, and reissuance, or 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 permit condition.
2. Transfers. This permit is not transferrable to any person except after notice is provided to the Director and the requirements of 40 CFR Section 144.38 are complied with. 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 SDWA.

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.

D. CONFIDENTIALITY

In accordance with 40 CFR, Part 2 and 40 CFR, Section 144.5, any information submitted to EPA pursuant to this permit may be claimed as confidential by the submitter. Any such claim shall 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 shall 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 about the existence, absence, or level of contaminants in drinking water.

E. GENERAL DUTIES AND REQUIREMENTS

1. Duty to Comply. The permittee shall comply with all conditions of this permit except to the extent and for the duration such noncompliance is authorized by an emergency permit. Any permit noncompliance constitutes a violation of the SDWA and is grounds for termination, revocation and reissuance, modification of this permit, and/or formal enforcement action. Such noncompliance may also be grounds for enforcement action under the Resource Conservation and Recovery Act (RCRA).

2. Continuation of Expiring Permit.

    a) Duty to Reapply. If the permittee wishes to continue an activity regulated by this permit after the expiration date of this permit, the permittee shall submit a complete application for a new permit at least one hundred and eighty (180) days before this permit expires.

    b) Permit Extensions. The conditions of an expired permit may continue in force in accordance with Title 5 of the United States Code (U.S.C.) 558(c) until the effective date of a new permit if:
        (i) The permittee has submitted a timely application that is a complete application for a new permit; and
        (ii) The Director, through no fault of the permittee, does not issue a new permit with an effective date on or before the expiration date of the previous permit.

    c) Enforcement. When the permittee is not in compliance with the conditions of the expiring or expired permit, the Director may choose to do any or all of the following:
        (i) Initiate enforcement action based upon the permit that has been continued;
        (ii) Issue a notice of intent to deny the new permit. If the permit is denied, the owner or operator would then be required to cease the

activities authorized by the continued permit or be subject to enforcement action for operating without a permit;

(iii) Issue a new permit under 40 CFR Part 124 with appropriate conditions; or

(iv) Take other actions authorized by these regulations.

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

3. Penalties for Violations of Permit Conditions. Any person who violates any requirement of the UIC Program is subject to enforcement action under Section 1423 of the SDWA (42 U.S.C. Section 300h-2, et seq.). Violations of this permit may be subject to such other actions pursuant to RCRA. If the violation is willful, criminal penalties and/or imprisonment may result in accordance with Title 18 of the U.S.C.

4. 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.

5. 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.

6. 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) that 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.

7. Duty to Provide Information. If at any time the Director issues a written request for information to determine whether cause exists for modifying, or to revoke and reissue, or terminate this permit, or to determine compliance with this permit, the permittee shall furnish the requested information within the time specified. The permittee shall also furnish to the Director upon request copies of records required to be kept by this permit.

8. 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 permittee's premises where a regulated facility or activity is located or conducted, or where records are kept under the conditions of this Permit;

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

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

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

9. Signatory Requirements. All reports or other information requested by the Director shall be signed and certified as follows:

a) All reports required by this permit and other information requested by the Director shall be signed as follows:
(i) for a corporation—by a responsible corporate officer, such as a president, secretary treasurer, or vice president of the corporation in charge of principal business function, or any other person who performs similar policy or decision-making functions for the corporation;
(ii) for partnership or sole proprietorship—by general partner or the proprietor, respectively; or
(iii) for municipality, state, federal, or other public agency—by either a principal executive or a ranking elected official.

b) A duly authorized representative of the official designated in paragraph (a) above also may sign only if:
(i) the authorization is made in writing by a person described in paragraph (a) above;
(ii) the authorization specifies either an individual or a position having responsibility for the overall operation of the regulated facility or activity, such as the position of plant manager, operator of a well or a well field, superintendent, or a position of equivalent responsibility. A duly authorized representative may thus be either a named individual or any individual occupying a named position; and
(iii) the written authorization is submitted to the Director.

c) If an authorization under paragraph (b) of this section is no longer accurate because a different individual or position has responsibility for the overall operation of the facility, a new authorization satisfying the requirements of paragraph (b) of this section shall be submitted to the Director prior to, or together with, any reports, information, or applications to be signed by an authorized representative.

d) Any person signing a document under paragraph (b) of this section shall make the following certification:
I certify under the penalty of law that I have personally examined and am familiar with the information submitted in this document and all attachments. Additionally, based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the information is true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fines and imprisonment.

10. Reporting of Noncompliance.

a) Anticipated Noncompliance. The permittee shall give advanced notice to the Director of any planned changes in the permitted facility or activity which may result in noncompliance with Permit requirements.

b) Compliance Schedules. Reports of compliance or noncompliance with, or any progress reports on, interim and final requirements contained in any compliance schedule of this Permit shall be submitted no later than thirty (30) days following each scheduled date. The permittee shall be notified by EPA in writing upon being subject to such a compliance schedule.

c) Twenty-four (24) Hour Reporting.

(i) **The permittee shall report to the Director any noncompliance that may endanger health or the environment**. Information shall be provided, either orally or by leaving a message, within twenty-four (24) hours from the time the permittee becomes aware of the circumstances by telephoning **303.312.6704 and asking for the EPA Region 8 UIC Program Compliance and Enforcement Director (during normal business hours)**, or by contacting the **EPA Region 8 Emergency Operations Center at 303.293.1788 (for reporting at all other times).** The following information shall be included in the verbal report:

- Any monitoring or other information which indicates that any contaminant may cause endangerment to a USDW.
- Any noncompliance with a permit condition or malfunction of the injection system which may cause fluid migration into or between USDWs.

(ii) Written notice of any noncompliance that may endanger health or the environment **shall be provided to the Director within five (5) calendar days** of the time the permittee becomes aware of the noncompliance. The written notice shall contain a description of the noncompliance and its cause; the period of noncompliance including exact dates and times; if the noncompliance has not been corrected, the anticipated time it is expected to continue; and steps taken or planned to prevent or reduce recurrence of the noncompliance.

d) Other Noncompliance. The permittee shall report all other instances of noncompliance not otherwise reported at the time of analysis submission. The reports shall contain the information listed in Part III, Section E.10.c. of this permit.

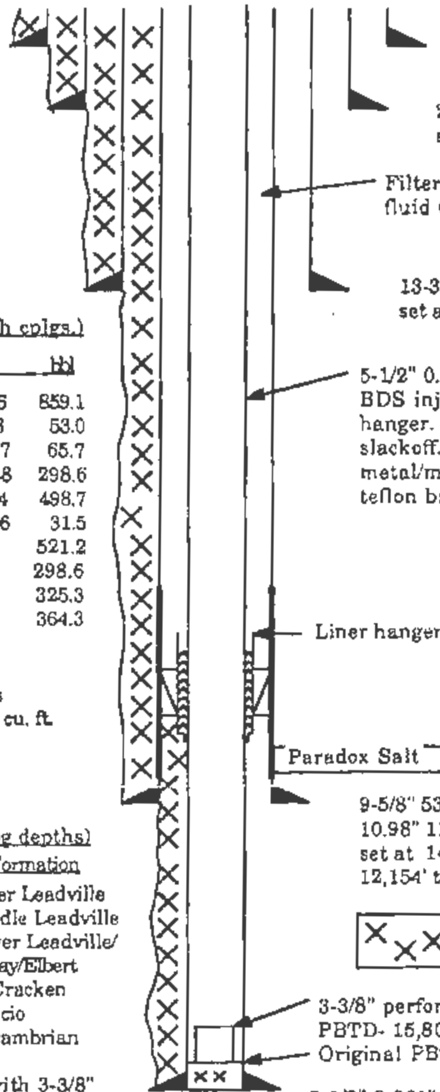
e) Other Information. When the permittee becomes aware that any relevant facts were not submitted in the permit application, or incorrect information was submitted in a permit application, or in any report to the Director, the permittee shall submit such correct facts or information within fourteen (14) calendar days of the time such information becomes known.

11. Oil Spill and Chemical Release Reporting. The operator shall comply with all other reporting requirements related to oil spills and chemical releases or other potential impacts to human health or the environment by contacting the National Response Center (NRC) at 1.800.424.8802 or 202.267.2675, or through the NRC website at http://www.nrc.uscg.mil/nrchp.html.

APPENDIX A

WELL CONSTRUCTION, TUBING, CASING AND CONSTRUCTION DETAILS

Figure 1- Wellbore Schematic
Paradox Valley Injection Test #1
Montrose County, Colorado



Tubular Capacities (with cplgs.)

Size	bbl/ft	bbl
9-5/8	0.070766	859.1
10.98	0.075228	53.0
5-1/2 (.361")	0.022177	65.7
5-1/2 (.304")	0.023248	298.6
9-5/8 x 5-1/2	0.040334	498.7
10.98 x 5-1/2	0.044796	31.5
Total annular cap.		521.2
Tbg. vol. to seal ass'y		298.6
Volume to top perf.		325.3
Volume to PBTD		364.3

1 bbl = 42 gallons
1 bbl = 5.6145833 cu. ft.

Perforation Depths (log depths)

Depth	Formation
14,080 - 14,185	Upper Leadville
14,215 - 14,350	Middle Leadville
14,380 - 14,504	Lower Leadville/ Ouray/Elbert
14,651 - 14,719	McCracken
15,376 - 15,386	Ignacio
15,489 - 15,827	Precambrian

All perforations shot with 3-3/8" hollow carrier guns loaded 6 spf with 20 gm deep penetrating charges.

*Tubular Ratings

Size (in.)	Weight (ppf)	ID (in.)	Drift (in.)	Burst (psi.)	Collapse (psi.)	Tensile (klb.)
9-5/8**	53.5	8.535	8.500	9410**	7330	1477
10.98	115.2	8.800	8.500	16,500	16,990	2061
5-1/2	23.1	4.778	4.653	17,230	13,480	874
5-1/2	19.2	4.892	4.767	12,440	7890	620

* The 20", 13-3/8", 9-5/8", and 10.98" were made by Mannesman of West Germany. The 5-1/2" C-276 was made by INCO Alloys of Huntington, West Virginia. The wellhead equipment was made by Cameron Iron Works of Houston, Texas. The liner hanger/ seal asssembly were made by Texas Iron Works of Houston, Texas.

** Casing caliper indicated 9-5/8" to have even ID wear from drilling. Minimum remaining wall thickness is 0.45". Maximum recommended working pressure of 9-5/8" is 7,400 psi (1.2 SFB) based on this minimum remaining wall.

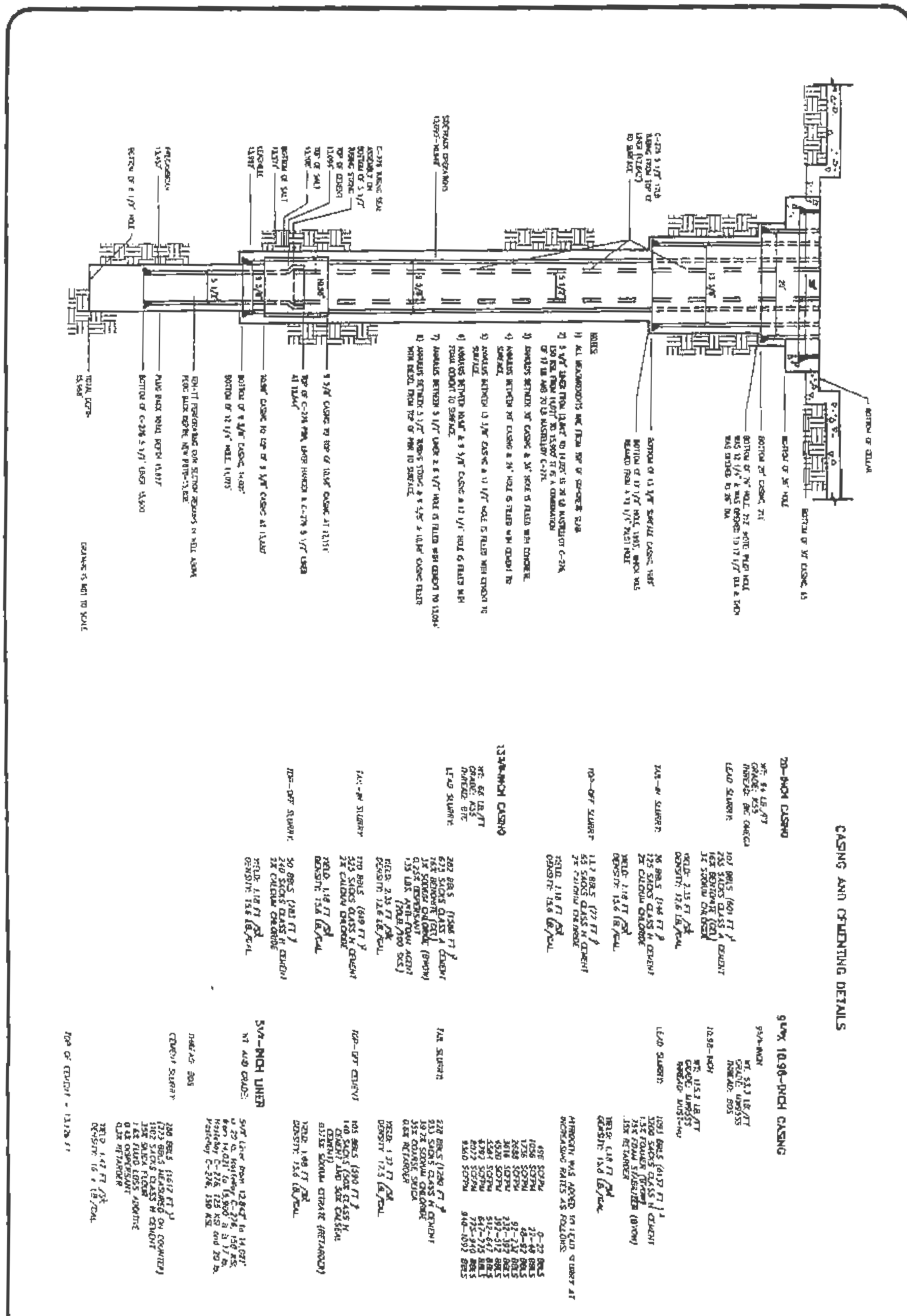


FIGURE 2B-5 INJECTION WELL CASING SECTION

APPENDIX B

REPORTING FORMS

OMB No. 2040-0042 Approval Expires 12/31/2011

United States Environmental Protection Agency
Washington, DC 20460

Injection Well Monitoring Report

Year	Month	Month	Month
Injection Pressure (PSI)			
1. Minimum			
2. Average			
3. Maximum			
Injection Rate (Gal/Min)			
1. Minimum			
2. Average			
3. Maximum			
Annular Pressure (PSI)			
1. Minimum			
2. Average			
3. Maximum			
Injection Volume (Gal)			
1. Monthly Total			
2. Yearly Cumulative			
Temperature (F °)			
1. Minimum			
2. Average			
3. Maximum			
pH			
1. Minimum			
2. Average			
3. Maximum			
Other			

Name and Address of Permittee		Permit Number
Name and Official Title *(Please type or print)*	Signature	Date Signed

Paperwork Reduction Act

The public reporting and record keeping burden for this collection of information is estimated to average 25 hours per quarter for operators of Class I hazardous wells, 16 hours per quarter for operators of Class I non-hazardous wells, and 30 hours per quarter for operators of Class III wells.

Burden means the total time, effort, or financial resource expended by persons to generate, maintain, retain, or disclose or provide information to or for a Federal Agency. This includes the time needed to review instructions; develop, acquire, install, and utilize technology and systems for the purposes of collecting, validating, and verifying information, processing and maintaining information, and disclosing and providing information; adjust the existing ways to comply with any previously applicable instructions and requirements; train personnel to be able to respond to the collection of information; search data sources; complete and review the collection of information; and, transmit or otherwise disclose the information. An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. Send comments on the Agency's need for this information, the accuracy of the provided burden estimates, and any suggested methods for minimizing respondent burden, including the use of automated collection techniques to Director, Collection Strategies Division, U.S. Environmental Protection Agency (2822), 1200 Pennsylvania Ave., NW., Washington, D.C. 20460. Include the OMB control number in any correspondence. Do not send the completed forms to this address.

OMB No. 2040-0042 Approval Expires 12/31/2011

United States Environmental Protection Agency
Washington, DC 20460

EPA

ANNUAL DISPOSAL/INJECTION WELL MONITORING REPORT

Name and Address of Existing Permittee

Name and Address of Surface Owner

Locate Well and Outline Unit on Section Plat - 640 Acres

N

W E

S

State

County

Permit Number

Surface Location Description

____ 1/4 of ____ 1/4 of ____ 1/4 of ____ 1/4 of Section ____ Township ____ Range ____

Locate well in two directions from nearest lines of quarter section and drilling unit

Surface
Location ____ ft. frm (N/S) ____ Line of quarter section
and ____ ft. from (E/W) ____ Line of quarter section.

WELL ACTIVITY
- [ ] Brine Disposal
- [ ] Enhanced Recovery
- [ ] Hydrocarbon Storage

TYPE OF PERMIT
- [ ] Individual
- [ ] Area

Number of Wells ____

Lease Name

Well Number

MONTH YEAR	INJECTION PRESSURE AVERAGE PSIG	MAXIMUM PSIG	TOTAL VOLUME INJECTED BBL	MCF	TUBING -- CASING ANNULUS PRESSURE (OPTIONAL MONITORING) MINIMUM PSIG	MAXIMUM PSIG

Certification

I certify under the penalty of law that I have personally examined and am familiar with the information submitted in this document and all attachments and that, based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the information is true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment. (Ref. 40 CFR 144.32)

Name and Official Title *(Please type or print)*	Signature	Date Signed

PAPERWORK REDUCTION ACT

The public reporting and record keeping burden for this collection of information is estimated to average 30 hours per quarter. Burden means the total time, effort, or financial resource expended by persons to generate, maintain, retain, or disclose or provide information to or for a Federal Agency. This includes the time needed to review instructions; develop, acquire, install, and utilize technology and systems for the purposes ofc ollecting, validating, and verifying information, processing and maintaining information, and disclosing and providing information; adjust the existing ways to comply with any previously applicable instructions and requirements; train personnel to be able to respond to the collection of information; search data sources; complete and review the collection of information; and, transmit or otherwise disclose the information. An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. Send comments on the Agency's need for this information, the accuracy of the provided burden estimates, and any suggested methods for minimizing respondent burden, including the use of automated collection techniques to Director, Collection Strategies Division, U.S. Environmental Protection Agency (2822), 1200 Pennsylvania Ave., NW, Washington, D.C. 20460. Include the OMB control number in any correspondence. Do not send the completed forms to this address.

OMB No. 2040-0042 Approval Expires 12/31/2011

EPA

United States Environmental Protection Agency
Washington, DC 20460

WELL REWORK RECORD

Name and Address of Permittee	Name and Address of Contractor

Locate Well and Outline Unit on Section Plat - 640 Acres

N

W E

S

State	County	Permit Number

Surface Location Description

___ 1/4 of ___ 1/4 of ___ 1/4 of ___ 1/4 of Section ___ Township ___ Range ___

Locate well in two directions from nearest lines of quarter section and drilling unit

Surface
Location ___ ft. frm (N/S) ___ Line of quarter section
and ___ ft. from (E/W) ___ Line of quarter section.

WELL ACTIVITY		TYPE OF PERMIT
☐ Brine Disposal	Total Depth Before Rework	__ Individual
☐ Enhanced Recovery	Total Depth After Rework	__ Area
☐ Hydrocarbon Storage	Date Rework Commenced	Number of Wells ___
Lease Name	Date Rework Completed	Well Number

WELL CASING RECORD -- BEFORE REWORK

Casing		Cement		Perforations		Acid or Fracture Treatment Record
Size	Depth	Sacks	Type	From	To	

WELL CASING RECORD – AFTER REWORK *(Indicate Additions and Changes Only)*

Casing		Cement		Perforations		Acid or Fracture Treatment Record
Size	Depth	Sacks	Type	From	To	

DESCRIBE REWORK OPERATIONS IN DETAIL USE ADDITIONAL SHEETS IF NECESSARY	WIRE LINE LOGS, LIST EACH TYPE	
	Log Types	Logged Intervals

Certification

I certify under the penalty of law that I have personally examined and am familiar with the information submitted in this document and all attachments and that, based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the information is true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment. (Ref. 40 CFR 144.32)

Name and Official Title *(Please type or print)*	Signature	Date Signed

PAPERWORK REDUCTION ACT

The public reporting and record keeping burden for this collection of information is estimated to average 4 hours per response annually. Burden means the total time, effort, or financial resource expended by persons to generate, maintain, retain, or disclose or provide information to or for a Federal Agency. This includes the time needed to review instructions; develop, acquire, install, and utilize technology and systems for the purposes of collecting, validating, and verifying information, processing and maintaining information, and disclosing and providing information: adjust the existing ways to comply with any previously applicable instructions and requirements; train personnel to be able to respond to the collection of information; search data sources; complete and review the collection of information; and, transmit or otherwise disclose the information. An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. Send comments on the Agency's need for this information, the accuracy of the provided burden estimates, and any suggested methods for minimizing respondent burden, including the use of automated collection techniques to Director, Collection Strategies Division, U.S. Environmental Protection Agency (2822), 1200 Pennsylvania Ave., NW., Washington, D.C. 20460. Include the OMB control number in any correspondence. Do not send the completed forms to this address.

APPENDIX C

PLUGGING and ABANDONMENT PLAN

PLUGGING AND ABANDONMENT PLAN

The UIC Director has determined that this well plugging and abandonment plan adequately protects the USDWs. The plan is incorporated into the permit and shall be binding on the permittee.

After receiving approval from the appropriate Regional EPA office, the permitted injection well will be plugged in accordance with the Plugging and Abandonment Plan as follows:

PLUG NO. 1: Install a bridge plug 14,080 feet to 14,185 feet below ground level (BGL).

PLUG NO. 2: Unlatch polished bore receptacle/liner at 12,884 feet (BGL) and recover the 5-1/2 inch 0.0304 wall 125ski C-276 BDS injection tubing.

PLUG NO. 3: Cement tubing from bridge plug to 12,900 feet (BGL).

PLUG NO. 4: Bentonite slurry to fill annulus casing to 1000 feet (BGL).

PLUG NO. 5: Cement annulus casing to surface and provide surface marker.

APPENDIX D

WAMS SOP

WELL ANNULUS MONITORING SYSTEM (WAMS) BASELINE PROCEDURE

I. **Purpose**: This procedure details the function and operation of the WAMS system as well as provides a platform to document all pertinent system information such as:
- System Overview
- Design Criteria
- Electrical Power Supplies
- Equipment Ratings
- Associated Safety Features
- System Pressure Ratings

II. Attachments:

A. Drawing: Surface Facilities for Injection Test Well No. 1 Process and Instrumentation Diagram Well Annulus Monitoring System (#1294-400-263-R)

B. Drawing: Surface Facilities for Injection Test Well No. 1 Process and Instrumentation Diagram Injection Well (#1294-400-258-R)

III. Associated Safety Hazards

- High Pressure
- Exposure to Hazardous Chemicals (CRW-37)
- Slipping/ Tripping
- Pinching

IV. Required PPE includes:

- Safety Glasses (when operating the system)
- Work Boots
- Face shield (if the potential for splashing CRW exists)
- Apron (if the potential for splashing CRW exists)

V. System Overview

During normal well operation, brine is pumped through the injection tubing string into the liner and out to the injection zones through perforations. It is intended that no brine leave the injection well at any place other than the intended injection zones. It is also necessary for protection of the well that the casing remain intact. The well casing and well string are as follows:

- The intermediate well casing (the 9-5/8"), extends from the christmas tree at the surface to approximately 14,000 feet below ground level.
- The injection tubing string (5½" Hastelloy C-276) runs inside the 9-5/8" intermediate well casing and extends from the christmas tree at surface to 12,808 feet below ground level
- At 12,808', the Tubing Seal Assembly (TSA) and the Polished Bore Receptacle (PBR) connect the 5 1/2" injection tubing string to the injection liner.
- The Hastelloy C-276 liner extends to approximately 15,900' (the well bottom) and has 3 perforated intervals at varying depths below 14,000'.
- The space between the 9-5/8" casing and the injection tubing is the **well annulus**. The well annulus, from the TSA/PBR to the surface, is filled with packer fluid [water treated with biocide and a corrosion inhibitor (CRW-37)].

The Well Annulus Monitoring System (WAMS) is located at the drilling pad for the injection well. The WAMS provides information used to determine well casing and injection tubing integrity and will usually be the first indication of downhole problems. Under normal well operating conditions, both the packer fluid in the annulus and the well materials will expand and contract. This expansion and contraction is normal and occurs primarily as a result of changing temperatures in the well system. The expansion and contraction of the well materials in turn cause changes in the well volume. As the well material heats or cools, the well's volume will expand and contract. This expansion and contraction, in the closed system within the well, translate to changes in pressure. As volume increases, so does the pressure and conversely, pressure decreases as volume decreases. However, over time, down hole temperatures stabilize, therefore temperature effects on volume and pressure are minimal for short term shutdowns.

The following discussion will help to interpret the information from the WAMS:

Visualize the annulus between the 5-1/2" injection tubing and the 9-5/8" casing from the surface to the top of the TSA/PBR as a pressurized vessel. As stated earlier, assume that the temperatures in the injection string have stabilized, therefore absolute volume of the vessel due to temperature effects is negligible. Since it is a closed system, the actual amount of water in the system cannot change unless the system is pumped or bled. For this reason, the WAMS unit provides the following information:

- By comparing WAMS storage tank transfers between successive days, the following can be concluded:
  - The storage tank is losing fluid.
  - The storage tank is gaining fluid.
  - No change in fluid level is occurring.
- By monitoring annulus pressure history, the following can be concluded
  - Pressure in the annulus is decreasing.
  - Pressure in the annulus is increasing.
  - No change in annulus pressure is occurring.

The system does not indicate why these events are occurring. However, these observations must be evaluated to determine if the integrity of the well casing and/or tubing string is compromised.

VI. **Major Components** The system includes three components.

The first major component of the system is a 400 bbl (16,800 gallons) frac tank (T-400), piped to provide fluid for the annulus, and receive the relief flows from the annulus system through motor controlled valve MOV-332 (MOV-332's motor controller has been disabled electrically, but is normally shut) located on the well pad. The usable storage capacity of the tank is approximately 16,000 gallons. The tank is equipped with a flame arrester vent since there will always be remnants of the original packer fluid (diesel).

The second major component of the WAMS is an electric motor driven triplex plunger pump (P-404), rated at 4.3 gpm at up to 10,000 psig. 2" CPVC piping is used to transfer water to this pump. High pressure piping is used to transfer water from this pump into the well annulus.

The third major part of the annulus pressure control system is located on the injection pad. It consists of 8,000 psig rated piping with relief valves, monitoring instrumentation and a 2-1/16 inch 10,000 psig gate valve, VCG-05. The WAMS system is isolated from the well by using valves VCG-05 and VB-419.

VII. System Description:

A. Process Monitoring:
The WAMS pressure is monitored hourly by the Stationary Engineer at the Control Room computer using transducers (PT-330 and PT 331) and locally at the well pad using a pressure gage (PI-400). The hourly readings are recorded on the Stationary Engineer's operating logs. The logs are reviewed and analyzed. Any abnormal pressure trends will be noted in the Stationary Engineer's log and supervisory personnel will be notified immediately so that changes to operating and/or maintenance procedures can be incorporated to minimize or eliminate any detrimental effects.

B. System Operation:

NOTE

- **WAMS Pressure is maintained at 1100 psi +/- 50 above the well injection pressure at all times.**
- **Adding one (1) gallon of water will increase the WAMS pressure approximately 10 psi.**

Various system line-ups allow water to be added (pumped) or removed (bled) from the WAMS system to and from the WAMS storage tank. The WAMS is bled to the WAMS storage tank to lower WAMS pressure or pumped from the WAMS storage tank using the triplex pump to raise WAMS pressure.

A small leak in the injection tubing was discovered during initial system start-up and injection operations. It was determined that the TSA/PBR seal was the most probable location for a leak to occur. To prevent brine from being introduced into the well annulus from the TSA/PBR seal leak, WAMS pressure is maintained 1100 +/- 50 psi **above** the well injection pressure.

X. Operating Parameters:

Parameter	Specification	Range
Differential Pressure (WAMS/Well Injection Pressure)	1100 psig	+/- 50 psi
WAMS Tank Level	--	7' to 18.5'

XI. Design Criteria of Major Components:

1. WAMS Storage Tank (T-400)

Manufacturer	Western Manufacturing Co.
Usable capacity	15,000 gal
Total capacity	16,900 gal
Pressure maximum	Atmospheric
Pressure minimum	Atmospheric
Material	Epoxy lined carbon steel

2. Triplex Pump (P404)

Manufacturer	National Water Blaster Inc. (NLB)
Model	1045
Type	3/4"Triplex plunger
Motor Rating	25 hp
Rated head, psig	10,000
Capacity	4.3 gpm
Speed	1760 rpm
Power supply	WAMS-PP

3. Triplex Pump Relief Valve (PSV 413)

Manufacturer	Baird
Type	Ball and Seat Disk spring
Size	1" X 1"
Pressure Rating	10,000 psi
Set Point	7500 psi

4. WAMS Relief Valves (PSV 421 and PSV 422)

Manufacturer:	Baird
Type	Ball and Seat
Size	1" x 1"
Pressure Rating	10,000 psi
Setpoint	7500 psi

5. Pressure Transducers (PT-330, PT331)

Manufacturer:	Stellar Technology
Output	4-20 ma
Range	0-7500 psi
Provides input to:	PDX PLC BIF Control Panel Page (PT-330)
	PDX PLC Well Annulus Monitoring System Page (PT-331)
Protective Feature:	Visual alarm if WAMS and Injection Pressure differential pressure fall outside the set point (1100 +/- 50 psid)

6. WAMS Isolation Valve (VCG-05)

Manufacturer:	Cameron
Type	Gate
Size	2 1/16"
Pressure Rating	10,000 psi

7. WAMS Piping

Piping	Material
Storage tank to Triplex Pump	2" CPVC Sch 80 pipe
Triplex pump to Cameron Valve	1" 10,000 psig Sch 80 carbon steel pipe
Relief valves to R1 pipe spec	1" 10,000 psig hose
Tank fill connection	1 ½" pipe

8. WAMS Control Valves (VB-412, VB-413, VB-401A, VB-401)

Manufacturer:	Edwards Univalve
Type	Globe Valve
Size	1"
Pressure Rating	10,000 psi

9. WAMS Flow Meter (FM-400)

Manufacturer:	Neptune
Type	Paddle Wheel
Size	1"

Valve / Component Table:

Components/Valves/ Breakers applicable to this SOP			
Component	**Description**	**Position**	**Image**
WAMS Storage Tank (T400)	See Above	N/A	
WAMS outside the WAMS building	See Above	N/A	
VB-412 & VB-413	Primary and Secondary Annulus Pressurization Valve	Shut (VB-412) Open (VB-413)	 

Components/Valves/ Breakers applicable to this SOP			
Component	**Description**	**Position**	**Image**
VB-401	Primary WAMS Bleed Valve	Shut	
PSV-421 & PSV-422	WAMS Relief Valves	Shut	**Relief valves are covered with insulation for winter freeze protection.**
VCG-05	WAMS Isolation Valve	Normally Open	

Components/Valves/ Breakers applicable to this SOP

Component	Description	Position	Image
WAMS Electrical Panels	North wall of the WAMS building	On	
WAMS Triplex Pump Controller	South Wall of WAMS Building	On when pumping the WAMS	
WAMS Storage Tank (T400) fill connection	West side of T400	Normally open, used during filling operations.	

REVISIONS AND APPROVALS

Record of Revisions					
Date	Revision or Minor Change	Revision Number	Reason for SOP change	Person making/ entering the change	Date change entered

AUTHOR

Eric Schank		OM&S	3/2/09
Printed Name of Author	Signature	Department	Date

REVIEWS AND CONCURRENCE

Concur

Jamie Chiles		QC/Safety	3/2/9	Yes	No
Printed Name of Reviewer	Signature	Division	Date		

FINAL APPROVAL

Approved

John Adams		02-MAR-09	Yes	No
Printed Name of Project Manager	Project Manager Signature	Date		

Bleeding the
Well Annulus Monitoring System (WAMS)

Purpose: To ensure that annulus pressure is maintained 1100$^+$/-50 psi above the injection pressure at all times.

Control: Stationary Engineer directs the operation of the WAMS system and will monitor differential pressure from the control screen located inside the BIF control room or locally on gage VN-400a during bleeding operations to verify system conditions.

Characteristics: Bleeding approximately one gallon of fluid decreases the annulus pressure approximately 10 psi.

Procedure:

NOTE. Annulus pressure is maintained 1100$^+$/-50 psi above the injection pressure at all times

1. Check open VB-413.
2. Check shut VB-412.
3. Open VB-401a.
4. Notify Stationary Engineer that system is lined up for bleeding operations.
5. Stationary Engineer direct cracking of VB-401 to commence bleeding operations.
6. Stationary Engineer monitors differential pressure during bleeding operation.
7. Stationary Engineer direct shutting of VB-401 when desired differential pressure is reached.
8. Torque shut VB-401 up to 75 ft-lbs.
9. Verify annulus pressure is within specified range
10. Shut VB-401A
11. Note and Record the pressure bled in the WAMS log book located in the BIF Control Room.

REVISIONS AND APPROVALS

Record of Revisions					
Date	Revision or Minor Change	Revision Number	Reason for SOP change	Person making/ entering the change	Date change entered

AUTHOR

Eric Schank		OM&S	3/2/09
Printed Name of Author	Signature	Department	Date

REVIEWS AND CONCURRENCE

Concur

Jamie Chiles		QC/Safety	3/2/9	Yes	No
Printed Name of Reviewer	Signature	Division	Date		

FINAL APPROVAL

Approved

John Adams		02-Mar-09	Yes	No
Printed Name of Project Manager	Project Manager Signature	Date		

Standard Operating Procedure		
SOP # WAMS-03	Revision: 0	Effective Date: 03/02/09

Pressurizing the Well Annulus Monitoring System (WAMS)

Purpose: To ensure that annulus pressure is maintained 1100^{+}/-50 psi above the injection pressure at all times

Control: Stationary Engineer directs the operation of the WAMS system and will monitor differential pressure from the control screen located inside the BIF control room or locally on gage VN-400a during pressurizing operations to verify system conditions.

Characteristics: Pumping approximately one gallon of fluid increases the annulus pressure approximately 10 psi.

Procedure:

NOTE: Annulus pressure is maintained 1100^{+}/-50 psi above the injection pressure at all times

1. Verify WAMS tank level is at least 7'.
2. Check open VB-413
3. Check shut VB-401
4. Shut VB-401a
5. Open primary fill valve VB-412
6. Check open VB-404
7. Check open VB-405
8. Stationary Engineer directs starting the triplex pump (P-400) to increase WAMS pressure.
9. Pump appropriate volume to achieve desired pressure increase.
10. Stop the triplex pump (P-400) when the desired pressure is reached.
11. Torque shut VB-412 up to 75 ft-lbs.
12. Verify annulus pressure is within specified range.
13. Note the WAMS pressure, and the gallons used.
14. Record and initial in the WAMS log book located in the BIF Control Room.

REVISIONS AND APPROVALS

Record of Revisions					
Date	Revision or Minor Change	Revision Number	Reason for SOP change	Person making/ entering the change	Date change entered

AUTHOR

Eric Schank		OM&S	3/2/09
Printed Name of Author	Signature	Department	Date

REVIEWS AND CONCURRENCE

Concur

Jamie Chiles		QC/Safety	3/2/9	Yes	No
Printed Name of Reviewer	Signature	Division	Date		

FINAL APPROVAL

Approved

John Adams		02-MAR-09	Yes	No
Printed Name of Project Manager	Project Manager Signature	Date		

Standard Operating Procedure

SOP # WAMS-04	Revision: 0	Effective Date: 03/02/09

Filling the WAMS Storage Tank (T-400)

Purpose: To fill the WAMS storage tank when level reaches the 7' level.

Control: Stationary Engineer will direct filling of the WAMS T-400 tank, all valve operations will be reported the Stationary Engineer.

Characteristics: The WAMS storage tank will be maintained between 7' and 18.5' as indicated by level indicators on the side of tank.

Procedure:

1. Corrosion inhibitor vendor attach a hose to the 1½" WAMS tank fill connection.
2. Open the T-400 tank fill valve
3. Pump 110 gallons of CRW37 into the WAMS tank
4. After vendor adds the110 gallons of CRW37, shut the WAMS fill valve.
5. Disconnect the CRW37 fill hose from the fill line.
6. Attach a hose from the 600 tank discharge valve to the suction of a portable pump.
7. Attach a hose from the discharge of the portable pump to the WAMS tank fill valve.
8. Open the 600 tank drain valve.
9. Open the WAMS tank fill valve.
10. Start the portable pump.
11. When the WAMS tank reaches the 18.5', stop the portable pump.
12. Shut the WAMS tank fill valve.
13. Shut the 600 tank drain valve.
14. Disconnect, drain and store the portable pump and hoses.

REVISIONS AND APPROVALS

Record of Revisions					
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REVIEWS AND CONCURRENCE

Concur

Jamie Chiles		QC/Safety	3/2/9	Yes	No
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FINAL APPROVAL

Approved

John Adams		02-MAR-09	Yes	No
Printed Name of Project Manager	Project Manager Signature	Date		

APPENDIX E

SEISMIC MONITORING PLAN

June 21, 2011

Bureau of Reclamation
Paradox Valley Seismic Network
Monitoring Plan

In compliance with the permit issued by the Environmental Protection Agency (EPA) for the Paradox Valley Unit's (PVU's) deep injection well, the Bureau of Reclamation (Reclamation) will operate a multi-station seismic monitoring network in the vicinity of Paradox Valley, Colorado. The purpose of the network, named the Paradox Valley Seismic Network (PVSN), is to monitor earthquakes induced by the deep injection of brine, as well as any naturally-occurring earthquakes in the Paradox Valley region.

PVSN will consist of two complimentary seismic monitoring components:

1. High-gain seismic array

The high-gain seismic array will consist of a multi-station, continuously recorded array of stations. The array will be sufficient to reliably detect earthquakes down to magnitude **M** 0.5 that may occur within 10 km of the injection well, and determine their characteristics. In addition, the array will be capable of detecting earthquakes of magnitude **M** 1.0 or larger occurring in the broader Paradox Valley region, out to a distance of at least 30 km from the well.

The density of high-gain seismic array stations will be sufficient to locate earthquakes occurring within 10 km of the injection well to within 1.5 km accuracy, and events occurring within the perimeter of the network to within 3 km accuracy. Because the spatial distribution of seismicity is not expected to be uniform, the density of seismic stations will vary. In general, stations will be spaced closer together near the injection well and in other seismically active areas, with a sparser station spacing in less active regions.

Each high-gain seismic station will measure ground motions in either one or three directions. Stations that measure motion in a single direction will consist of a vertically-oriented, single-component seismometer. Stations that measure motion in three directions will have a three-component seismometer aligned vertically and in the north-south and east-west directions. Because three-component stations provide additional information that enables more accurate estimates of earthquake depths compared to single-component stations, three-component stations should be used whenever feasible.

The high-gain array will be designed so that seismic data recorded by each station will be continuously transmitted to a centralized data processing center where seismic events will be automatically detected and recorded.

2. Strong-motion array

The strong-motion array will consist of a small number of event-triggered stations located in or near populated areas subject to shaking from induced earthquakes, or at critical project facilities such as the injection well. The strong-motion array will be designed to measure ground motions from events that are large enough to be felt or cause damage, and which would tend to saturate the high-gain array. The strong-motion array may operate in either a continuously transmitted mode, or in an event-triggered mode such that waveform data from discrete earthquakes is stored locally until it can be downloaded. If an event-triggered mode is used, communications will be provided so that data can be downloaded automatically to a centralized data processing center within 1 hour of the occurrence of an earthquake.

The configuration of the high-gain seismic array and the locations of strong motion instruments may change over time, as needed to adapt to any evolution in the spatial distribution of seismicity or major modifications to PVU's infrastructure.

Reclamation will keep PVSN's data acquisition systems operating as continuously as practical, with a goal of achieving an annual uptime of 95% or higher. The operational status of the network will be evaluated on a regular basis, and maintenance and upgrades to the network components will be performed as needed to maintain the desired monitoring capabilities and as resources and field conditions allow.

In addition to the automatic processing of each seismic event discussed above, Reclamation personnel will manually review and process each detected seismic event in a timely manner. Individual characteristics of the earthquakes will be determined, such as location, magnitude, and time of occurrence, as well as their cumulative characteristics, such as their distribution in time. A database of all local earthquakes detected by PVSN will be maintained by Reclamation. The earthquake data will be used to identify and evaluate relationsbips between seismicity, geology, tectonics, and injection operations. Reports concerning network operations and recorded seismicity will be prepared as deemed appropriate by Reclamation project managers

FACT SHEET
Application for Reauthorization of a
Class V Underground Injection Control Permit
for the Paradox Salinity Control Well No. 1
SE NW SE Section 30
Township 47 North, Range 18 West
Montrose County, Colorado
EPA Permit CO50108-00647

I. Background

The Upper Colorado Regional Office of the U.S. Bureau of Reclamation (USBR) is involved in studies of methods to reduce the salinity of the Colorado River in accordance with the Colorado Salinity Control Act of June 24, 1974 (Public Law 93-320). The Paradox Valley Salinity Control Project was established under Title II Public Law 93-320 to reduce the salinity of the Colorado River and its tributaries. The Paradox Salinity Control Project captures highly saline brine (with an approximate total dissolved solids content of 260,000 mg/liter) emanating from springs discharging into the Dolores River near Bedrock, Colorado. The brine is extracted by pumping wells completed near the springs. The wells capture up to 600 gallons per minute (gpm) of brine that would otherwise discharge into the Dolores River. The brine is transported from the well field in a buried 10-inch high density polyethylene (HDPE) pipeline 3.7 miles along the Dolores River to the site of a Class V brine injection well, the Paradox Salinity Control Well No. 1. The USBR has been operating this injection well under the current UIC permit since March 19, 1997.

A Class V permit expires 10 years after the effective date of the permit. Title 40 of the Code of Federal Regulations (40 CFR) Part 144.37 allows for the continuation of expiring permits. This part states that when EPA is the permit-issuing authority, the conditions of an expired permit continue in force under Title 5 of the United States Code (U.S.C.) 558(c) until the effective date of a new permit if:

(1) The permittee has submitted a timely application, which is a complete application for a new permit; and
(2) The Regional Administrator, through no fault of the permittee does not issue a new permit with an effective date on or before the expiration date of the previous permit (for example, when issuance is impracticable due to time or resource constraints).

On March 31, 2006, the Environmental Protection Agency (EPA), Region 8, Underground Injection Control (UIC) Program received an application from the USBR Upper Colorado Region Office in Salt Lake City, Utah, for continued operation of the Paradox Salinity Control Well No. 1. After determining that the application was complete, EPA has allowed the Paradox injection well to operate under the expired permit since March 19, 2007. EPA now proposes the issuance of a third permit authorizing the injection of brine into the Paradox Salinity Control Well No. 1.

This Fact Sheet was developed partially from information supplied by the USBR in the original (January 13, 1986) Permit application, the first application (June 14, 1996) for reauthorization, as well as the current (March 31, 2006) application for reauthorization. Other documents used in developing this Fact Sheet are given on page 14, entitled "Reference Documents."

II. Previous Permitting Actions

40 CFR Section 144.36 requires that Permits for Class V wells be issued if the EPA determines such action is necessary to protect underground sources of drinking water. Because of the salinity and corrosiveness of the brine, EPA determined that a Permit was necessary and the first Permit for the operation of the Paradox Salinity Control Well No. 1 was issued and became effective on June 13, 1986. Construction of the well began on December 19, 1986. USBR began injection into the well on August 13, 1990, with 100 percent fresh Dolores River water followed by a 30 percent brine 70 percent fresh water mix for the second injection cycle. The increasingly brine nature of the injected fluid in subsequent injection is summarized in Section VI.

The second permit for the Paradox Salinity Control Well No. 1 was issued on March 19, 1997. Minor changes from the original 1986 permit included adjustments of the injection intervals, no volume-rate (gpm) limitation on the injected brine, and modification of monitoring, reporting and recordkeeping requirements.

On February 13, 2004, the USBR requested a modification of the second Permit to increase the Maximum Allowable Surface Injection Pressure (MASIP). The Paradox Valley Unit Salinity Control Injection Well No. 1 has been continuously injecting brine as a method of disposal since 1996. Since injection operations began, the surface pressure necessary to inject the brine into fractures of the Leadville formation at a depth of 14,000 feet below land surface has increased as a result of the injectate filling the available fractures and natural porosity of the injection interval formation. As the fluid migration extends away from the wellbore, the pressure necessary to push the fluid farther through the natural formation fractures increases.

On April 29, 2004, the EPA approved the permit modification to increase the MASIP from 5,000 pounds per square inch gauge (psig) to 5,350 psig. The modification required that USBR inspect and recertify the injection pumps, lines, and wellhead before initiating injection at 5,350 psig. In a letter dated February 23, 2010, the BOR submitted documentation demonstrating that the previous permit requirements were addressed and requested that EPA issue an Authorization to Inject at the new MASIP of 5,350 psig. EPA approved the authorization on May 10, 2010.

III. Area Geology, Hydrology, and Seismicity

1. Structural Geology and Stratigraphy: The Paradox Basin is located in the northeastern portion of the Colorado Plateau, which is characterized by thick sedimentary sequences and a tectonically stable environment. In the vicinity of the injection well, the sedimentary sequence is approximately 16,000 feet thick, comprised mainly of siltstone, shale, sandstone, limestone, and salt in the following formations:

Formations	Depth to Top of Formation Measured in feet from Kelly Bushing (KB)
Chinle	0 (at surface)
Cutler	1,140'
Honaker Trail	8,330'
Paradox	12,384'
Ismay	12,872'
Salt	13,140'
Lower Paradox	13,606'
Pinkerton Trail	13,731'
Molas	13,984'
Leadville	14,024'
Ouray	14,440'
Elbert	14,480'
McCracken	14,648'
Aneth-Lynch-Muav-Bright Angel	14,722'
Ignacio	15,288'
Precambrian	15,489'

Plug Back Total Depth (PBTD): 15,808 feet (Below ground surface)

The Paradox Valley area falls in the Paradox fold and fault belt of the northeastern Paradox Basin. The area is dominated by northwesterly-trending folds and faults, which are commonly staggered and in places broadly curved. The Valley follows the trend (strike) of one of the anticlines formed by a large salt pillow, which overlies pre-salt fault structures. The center of the anticline is estimated to have 15,000 feet of salt.

The Paradox Salinity Control Well No. 1 is located on the southern flank of the collapsed Paradox Valley salt anticline where the Paradox salt and anhydrite are nearly flat lying and are about 1,000 feet thick. The well is completed in one of the fault blocks of the Mississippian and Devonian Formations, which underlie the salt. This block is bounded by northwest-southeast trending faults having throws in excess of 1,000 feet and lying roughly 1 mile apart. The boundaries of the proposed pre-Cambrian to Leadville reservoir to the northwest and southeast are not identifiable from the available data but a reservoir length of at least 20 to 50 miles in the NW-SE direction is expected.

2. Induced Seismicity: During planning for the Paradox Valley Unit, USBR anticipated that earthquakes would be induced by the high-pressure, deep-well injection of brine. In 1983, eight years before the first injection, USBR commissioned the Paradox Valley Seismic Network (PVSN) to characterize the pre-injection, naturally-occurring seismicity in the Paradox Valley region, and to monitor earthquakes that would be induced once injection operations began. The initial seismic network consisted of 10 vertical-component short-period seismic stations. Over the years, the seismic network has been expanded to its current configuration of 16 stations. Installation of several additional stations is planned for 2011 to provide additional coverage for the Paradox Valley region. Other PVSN upgrades that have been performed over the years include the conversion of analog signal transmission to digital, the replacement of analog short-period vertical-component stations with three-component broadband digital stations, and the addition of a second data acquisition system in Nucla, Colorado. Also, three event-triggered strong motion instruments have been installed to provide ground motion recordings for larger-magnitude earthquakes.

Natural seismicity rates in the Paradox Valley area are low. During pre-injection monitoring, only a single local earthquake was recorded, located 18 km north of the injection well. Upon initiation of injection, numerous induced earthquakes were detected in the immediate vicinity of the injection well. By the end of 1998, the region of induced seismicity had expanded to a maximum distance of 8.5 km from the well. The induced seismicity occurred in two distinct zones: a primary zone immediately surrounding the well and extending to a radial distance of about 3.5 km, and a secondary zone centered approximated 7.5 km northwest of the well. In January, 1999, the frequency of recorded induced seismicity reached its peak value of over 150 events per month.

While the vast majority of seismicity induced by injection operations has been below the threshold of human detection, approximately 70 events large enough to potentially be felt (**M** >= 2.5) occurred between 1991 and 2010. On two occasions, injection operations were adjusted in an attempt to minimize the potential for generating large felt earthquakes. In response to two **M** 3.5 events that occurred in mid-1999, the operation of the injection well was altered to require a minimum of two shut down periods of at least 20 days per year. On May 27, 2000, an **M** 4.3 earthquake was induced. In response to this earthquake, operations were modified to reduce the nominal injection flow rate from 345 gpm to 230 gpm. Partially as a result of these changes in injection operations, the frequency of seismic activity generally declined from its peak value in January 1999 until late 2000.

Since late 2000, the frequency of seismic activity has fluctuated slightly in response to injection operations, but has remained very low compared to pre-2000 levels. Although the rate of induced seismic activity continues to be low, induced seismic events have been detected in several new locations since 2009, compared to earlier years. Earthquakes believed to be induced by fluid injection are now being detected at distances up to 9 km from the injection well in several azimuths. In addition to these clearly-induced earthquakes, more than 600 local earthquakes have been detected in the Paradox Valley area at distances greater than 9 km from the well since injection began, mostly near the northern end of the valley. The potential relationship of these events to injection operations is not clear.

More than 4,800 seismic events located within 9 km of the injection well have been recorded by PVSN since injection operations began in 1991 (through 2010). Computed event focal depths indicate that the vast majority of the induced earthquakes follow the targeted injection horizons, suggesting that the injected brine is remaining below the confining layers as anticipated.

3. Hydrogeology: Very little data is available on the water bearing nature of the bedrock in the vicinity of the well. The shallow alluvium contains potable water in parts of the Paradox

Valley. The underlying Chinle also contains water that may have a total dissolved solids (TDS) content of less than 10,000 mg/liter. Water bearing zones occur in several other underlying units, which includes the Honaker Trail Formation and the Pinkerton Trail Formation. The Honaker Trail Formation overlies the Paradox Salt Unit and is believed to contain saline brine with a TDS in excess of 10,000 mg/liter. The Pinkerton Trail Formation, which underlies the Paradox, may also contain brines.

Data collected on the Leadville Limestone indicate that it contains connate water with TDS, which approximates 250,000 - 260,000 mg/liter. The permeability and porosity of this aquifer are variable. The porosity has been found to be in excess of 10 percent with permeability in excess of 100 millidarcies (md) in some test wells. The nearby Union test well, however, had a porosity of less than 10 percent with a permeability of less than 10 md.

4. Local Groundwater Utilization: There are no existing wells penetrating the injection zone within the ¼ mile area of review (AOR). There was one test well drilled into the Leadville Formation within the AOR. This well was an oil test hole (Union Ortho Ayers) which was cased to 2,000 feet and then drilled to 14,400 feet. Some additional casing was set to prevent hole collapse. The abandonment report indicates that this well was properly plugged and abandoned. There are no water wells within the AOR although the shallow alluvium at the site is believed to contain potable water. The Chinle Formation, as noted before, is the bedrock surface directly underlying alluvium; in the area of the subject well the Chinle TDS will probably be less than 10,000 mg/liter.

5. Injection Zone: The injection zone includes the Mississippian Leadville Formation, the Devonian Ouray and McCracken Formations, the Cambrian Ignacio, and the Precambrian. The Leadville (14,024 to 14,440 feet measured from kelly bushing (KB)) is 416 feet thick. The Ouray Formation (14,440 to 14,480 feet KB) underlies the Leadville and is 40 feet thick. The Ouray Formation is underlain by 168 feet of the Elbert Formation (14,480 to 14,648 feet KB), 74 feet of McCracken sandstone (14,648 to 14,722 feet KB), and 566 feet of Aneth-Lynch-Muav-Bright Angel (14,722 to 15,288 feet KB). Below the ineffective Aneth through Bright Angel Formations are 201 feet of the Ignacio Formation (15,288 to 15,489 feet KB). The Precambrian granite occurs at 15,489 feet KB and was penetrated for 511 feet.

Lithology of the Leadville is limestone, often oolitic and fossiliferous, changing to dolomite in the lower half of the unit. The Ouray Formation is limestone and dolomite with occasional streaks of gray-green waxy shale. The McCracken Formation is sandstone. The sedimentary units Aneth-Lynch-Muav-Bright Angel are primarily limestone with some sandstone. Ignacio is sandstone. The top of the Precambrian is an erosion unconformity which may have permeable residual soils overlying bedrock.

6. Confining Zone: The Leadville is overlain by 5,694 feet of Pennsylvanian limestones. shales, salts, and anhydrite beds (14,024 – 8,330 feet KB = 5,694 feet). More specifically, the Leadville is overlain by forty (40) feet of impervious Molas limestone (13,984 - 14,024 feet KB). Above the Molas is 253 feet of impervious Pinkerton Trail carbonate (13,731 - 13,984 feet KB), which is overlain by 125 feet of tight Lower Paradox carbonate (13,606 - 13,731 feet KB).

IV. Injection Well Design and Construction

The well was originally drilled to a total depth of 16,000 feet below ground surface (bgs). The first plug back total depth (PBTD) was 15,827 feet measured from the kelly bushing (KB). A ten (10) foot section of a perforating gun could not be retrieved from the hole and was wedged above the first PBTD. The well was plugged back a second time due to 3 3/8-inch perforator left in hole. The second PBTD is 15,808 feet KB. On March 3, 1994, a temperature logging tool became stuck and was left in the hole at 14,582 feet. A wireline survey conducted in June 2001 indicated the well contains fill material up to a depth of 14,185 feet, the bottom of the top perforated interval. The fill was identified as elemental sulfur.

In the spring of 1984, the United States Bureau of Reclamation (USBR) selected seven (7) zones in four (4) separate formations to evaluate for injectivity potential. The seven (7) test zones and their injectivity potential, as defined by cores, drill cuttings, and open-hole logs, are summarized by the USBR as shown in Table 1.

Table 1. Zone Tested for Injectivity Potential

RESERVOIR ZONE	INTERVAL DEPTH (feet KB)	INJECTIVITY POTENTIAL
Leadville	14,024 – 14,440	Excellent; highly fractured; matrix porosity; fracture
Ouray	14,440 – 14,480	Good; probably well fractured and in good communication with middle and upper Leadville.
McCracken	14,655 – 14,722	Poor; probably fractured; no matrix porosity.
Ignacio	15,288 – 15,489	Very poor; probably fractured; lateral extent of perforated zone is limited.
Upper Precambrian	15,489 - 15,680	Fair; good fractures; secondary to Leadville
Lower Precambrian	15,750 - 15,850	Very poor-negative data

The Lower Precambrian zone was eliminated as a potential injection zone. The USBR appraised the injectivity of the remaining zones as shown in Table 2.

Table 2. USBR Appraisal of Injectivity for each Zone

FORMATION	MATRIX POROSITY	PERMEABILITY	SRT FRAC. GRAD
Combined Ouray thru Upper Leadville	14,504' - 14,080' = 424'		0.685 psi/ft
Ignacio	23' of 4%+ 5' of 7%+	Not available Not viable injection	0.685 psi/ft

		zone	
Upper Precambrian	42' of 3%+ 30' of 5%+ 10' of 9%+	3.2 millidarcies	0.685 psi/ft
Lower Precambrian	Eliminate as potential injection zone		

Based on this appraisal, the **permitted gross perforated interval of the injection well is 14,080 to 15,827 feet KB**. Net perforated intervals are:

Formation	Feet KB
Upper Leadville	14,080' -14,185'
Middle Leadville	14,215' -14,350'
Lower Leadville/Ouray	14,380' -14,504'
McCracken	14,651' -14,719'
Ignacio	15,376' -15,489'
Precambrian	15,489' -15,827'

Analysis of the induced seismicity suggests that the majority of the injected brine is entering the sedimentary layered formations rather than the Precambrian basement.

The Paradox Salinity Control Well No. 1 is designed withstand collapse form flowing salt and resistance to corrosion, and for the protection of USDWs. The well was drilled and cased in five stages starting with a 30-inch hole and ending with an 8 ½-inch hole at approximately 16,000 feet. Numerous open hole logs were run during drilling to ascertain the conditions in the hole, obtain geologic and hydrologic data, and obtain data for use in calculating final cement volumes. A summary of open and cased hole logs run follows:

DATE RUN	TYPE LOG	INTERVAL LOGGED in feet bgs
7/31/97	Detailed Core Log	Surface to 16,0001
8/7/87	Sonic Porosity STC Processing	14,003'-15,943'
8/7/88	True Vertical Depth Log	
11/15/88	Cement Bond Log	12,988'-13,188'
11/15/88	Temperature Log	12,483'-15,500'
11/15/88	Multi-Arm Caliper	Surf. - 12,901'
11/26/88	Pulse Echo Cement Evaluation Log	12,790'-15,841'
10/26/89	Fluid Flow Tracer Temperature Survey	13,600' to 14,562'
8/7/90	Spinner Survey	13,500' to 14,516'
8/7/90	Fluid Flow Tracer Temperature Survey	13,500' to 14,516'
8/14/90	Gamma Ray Temperature	14,000' to 15,810'
8/15/90	Spinner Survey (during injection)	13,900' to 15,800'
8/16/90	Fluid Flow Tracer Temperature Survey(during injection)	13,500' to 15,800'
9/16/90	Fluid Flow Tracer Temperature Survey	13,500' to 15,800'
6/23/92	Fluid Flow Tracer	13,800' to 14,779'

6/23/92	Six Arm Caliper	Surface to 13,000'
6/23/92	Temperature Survey	14,000' to 14,779'
10/3/92	Fluid Flow Tracer Temperature Log	13,900' to 14,767'
3/1/94	Temperature Log	Surface to 14,375'
3/2/94	Temperature Log	Surface to 14,604'
3/3/94	Temperature Log	Surface to 14,605'
6/19/01	Multi-Arm Caliper	14,070' to Surface
6/20/01	Temperature Log	14,084' to Surface

Injection Tubing:

The internally polished 5 ½-inch injection tubing runs from the surface to 15,901 feet bgs. The tubing is made of Hastelloy C-276 alloy to provide corrosion resistance and sufficient strength to resist high surface pressures. The connection to attach to the liner seat is an internally shouldered metal to metal seal with an elastomer seal ring for back-up leak resistance. The liner seat was originally designed to withstand any pressure differential between the annulus filled with fresh water and a corrosion inhibitor, and the injection tubing. This differential may occur due to temperature changes or injection pressure changes, but with no leakage into the annulus. However, minor leakage does occur at this seal. As of this reauthorization, approximately 45 gallons per day leak from the annulus. Standing operating procedure calls for maintaining pressure in the annulus slightly over equilibrium at the seal to prevent brine from entering and corroding the annulus. The casing-tubing annulus is filled with stabilized water, from 13,092 feet to surface, to provide corrosion protection for the long string casing. Below 13,092 feet to 15,808 feet (plug back total depth [PBTD]), this annulus is filled with cement.

V. Plan for Well Failure

The applicant has made provisions in case there is a problem with the well operating properly. These are enumerated below:

1. Valves are installed to monitor casing-tubing annulus pressure and the injection pressure.
2. A safety valve is installed at the tree that can be activated to isolate the well in case of a problem. A manually controlled master valve is on the tree.
3. In case water can no longer be injected, the source of brine will be stopped by shutting down the relift pumping plant located at the beginning of the supply pipeline.
4. Safety control equipment is installed on the injection pump that allows bypassing of the brine if well problems occur.

VI. Nature of Injected Fluid

The Paradox Salinity Control Well No. 1 shall be used for disposal of only the brine produced from the saline springs near Bedrock, Colorado, described in Part II, Section E.6., of the Permit. The source of the brine is limited to the recovery wells completed in the saline spring area.

The composition of the brine is mainly sodium chloride with a TDS content ranging from

250,000 mg/liter to 260,000 mg/liter. One chemical additive, a corrosion inhibitor intended to reduce the corrosive effects of the brine on expendable components in the injection pumps, is added prior to injection. Official EPA approval of the additive was received on February 19, 1998.

During the test phase of the facility from 1990 through 1995, and permanent operations from 1996 through 2001, a mix of 30 percent fresh water and 70 percent brine was injected to avoid near wellbore precipitation of calcium sulfate. In 2002, after six years of continuously pumping cold brine into a hot aquifer, it was determined that sufficient cooling of the formation had occurred to inject 100 percent brine with little risk of precipitation in the near well bore area. The facility has injected 100 percent brine since 2002 with no apparent adverse affect to the well. The USBR has determined that 100 percent brine injection is viable and will continue to inject brine without dilution witb fresh water unless or until such evidence exists that demonstrates that damage is occurring to the injection zone.

VII. Monitoring Requirements

EPA regulations for the other types of injection wells require continuous monitoring and recording of injection pressure, flow rate, volume and annular pressures. Annular monitoring can be required as a means of determining on-going mechanical integrity. Because of the salinity and corrosive nature of the brine and the high surface injection pressures, EPA has determined that continuous monitoring and recording of injection pressure, flow rate, cumulative volume, and annulus pressure is needed to insure that this Class V well is being operated as designed. In order that an EPA representative may inspect the well and take pressure readings, it is required that ½-inch FIP fittings be installed and maintained on the wellhead. This Permit requires continuous monitoring and recording of injection pressure, flow rate, volume, and annulus pressure. The Permit also requires that the injection fluid be analyzed annually for TDS, pH, specific conductivity and specific gravity. A complete water analysis shall be performed if tbe source or type of the injection fluid changes. To facilitate analysis of the data from the continuous monitoring devices and to provide a clear picture of injection activities, the Permit requires that data be averaged daily. A paired reading of the annulus and injection pressures shall be taken at the same time on a weekly basis. Monthly averages of the daily averages are also required. The daily and monthly averages along with the weekly paired readings are reported quarterly, along with the data from the fluid analyses, to the EPA Denver Regional Office, according to the schedule detailed in the Permit (see Part II, Section F.1.).

Because injection activity has been demonstrated to result in induced seismic activity. USBR, in conjunction with U.S. Geological Survey (USGS), has installed monitoring devices to track tbis activity. The USBR monitors the Paradox Valley Seismic Network (PVSN), which consists of 16 stations that monitor horizontal and vertical ground movement. Seismic events are analyzed with respect to date and time of occurrence, focal depth, geographic location, magnitude, type of faulting, and relation to injection operations. The permit requires that a monthly evaluation of the PVSN is performed to determine the operating status of the seismometers, including any excessive noise at any of the directional components, and continuity of data transmission. If a seismic event is felt at the Brine Injection Facility Control Room, injection activity shall be temporarily halted according to the USBR Emergency Action Plan, and the permittee shall notify EPA within 24 hours according to Part III, Section E.10.(c). The permit also requires an annual report describing all monitored local seismic events be submitted to the EPA by June 1 of each year.

The permittee is required to maintain a positive pressure on the annulus and monitor pressures on a continuous basis to show continued mechanical integrity, as described in the Standard Operating Procedure for the Well Annulus Monitoring System adopted by USBR on March 2, 2009.

In addition to routine quarterly reporting, the regulations require the permittee to report the results of any mechanical integrity test or any well workover, logging, or testing that reveals conditions in the well or injection zone to the Director. These reports are due within sixty (60) days of the completion of the activity or at the time of the next scheduled quarterly report, whichever is sooner. The most recent MIT is dated February 10, 2011.

VIII. Injection Pressure

EPA regulations requires the monitoring of injection pressure limited to assure that fractures are not initiated in the confining zone, that injected fluids do not migrate into any underground source of drinking water, and that formation fluids are not displaced into any underground source of drinking water throughout the operating life of the project. When the Permit was initially issued, the permittee submitted information with the application that established the fracture gradient of the overlying confining intervals as 0.97 psi per foot of depth and that the surface injection pressure must exceed 6,106 psig to breech the confining layers. This determination is documented in reports submitted by John Dewan, Dewan and Timko, Inc., in 1987 and 1988. Analysis of open-hole geophysical logs predicted a range of fracture pressures for the injection and confining zones. In the confining zones, the fracture gradient ranged from 0.8 psi/ft to 1.2 psi/ft with a gradient of 0.97 psi/ft in the salt (Dewan and Timko, Inc., June 22, 1987; Dewan and Timko, Inc., January 27, 1988). During the review of the original application, EPA concurred with that the fracture gradient of the overlying confining intervals is 0.97 psi per foot of depth and that the surface injection pressure must exceed 6,106 psig to breech the confining layers.

From October 1986 through February 2004, the EPA Final Permit (CO50108-00647, dated March 19, 1997) established a Maximum Allowable Surface Injection Pressure (MASIP) of 5,000 psig. The Permit also provided a mechanism for increasing the pressure. The pressure limit may be increased by the Director if the fracture pressure of the confining formation will not be exceeded, and the permittee demonstrates that the proposed increase in surface injection pressure is necessary: (1) to overcome friction losses in the injection system, or (2) to inject the volume rate of fluid set in the Permit. Either demonstration shall be made by performing a step rate injection test, using fluid normally injected, to determine both the instantaneous shut-in pressure and the formation breakdown pressure. The Director will determine any allowable increase based upon the test results and the results of an analysis by the applicant of potential fracture growth in the confining layers as a result of an increase in injection pressure.

On February 13, 2004, the USBR requested a modification in their Permit for the Paradox Salinity Control Well No. 1 to increase the MASIP. The Paradox Valley Unit Salinity Control Injection Well No. 1 had been continuously injecting brine as a method of disposal since 1996. Since injection operations began, the surface pressure necessary to inject the brine into fractures of the Leadville formation at 14,000 feet had increased consistently. The pressure increase is a result of the injectate filling the available fractures and natural porosity of the formation rock. As the fluid migration extends away from the wellbore, the pressure necessary to push the fluid farther through the natural formation fractures increases.

On April 29, 2004, EPA issued a permit modification requiring inspection and recertification of injection pumps, lines, and wellhead before initiating injection at 5,350 psig. On February 23, 2010, USBR submitted documentation demonstrating the modification requirements were addressed. On May 10, 2010, EPA issued authorization to inject at increased surface injection pressure of 5,350 psig.

As stated in the last paragraph above, the existing Permit language in Part II Section E.4.b of the Permit allows for an increase in the MASIP as a major modification if certain requirements are met. The first requirement is that increased surface injection pressure is necessary to overcome friction losses in the injection system. The second requirement is that the demonstration be made by performing a step rate injection test, using fluid normally injected, to determine both the instantaneous shut-in pressure and the formation breakdown pressure. Any increase in the MASIP must be analyzed to assure that the fracture pressure of the confining formation will not be exceeded.

Table 3 illustrates the fracture stress applied to the various confining layers; as a result, increasing the MASIP from 5,000 psig to 5,350 psig, with an injectate specific gravity of 1.17 and with no consideration for friction pressure loss in the injection tubing.

$G_f = \frac{P_f}{D}$ where

G_f = applied fracture gradient
D = depth
P_f = pressure at depth D, and

$P_f = P_s + P_h$;

where

P_s = surface injection pressure
P_h = hydrostatic pressure of fluid
= depth (D) x specific gravity (SG) x 0.433 psi/ft.

Substituting:

$$G_f = \frac{P_s + (D \times SG \times 0.433)}{D}$$

Table 3. Fracture Stress Applied to the Various Confining Layers

Formation	Depth to Base of Confining Unit (feet KB)	Stress Gradient at 5,000-psig Surface Injection Pressure	Stress Gradient at 5,350-psig Surface Injection Pressure
Salt	13,606	0.874 psi/ft	0.8977 psi/ft
Lower Paradox Carbonate	13,731	0.870 psi/ft	0.8962 psi/ft
Pinkerton Trail	13,984	0.864 psi/ft	0.8891 psi/ft
Molas	14,024	0.863 psi/ft	0.8887 psi/ft
Top Perforation	14,080	0.862 psi/ft	0.8866 psi/ft

By increasing the MASIP from 5,000 psig to 5,350 psig, the effective increase in the fracture stress gradient at the base of the confining layers ranges from 0.0237 psi/ft to 0.0246 psi/ft. The maximum fracture stress gradient at the base of the salt is 0.8977 psi/ft, which is significantly less than the 0.97 psi/ft fracture gradient calculated by Dewan. Therefore, it is reasonably certain increasing the injection pressure from 5,000 to 5,350 psig will not adversely affect the confinement provided by the salt and formations between the salt and the Leadville perforations.

Maximum allowable surface injection pressure per the subject UIC Permit and the surface equipment limitation is 5,350 psig. The facility is currently operating at approximately 4,400 to 4,999 psig. Since June 1999, the well has been shut in twice a year for twenty days. Each successive injection period prior to 2006 produced a higher pressure than the previous by approximately 50 to 80 psi. The injection pressure did level off and remained fairly constant during 2007 and 2008 with a maximum surface injection pressure less than 4,900 psig through September 2008. In 2009 and 2010 the well was operated between 4,400 and 4,999 psig.

Since the injection pumps are positive displacement and are not variable rate, two options for reducing the surface pressure are available. One option would be to replace the current size plungers to a smaller size, thereby reducing the rate of each pump. There are a variety of smaller sizes and with each smaller size a reduction in rate. A reduced rate requires less surface pressure to force the brine into the formation. The other alternative would be to reduce the injection rate by one half by simply operating one pump (115 gpm) rather than two pumps (230 gpm). Unfortunately, both options will reduce the Colorado River salinity control benefits according to the rate reduction.

Considering the magnitude of salinity contribution to the Colorado River system at Paradox Valley, USBR is investigating methods of maintaining and eventually enhancing salinity control benefits there. One method to maintain benefits is to increase the maximum injection pressure limit at the existing injection facility. Surface equipment may be modified to safely accommodate a higher maximum pressure, and according to the evaluation conducted by a contractor, Subsurface Technology, Inc., the confining layers would not be breached. The other major consideration of increased maximum injection pressure is seismicity. Analysis of the seismicity induced by PVU to date suggests that the potential for generating large felt earthquakes is not affected by the maximum injection pressure experienced over short time periods (days to months). Rather, there may be a correlation between injection pressures averaged over much longer time periods – two years or longer – and the potential for generating larger-magnitude earthquakes. Hence, if necessary, any potentially increased seismic risk due to increasing injection pressures could be reduced by implementing more shut-down days or periodically reducing injection rates.

IX. Well Plugging and Abandonment

The plugging and abandonment plan submitted by the applicant with the Permit application is incorporated into the Permit and is binding on the permittee. The minimum requirements for pre-plugging notice (45 days) and post-plugging reporting (60 days) have been incorporated. In addition, if the injection activities are halted for a period of more than two (2) years, the permittee is required to plug the well or demonstrate that it will be used in the future and will not endanger the environment during temporary abandonment. After plugging or converting the well, the permittee will submit a plugging report to the Denver Office to complete the file.

X. Financial Responsibility

The applicant is a U.S. Government agency and financial responsibility is assured by its participation in the budgetary process and by the authorization for the projects by public law 93-320. EPA requires that the permittee show that the annual budget has authorized sufficient funds to operate or plug the well. This report may be submitted with a quarterly report.

XI. Reference Documents

All documents used in the preparation of the Permit are available at EPA, Region VIII, or in a local library. Specific documents used are referenced as follows:

Baars, D. L. and Stevenson, G.M., Tectonic Evaluation of the Paradox Basin, Utah, and Colorado, 1981.

Dewan, John T., Dewan and Timko, Inc., Paradox Valley Injection Test Well #1. Well logs (2,020 to 14,050 ft) and Mechanical Properties, June 22, 1987.

Dewan, John T., Dewan and Timko, Inc., Paradox Valley Injection Test Well #1. Well logs (14,050 to 15,950 ft) and Mechanical Properties, January 27, 1988.

Hanshaw, B.B. and Hill, G.A., Geochemistry and Hydrodynamics of the Paradox Basin Region, Utah, Colorado, and New Mexico, 1968.

Odell, J. W., Coffin, D. L., and Langford, R. H., Water Resources, Mineral and Water Resources of Colorado, 1964.

Repplier, F. N., Healy, E. C., Collins, D. B. and Longmire, P. A., Atlas of Ground Water Quality in Colorado, 1981.

U.S. Bureau of Reclamation, Colorado River Basin Salinity Control Project - Paradox Valley Unit Final Environmental Statement, March 20, 1979.

Report of Evaluation of Injection Testing for Paradox Valley Injection Test No. 1, Envirocorp Services & Technology, Inc., Houston, Texas, for the Bureau of Reclamation, Durango, Colorado, June 1995.

Envirocorp Services & Technology, Inc., Presentation Outline for the EPA, November 19, 1996. Denver, CO.

Review of Plans and Recommendations for Installation of Second Paradox Valley Brine Injection Well , Subsurface Technologies Inc., Houston Texas for the Bureau of Reclamation, Durango Colorado, January 2003

XII. The Administrative Record and Public Review Process

The administrative record for this Draft Permit includes the permit application, the Draft Permit, Fact Sheet, the Public Notice, and Standard Operating Procedure for the Well Annulus Monitoring System, adopted by USBR on March 2, 2009. These documents are available for public review at 1595 Wynkoop Street, Denver, Colorado, 80202-1129, from 9:00 am to 4:00 pm. Monday through Friday. To review these documents, or to request copies of these documents through mail or email, contact:

Craig Boomgaard
Mailcode: 8P-W-GW
1595 Wynkoop Street
Denver, CO 80202
Boomgaard.Craig@epa.gov
1-800-227- 8917, extension 312-6794, or 303-312-6794

The public notice announcing the issuance of this Draft Permit and the beginning of the public comment period was published in the Montrose Daily Press and San Miguel Basin Forum on March 31, 2011. A public hearing will be held upon request. EPA Region 8 is receiving comments on the Draft Permit until May 27, 2011. Comments can be submitted to EPA either email or in writing to Craig Boomgaard.

XIII. Procedures for the Final Permit Decision

In making the final permit decision, EPA will consider all comments received during the public comment period and during a public hearing, if one is requested. The final permit decision may be to issue the permit without any changes, to issue the permit with changes, or to deny issuance of the permit. EPA will respond to all public comments in a Responsiveness Summary document that will be released at the time the final permit decision is issued. Everyone who submits comments to EPA or attends the public hearing will receive this Responsiveness Summary document along with notification of the final permit decision.

The final permit decision will become effective 30 days after the date it is issued, unless no comments requested a change in the draft permit, in which case the permit shall become effective immediately upon issuance. The purpose of this 30-day period is to allow time for anyone who commented on the Draft Permit to appeal the final permit decision to the Environmental Appeals Board. Information for how to appeal the final permit decision will be provided in the notification of the final permit decision.

STATEMENT OF BASIS

UNITED STATES BUREAU OF RECLAMATION

PARADOX SALINITY CONTROL WELL NO. 1
A CLASS V INJECTION WELL
MONTROSE COUNTY, COLORADO

UIC PERMIT NUMBER: CO50108-00647

CONTACTS:

Craig Boomgaard
U.S. Environmental Protection Agency (EPA)
Region VIII
UIC Implementation Section (8P-W-GW)
1595 Wynkoop Street
Denver, Colorado 80202
Telephone: (303) 312-6794

DESCRIPTION OF FACILITY AND BACKGROUND INFORMATION

On March 31, 2006, Mr. Rick Gold, Regional Director, Upper Colorado Regional Director, USBR, filed a letter with EPA requesting the EPA to reauthorize the use of the Paradox Salinity Control Well #1 for an additional ten (10) years of brine injection, in accordance with 40 CFR Sections 124.5 and 144.39

The USBR is involved in the capture, and injection, of saline brine emanating from springs near Bedrock, Colorado. The saline brine is being injected into deep Mississippian, Devonian, Cambrian and Precambrian Formations. The enclosed updated Fact Sheet explains the site conditions.

This Permit is being reissued with some minor changes (modifications) from the existing/expiring UIC Class V Permit for the Paradox Salinity Control Well No. 1 (CO50108-00647).

1. PART II, Specific Permit Conditions, E.3. Injection shall be limited to the gross interval 14,080 feet from Kelly Bushing (KB) to the plug back total depth 15,827 feet KB. Net perforations are Upper Leadville: 14,080 to 14,185 feet KB; Middle Leadville: 14,125 to 14,350 feet KB; Lower Leadville/Ouray: 14,380 to 14,504 feet KB; McCracken: 14,651 to 14,719 feet KB; Ignacio: 15,376 to 15,489 feet KB; and Precambrian: 15,489 to 15,827 feet KB.

2. PART II, Specific Permit Conditions, E.5., Injection Volume-Rate Limitation. There will be no limit on the number of gallons per minute (GPM) of

captured brine that shall be injected into this disposal facility, provided that in no case shall surface injection pressure exceed that limit shown in Part II, Section E.4. of this Permit.

3. PART II, Specific Permit Conditions, F.1., Injection Well Monitoring Program, EPA requires annual analyses of certain parameters. This requirement includes total dissolved solids (TDS), conductivity, pH and specific gravity, unless a major new source is added which results in a significant change in water chemistry. If the character of the injected stream is significantly modified by the addition of new sources, a complete analysis is required.

EPA requires continuous monitoring of the injection pressure, flow rate, volume, annular pressure, and monitoring/observation of micro seismic activity to assure there are no negative aspects attendant to induced fracture propagation.

At least once a year, the applicant will be required to assure that the annulus is full of fluid, and to submit a brief report relative to the observation/monitoring of induced micro-seismic events. The seismic report, the required summary of injection volumes and pressures, and annulus fluid observation should be reported to the EPA no later than June 1 of the year following observations.

4. PART II, Specific Permit Conditions, F.3., Records to Retain and Retention Time, requires significant record keeping. The recordkeeping requirements are a three (3) year retention period for all records after the well is plugged and abandoned, and while the facility remains in an active mode, a five (5) year retention of all records from the date of data acquisition is required.

The operator was advised that a complete Permit reauthorization application had been received March 31, 2006, and that the USBR could continue to operate the Paradox Salinity Control Well No. 1. Because there have been no significant changes to the expiring Permit for the subject injection facility, the Statement of Basis for this Permit reissuance action was prepared with reference to, and in consideration of the original Permit "Fact Sheet".

This repermitting action, under the Safe Drinking Water Act (SDWA), applies only to the "reissuance" of the Class V UIC Permit for the Paradox Salinity Control Well No. 1, SE NW SE (1672' FSL and 1674' FEL) Section 30 - T47N - R18W, Montrose County, Colorado. Issuance or denial of this Permit does not preempt any other Federal, State, or local permitting requirements.

Class V well Permits shall be effective for a fixed term not to exceed 10 years (40 CFR Part 144.36). This Permit, if reissued as drafted, will expire in 10 years from the effective date. This Permit contains conditions which state that EPA may again, with due cause, modify, revoke, and reissue, or terminate the Permit in accordance with Federal regulations, if and when revisions or amendments to the SDWA are made.

The USBR has identified brine injection into the Mississippian Leadville limestone; the Devonian Ouray limestone/dolomite and green, waxy shale; the Devonian McCracken sandstone; the Cambrian Ignacio sand; and Precambrian granite.

The applicant has identified three (3) injection intervals within the Leadville, designated as Upper, Middle, and Lower. The entire Leadville is 416 feet thick and occurs between 14,024 and 14,440 feet from Kelly Bushing (KB). The 40-foot Ouray, occurs between 14,440 to 14,480 feet KB. Seventy-four (74) feet of McCracken sand occur between 14,648 and 14,722 feet KB. Two hundred and one (201) feet (15,288 to 15,489 feet KB) of Ignacio sand overlie the eroded top (15,489 feet KB) of Precambrian granite. Plug back total depth (PBTD) in Precambrian granite is 15,827 feet KB.

The gross permitted injection interval is 14,080 feet to PBTD (15,827 feet KB) in the Precambrian. Leadville net perforations are: Upper Leadville - 14,080 to 14,185 feet KB; Middle Leadville - 14,215 to 14,350 feet KB; Lower Leadville/Ouray - 14,380 to 14,504 feet KB. McCracken net perforations are: 14,651 to 14,719 feet KB. Net Perforations in the Ignacio are 15,376 to 15,489 feet KB. Precambrian net perforations are 15,489 to 15,827 feet KB.

The confining zone is considered to be the 418 feet of Pennsylvanian limestone, shale, salt, and anhydrite. In ascending order above the Leadville are: forty (40) feet of Molas limestone (13,984 to 14,024 feet KB); 253 feet of Pinkerton Trail carbonate (13,731 to 13,984 feet KB); overlain by 125 feet of Lower Paradox carbonate (13,606 to 13,731 feet KB); and 466 feet (13,140 to 13,606 feet KB) of Paradox salt. The subject Paradox salt dome is a portion of regional salt doming. The salt is plastic and will prevent upward movement of fluid. All these litbologies are competent and impervious.

The Paradox Salinity Control Well No. 1 injection well was drilled and completed as a Class V well injecting brine fluid captured from several salt springs in the area of Bedrock, Colorado. The intent of the facility is to prevent salt contamination of the Dolores River. Injection is into formations significantly deeper than the lowermost under ground source of drinking water (USDW) (Triassic Chinle: surface to a depth of 1,140 feet KB, and protected by annular cement) within the one-quarter (1/4) mile area-of-review (AOR) for this reissued permit.

Continuous monitoring is required. Daily monitoring of the injection pressure, flow rate, cumulative volume, and annulus pressure shall be averaged daily, with daily averages averaged monthly, and both values shall be reported quarterly to the EPA. A paired reading of the annulus and injection pressures shall be taken at the same time on a weekly basis. These paired readings shall also be reported quarterly.

In addition, the permit requires the permittee to report to the Director the results of any mechanical integrity tests (MIT), well workovers, logging, or testing that reveals the conditions of the well or injection zone. These reports are due within sixty (60) days of the completion of the activity, or at the time of the quarterly report, whichever is sooner.

This Statement of Basis gives the derivation of the site specific Permit conditions and reasons for them on the basis of the Class V direct implementation regulations promulgated in the State of Colorado under the UIC program provision of the Safe Drinking Water Act (SDWA). The general Permit conditions, for which the content is mandatory and not subject to site specific differences (based on 40 CFR §§ 144, 146 and 147) are not included in the following discussion.

Section II - FINANCIAL RESPONSIBILITY

The applicant is a United States Government Agency and financial responsibility is assured by its participation in the budgetary process and by the authorization for the projects by Public Law 93-320. EPA requires that the permittee show that the annual budget has authorized sufficient funds to operate or plug the well. This report may be submitted with a quarterly report.

Appendix C - PLUGGING AND ABANDONMENT

The UIC Director has determined that this well plugging and abandonment plan adequately protects the USDWs. The plan is incorporated into the permit and shall be binding on the permittee.

After receiving approval from the appropriate Regional EPA office, the permitted injection well will be plugged in accordance with the Plugging and Abandonment Plan as follows:

PLUG NO. 1: Install a bridge plug 14,080 feet to 14,185 feet below ground level (BGL).

PLUG NO. 2: Unlatch polished bore receptacle/liner at 12,884 feet (BGL) and recover the 5-1/2 inch 0.0304 wall 125ski C-276 BDS injection tubing.

PLUG NO. 3: Cement tubing from bridge plug to 12,900 feet (BGL).

PLUG NO. 4: Bentonite slurry to fill annulus casing to 1000 feet (BGL).

PLUG NO. 5: Cement annulus casing to surface and provide surface marker.

Revisions to Paradox draft documents based on public comments

SOB Page 9 The sentence "The Paradox Valley Seismic Network consists of 16 stations that monitor horizontal and vertical ground movement. " was changed to "The USBR monitors the Paradox Valley Seismic Network (PVSN), which consists of 16 stations that monitor horizontal and vertical ground movement."

SOB Page 14 date changed from April 30, 2011 to May 27, 2011

Permit Document
The draft water mark has been removed.
The term "Draft" was removed from the cover page
"Draft" was removed from the footers

Page 4
Section E Item 1: Old
Well Injection and Seismicity. A monthly evaluation of the Paradox Valley Seismic Network (PVSN) shall be performed to determine the operating status of the seismometers, including any excessive noise at any of the directional components and continuity of data transmission. If a seismic event is felt in the Brine Injection Facility Control Room, injection activity shall be temporarily halted according to the USBR Emergency Action Plan, and the permittee shall notify EPA within twenty-four (24) hours according to Part III, Section E.10.

Replaced with:

1. Well Injection and Seismicity.
    a. Response to Felt Seismicity. Injection activity shall be temporarily halted to inspect for damage, according to the USBR Emergency Action Plan, and the permittee shall notify EPA within twenty-four (24) hours according to Part III, Section E.10, if either of the following occur:
        i. A seismic event is felt in the Brine Injection Facility Control Room.
        ii. A seismic event is recorded on the strong-motion instrument located at the Brine Injection Facility, and the instrument measures a peak horizontal acceleration of 0.1 g or greater.
    b. Response to Other Potentially Significant Seismicity. If a significant seismic event is reported in the Paradox Valley area, but is not felt in the Brine Injection Facility Control Room, then within 72 hours of the report the USBR shall notify EPA and perform an inspection if any of the following occur:
        i. A seismic event is recorded on the strong-motion instrument located at the Brine Injection Facility, and the instrument measures a peak horizontal acceleration of 0.05 g or greater.
        ii. A magnitude 3 or greater earthquake is recorded by PVSN or the U.S. Geological Survey, and is predicted to have produced a

median peak horizontal acceleration of 0.05 g or greater at the Brine Injection Facility, based on empirical ground motion attenuation curves.

iii. A seismic event is reported by the news media as being widely felt in the Paradox Valley area.

c. Seismic Monitoring Monthly Evaluation. A monthly evaluation shall be performed to summarize the operating status of the Paradox Valley Seismic Network (PVSN) and local seismicity recorded during the previous month. The evaluation shall assess induced and natural seismicity located within 30 km of the injection well and its potential relation to injection operations. The evaluation shall also include an assessment of the operation of the seismic instrumentation, data telemetry, data recording, and earthquake notification systems. Based on this evaluation, USBR will schedule preventative and remedial maintenance needed to maintain compliance with the Seismic Monitoring Plan. Should immediate maintenance be needed to comply with the minimum standards of the Seismic Monitoring Plan, EPA will be notified within 72 hours. Within two weeks, the needed maintenance shall either be performed or, if circumstances prevent immediate action, a proposed corrective action plan shall be submitted to EPA.

Comments and response to comments received on Underground Control Permit CO50108-00647
Paradox Salinity Control Well No. 1

This response to comments follows the requirements of 40 CFR 124.17(a)(2) "Briefly describe and respond to all significant comments on the draft permit or the permit application (for section 404 permits only) raised during the public comment period, or during any hearing." These are the responses to significant and relevant comments

Original Comment provided in italics.

1. In the Statement of Basis for this Permit reauthorization, It is indicated that on March 31, 2006, the Regional Director of the USBR requested that EPA reauthorize the Salinity control well. The Paradox # 1 UIC permit expired three and a half years ago on July 13, 2006. It is my understanding that in June of 2009, BOR sent comments to R8 regarding a preliminary Draft Permit for the Paradox Well that was sent to them earlier. Although two additional years have gone by before a final draft Permit has been issued, there is no discussion in the Statement of Basis as to why the issuance of this Permit was delayed for such a log[sic] *period of time, almost five years. I do not believe that the fact that the rules allow a delay in Permit issuance is an adequate explanation for the long delay.*

2. The draft Fact sheet indicates that the existing Permit has been expired since March 19, 2007. It is my understanding that the effective date of the Permit expiration was actually July 13, 2006. The Region did not reissue the Permit (originally issued on July 13, 1986) until 1997 because EPA had requested additional information on the seismic monitoring program that was installed and operated by the USBR. I am under the belief that the Permit presently up for renewal ran for 10 years from the date of its original expiration on July 13, 1996 to July 13, 2006. This issue needs to be explained and the appropriate expiration date placed in the renewed Permit.

3. Although EPA is allowed by the Regulations to not issue a new Permit immediately, the existing Permit continues in force as written when the Permit expired. This raises a potential problem if something occurs that requires a Permit Modification. It is my understanding that a Permit modification may have been made during the period that the Permit was expired. It is not clear that such a modification is allowed as the Permit is expired and remains in force as written. This issue should be explained in the Statement of Basis for this renewal.

4. Page 9 of Fact Sheet. The fact sheet has a brief discussion of the switch made to 100% brine. I believe that this was a most import[sic] *decision made jointly by the USBR and the EPA and recommend that the details be discussed more completely. The following information should be used to explain this issue:*

"Long term operation of the facility officially began on June 24, 1996, with 70% brine/30% fresh water. Southwest Contracting, Inc. operated and maintained PVU under an interim contract until long term contract could be awarded. Semi-consistent long term operations began on July 22 after encountering various problems due to the new injection pumps and the facilities that set idle for over a year. Injection rates fluctuated from 0 to 345 gpm as the crew became accustomed to the new pumps. Injection pressures fluctuated with injection flow rates with a maximum of pressure of 4,899 psi.

DOW Chemical operated a pilot sulfate removal skid at the Surface Treatment Facility. The skid's purpose was to remove the high concentration of sulfates from Paradox Valley Brine (PVB) in order to allow injection of 100% PVB. The results of the pilot program were inconclusive due to inferior skid equipment and construction.

In 2001, Long term operations continued with 70% brine/30% fresh water injection. In June, during the biannual shut in, a wireline survey was conducted to determine injectate flow patterns, with an EPA representative on site. The wire line surveys included a "dummy" tool run which indicated a well total depth (TD) of 14,170', a caliper survey to determine the integrity of the wellbore which indicated a deformation at the top of the top perforated interval (14,070') and a temperature survey which indicated a temperature equal to that of a 1994 survey. The difference from the 1994 temperature survey was that the 1994 survey was performed 3 days after the well was shut in and the 2001 survey was conducted 20 days after the well was shut in. The wellbore deformation at 14,070' is indicative of "point stress", possibly due to near wellbore seismicity and the 14,170' TD is a result of deposition of elemental sulfur precipitation from mixing fresh water (6 ppm dissolved O2) with PVB (65 ppm hydrogen sulfide).

On August 23, 2001, a meeting was held in Denver to discuss the wire line survey results. It was decided at this meeting that an injection test of 100% brine would present limited risk after five years of nearly continual injection of cold brine into a hot aquifer."

5. Page 9 of Fact Sheet. The monitoring requirement section mentions that the USBR operates the Paradox Seismic network in conjunction with the USGS. This is a misleading statement. The USBR has a contract with the USGS to assist in the construction of the actual stations. The collection and analysis of the data is done solely by the USBR. This section should be clarified to reflect the actual relationship.

6. Page 13 of Fact Sheet. The last paragraph of this section briefly discusses some ways of reducing the seismic events in the vicinity of the well, but does not mention the preferred solution to this potential problem; drilling a second. The need for drilling a 2nd well was discussed in the final EIS for this project. The USBR has looked closely at this issue and determined that a 2nd well should be drilled in the middle of the valley into a separate fault block.

I recommend that the Fact sheet be modified to indicate that a 2nd well was part of the original final EIS, and provide details to explain the work done in the early 2000s to design and locate a 2nd well. It should be noted that after the switch to 100% PVB was made, the BOR carried out an extensive feasibility study on drilling a new well. A good target zone on Federal land in the center of the valley was identified. This proposed well site is much closer to the brine source than the existing well. It received some support at a meeting (prior to my retirement) but no action on initiating the process to Permit and drill a new well has yet occurred.

7. Page 14 of the Fact Sheet. Section 12 indicates that the comment period for the draft Permit ended on April 30, 2011. After some panic on my part, I learned that the comment period did not commence as stated in the Fact Sheet and the comment period actually ends at the end of May. I do not understand why the fact sheet was not corrected to reflect this change before the material was released for comment. This error may have resulted in some folks not providing comments. The final fact sheet should explain what happened and why this error was not corrected.

8. Page 1 of the Draft Permit. The third paragraph for the bottom should be modified to reflect that the Permit expires 10 years after the expiration of the previous permit, July 13, 2006.

9. Page 4 of the Draft Permit. Section E. 1 indicates that the USBR will perform an analysis of the Paradox Valley Seismic network to determine the operating status of the seismometer stations. There is no explanation as to what corrective action will be taken if an inadequate number of stations are online to enable the seismic epicenters to accurately located. These details should be included.

This section also requires that any seismic event felt in the control room will result in a shut down of the well and a notification of EPA. It is not clear what this means. Is there a magnitude of the event that triggers this shut down. What if there is an event felt on the surface elsewhere in the valley that is not of significance at the control room.

10. Page 7 of the Draft Permit. Section 4 stipulates the reports required of the USBR Paradox facility. There is no mention of the need to report the monthly evaluation of the seismic network operating status. I recommend that this information be supplied to EPA when it is prepared.

<u>Responses to comments submitted May 20, 2011 via electronic mail</u>

1. The dates provided in the reauthorization are correct and have been rechecked based on these comments. The last permit issuance and effective date was March 19, 1997.

2. The effective period for a Class V permit begins on its effective date and is effective for a fixed term not to exceed 10 years. See 40 C.F.R. section 144.36(a). The permit can be extended past its expiration date if it meets the criteria at 40 C.F.R. section 144.37. This is an extension of the expired permit and does not affect the effective date, or the term, of the new permit. Issuance of the new permit will end the effectiveness of the prior permit. The new permit will become effective on its effective date and will expire 10 years after this date, in accordance with the regulations

3. On April 29, 2004 a major modification was approved to increase the maximum allowable injection pressure (MAIP) and included the public notification process. After the BOR made the necessary equipment modification outlined in the modification approved in 2004, specifically certifying that the surface equipment would be capable of safely handling the increased injection pressure, authorization to inject was give on May 10, 2010. Thus, no modifications were issued while the permit was in continuation and therefore does not need to be addressed in the renewal.

4. EPA has this information in the permit file, which was reviewed as part of the re-authorization of the permit. The information was not considered relevant to the re-issuance of the permit, since no conditions of the permit were based on this information; therefore, it was not included. If the public is interested in learning more about the permit history or operations, inquiries to the permittee and/or the EPA could be made. Since both are Federal agencies, the public may also obtain additional information under a Freedom of Information Act (FOIA) request.

5. The issue of the seismic network installation and monitoring will be clarified. The Fact Sheet has been revised to reflect that the USGS assisted in the installation of the seismic monitoring network and that the USBOR monitors the network and prepares the annual reports.

6. The BOR has decided to move forward with requesting reauthorization of a single injection well at the site, and this permit and the Statement of Basis provide the rationale for the approval. While the BOR's EIS has discussions regarding the future direction for the project and the options available, EPA only has a permit application for the single injection well. If the BOR submits an application for a second well, EPA will address information related to that second well.

7. The fact sheet reflected the date 30 days after the notice was published in the San Miguel Basin Forum and the Montrose Daily Press news papers. EPA allowed extra time for the public comment on this permit re-issuance. The fact sheet has been updated to reflect this extension.

8. The seismic monitoring network plan is now included as Appendix E. Additionally, Section E has been revised with corrective actions as permit requirements. In discussions with the USBR, it was noted that the actual number of stations is not as important as the type and location. There are three types of sensors with varying levels of resolution. EPA decided that data resolution quality was a better measure of protection than just the number on sensors.

9. The monthly reports are provided as a courtesy and can be used to cross check the annual report. Should an event or a non-compliance issue arise, it is the permittee's responsibility to notify the EPA according to the requirements in the permit. The annual reports provide sufficient information to properly monitor project activities and are compliant with the intent of the permit.