UTAH WATER QUALITY BOARD

CLASS III AREA PERMIT

UNDERGROUND INJECTION CONTROL (UIC) PROGRAM

UIC Permit Number: UTU-19-AP-1C3C2E8

Cane Creek Mine
Grand County, Utah

Permit Renewal Issued to:

Intrepid Potash - Moab, L.L.C.
## TABLE OF CONTENTS

<table>
<thead>
<tr>
<th>Contents</th>
<th>Page</th>
</tr>
</thead>
<tbody>
<tr>
<td>Title Sheet</td>
<td>i</td>
</tr>
<tr>
<td>Table of Contents</td>
<td>i</td>
</tr>
<tr>
<td><strong>Part I. AUTHORIZATION TO CONSTRUCT AND INJECT</strong></td>
<td>1</td>
</tr>
<tr>
<td><strong>Part II. GENERAL PERMIT COMPLIANCE</strong></td>
<td>3</td>
</tr>
<tr>
<td><strong>Section A. EFFECT OF PERMIT</strong></td>
<td>3</td>
</tr>
<tr>
<td><strong>Section B. PERMIT ACTIONS</strong></td>
<td>3</td>
</tr>
<tr>
<td>1. Modification, Revocation, Reissuance and Termination</td>
<td>3</td>
</tr>
<tr>
<td>2. Transfer of Permits</td>
<td>3</td>
</tr>
<tr>
<td><strong>Section C. SEVERABILITY</strong></td>
<td>3</td>
</tr>
<tr>
<td><strong>Section D. CONFIDENTIALITY</strong></td>
<td>4</td>
</tr>
<tr>
<td><strong>Section E. DUTIES AND REQUIREMENTS</strong></td>
<td>4</td>
</tr>
<tr>
<td>1. Duty to Comply</td>
<td>4</td>
</tr>
<tr>
<td>2. Penalties for Violations of Permit Conditions</td>
<td>4</td>
</tr>
<tr>
<td>3. Duty to Reapply</td>
<td>4</td>
</tr>
<tr>
<td>4. Need to Halt or Reduce Activity Not a Defense</td>
<td>4</td>
</tr>
<tr>
<td>5. Duty to Mitigate</td>
<td>5</td>
</tr>
<tr>
<td>6. Proper Operation and Maintenance</td>
<td>5</td>
</tr>
<tr>
<td>7. Duty to Provide Information</td>
<td>5</td>
</tr>
<tr>
<td>8. Inspection and Entry</td>
<td>5</td>
</tr>
<tr>
<td>9. Records</td>
<td>6</td>
</tr>
<tr>
<td>10. Signatory Requirements</td>
<td>6</td>
</tr>
<tr>
<td>11. Reporting Requirements</td>
<td>6</td>
</tr>
<tr>
<td>12. Electronic Reporting</td>
<td>10</td>
</tr>
</tbody>
</table>
Contents ........................................................................................................................................................................ Page

Part III. SPECIFIC PERMIT CONDITIONS .......................................................................................................................... 11

Section A. MONITORING REQUIREMENTS ............................................................................................................................ 11

  1. Injection and Extraction Volumes ................................................................................................................................. 11
  2. Injection Pressure/Flow Rate/Brine Level ......................................................................................................................... 11
  3. Injectate-Extractate Temperature and Flow Rate ........................................................................................................... 12
  4. Injection Fluid Quality ...................................................................................................................................................... 12
  5. Quality Assurance Procedures ......................................................................................................................................... 13

Section B. NEW WELL REQUIREMENTS .............................................................................................................................. 14

  1. New Well Design and Construction Requirements ....................................................................................................... 14
  2. New Wells Constructed in the Colorado River Alluvium ................................................................................................. 15

Section C. OPERATION REQUIREMENTS .......................................................................................................................... 15

  1. Injection Formations ......................................................................................................................................................... 15
  2. Injection Pressure/Brine Level Limitations ....................................................................................................................... 16
  3. Injection/Extraction Ratio ................................................................................................................................................. 16
  4. Injection Fluid Limitations ................................................................................................................................................. 17
  5. Operation Without Mechanical Integrity ......................................................................................................................... 17
  6. New Well Operation ......................................................................................................................................................... 17
  7. Prohibition of Injection into Waters of the State ............................................................................................................... 17

Section D. PLUGGING AND ABANDONMENT OF WELLS ................................................................................................. 18

  1. Notice of Plugging and Abandonment .............................................................................................................................. 18
  2. Emergency Well Conversion or Plugging and Abandonment ......................................................................................... 18
  3. Plugging and Abandonment ............................................................................................................................................ 19
  4. Plugging and Abandonment ("As-Plugged") Report ...................................................................................................... 19
  5. Inactive or Temporarily Plugged Wells ........................................................................................................................... 19
Section E. FINANCIAL RESPONSIBILITY .................................................................21
  1. Demonstration of Financial Responsibility ....................................................21
  2. Renewal of Financial Responsibility .............................................................21
  3. Insolvency of Financial Institution .................................................................21

Section F. MECHANICAL INTEGRITY .................................................................21
  1. Standards ....................................................................................................21
  2. Prohibition Without Demonstration .............................................................22
  3. Loss of Mechanical Integrity .......................................................................22
  4. Mechanical Integrity Testing (MIT) Methods ...............................................23
  5. MIT Frequency ............................................................................................24
  6. Mechanical Integrity Requests ....................................................................24
  7. MIT Inspections ..........................................................................................24
  8. MIT Reporting ............................................................................................25

Section G. CORRECTIVE ACTION .....................................................................25
  1. Corrective Action for New Wells Outside the Original Mine Cavity ..........25
  2. Upward Fluid Migration .............................................................................25

Section H. CONTINUATION OF EXPIRING PERMIT .....................................25
  1. Permit Extension .........................................................................................25
  2. Effect ..........................................................................................................26
  3. Enforcement ...............................................................................................26

Attachment B. Cane Creek Mine - Plan for Abandonment of Class III Wells and Mine Shafts.
Attachment C. Standby Trust Agreement and Reclamation Guarantee Bond
Attachment D. Well Construction Plans (As-Built Well Diagrams)
Attachment E. Monitoring Protocols
Attachment F. Mechanical Integrity Testing (MIT) Protocols
Attachment G. Reporting Tables
PART I. AUTHORIZATION TO CONSTRUCT AND INJECT

Pursuant to the Underground Injection Control (UIC) Program Regulations of the Utah Water Quality Board (UWQB) codified in the Utah Administrative Code (UAC) R317-7,

Intrepid Potash - Moab, LLC
P.O. Box 1208
Moab, Utah 84532

is hereby authorized to construct new Class III injection wells and operate existing Class III injection wells in an area at 38° 30' 30" latitude 109° 39' longitude, approximately located in SE l/4 Sec. 22, SW l/4 Sec. 23, S l/2 Sec. 24, Sec. 25 and 26, E l/2 Sec. 27, N l/2 Sec. 35, Sec. 36, T.26S., R.20E., and SW l/4 Sec. 19, and W l/2 Sec. 30, T.26S., R.21E., Grand County, Utah. UIC-permitted facilities and the UIC permit area are specifically located on Exhibit 14 of “UIC Permit Technical Report Exhibits, Intrepid Potash – Moab, LLC”. Since issuance of the original permit in December 1987 to Texasgulf Chemicals Company, ownership of the facility was transferred to Moab Salt, Inc. ("MSI"), a Delaware corporation, a subsidiary of Potash Corporation of Saskatchewan. Intrepid Oil & Gas, LLC purchased all of the stock of MSI from Potash Corporation and subsequently transferred the stock to Intrepid Mining LLC which then converted MSI from a DE corporation into a DE LLC called Moab Salt, LLC. The name of Moab Salt, LLC was changed to Intrepid Potash-Moab, LLC when the rest of the sub name changes were made. In April, 2008, the Intrepid Potash entities were all consolidated into Intrepid Potash, Inc. and the combined companies became a single, publicly traded company.

Injection is explicitly limited to the Salt 3 zone of the Paradox Formation and below, down to and including the Sylvite 9 salt zone, upon the express conditions that the permittee meets the restrictions set forth herein. Injection into new wells shall not commence until the operator has fulfilled all applicable conditions of this permit and has received written authorization from the Executive Secretary of the UWQB to inject.

All references to UAC R315-2-3, UAC R317-7, and to Title 40 of the Code of Federal Regulations (40 CFR) are to all regulations that are in effect on the date that this permit becomes effective. The following attachments are incorporated into this permit:


Attachment B - Cane Creek Mine - Plan for Abandonment of Class III Wells and Mine Shafts.

Attachment C - Standby Trust Agreement and Reclamation Guarantee Bond

Attachment D - Well Construction Plans (As-Built Well Diagrams)

Attachment E – Monitoring Protocols

Attachment F – Mechanical Integrity Testing (MIT) Protocols
Attachment G – Reporting Tables

This renewed permit consists of a total of 26 pages plus the above 7 attachments and includes all items listed in the Table of Contents. Further, it is based upon representations made by the permittee and other information contained in the administrative record. **It is the responsibility of the permittee to read and understand all provisions of this permit.**

This renewed permit shall become effective May 4, 2009.

This renewed permit and the authorization to inject shall expire at midnight May 4, 2014, unless terminated.

_____________________________
Walter L. Baker, P.E.
Executive Secretary
Utah Water Quality Board
PART II. GENERAL PERMIT COMPLIANCE

A. EFFECT OF PERMIT

The permittee is allowed to engage in underground injection in accordance with the conditions of this permit. The permittee, 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 underground sources of drinking water (USDW), if the presence of that contaminant may cause a violation of any primary drinking water standard under the Utah Public Drinking Water Administrative Rules, UAC R309-200 and 40 CFR Part 141 or may otherwise adversely affect the health of persons. Any underground injection activity not specifically authorized in this permit is prohibited. Compliance with this permit does not constitute a defense to any action brought under the Utah Water Quality Act (UWQA) Title 19, Chapter 5 Utah Code Annotated 1953, or any other common or statutory law or regulation. 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. Nothing in this permit shall be construed to relieve the permittee of any duties under applicable regulations.

B. PERMIT ACTIONS

1. Modification, Revocation, Reissuance and Termination

The Executive Secretary may, for cause or upon request from the permittee, modify, revoke and reissue, or terminate this permit in accordance with UAC R317-7-5.4, R317-7-9.6 (40 CFR 144.39 and 144.40), and R317-7-5.8. Also, the permit is subject to minor modifications for cause as specified in UAC R317-7-9.6 (40 CFR 144.41). The filing of a request for a permit modification, revocation and re-issuance, 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. Transfer of Permits

This permit is not transferable to any person except in accordance with UAC R317-7-9.6 (40 CFR 144.38).

C. SEVERABILITY

The provisions of this permit are severable. If any provision of this permit or the application of any provision of this permit to any circumstance is held to be 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 UWQA 19-5-113 (2) any information deemed by the permittee to be entitled to trade secret protection submitted to the UWQB pursuant to this permit may be claimed as confidential by the submitter. Any such claim must be asserted at the time of submission by stamping the words "Confidential Business Information" on each page containing such information. If no claim is made at the time of submission, the UWQB may make the information available to the public without further notice. Claims of confidentiality for the following information will be denied as per UAC R317-7-9.7:

1. The name and address of the permittee.
2. Information that deals with the existence, absence or level of contaminants in drinking water.

E. DUTIES AND REQUIREMENTS

1. Duty to Comply

The permittee shall comply with all applicable UIC Program regulations and conditions of this permit, except to the extent and for the duration such noncompliance is authorized by an emergency permit issued in accordance with UAC R317-7-8 (40 CFR 144.34). Any permit noncompliance constitutes a violation of the UWQA and is grounds for enforcement action, permit termination, revocation and re-issuance, modification, or for denial of a permit renewal application. Such noncompliance may also be grounds for enforcement action under the Utah Solid and Hazardous Waste Act (USHWA), Title 19, Chapter 6, Utah Code Annotated 1979.

2. Penalties for Violations of Permit Conditions

Any person who violates a permit requirement is subject to civil penalties, fines, and other enforcement action under the UWQA and may be subject to such actions pursuant to USHWA. Any person who willfully violates permit conditions may be subject to criminal prosecution.

3. Duty to Reapply

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

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) which are installed or used by the permittee to achieve compliance with the conditions of this permit. Proper operation and maintenance includes effective performance, adequate funding, adequate operator staffing and training, and adequate laboratory and process controls, including appropriate quality assurance procedures. This provision requires the operation of back-up or auxiliary facilities or similar systems only when necessary to achieve compliance with the conditions of this permit.

7. **Duty to Provide Information**

The permittee shall furnish to the Executive Secretary within a time specified, any information which the Executive Secretary may request to determine whether cause exists for modifying, revoking and reissuing, or terminating this permit, or to determine compliance with this permit. The permittee shall also furnish to the Executive Secretary upon request, copies of records retained as required by this permit.

8. **Inspection and Entry**

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

a) Enter upon the 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 are 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 UWQA any substances or parameters at any location.
9. Records

a) The permittee shall retain records and all monitoring information, including all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation and copies of all reports required by this permit, for a period of at least three years from the date of the sample, measurement or report.

b) The permittee shall maintain records of all data required to complete the permit application form for this permit and any supplemental information submitted under UAC R317-7-9.2 for a period of at least three years from the date the application was signed. These periods may be extended by request of the Executive Secretary at any time.

c) The permittee shall retain records concerning the nature and composition of all injected fluids until three years after the completion of plugging and abandonment that has been carried out in compliance with Part III D of this permit.

d) The permittee shall continue to retain such records after the retention period specified by paragraphs (a) to (c) above, unless it delivers the records to the Executive Secretary or obtains written approval from the Executive Secretary to discard the records.

e) Records of monitoring information shall include:

   (1) The date, exact place, and time of sampling or measurements;
   (2) The individual(s) who performed the sampling or measurements;
   (3) A precise description of sampling methodology, sample handling or custody, and all quality assurance methods used;
   (4) The date(s) analyses were performed;
   (5) The names of individual(s) who performed the analyses;
   (6) The analytical techniques or methods used; and
   (7) The results of such analyses.

10. Signatory Requirements

All reports or other information, submitted as required by this permit or requested by the Executive Secretary, shall be signed and certified in accordance with UAC R317-7-9.3 (40 CFR 144.32).

11. Reporting Requirements

a) Planned Changes

The permittee shall give written notice to the Executive Secretary, as soon as possible, of any planned physical alterations or additions to the UIC-permitted facility. The UIC-permitted facility includes:
(1) The final pumps that boost fluids into the injection wells, and remove fluids from the extraction well(s).

(2) Pipelines between the final injection pumps and the injection wellheads,

(3) Injection and extraction wells, wellheads and all downhole and wellhead equipment and instrumentation within the area of review, and

(4) Instrumentation and equipment used to measure and control volume, flow rate, and pressure of fluids injected into and extracted from the mine(s).

b) Anticipated Noncompliance

The permittee shall give advance notice to the Executive Secretary of any planned changes in the permitted facility or activity that may result in noncompliance with permit requirements.

c) Endangering Noncompliance

The permittee shall report to the Executive Secretary any noncompliance that may endanger health or the environment, as follows:

(1) Twenty-four Hour Reporting

Endangering noncompliance information shall be provided orally within 24 hours from the time the permittee becomes aware of the circumstances. Such reports shall include, but not be limited to, the following information:

(i) Any monitoring or other information that indicates any contaminant may cause an endangerment to an underground source of drinking water or the Colorado River.

(ii) Any noncompliance with a permit condition, or malfunction of the injection system, which may cause fluid migration into or between underground sources of drinking water or into the Colorado River.

(iii) Annual mine cavity brine level tests that show three consecutive drops in brine level.

(2) Five-day Reporting

A written submission shall be provided within five days of the time the permittee becomes aware of the circumstances of the endangering noncompliance. The written submission shall contain a description of the noncompliance and its cause, the period of noncompliance, including exact dates and times, and if the noncompliance has not been corrected, the anticipated time it is expected to continue; and steps taken or planned to reduce, eliminate, and prevent recurrence of the noncompliance.
d) Other Noncompliance

The permittee shall report all other instances of noncompliance in the next Quarterly Monitoring Report, if not otherwise reported. The reports shall contain a description of the noncompliance and its cause, the period of noncompliance, including exact dates and times, and if the noncompliance has not been corrected, the anticipated time it is expected to continue; and steps taken or planned to reduce, eliminate, and prevent recurrence of the noncompliance.

e) Quarterly Monitoring Reports

Quarterly monitoring reports shall be submitted to the Executive Secretary according to the following schedule:

<table>
<thead>
<tr>
<th>Quarter</th>
<th>Report due on</th>
</tr>
</thead>
<tbody>
<tr>
<td>1st Quarter</td>
<td>April 15</td>
</tr>
<tr>
<td>2nd Quarter</td>
<td>July 15</td>
</tr>
<tr>
<td>3rd Quarter</td>
<td>October 15</td>
</tr>
<tr>
<td>4th Quarter</td>
<td>January 15</td>
</tr>
</tbody>
</table>

These reports shall consist of the following information:

1) **Injection and Extraction Volumes for Wells Into the Original Mine Cavity**

Volumes of fluids injected into and extracted from the original mine cavity shall be reported by individual source on a total weekly basis, as well as the weekly volume of environmental reclaim brine transferred to the tailings pond. Total mine injection (a sum of the individual source volumes), total mine extraction and the mine injection/extraction ratio shall also be reported on a total weekly basis.

2) **Injection and Extraction Volumes for Wells Into the Sylvite 9 Solution Mine**

Volumes of fluids injected into and extracted from the Sylvite 9 solution mine shall be reported by individual source on a total weekly basis for each period of operation. Total injection, total extraction and the injection/extraction ratio shall also be reported on a total weekly basis.

3) **Original Mine Cavity Injection Pressure/Flow Rate/Brine Level.**

   i) The weekly minimum and maximum depth to water (ft), measured at the No. 2 shaft, shall be reported. The weekly minimum depth to water shall be converted to the weekly maximum mine cavity pressure at the highest point of elevation in
the mine cavity (1,700 feet above sea level (asl)) according to the following relationship:
\[ A = B \times C \times D \times E \]

Where:
- \( A \) = Maximum Mine Cavity Operating Pressure at the Highest Elevation in the Mine Cavity, calculated in PSI at 1,700’ asl
- \( B \) = Height of the Fluid Column, measured in feet = \( F \) – \( G \) - \( H \)
  - \( F \) = Elevation of the Drilling Collar at No. 2 Shaft, measured in feet = 4,018’ asl
  - \( G \) = Elevation of the Highest Point in the Original Mine, measured in feet = 1,700’ asl
  - \( H \) = Weekly Minimum Depth to Water Measured Relative to the Drilling Collar at No. 2 Shaft, measured in feet.
- \( C \) = Constant when Fluid Density of Pure Water is reported in Pounds/Gallon = 0.051948 gal/(sq. in. x ft)
- \( D \) = Specific Gravity of the Fluid of Maximum Possible Concentration in the Mine, dimensionless number = 1.233
- \( E \) = Fluid Density of Pure Water, reported in pounds/gallon = 8.3454 Pounds/Gallon

(ii) The weekly minimum and maximum injection gauge pressure (psig) and flow rate (gpm, etc.) shall be reported for each injection well in operation.

(iii) Annual mine cavity brine level test results, for the quarter in which the tests were run.

(4) **Injection Pressures and Flow Rates for Wells in the Sylvite 9 Solution Mine.**
Maximum and minimum gauge pressures (psig) and corresponding flow rates (gpm) for each well shall be reported for each week of operation.

(5) **Injectate Water Quality.** Results from injection fluid sample analyses and field determinations, as required in Part III A(4) of this permit, shall be reported.

(6) If the following Injection/Extraction ratio(s) are exceeded for 2 consecutive weeks or more, results of the investigation required by Part III C(3) of this permit and any corrective action taken shall be reported:

<table>
<thead>
<tr>
<th>Mine Cavity Type</th>
<th>Ratio</th>
</tr>
</thead>
<tbody>
<tr>
<td>Original mine cavity</td>
<td>1.02</td>
</tr>
<tr>
<td>Sylvite 9 solution mine cavity</td>
<td>River water injectate</td>
</tr>
</tbody>
</table>
(7) Results of continuous liquid level monitoring in Shaft #2

(8) Salt Loading Management Activity - Report annual activity to reduce/manage salt loading from evaporation ponds to the local hydrologic system.

Failure to submit complete quarterly reports by the due dates noted above shall be deemed as noncompliance and may result in enforcement action.

f) Other Information

When the permittee becomes aware that he failed to submit any relevant facts in the permit application or submitted incorrect information in a permit application or in any report to the Executive Secretary, the permittee shall submit such facts or information within 10 days after becoming aware of the failure to submit relevant facts.

g) Report on Permit Review

Within 30 days after receipt of this permit, the permittee shall report to the Executive Secretary that he has read and is personally familiar with all terms and conditions of this permit.

12. Electronic Reporting

In addition to submittal of the hard copy data, the permittee shall electronically submit required monitoring data in the electronic format specified by the Executive Secretary. The data may be sent by e-mail, CD, floppy disc, modem, or other approved transmittal mechanism.
PART III. SPECIFIC PERMIT CONDITIONS

A. MONITORING REQUIREMENTS

Samples and measurements taken for the purpose of monitoring shall be representative of the monitored activity. Monitoring results shall be reported at the intervals specified in Part II Section E 11(e) of this permit.

1. Injection and Extraction Volumes (40 CFR 146.33 (b) (2))

   a) Wells Into the Original Mine Cavity

      (1) Total mine injection volume shall be recorded on a daily basis by summing the daily injection volumes for the following sources with their corresponding flow meter locations:

<table>
<thead>
<tr>
<th>Source</th>
<th>Monitoring Location</th>
</tr>
</thead>
<tbody>
<tr>
<td>Tailings lake brine</td>
<td>Flow is measured at the well #24 flow meter located on the tailings lake brine injection line.</td>
</tr>
</tbody>
</table>

      (2) The weekly volume of environmental reclaim brine transferred to the tailings pond shall be recorded at the main pit scavenger brine flow meter located north of the main pit scavenger brine pond.

      (3) Total mine extraction volume shall be recorded on a daily basis by summing the daily extraction volumes from each extraction well.

   b) Wells Into the Sylvite 9 Solution Mine

      (1) Before injecting/extracting with any of these wells the permittee shall ensure that appropriate meters have been installed to measure the volume of all fluids injected and extracted from each well.

      (2) During periods of operation the permittee shall record volumes of injection into and extraction from each well, on a daily basis.

   c) An injection volume/extraction volume ratio shall be calculated and recorded on a weekly basis for the original mine cavity and the Sylvite 9 solution mine.

2. Injection Pressure/Flow Rate/Brine Level

   (40 CFR 146.33 (b) (2)) and (40 CFR 146.33 (b) (4))

   a) Wells into the Original Mine Cavity
(1) The brine level in the original mine will be measured by continuous monitoring of the liquid level in feet below the casing collar of the No. 2 shaft. These measurements shall be converted to actual mine cavity pressure in units of pounds per square inch (psi) as indicated in Part II E(11)(e)(3)(i).

(2) Injection pressure (psig) and flow rate (gpm, etc.) shall be continuously recorded daily for each injection well in operation.

b) Wells into the Sylvite 9 Solution Mine

(1) Before injecting or extracting, the permittee shall ensure that appropriate pressure gauges and flow rate gauges have been installed on each well.

(2) Injection pressure (psig) and flow rate (gpm, etc.) shall be continuously recorded daily for each injection and extraction well in operation.

3. **Injectate-Extractate Temperature and Flow Rate (40 CFR 146.33 (b) (2))**

Injectate-extractate temperature, and injectate-extractate flow rate shall be continuously recorded using three-trace recorders during injection and extraction for wells completed in the pressurized Sylvite 9 solution mine.

4. **Injection Fluid Quality (40 CFR 146.33 (b) (1))**

Injectate monitoring samples shall be taken during normal injection operations for each of the following sources during every quarter they are injected:

a) Mine injection sources - one sample shall be collected from each mine injection source from the following locations, as applicable:

<table>
<thead>
<tr>
<th>Source</th>
<th>Sampling Location</th>
</tr>
</thead>
<tbody>
<tr>
<td>Tailings Lake Brine</td>
<td>At 800 HP Pump at tailings lake</td>
</tr>
<tr>
<td>Original Mine Cavity Brine</td>
<td>At Any Appropriate Injection Well Wellhead</td>
</tr>
</tbody>
</table>

b) Common sources - If the same source and pump is simultaneously supplying both the original mine cavity and the Sylvite 9 solution mine, only one sample is necessary for that source.

c) Injection fluid analysis parameters shall include:

(1) Inorganics
- Potassium

(2) Acid-Soluble (H+) Metals (unfiltered sample)

- Arsenic, Chromium, Selenium, and Zinc.

d) Field determinations to be made on injection fluid samples, immediately upon collection, shall include:

(1) pH

(2) temperature, and

(3) conductivity

5. Quality Assurance Procedures

The permittee shall implement appropriate quality assurance procedures for the following:

a) All meters measuring injection and extraction flow rates/volumes into and out of the original mine cavity and Sylvite 9 solution mine.

b) Pressure gauges and electric droplines used to measure injection pressure/head in the original mine cavity and Sylvite 9 solution mine.

c) All field testing equipment.

d) Sampling and analysis methods.

The equipment noted in (a), (b) and (c) above shall be maintained according to manufacturer's specifications. Calibration of the items noted in (a) and (b) above shall be done at the time intervals and in the manner specified by the equipment manufacturer.

Calibration of field-testing equipment shall be done immediately prior to each sampling event or sampling session in the manner specified by the equipment manufacturer. A copy of the calibration schedule(s) and procedures for items (a) and (b) above shall be submitted to the Executive Secretary within 90 days of the effective date of this permit. The permittee shall be responsible to maintain records of calibrations and other quality assurance procedures in compliance with Part II E(9) of this permit.

The permittee shall follow all pertinent quality assurance procedures in accordance with the Utah Quality Assurance (QA) Plan for the Underground Injection Control (UIC) Program (July 5, 1990), including proper sample containers, preservatives, and holding times. Utilizing proper chain-of-custody procedures, monitoring samples must be sent to a State-certified environmental
lab for analyses. Sample analysis shall comply with applicable analytical methods cited and described in Table 1B of 40 CFR 136.3 or in Appendix III of 40 CFR 261 or in certain circumstances by other methods that have been approved by the Executive Secretary.

B. NEW WELL REQUIREMENTS

1. New Well Design and Construction Requirements

The construction of new vertical wells into Sylvite 5 will follow the plans detailed in Section 9.1 of the “Technical Report – Revised March 17, 2009” (Attachment A of this Permit). The construction of new vertical and horizontal wells into Sylvite 9 will follow the plans detailed in Section 9.2 of the “Technical Report – Revised March 17, 2009”.

All new wells shall have centralizers installed on the bottom three joints of the surface casing and on the bottom three joints of any casing string that is placed in or below the salt. The latter shall also have centralizers on every third joint of casing to the surface above the bottom three joints.

Except for shallow surface casings, a cement bond log and a background gamma ray log shall be run on each casing string placed directly adjacent to bare formations.

A baseline temperature log shall be run on each new horizontal well after it has time to remain static for a minimum of two days following drilling, and prior to startup of injection/extraction. This log shall be run from the surface down to where the tool starts to fall into the curve of the horizontal well.

Wells in original mine cavity

New vertical well construction into the Sylvite 5 as specified in Section 9.1 of the “Technical Report – Revised March 17, 2009” (Attachment A of this Permit) is deemed adequate contingent on compliance with Part III (B)(1)(a) through (e) below. Exceptions may be made on an individual well basis with authorization from the DEQ depending on well objectives and geologic circumstances.

Wells in pressurized Sylvite 9 solution mine

New vertical or horizontal well construction into the Sylvite 9 as specified in Section 9.2 of the “Technical Report – Revised March 17, 2009” (Attachment A of this Permit) is deemed adequate contingent on compliance with the following and Part III (B)(1)(a) through (e) below. Typical Vertical Well and Typical Horizontal Well schematics for wells constructed in the Sylvite 9 are in Attachment D of this Permit.

All wells into the pressurized Sylvite 9 solution mine must inject and extract through tubing connected to a packer set at the base of Clastic 2 or lower, with the annulus filled with non-
corrosive/non-toxic liquid. The operator may install a tubing string without a packer inside the tubing string connected to a packer if desired.

a) No less than 30 days prior to the planned construction of a new well, the permittee shall submit individual plans for each new well to be constructed, for review and approval by the Executive Secretary. Well construction may begin only after receipt of written approval from the Executive Secretary.

b) Well design and construction shall comply with the requirements of 40 CFR 146.32(a) and (b). This shall also include all logging or test methods to be conducted during drilling and construction of a new well as deemed necessary by the Executive Secretary.

c) Within 60 days after completion of well construction the permittee shall submit an "As Constructed" report for each new well for review by the Executive Secretary. Any deviation from the approved plan, not justified by the permittee, shall be cause for the Executive Secretary to:

(1) Require the permittee to cease operation of the well, and

(2) Remediate or abandon the well.

d) Within 90 days after completion of well construction the permittee shall modify the Plan for Abandonment of Class III Wells and Mine Shafts (Attachment B) to include plans for the new well. The permittee shall also attach a reliable estimate of costs for plugging and abandonment of the new well, based on the new well's current condition. Any resultant needed increase in the total bond amount of the Financial Guarantee Bond (Schedule B of Attachment C) shall be cause for the Executive Secretary to require the permittee to post a new or amended Financial Guarantee Bond for the facility.

e) Each well shall be suitably equipped with pressure gauges and flow meters. All gauges and meters shall be certified for at least ninety-five (95) percent accuracy throughout the ranges allowed by the permit.

2. New Wells Constructed in the Colorado River Alluvium

New wells constructed in Colorado River alluvium, identified as stratigraphic units Qu and QTu on Figure 2 of the 1985 Huntoon Report, shall be constructed in accordance with the additional requirement that the surface casing extends significantly into bedrock. The depth to bedrock shall be determined by geophysical or sample logs at the time of well construction. These logs shall be included in the "As-Constructed" report required by Part III B(1)(c) of this permit.

C. OPERATION REQUIREMENTS

1. Injection Formations
Injection shall be explicitly limited to the Salt 3 zone of the Paradox Formation and below, down to and including the Sylvite 9 salt zone.

2. Injection Pressure/Brine Level Limitations

The original mine cavity shall not be operated in pressurized mode. The original mine cavity shall at all times be open to atmospheric pressure through a well bore or a shaft, with brine extraction by pumping.

The hydrostatic mine operating pressure shall be maintained below the safe mine cavity pressure of 1,916 psi at all times during operation of the facility. The hydrostatic operating pressure shall be calculated by converting the minimum depth-to-water at the No. 2 Shaft to reflect the mine cavity pressure as indicated in Part II E(11)(e)(3)(i).

Brine levels shall be maintained in the original mine cavity so as to preclude brine escaping through any fractures or joints in the cavity. Mine cavity operational brine level shall not be higher than 125 feet below the casing collar at the No. 2 shaft.

Solution mining of the Sylvite 9 salt zone may be done in pressurized mode according to the following limitations:

   a) For Sylvite 9 solution mining cavities that pass beneath or within 500 feet of the boundary of the original mine cavity, surface pressure (psig) + (plus) injection column static pressure - (minus) friction losses shall not exceed .85 psi/ft x (times) depth (ft) to the Sylvite 9 cavity roof.

   b) For other Sylvite 9 solution mining cavities, surface pressure (psig) + (plus) injection column static pressure - (minus) friction losses shall not exceed .98 psi/ft x (times) depth (ft) to the Sylvite 9 cavity roof.

3. Injection/Extraction Ratio

Original mine cavity injection/extraction ratios that exceed 1.02, or Sylvite 9 solution mine injection/extraction ratios that exceed those in the following table for 2 consecutive weeks or more may be indicative of possible fluid loss and shall require investigation as to the cause within 72 hours:

<table>
<thead>
<tr>
<th>Injectate</th>
<th>Injection/Extraction Ratio</th>
</tr>
</thead>
<tbody>
<tr>
<td>River water</td>
<td>1.08</td>
</tr>
<tr>
<td>Lake brine</td>
<td>1.02</td>
</tr>
<tr>
<td>Mine brine</td>
<td>1.02</td>
</tr>
</tbody>
</table>
If the investigation indicates leakage, appropriate corrective action shall be taken without delay, including, if necessary, lowering the brine level in the original mine cavity or Sylvite 9 solution mine.

4. Injection Fluid Limitations

Injection fluid shall be expressly limited to:

(a) Colorado River water
(b) Tailings lake brine
(c) Brine from the original mine cavity

These fluids may be heated up to 200 degrees F prior to injection. The permittee shall not inject any hazardous substance as defined by UAC R315-2-3 at any time during operation of the facility.

Well No. 6 shall not inject by-pass brine. Fresh water may be injected into well No. 6 to remove salt build-up, during mechanical integrity tests, and prior to pump start-up.

5. Operation Without Mechanical Integrity

The permittee is hereby prohibited from operating any injection or extraction well without mechanical integrity as defined in Part III F(1) of this permit. Wells that fail a mechanical integrity test (MIT) shall be subject to the requirements of Part III F(3) of this permit.

6. New Well Operation

The permittee may commence operation of new wells after:

a) Compliance with the new well design and construction requirements of Part III B(1) of this permit.

b) Compliance with all applicable Corrective Action requirements of Part III G(1) of this permit.

c) Submittal of demonstration of mechanical integrity to the Executive Secretary, and

d) Receipt of Executive Secretary approval of the mechanical integrity demonstration.

7. Prohibition of Injection into Waters of the State

The permittee is hereby prohibited from any injection into waters of the State of Utah, including any USDW and/or the Colorado River. The prohibition does not include injection into brine-containing mine cavities at the permitted site.
D.  PLUGGING AND ABANDONMENT OF WELLS

1.  Notice of Plugging and Abandonment

The permittee shall notify the Executive Secretary in writing no later than 45 days before planned conversion or abandonment of the well(s). This notice shall also include:

a)  Well Condition Report

The permittee shall provide a report on the current condition of the well in order to update, supplement or complete any information found in the Plan for Abandonment of Class III Wells and Mine Shafts (Attachment B). This report shall discuss in detail and evaluate:

(1) The results of the well's most recent mechanical integrity test,

(2) The location of any leaks or perforations in the casing,

(3) The location of any vertical migration of fluids behind the casing, and

4) The adequacy of casing cement bonding across the Paradox Formation, as determined from cement bond logs run at the time of well construction or just prior to well abandonment.

Any supporting data or test results shall be attached to confirm the conclusions of the report.

b)  Individual Plugging and Abandonment Plan

The permittee shall also submit an individual plugging and abandonment plan for each well to be plugged and abandoned. In coordination with the Well Condition Report, this plan shall modify and supercede the Plan for Abandonment of Class III Wells and Mine Shafts (Attachment B), as necessary, to ensure adequate plugging and abandonment of the well.

The plugging and abandonment of the well shall be subject to prior Executive Secretary approval of the individual plugging and abandonment plan. The Executive Secretary reserves the right to grant conditional approval of any individual plugging and abandonment plan to ensure adequate plugging of a well.

2.  Emergency Well Conversion or Plugging and Abandonment

Emergency conversion or abandonment of wells is allowed by this permit, conditional upon the following requirements:
a) The permittee will seek oral approval from the Executive Secretary for emergency well conversion or abandonment no less than 24 hours prior to the emergency action.

b) The permittee will subsequently submit a written request for Executive Secretary approval of emergency well conversion or abandonment, with appropriate justification, within 5 working days after receiving oral approval.

c) The Executive Secretary reserves the right to modify any oral approval for emergency action, subsequent to review of the written request.

d) Oral or written approval from the Executive Secretary for emergency well conversion or abandonment will not waive or absolve the permittee from its responsibility to comply with the conditions of this permit, including requirements of the Plan for Abandonment of Class III Wells and Mine Shafts (Attachment B).

3. **Plugging and Abandonment**

The permittee shall plug and abandon the well(s) consistent with 40 CFR 146.10, as provided for in the attached Plan for Abandonment of Class III Wells and Mine Shafts (Attachment B), and any conditions issued by the Executive Secretary in approval of the individual plugging and abandonment plans required by Part III D(1) of this permit.

4. **Plugging and Abandonment ("As-Plugged") Report**

Within 60 days after permanently or temporarily plugging and abandoning a well, the permittee shall submit a Plugging and Abandonment Report to the Executive Secretary. The report shall be certified as accurate by the person who performed the plugging operation, and shall consist of either:

a) A statement that the well was plugged in accordance with the plan(s) previously submitted to, and all conditions of approval provided by, the Executive Secretary; or

b) If the actual plugging differed from the approved plan(s), a statement and diagrams defining the actual plugging and why the Executive Secretary should approve such deviation. Any deviation from the previously approved individual plugging and abandonment plans required by Part III D(1) of this permit which may endanger waters of the State of Utah, including USDWs and/or the Colorado River, is cause for the Executive Secretary to require the operator to re-plug the well.

5. **Inactive or Temporarily Plugged Wells**

a) Inactive Wells
After cessation of operation of a well(s) for two years the permittee shall plug and abandon the well(s) in accordance with Part III D(1), (3), and (4) of this permit, unless the permittee requests and receives a variance from this requirement from the Executive Secretary prior to the end of the two year cessation period, based on:

1) A demonstration that the well will be used in the future; and

2) A satisfactory description of actions or procedures that the permittee will take to ensure that the well will not endanger an USDW or the Colorado River during the period of temporary abandonment. These actions and procedures shall include compliance with technical requirements applicable to active injection wells unless waived by the Executive Secretary.

b) Temporary Plugging of a Well

Temporary plugging of a well shall consist of:

(1) Submittal of a notice of well conversion.

(2) Submittal of a well condition report, and an individual plugging plan as required by Part III D(1) of this permit, for Executive Secretary approval.

(3) Emplacement of a bridge plug below the lowermost leak in the casing, if any, or at a depth required by the Plan for Abandonment of Class III Wells and Mine Shafts (Attachment B), or at a depth as directed by the Executive Secretary.

4) Emplacement of at least 10 feet of salt saturated Class B cement immediately above the bridge plug. This cement and its emplacement shall meet requirements of the Plan for Abandonment of Class III Wells and Mine Shafts (Attachment B) and 40 CFR 146.10.

5) Submittal of an "As-Plugged" Report as required by Part III D(4) of this permit.

c) At the end of the second and fourth years of this permit, the permittee shall review and evaluate all temporarily abandoned or inactive wells to ensure compliance with Part III D(5)(a) of this permit. Submit Inactive/Temporarily Abandoned Well Evaluation Report to Executive Secretary.

d) Temporarily plugged or inactive wells may be reactivated at the discretion of the permittee after:

(1) Submitting a written notification of intent to reactivate to the Executive Secretary, and

(2) Demonstration of mechanical integrity to the Executive Secretary, as defined in Part III F of this permit, and
(3) Receipt of Executive Secretary written approval of mechanical integrity demonstration and approval to reactivate the well.

E. FINANCIAL RESPONSIBILITY

1. Demonstration of Financial Responsibility

The permittee is required to maintain financial responsibility and resources to close, plug, and abandon all wells referenced in the Plan for Abandonment of Class III Wells and Mine Shafts (Attachment B), not already plugged and abandoned at the time of issuance of this permit. Satisfaction of this requirement is demonstrated by the attached Financial Guarantee Bond and the Standby Trust Agreement and their associated schedules and exhibits (Attachment C).

2. Renewal of Financial Responsibility

Upon application for permit renewal, the permittee shall demonstrate the adequacy of the surety bond and standby trust agreement to close, plug and abandon all wells not permanently plugged and abandoned by the permittee in compliance with Part III D of this permit.

3. Insolvency of Financial Institution

The permittee must submit an alternate demonstration of financial responsibility acceptable to the Executive Secretary within 60 days after either of the following events occurs:

a) The institution issuing the trust or financial instrument files for bankruptcy; or

b) The authority of the trustee institution to act as trustee, or the authority of the institution issuing the financial instrument, is suspended or revoked.

F. MECHANICAL INTEGRITY (MI)

1. Standards

All injection and extraction wells shall have and maintain mechanical integrity consistent with the requirements of 40 CFR 146.8, including:

a) No significant leak in casing, tubing, or packer, and

b) No significant fluid movement into an USDW through vertical channels adjacent to the injection well bore.
For purposes of this permit, mechanical integrity shall also include the absence of significant fluid movement from the original mine cavity or the Sylvite 9 solution mine into any overlying waters of the State of Utah, including an USDW and/or the Colorado River, through vertical channels adjacent to the well bore or casing.

2. **Prohibition Without Demonstration**

The permittee shall not:

- a) Operate any existing well without demonstration of mechanical integrity, as defined by Part III F(1) of this permit, nor

- b) Commence operation of any new well without:

  1) Prior demonstration of mechanical integrity as defined by Part III F(1) of this permit, and

  2) Receipt of Executive Secretary written approval of the mechanical integrity demonstration.

3. **Loss of Mechanical Integrity**

If the permittee or the Executive Secretary determines that a well fails to demonstrate mechanical integrity, as defined by Part III F(1) of this permit, the permittee shall:

- a) Cease operation of the well immediately, and

- b) Take steps to prevent losses of mine brine through the leak(s) caused by high hydrostatic head or pressure in the original mine cavity or Sylvite 9 solution mine, and

- c) Mechanical Integrity failure which may potentially endanger an USDW and/or the Colorado River shall be reported to the Executive Secretary verbally within 24 hours according to Part II E (11) (c) (1) followed by submission of a written within 5 days according to Part II E (11) (c) (2).

- d) Within 15 days after loss of mechanical integrity, submit to the Executive Secretary a schedule indicating what will be done to restore mechanical integrity to the well, or if it will be plugged.

- e) Within 90 days after loss of mechanical integrity, restore mechanical integrity or plug and abandon the well in accordance with a plugging and abandonment plan approved by the Executive Secretary.
The permittee may resume operation of the well after demonstration of mechanical integrity and receiving written approval from the Executive Secretary.

4. Mechanical Integrity Testing (MIT) Methods

The permittee shall use testing methods approved by both the U.S. Environmental Protection Agency (EPA) and the Executive Secretary for the following mechanical integrity determinations:

a) Significant Leaks [40 CFR 146.8(a)(1)]

Methods outlined in 40 CFR 146.8(b), or Radioactive Tracer Survey (RTS), as approved by the EPA in the December 10, 1987 Federal Register (52 FR 46837). If RTS is utilized, injection pressure or flow rate during the MIT must equal or exceed maximum operational injection pressure or flow rate, and fresh water must be the carrier fluid. A background gamma-ray log must be run prior to the RTS. The casing must be completely filled with the carrier fluid during the background gamma-ray log and RTS.

A casing pressure test shall consist of filling the inside of the well casing with liquid and pressuring to a minimum of 300 psi (provided 300 psi meets the conditions in determining SSAPT test conditions detailed in Attachment F – Mechanical Integrity Testing (MIT) Protocols) for 45 minutes with no more than 10% variation allowed in order to pass MIT. Pressuring the inside of the well casing may be carried out: 1) using the cementing contractor upon completion of cementing casing below the base of elastic 2; 2) with drilling rig equipment prior to drilling out the cement and casing guide shoe; 3) with drilling rig equipment using a packer on tubing after drilling out the cement and casing guide shoe. Detailed procedures for the above can be found in Attachment F - Mechanical Integrity Testing (MIT) Protocols.

The annulus pressure test shall consist of pressuring the annulus to a minimum of 300 psi (see exception above) for 45 minutes (with injection/extraction pumps off), with no more than 10% variation allowed in order to pass MIT.

b) Significant Fluid Movement [40 CFR 146.8(a)(2) and Part III F(1) of this permit]

Methods outlined in 40 CFR 146.8(c), or RTS as approved by the EPA in the December 10, 1987 Federal Register (52 FR 46837). If RTS is utilized, injection pressure or flow rate during the MIT must equal or exceed maximum operational injection pressure or flow rate, and fresh water must be the carrier fluid. A background gamma-ray log must be run prior to the RTS. The casing must be completely filled with the carrier fluid during the background gamma-ray log and RTS.

Well casings to be tested by radioactive tracer must first be flushed with fresh water (Colorado River water is acceptable) and a caliper log run. If the caliper log shows
significant encrustation, flushing with fresh water or some method of mechanical removal must be utilized to remove precipitates before the MIT is run.

The rationale for selecting Mechanical Integrity Test methods, and the procedures for conducting them are detailed in Attachment F.

c) Other Approved Methods

Other MIT methods approved by the EPA Administrator may be used upon the written approval of the Executive Secretary.

5. MIT Frequency

The permittee shall conduct mechanical integrity testing of injection and extraction wells as follows:

a) For active wells into the original mine cavity:

- Annular pressure test (for those so-equipped) – yearly
- Test for casing leaks (for those not equipped to run annular pressure tests), and test for vertical flow behind casing - every five years

b) For active wells into the Sylvite 9 solution mine(s):

- Annular pressure test - yearly
- Test for vertical flow behind casing - every five years

c) For new wells, MIT shall be conducted prior to well operation in accordance with Part III C(5) of this permit.

d) Following any repair or workover of a well, prior to placing it back into operation.

6. Mechanical Integrity Requests

With just cause, the Executive Secretary may at any time require, by written notice, the permittee to demonstrate mechanical integrity of a well(s).

7. MIT Inspections
The permittee shall allow the Executive Secretary, or his representative, to observe any or all mechanical integrity testing. The permittee shall notify the Executive Secretary, in writing, of its intent to conduct MIT, no less than 30 days prior to the intended testing.

8. **MIT Reporting**

The permittee shall submit the results of any MIT within 60 days after completion of the test. In the case of MIT failure, the permittee shall also describe in detail what and when steps were taken to comply with Part III F(3) of this permit.

**G. CORRECTIVE ACTION**

The permittee has a responsibility for corrective action of known wells improperly plugged and abandoned within the area of review. This responsibility is acute for those wells deemed critical or most likely to come in contact with the original mine cavity or the Sylvite 9 solution mine. Corrective action includes remedial well plugging and/or changes in mine operation to prevent mine brine from escaping the original mine cavity or the Sylvite 9 solution mine and entering a USDW or the Colorado River via an abandoned well(s). Specific corrective action requirements are as follows:

1. **Corrective Action for New Wells Outside the Original Mine Cavity**

   The permittee shall not commence injection in a new well outside the original mine cavity until after a review of wells within a two mile radius that penetrate the injection zone has been completed, results thereof submitted to the Executive Secretary, and any corrective action has been completed, as may be found necessary by the Executive Secretary in accordance with 40 CFR 144.55.

2. **Upward Fluid Migration**

   Should upward fluid migration from the original mine cavity or the Sylvite 9 solution mine occur through the well bore of any previously unknown, improperly plugged, or unplugged well within the area of review above the permitted injection zone due to the injection of permitted fluids, the permittee shall cease injection immediately until proper plugging or repair of the well can be accomplished. Any such discharge to waters of the State of Utah, including USDWs and/or the Colorado River, shall be considered noncompliance with this permit.

**H. CONTINUATION OF EXPIRING PERMIT**

1. **Permit Extension**

   The conditions of an expired permit may continue in force if a complete permit renewal application has been submitted at least 180 days before expiration of this permit.
2. **Effect**

Permits continued under this special condition remain fully effective and enforceable.

3. **Enforcement**

When the permittee is not in compliance with the conditions of the expiring or expired permit the Executive Secretary may choose to do any or all of the following:

   a) Initiate enforcement action based upon the permit that has been continued;

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

   c) Issue a new permit with appropriate conditions; or

   d) Take other actions authorized by Underground Injection Control Program rules (UAC R317-7).
TECHNICAL REPORT
CLASS III INJECTION WELLS
FOR
INTREPID POTASH-MOAB, LLC., MOAB, UTAH
CANE CREEK MINE
AMENDED MARCH 17, 2009

PROCESS DESCRIPTION

Potash, along with nitrogen and phosphate, is classified as a primary plant nutrient. Most fertilizers available in the marketplace are identified by the letters N-P-K; the N refers to the nitrogen component, P to the phosphate component and K to the potash component.

In the mining world, potash (potassium chloride) is known as the mineral sylvite. It was first discovered in Germany in 1839, in Carlsbad, New Mexico in 1926, and later in California, Utah and Canada. Ninety to 95 percent of all potash produced today is used for fertilizer. Other uses are in the manufacture of matches, dyes, television tubes, pharmaceuticals, synthetic rubber, detergents, films, insecticides, chinaware and solid fuel. Potash from Moab Salt is often used as a shale inhibitor in oil field fracturing and drilling fluids.

The Cane Creek Mine, formerly owned by Texasgulf, Inc. and currently owned by Intrepid Potash, Inc., is one of the most unusual in the world because it is completely filled with water. Since potash and salt are soluble, they can be removed from the mine by pumping the saturated solution from the approximately 3,000-foot mine into shallow ponds. The water is then evaporated, leaving the solid potash and salt to be removed by earth-moving equipment.

It was not originally intended that Cane Creek's potash would be mined with water. The operation started as a conventional mine in Sylvite 5 ore body in 1964 but was plagued with problems from the start. The mine was gassy, the temperature ranged up to 95°F and instead of being level and flat, the ore layer was distorted and undulating.

After extensive research into the feasibility of solution mining, the unique program was started in 1970.

Simply, water from the Colorado River and near saturated salt water from the brine tails pond is pumped into the mine at one area and drawn out of another area at the other end. The extracted solution is saturated with potash and salt. This is a continuous process running up to 2,000 gallons per minute. It takes any given unit of water about 300 days to complete the trip through the mine. The temperature in the mine is warmer than the injection water and as the water flows through the mine the temperature increases.

There are 150 miles of entryways in the potash bed created by past underground mining. The pillars and the walls of the entire system will eventually dissolve. The highest rate of production comes from the pillars and sidewalls in the active sections around the injection wells.
In April 2002, horizontal drilling technology was used at the mine property to begin the solution mining process in Sylvite 9 Potash ore approximately 800 feet below the original Sylvite 5 ore body. Over 25,000 feet of near horizontal wellbore has penetrated this lower ore body where similar solution mining takes place at a rate of 200 to 300 GPM. Horizontal drilling has contributed 214,000 tons of Potash since production started in July 2002.

The potash solution is pumped out of the mine cavities and three miles away to 23 solar evaporation ponds with a combined surface of 400 acres. The ponds range in size from 6 to 52 acres each depending on how they have been contoured into the hills. More than two million cubic yards of dirt and rock were moved to build them. The ponds are lined with an impervious material to minimize leakage into adjoining soil.

When the ponds were completed, salt brine from the waste tailings was pumped in to provide a six-inch base over the plastic liner to support the scraper-loaders used to harvest the potash. Conventional road building scraper-loaders, each scooping up 23 tons, are used for harvesting the ponds. Blades of the machine are closely controlled by an automatic laser beam system that prevents them from cutting into the six-inch base. They dump their loads into a brine slurry system that pumps approximately three miles to the processing plant.

The Cane Creek mill separates the salt and potash by flotation. The potash is then dewatered by centrifuges and dried in a large gas-fired rotary drum. The dry product is screened and sized into three grades. All grades are white, premium quality potash containing 60 to 62% K₂O (see Detailed Process Flow Diagrams in Exhibit 1).

The waste salt is saved and stockpiled for later drying and sizing, dissolved and re-injected to the mine or sold as product quality and inventories dictate.

Potash and salt are produced in the plant during alternating periods at the rate of 1,000 to 1,200 tons per operating day. The products are shipped via rail cars and trucks to customers in many parts of the country.

1. There are no known sources of drinking water within a two-mile radius of the Cane Creek Mine as demonstrated by the Huntoon report.

The two wells used to determine the quality of the groundwater above the Cane Creek Mine are:

a. No. 1 shaft
b. Well No. 15

The water quality analyses are found in Tables B1 and B2 of Appendix B of the Huntoon report. The well locations are marked on Figures 1 and 8, which are located in the pocket of the Huntoon report. Huntoon’s descriptions of the water sampling method and flow capacity are found on Pages 26 and 27.
A detailed description of the sampling of Well 15 was supplied to the Utah Department of Health by registered mail on August 2, 1985.

2. There is insufficient data available from the wells in Item 1 to develop a piezometric map of the brine aquifer in the vicinity of the Cane Creek Mine. Huntoon describes the general nature and migration patterns of the groundwater on Pages 30-38 and in the supplement report.

3. Figure 1 of the Huntoon report shows the location of all known artificial penetrations within two miles of the solution mine cavity. Exhibit 2, Artificial Penetrations within a 2-Mile Radius (see attached), is a revised map which includes all artificial penetrations within a 2-mile radius from the solution mining cavern through October 2003.

4. Charts and schematics tabulating well data:
   
a. Well bore schematics near the Moab Salt mine, drilled as early as 1928, are included where records are available. See Exhibit 3

b. Texasgulf Sulphur Company Potash Division, Moab, Utah, General Area Well Data Chart (Pocket Huntoon Report) Figure 1 Wells Symbol. A chart in the pocket of the Huntoon Report titled “Well Profile Diagram” depicts wells drilled between 1970 and 1984. This chart does not contain all abandonment and cementing information. See well schematics in the UIC Permit abandonment plan for cementing data.

c. A comprehensive chart tabulating the well data for wells in the vicinity of the Potash lease is contained below at point 5 (b) and in Exhibit 4.

5. Well Critical Distances Schematics:

a. Criteria for determining critical distance from the solution mine cavity.

   The critical distance from the solution mine cavity is defined as the maximum horizontal distance that the cavity wall can progress to some point outside the original mine entry until solution mining operations permanently cease.

   The average annual dissolution rate is estimated below from past production rate data.

   Mine cavity dissolution in the Potash 5 Cane Creek underground mine will continue as long as solution mining activities continue. Dissolution will stop unless the area is continually fed an unsaturated supply of water. Sump areas where saturated Potash solutions cannot drain and be replenished will stop their solution mining activity.
A meaningful average yearly dissolution rate is unacceptably inaccurate with the data available from wells and tons extracted. Abandoned wells drilled outside the original Potash 5 mining cavern may never be intersected by the Potash 5 cavern during the anticipated operations lifetime. No intersection will be made with those wells where there is no point of extraction that is lower than the point where the well penetrates the Potash ore.

Critical distance poses little concern since all abandoned wells on the property have been properly plugged according to DEQ regulations. Additionally, the critical distance from the mine cavity is irrelevant for most of the wells on the property since many were intentionally drilled into the mine cavity for the purpose of solution mining. Please see the list below for the relevant distances.

The following dissolution calculations are considered valid for the ongoing mining operation. Yearly tons of dissolved solids markedly decreased from 1984 through 2003 averaging just 105,000 tons/year with a high of 168,000 tons in 1988 and a low of 49,000 tons in 1998. Yearly wall dissolution rates using 420,000 tons will give a more than acceptable margin of error in calculating critical well distances. The numbers in the formulas below are updated accordingly.

From 1980 through 2003, the mine yielded an average of 420,000 tons/year of dissolved solids consisting principally of potassium and sodium chlorides. The original entryways were normally cut 8 feet high. For a total entry length of 150 miles, the amount of vertical wall area is calculated as:

\[
150 \text{ miles} \times 5,280 \text{ ft/mile} \times 8 \text{ ft} = 6,336,000 \text{ ft}^2
\]

The volume of solids dissolved is calculated as:

\[
420,000 \text{ tons/yr.} \times 15.3 \text{ ft}^3/\text{ton} = 6,426,000 \text{ ft}^3/\text{yr}
\]

The average annual wall dissolution rate equals:

\[
\frac{6,426,000 \text{ ft}^3/\text{yr}}{6,336,000 \text{ ft}^2} = 1.101 \text{ ft/yr}
\]

The above calculation assumes no cavity roof or floor dissolution, and therefore, constitutes a maximum average horizontal dissolution rate. For a project life of 50 years (1971-2021), the mine’s outermost perimeter is projected to expand approximately 25 feet horizontally beyond the original entry boundary.

Dissolution rates are also dependent on solution saturation. Since injection fluids are generally slightly under-saturated, dissolution rates in the vicinity of injection wells could be greater than the average. Because of the inaccessibility of the solution mine cavity, no direct measurements of dissolution rates have been made.
Evaluation of the potential for the mine cavity to expand into an open or improperly plugged hole drilled outside the original mine entries has involved monitoring the open wells near the mine cavity. The two holes considered most likely to intersect the mine cavity are Solution Mining Well Nos. 1 and 9.

Well No. 9 is approximately 160 feet from the nearest mine entry and the closest outside well to an injection well, Well No. 10 (see Figure 8 in the Huntoon report). Upon completion, the well was hydraulically fractured in an unsuccessful attempt to achieve a connection with the mine. Well No. 9 was monitored on a regular basis until June 1986 at which time it was permanently plugged. Well No. 10 was also plugged in May 1986. The mine cavity never intersected Well No. 9 in 15+ years of mining.

Well No. 1 was drilled 130 feet outside the nearest mine entry and repeated attempts to make a connection through hydraulic fracturing were also unsuccessful. Well No. 1 is remote from any active injection well. In 1975, Well No. 1 was fitted with a tubing string inside the casing and operated as a solution mining experiment independent of the mine. After ten years of intermittent operation, Well No. 1’s cavity had not connected with the mine. If Well No. 1 ever connects with the mine, it would not indicate the mine rate of dissolution since Well No. 1 has developed a cavity of its own. Well No. 3, which is located 240 feet from the nearest mine entry, was also operated for a short period as an independent test. Well No. 3’s cavity never intersected the mine.

Based on the information presented above, a horizontal distance of approximately 150 feet from the original mine perimeter is considered the limit or critical distance beyond which the mine cavity will not progress during the expected life of the project. This figure is six times greater than the calculated average of 25 feet.

### b. Tabulation of Well Schematic Diagrams

<table>
<thead>
<tr>
<th>Well No.</th>
<th>Status</th>
<th>Distances From Nearest Mine Entry</th>
<th>Diagram Reference</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Plugged</td>
<td>130 ft.</td>
<td>As-Plugged Diagram***</td>
</tr>
<tr>
<td>2 Shaft</td>
<td>Plugged</td>
<td>Into Mine</td>
<td>As-Plugged Diagram***</td>
</tr>
<tr>
<td>3</td>
<td>Plugged</td>
<td>240 ft.</td>
<td>As-Plugged Diagram***</td>
</tr>
<tr>
<td>4</td>
<td>Plugged</td>
<td>Into Mine</td>
<td>As-Plugged Diagram***</td>
</tr>
<tr>
<td>5</td>
<td>Plugged</td>
<td>Into Mine</td>
<td>As-Plugged Diagram***</td>
</tr>
<tr>
<td>6</td>
<td>Operating</td>
<td>Into Mine</td>
<td>Abandonment Plan***</td>
</tr>
<tr>
<td>7</td>
<td>Plugged</td>
<td>Into Mine</td>
<td>As-Plugged Diagram***</td>
</tr>
<tr>
<td>8</td>
<td>Plugged</td>
<td>Into Mine</td>
<td>As-Plugged Diagram***</td>
</tr>
<tr>
<td>9</td>
<td>Plugged</td>
<td>Into Mine</td>
<td>As-Plugged Diagram***</td>
</tr>
<tr>
<td>10</td>
<td>Plugged</td>
<td>Into Mine</td>
<td>As-Plugged Diagram***</td>
</tr>
<tr>
<td>11</td>
<td>Plugged</td>
<td>Into Mine</td>
<td>As-Plugged Diagram***</td>
</tr>
<tr>
<td></td>
<td>Status</td>
<td>Depth</td>
<td>Diagram Type</td>
</tr>
<tr>
<td>---</td>
<td>---------------</td>
<td>----------</td>
<td>-----------------------------------</td>
</tr>
<tr>
<td>12</td>
<td>Plugged Into Mine</td>
<td></td>
<td>As-Plugged Diagram***</td>
</tr>
<tr>
<td>13</td>
<td>Plugged Into Mine</td>
<td></td>
<td>As-Plugged Diagram***</td>
</tr>
<tr>
<td>14</td>
<td>Plugged Into Mine</td>
<td></td>
<td>As-Plugged Diagram***</td>
</tr>
<tr>
<td>15</td>
<td>Plugged Into Mine</td>
<td></td>
<td>As-Plugged Diagram***</td>
</tr>
<tr>
<td>16</td>
<td>Plugged Into Mine</td>
<td></td>
<td>As-Plugged Diagram***</td>
</tr>
<tr>
<td>17</td>
<td>Plugged 1490 ft.</td>
<td></td>
<td>As-Plugged Diagram***</td>
</tr>
<tr>
<td>18</td>
<td>Plugged 1590 ft.</td>
<td></td>
<td>As-Plugged Diagram***</td>
</tr>
<tr>
<td>19</td>
<td>Plugged 950 ft.</td>
<td></td>
<td>As-Plugged Diagram***</td>
</tr>
<tr>
<td>20</td>
<td>Plugged Into Mine</td>
<td></td>
<td>As-Plugged Diagram***</td>
</tr>
<tr>
<td>21</td>
<td>Plugged 1600 ft.</td>
<td></td>
<td>As-Plugged Diagram***</td>
</tr>
<tr>
<td>22</td>
<td>Plugged 1690 ft.</td>
<td></td>
<td>As-Plugged Diagram***</td>
</tr>
<tr>
<td>23</td>
<td>Plugged 2080 ft.</td>
<td></td>
<td>As-Plugged Diagram***</td>
</tr>
<tr>
<td>24</td>
<td>Operating Into Mine</td>
<td></td>
<td>Abandonment Plan***</td>
</tr>
<tr>
<td>25</td>
<td>Operating Into Mine</td>
<td></td>
<td>Abandonment Plan***</td>
</tr>
<tr>
<td>26</td>
<td>Operating Into Mine</td>
<td></td>
<td>Abandonment Plan***</td>
</tr>
<tr>
<td>27</td>
<td>Operating *375 ft.</td>
<td></td>
<td>Abandonment Plan***</td>
</tr>
<tr>
<td>28</td>
<td>Operating *1500 ft.</td>
<td></td>
<td>Abandonment Plan***</td>
</tr>
<tr>
<td>29</td>
<td>Operating *250 ft.</td>
<td></td>
<td>Abandonment Plan***</td>
</tr>
<tr>
<td>30</td>
<td>Oil Well</td>
<td></td>
<td>Permitted with DOGM</td>
</tr>
<tr>
<td>31</td>
<td>Plugged</td>
<td></td>
<td>Abandoned Corehole</td>
</tr>
<tr>
<td>32</td>
<td>Operating Into Mine</td>
<td></td>
<td>Abandonment Plan***</td>
</tr>
<tr>
<td>33</td>
<td>Operating Into Mine</td>
<td></td>
<td>Abandonment Plan***</td>
</tr>
<tr>
<td>34</td>
<td>Operating Into Mine</td>
<td></td>
<td>Abandonment Plan***</td>
</tr>
<tr>
<td>35</td>
<td>Operating Under Construction</td>
<td></td>
<td></td>
</tr>
<tr>
<td>36</td>
<td>Operating Planned</td>
<td></td>
<td></td>
</tr>
<tr>
<td>CC 1</td>
<td>Plugged 490 ft.</td>
<td></td>
<td>As-Plugged Diagram***</td>
</tr>
<tr>
<td>CC 2</td>
<td>Plugged 490 ft.</td>
<td></td>
<td>As-Plugged Diagram***</td>
</tr>
<tr>
<td>CC 6</td>
<td>Plugged 250 ft.</td>
<td></td>
<td>As-Plugged Diagram***</td>
</tr>
<tr>
<td>CC 8</td>
<td>Plugged 130 ft.</td>
<td></td>
<td>As-Plugged Diagram***</td>
</tr>
<tr>
<td>CC 9</td>
<td>Plugged Into Mine</td>
<td></td>
<td>As-Plugged Diagram***</td>
</tr>
<tr>
<td>CC 10</td>
<td>Plugged 30 ft.</td>
<td></td>
<td>As-Plugged Diagram***</td>
</tr>
<tr>
<td>CC 11A</td>
<td>Plugged 420 ft.</td>
<td></td>
<td>As-Plugged Diagram***</td>
</tr>
<tr>
<td>CC 12</td>
<td>Plugged 130 ft.</td>
<td></td>
<td>As-Plugged Diagram***</td>
</tr>
<tr>
<td>CC 14</td>
<td>Plugged 1360 ft.</td>
<td></td>
<td>As-Plugged Diagram***</td>
</tr>
<tr>
<td>CC 16</td>
<td>Plugged NA**</td>
<td></td>
<td>As-Plugged Diagram***</td>
</tr>
<tr>
<td>Utah So. 1A</td>
<td>Plugged 230 ft.</td>
<td></td>
<td>As-Plugged Diagram***</td>
</tr>
<tr>
<td>MGM #1</td>
<td>Plugged 1300 ft.</td>
<td></td>
<td>As-Plugged Diagram***</td>
</tr>
<tr>
<td>MGM #2</td>
<td>Plugged 1220 ft.</td>
<td></td>
<td>As-Plugged Diagram***</td>
</tr>
<tr>
<td>TGP 1-X</td>
<td>Plugged 1050 ft.</td>
<td></td>
<td>As-Plugged Diagram***</td>
</tr>
</tbody>
</table>

*Note #1: Wells 27H, 28H & 29H were constructed as solution mining wells into Sylvite 9. Steel casing and cement from surface to TD isolates the well bore from Sylvite 5.

**Note #2: Well CC 16 does not penetrate injection zone.

*** Abandonment Plans for active wells are included in Attachment B of the permit. As-Plugged Diagrams are in Utah 1422 UIC Program files.
6. Description of the local topography and geology.

   a. Figure 1 of the Huntoon report shows the existing plant and solution mine boundaries. All active solution mining wells were located within the existing mine Sylvite 5 cavity boundary prior to April 2002. Since the last revision of this report, five new extraction wells (Nos. 32, 33, 34, 35 and 36) have been drilled or are in the process of drilling into the existing Sylvite 5 mine cavity and well 29 was constructed in 2005 in the sylvite 9 solution mine. Two other wells have also been drilled in the last 5 years: well 30, which was drilled to ~3000’ as an oil exploration that has not been completed, and well 31 which was an exploration core well. Well 30 was permitted with DOGM and well 31 was filled to surface with cement. Exhibit 5 shows the location of all wells and the outline of their solution mining cavity. The legend depicts the solution mining formation, active status and whether the well is an injection or extraction well.

   b. Figure 2 of the Huntoon report the supplemental map, Geologic Map of Canyonlands National Park and Vicinity, depict the regional surface geology and structure. (Note: Huntoon figures and an Intrepid Potash topo map are included as exhibit 18).

   c. Figure 3 of the Huntoon report contains two cross sections perpendicular to each other. The cross sections intersect through the center of the solution mine cavity which is also the injection zone. Exhibit 5 is two perpendicular cross sections intersecting near the center of Sylvite 9 solution mining cavity/injection zone.

   d. Figures 3, 4 and 7 of the Huntoon report depict the nature and aerial development of the confining strata.

   e. Huntoon describes the faulting and fracturing and their lineation using Figures 2 and 6.

   f. The depositional, structural and tectonic history of the area including lithology and hydrologic properties is described in detail by Huntoon on pages 4 through 17.

   g. Figure 8 of the Huntoon report is a structural contour map of the top of the existing injection zone. Exhibit 6 contains a structure contour map of the Sylvite 9 and Sylvite 5 Injection Zone at the mine property.

   h. The Sylvite 5 ore strata was the only injection zone prior to July 2002. Injection into Sylvite 9 began in July 2002. Exhibit 7 is a map titled “Moab Salt Isopach Map, Thickness of Potash Sylvite 5.” Exhibit 8 is an Isopach of Sylvite 9.

7.1 Geohydrology - Reservoir Mechanics of the Injection Interval (Sylvite 5):

   a. The injection zone is permeated by approximately 150 miles of tunnels excavated during conventional mining operations between 1964 and 1970 (see Figure 8 of the
Huntoon report). In 1970 and 1971, the conventional mine was converted to a solution mine by filling the existing mined-out cavity with water and brine. The pre-existing passageways offer negligible resistance to the movement of brine within the injection zone. The injection fluid is confined to the pre-existing passageways within the injection zone and between upper and lower confining strata as explained by Huntoon on pages 10-17, 22-25 and 37-38.

By nature of the solution mining process, the pre-existing passageways will continue to enlarge until a majority of the remaining ore contained within the pillars and mine perimeter has been dissolved. Continued mine operation then becomes uneconomical.

The temperature of the injection zone was measured during conventional mining operations at ±90°F. The injection of cooler water and brines into the mine has caused a cooling trend within the mine. The cooling effect is most pronounced near the injection points with increasing temperatures along the paths towards the extraction wells. There are several inactive or dormant zones within the solution mine where there is no significant brine movement. The temperatures in the inactive areas are equal to the host strata.

Based on available measurements, the injection zone temperature may vary between the temperature of the coolest injection streams (40°F) and the pre-solution mine host strata temperature of 90°F.

b. Because of the nature of the solution mining process, the injection zone reservoir should be classified as an artificial reservoir rather than a natural reservoir. During the period of conventional mining, no major natural reservoirs were encountered. However, there were encounters on occasion with small isolated pockets of pressurized gas and petroleum seeps that originated from Clastic No. 4 strata directly above the mine entries. Since the artificial reservoir (mine cavity) is in direct communication with the surface, the hydrostatic head or reservoir pressure is equivalent to the depth of the fluid column in the connecting wells.

The injection interval is an ore stratum of variable thickness (0-30 ft.) of sylvite ore. Sylvite is made up of a conglomerate of NaCl and KCl salt crystals.

c. See the Huntoon report, pages 37 and 38, for the effect of formation deformation and Figure 8 for the location and extent of the solution channels.

d. See Exhibit 9, a letter dated February 5, 1985 to Loren Morton from R. E. MacAdams, for a calculation of mine formation breakdown pressure.

e. The injection fluid is confined to the pre-existing channels as explained in 7.a above. The static fluid level will be assumed equal to the lowest surface elevation of all the wells in communication with the injection zone. This corresponds to the No. 2 shaft with a surface elevation of 4,018 feet above sea level less the mine
operating level of 130 feet below the surface of No. 2 Shaft. The static fluid level would be achieved when injection is ceased.

7.2. Geohydrology - Reservoir Mechanics of the Injection Interval (Sylvite 9):

a. In July 2002, solution mining in Sylvite 9 began by way of injecting into newly constructed Well 27 and extracting from newly constructed Well 28. Approximately 16,000 ft. of 8 ¾” borehole was drilled to connect these two wells and form a continuous path for injection/extraction. In 2005 an additional injection well (29) was constructed intersecting the lateral portion of well 27, adding an additional 10,000 ft of 8 ¾” borehole. The shaft diameter in these passageways is expected to be no greater than an average of 6 ft. Injection fluid is confined in Sylvite 9 by the layers of salt and clastic above and below. When the cavern was newly constructed and during the last MIT a pressure integrity test was performed in the presence of the DEQ representative proving that the cavern could hold pressure of 350 psi for 45 minutes with no losses. This was deemed as sufficient evidence that there was no upward fluid migration behind the well casings. The cross section attached as Exhibit 6.a.c. shows these confining strata above and below the Sylvite 9 cavern.

The strata temperature of the Sylvite 9 ore was measured during drilling operations at 105°F. Subsequent temperature logs on file with the DEQ confirm that this temperature is correct. In order to enhance the dissolution of KCl, heated brines are being injected into the cavern. The average temperature of the injected brine is 150°F with an average extraction temperature of 104°F. Temperature drops are assumed to be linear along the cavern length. It is estimated that the strata temperature near the injection point has been increased to approximately 130°F degrees or 25°F above its natural state.

b. The Sylvite 9 cavern should also be classified as an artificial reservoir. No natural reservoirs were encountered during the drilling process. Sylvite 9 is operated as a pressurized cavity. The reservoir pressure is equivalent to the depth of the cavity times the density in pounds per gallon of the fluid column times the constant .052 plus pressure due to friction as the fluid flows through the cavity and up well 28 and into the holding tank at Well 6. The Sylvite 9 cavern is operated at all times under the pressures regulated by UIC Permit 300001 issued December 2, 2002, Section 2.a,b.

The Sylvite 9 ore strata thickness varies between 5 and 9 ft.

c. The effects of formation deformation are described in the Huntoon report (pages 37 and 38) for confining layers above and below Sylvite 5. The same ductile flowage between adjacent enclosing salt strata around Sylvite 9 provides “even more substantial seals” to fluid migration when compared to similar strata around Sylvite 5. Exhibit 10 is a structure contour showing the solution mining boundary extensions of 200 ft., which is the maximum anticipated extent of dissolution.
d. A report submitted October 10, 2001 by Agapito Associates, Inc. provided the basis for the maximum allowable surface injection pressure as included in UIC Permit, Part III, Section C.2.a,b. (see Exhibit 11).

e. The injection fluid is confined in the channels of the Sylvite 9 cavern, which is demonstrated by the mechanical integrity test where the entire cavern system was pressured to 350 psi for 45 minutes prior to operating the new cavern. Since the mine is operated in a pressurized mode, the static fluid level will be at the surface.

8.1. Characteristics of Injection Streams (Sylvite 5):

a. Detailed analyses of the injection fluid have been reported to the DEQ on a quarterly basis since the beginning of 1985. Please reference quarterly reports submitted to the DEQ.

b. The injection fluid is very compatible with the Sylvite 5 formation and formation fluids. The injection brines are almost entirely composed of the soluble elements of the injection zone. There are trace amounts of flotation chemical introduced to the injection brine via the plant tailings stream.

c. Even though the injection brine can be corrosive, past experience has demonstrated that the most severe corrosion of well casings and surface pipelines is caused by formation fluid and external surface fluids. The best conditions for corrosion occur where fluid and air (oxygen) are in contact. These conditions exist below the surface at groundwater elevation and above the surface where unprotected pipelines are in contact with soil frequently saturated with runoff.

All wells constructed since 2000 have been cemented from total depth to surface to mitigate external corrosion.

Data on weekly injection volumes has been reported to the DEQ on a quarterly basis since the beginning of 1985. The report contains average and maximum rates of injection. At the maximum rate of 1,700 gal/min, a maximum of 72,000,000 gallons can be injected during a one-month time period.

The solution mining operation is projected to continue until 2050 or later depending on economics.

8.2. Characteristics of Injection Streams (Sylvite 9):

a. Moab Salt reports quarterly to the DEQ according to the UIC Permit, Part II, Section E.11.

b. The injection fluids are very compatible with the Sylvite 9 formation and formation fluids. The injection brines from either the tailings lake or Well 6 are
almost entirely composed of the soluble elements of the injection zone. There is also trace amounts of flotation chemical introduced to the injection brine via the plant tailings stream. Fresh water injected from the Colorado River is also compatible with the formation.

c. Even though the injection brine can be corrosive, past experience has demonstrated that the most severe corrosion of well casings and surface pipelines is caused by formation fluid and external surface fluids. The best conditions for corrosion occur where fluid and air (oxygen) are in contact. These conditions exist below the surface at groundwater elevation and above the surface where unprotected pipelines are in contact with soil frequently saturated with runoff. Wells 27, 28, 29 and newly constructed are equipped with an extra internal protective casing string, which prevents corrosion from occurring internally on the externally cemented strings above the permitted zone of injection. All wells constructed since 2000 have been cemented from total depth to surface to mitigate external corrosion.

A maximum rate of injection for the Sylvite 9 mining cavity is 350 gpm, which corresponds to 15,120,000 gallons per month. The current normal operating rate of injection is 200 Gallons per minute or 8,640,000 gallons per month.

The solution mining operation is projected to continue to 2050 or later depending on the economic analysis.

9.1. Typical Well Construction Data (Sylvite 5 Wells):

Class III wells in sylvite 5 are constructed to conform with UAC R317-7-10.1 B (1), which states: "All new Class III wells shall be cased and cemented to prevent the migration of fluids into or between underground sources of drinking water." Although there are no USDWs within two miles of the facility, all wells are cased and cemented from surface to below the permitted injection zone. Wells are subject to MIT tests conforming to CFR 146.8 prior to operation.

NOTE: All specifications listed below are typical of the Intrepid Potash well construction practices. Variations to the specifications below according to the uniqueness of each well may be submitted to the DEQ for approval prior to well construction. For example, cement volumes may be calculated based on an open hole caliper log.

a. Total depth of existing wells varies from 2,700 feet to 3,300 feet. The depth of any new injection wells would be within the range of existing wells. Wells already completed comprise a variety of the well designs. The well design described below is similar to the most recently completed wells. Future wells will follow the same design.
b. Injection pressure, external pressure, internal pressure, axial loading

i. Injection pressure – Well 24 is the only sylvite 5 injection well, and typically injects at a negative pressure. Fluid level in the mine cavity is 400 ft below ground surface, creating a hydraulic gradient into the mine cavity. The mine itself is not operated in a pressurized state, and is allowed a maximum hydrostatic pressure of 1,916 psi, as dictated in the current UIC permit Part III Section C (2).

ii. External pressure – Hydrostatic pressure from formation salt water is representative of the external pressure exerted on the casing strings. Given a maximum water level of 3,893’ m.s.l., casing depths ranging from 800’-1200’, and fluid densities of 9.3-10.0 lbs/gal, the external pressure ranges from 1,302 – 1,608 p.s.i. with completely evacuated casing.

iii. Internal pressure – Internal pressure is equal to the hydrostatic pressure inside the casing string, and should be equal to the external pressure. During pumping, denser brine from the mine workings could fill the interior casing. Given a density difference of 0.7 lbs/gal, this would create a pressure differential between external and internal pressures of .0374 psi/ft, or 120 p.s.i. for a 3300’ deep well.

iv. Axial loading – The maximum load on the exterior casing, using a buoyancy correction for 10.0 PPG mud, is 77,942 lbs for a typical string length of 2300 ft. The interior string is run after cementing the exterior string and is typically 1000’ long, giving an axial load of 19,486 lbs.

The casing string intended for use is well within its capacities concerning the above pressures and load.

c. Borehole size typically ranges from 20” for the surface casing, 15”-12 ¾” where the exterior casing is set, 8 ¾” where the interior casing is set, and 5-7/8”-6-1/8” for the open hole completion into the mine workings.

d. Completion is open hole.

e. Casing String (Typical):

Surface Casing – 10 ¾” - 20" line pipe, ¼” wall, setting depth 30 to 600 feet depending on well location. The setting depth is unique to each well. The main criteria for determining this surface casing depth is when the surface hole has penetrated through the alluvium and into at least 20’ of solid bedrock. The currently approved UIC requires that “New wells constructed in Colorado River alluvium, identified as stratigraphic units Qu and QTu on Figure 2 of the 1985 Huntoon Report, shall be constructed in accordance with the additional requirement that the surface casing extends significantly into bedrock”. The annulus between the drill hole and the surface casing is cemented back to the surface.
Exterior Casing – 9-5/8” 40#, J-55 or K-55, 0.395” wall, 8 round thread, API standard, setting from the surface to about 2300 feet or through Clastic 1. This 9-5/8” casing is omitted on some wells depending upon well objectives, drilling parameters and geologic strata unique to each well. A solid annular cement plug from surface to total depth in the open hole annulus is considered critical in order to protect the casing from external ground water corrosion.

Interior Casing - 7” 23#, J-55 or K-55, 0.317” wall, 8 round thread, LTC, API Standard, (or higher grade) set from approximately 200’ above the bottom of the 9-5/8” casing to about 3300 feet or into clastic 4. This casing is cemented from the base of clastic 2 (or lower) to the top of the 200’ overlap. This creates a 200’ sealed overlap between the two strings of casing.

f. Corrosiveness of injected fluids – see section 8.1 of this report.

g. The injection zone is the pre-existing brine filled cavity within the sylvite 5 zone of the Paradox formation intersected by drilling an open bottom bore hole just below the last casing. Clastic and salt intervals of the Paradox formation overlie and underlie sylvite 5. The salts of the Paradox formation are impermeable confining layers as reported in the Huntoon Report.

h. Typical Cementing Procedures - Halliburton or other reputable well cementing companies perform the primary cementing jobs and provide cement, equipment and personnel. If cement does not return to surface, additional cement is pumped via tremie until cement reaches surface.

Lost circulation material (LCM) is often used while drilling and remains in borehole prior to cementing. LCM additives are also present in the cement mixture. Primary cementing of the exterior casing is performed by circulating cement down the inside of the casing and up the annulus. 120-150% of calculated cement volume is used on the primary lift.

The interior casing is cemented by forcing the cement through a shoe in the bottom of the casing and up the annulus. 120-150% of calculated cement volume is used to ensure full coverage. A packer at the top of the 7” casing is inflated after cementing, closing off the lower borehole and 9-5/8”-7” annulus. Excess cement is circulated out of the hole, verifying full cement placement.

i. Surface Casing, 20"
   Volume between hole and casing = .1710 bbl/lin.ft.
   Volume of cement required = .2565 bbl/lin ft. (20-50% excess)
   Cement Type = Ready-Mix cement, 15 lbs/gal. slurry wt.
   Equipment: None, open ended.
If cement is not circulated then the annulus will be filled with ready mix from the top.

*NOTE: Typical Well Information

ii. Main Casing, 9-5/8" (Primary)
Volume Between Hole and Casing = .1286-.0679 bbl/lin ft.
Volume of cement to be used = .19335-.1019 bbl/lin ft. (20-50% excess or greater)
Cement Type = Type V; 12.7-14 lbs/gal with 1/4#/SK of Flocele for lost circulation control
Equipment: float collar; float shoe; rubber top plug; tremie pipe

iii. Lower Casing, 7" Liner
Volume between hole and casing = 0.0268 bbl/lin ft.
Volume of cement to be used = 0.0402 bbl/lin ft. (100% excess)
Typical Cement Type = Class V, salt-saturated, 16.1 lbs/gal.
Equipment: float collar; float shoe; landing collar; plug holder bushing; drill pipe pumpdown plug; Type #1 liner wiper plug

i. The current UIC Permit requires that “All new wells shall have centralizers installed on the bottom three joints of the surface casing and on the bottom three joints of any casing string that is placed in or below the salt. The latter shall also have centralizers on every third joint of casing to the surface above the bottom three joints.”

j&k. All tubing that was previously in any wells into the mine has been removed and all wells previously containing tubing have been plugged and abandoned.

l. A typical sylvite 5 well diagram reflecting updated construction practices is included with the 2009 revision as Exhibit 12.

m. The only injectivity test necessary is to demonstrate that the bore hole is in communication with the mine cavity. This is accomplished by pumping fluid into the well and monitoring the pressure and flow rate.

n. Typical Logging
   (1) Borehole deviation surveys are run throughout drilling operations.
   (2) 20-50% excess cement may be calculated for surface casing. If a borehole caliper log is run, it will be used to determine cement volumes. The volume indicated from the caliper log will be increased by 10% or more.
(3) A gamma ray and caliper log will be obtained for the hole from the clastic bed directly above the ore zone or to total depth of the vertical portion of the well to surface.

(4) Cement bond logs along with a casing caliper log are run after cementing of each casing string to ensure adequate cement placement and provide records thereof.

(5) Temperature survey to provide baseline temperature profile.

(6) Injection Zone

a. No core samples can be obtained from the injection zone. Ore zone composition is well documented from previous conventional mining. No core samples will be taken from Sylvite 9 ore zones since penetrations into this zone are horizontal.

b. Bottom hole pressure is not required but can be determined from surface pressure gauge and density of fluid in well column. Temperature log may be run but is not necessary.

c. Samples of cavity brine will be obtained if the new well is to be used for extraction.

Fracture pressure – based on records of Texas Gulf wells 19, 20 and 21, which were hydraulically fractured, a fracture gradient was calculated at .984 psi/ft with a safety factor of 75%. (Exhibit 11, Agapito Associates Inc.) The depth to the injection zone varies from 2624’ to 3284’. Therefore the fracture pressure (assuming that injection occurs at the top of the permitted injection zone) ranges from 2582 to 3231 psi.

9.2. Typical Well Construction Data (Sylvite 9 Wells):

Class III wells in sylvite 9 are constructed to conform with UAC R317-7-10.1 B (1), which states: "All new Class III wells shall be cased and cemented to prevent the migration of fluids into or between underground sources of drinking water." Although there are no USDWs within two miles of the facility, all wells are cased and cemented from surface to below the permitted injection zone. Wells are subject to MIT tests conforming to CFR 146.8 prior to operation.

a. Total depth of the Sylvite 9 wells is approximately 4,330’. True Vertical Depth depends on the formation depth at any particular location. Any future wells into the Sylvite 9 ore body would have very similar depths to existing wells. Attached
as Exhibit 13 is a Typical K-9 Horizontal Well Plan which is approved by the DEQ and is representative of the three horizontal wells already constructed at Moab Salt.

b. Injection pressure, External pressure, Internal pressure, axial loading

i. Injection pressure – Based on limits set forth in the current UIC permit (UTU300001) Part III Section 2 (a) (b).

ii. External pressure - Hydrostatic pressure from formation salt water is representative of the external pressure exerted on the casing strings. Given a maximum water level of 3,893’ m.s.l., casing depths from 0’-200’ m.s.l., and fluid densities of 9.3-10.0 lbs/gal, the external pressure ranges from 1,738 – 2,024 p.s.i. with completely evacuated casing.

iii. Internal pressure – While not injecting/pumping the internal pressure is the hydrostatic pressure which should be similar to the external pressure. While injecting, the maximum internal pressure exerted on the interior casing string is equal to the maximum injection pressure.

iv. Axial loading - The maximum load on the exterior casing, using a buoyancy correction for 10.0 PPG mud, is 137,246 lbs for a typical string length of 4500 ft. The injection tubing string is sometimes run to the base of clastic 2 (~2600’) after cementing the exterior string, giving an axial load of 50,663 lbs.

The casing string intended for use is well within its capacities concerning the above pressures and load.

c. Borehole size typically ranges from 24” for the surface casing, 15”-12 1/4” where the 9-5/8” casing is set, and 8 ¾” for the open hole completion into the mine workings.

d. Completion is open hole to allow solution mining of potash.

e. Casing Strings (Typical):

Surface Casing – 10 ¾” - 20” line pipe, setting depth 30 to 600 feet depending on well location. The setting depth is unique to each well. The main criteria for determining this surface casing setting depth is when the surface hole has penetrated through the alluvium and into at least 20’ of solid bedrock. The annulus between the drill hole and the surface casing is cemented back to the surface with Ready Mix.

Exterior casing – 4,330 ft. TVD of 12 1/4” hole with 9 5/8” 36#, J-55 casing set near base of Clastic 8. Cement to surface with SSW cement adjacent to salt formations or FW Cement adjacent to non-salt formations.
Injection tubing – 7” J55 23# casing set at base of Clastic 2 or lower with an annular packer to provide a sealed annulus which may be pressurized for mechanical integrity testing. Not cemented.

Other casings – Hole conditions such as loss circulation or other unforeseen problems may require that an additional casing string be cemented in place. Individual well plans that require casing strings other than the above will be submitted for approval.

g. For corrosiveness of injection fluids, please see section 8.2 of this report.

h. The injection zone is a horizontally drilled cavity in the sylvite 9 zone of the Paradox formation. Clastic and salt intervals of the Paradox formation overlie and underlie sylvite 9. These salt layers were deposited and deformed under the same conditions as those bounding sylvite 5 and therefore likely share hydrological characteristics, namely that they are confining layers.

i. Typical Cementing Procedures for Sylvite 9 wells.

Halliburton or other reputable well cementing companies perform the primary cementing jobs and provide cement, equipment and personnel. If cement does not return to surface, additional cement is pumped via tremie until cement reaches surface.

Lost circulation material (LCM) is often used while drilling and remains in borehole prior to cementing. LCM additives are also present in the cement mixture. Primary cementing of the exterior casing is performed by circulating cement down the inside of the casing and up the annulus. 120-150% of calculated cement volume is used on the primary lift.

i. Surface Casing, 20"
Volume between hole and casing = .1710 bbl/lin.ft.
Volume of cement required = .2565 bbl/lin ft. (20-50% excess)
Cement Type = Ready-Mix cement, 15 lbs/gal. slurry wt.
Equipment: None, open ended.

If cement is not circulated then the annulus will be filled with ready mix from the top.

ii. Main Casing, 9-5/8" (Primary)
Volume Between Hole and Casing = .1286-.0679 bbl/lin ft.
Volume of cement to be used = .19335-.1019 bbl/lin ft. (20-50% excess or greater)
Cement Type = Type V; 12.7-14 lbs/gal with 1/4#/SK of Flocele for lost circulation control
Equipment: float collar; float shoe; landing collar; plug holder bushing; drill pipe pumpdown plug; Type #1 liner wiper plug; tremie pipe

j. Typical Logging

(1) Borehole deviation surveys are run throughout drilling operations.

(2) 50% excess cement may be calculated for surface casing. If a borehole caliper log is run, it will be used to determine cement volumes. The volume indicated from the caliper log will be increased by 10% or more.

(3) A gamma ray and caliper log will be obtained for the hole from the clastic bed directly above the ore zone or to total depth of the vertical portion of the well to surface.

(4) Cement bond logs along with a casing caliper log are run after cementing of each casing string to ensure adequate cement placement and provide records thereof.

(5) Temperature survey to provide baseline temperature profile from surface to a point where the survey tool starts to fall into the curve of the horizontal well.

(6) Injection Zone

a. No core samples can be obtained from the injection zone. Ore zone composition is well documented from previous conventional mining. No core samples will be taken from Sylvite 9 ore zones since penetrations into this zone are horizontal.

b. Bottom hole pressure is not required but can be determined from surface pressure gauge and density of fluid in well column. Temperature log may be run but is not necessary.

c. Samples of cavity brine will be obtained if the new well is to be used for extraction.

k. Fracture pressure – the same gradient applies as mentioned above in section 9.1 (n) of this report. In addition, the current UIC permit (UTU 30001) requires use of a gradient of .85 psi/ft where the cavern is below or within 500 ft of the sylvite 5 mine cavity (Part III section C 2 a and b). The cavern depths range from 3657’ to 4389’ in wells 27H, 28H and 29H, giving a range of fracture pressures from 3108 to 4319 psi.

10.1 Surface Installations (Sylvite 5):
The volume monitoring system was designed for the purpose of controlling the flow rates into and out of the solution mine. The mine operates in the following manner:

Below Surface Operation - Mine fluid surface pressure is completely relieved at the extraction wells and mine fluid level is maintained some distance below the surface. This method of operation is accomplished by installing a deep well pump partway down the No. 6 extraction well. The down hole pump provides the energy to lift mine fluid from within the extraction well to the surge tank. In November 2000, Moab Salt completed drilling operations on two wells (Nos. 25 and 26) into the Sylvite 5 cavity to provide additional points of fluid extraction. Two 300 horsepower electric submersible pumps were installed in each of these wells to lift fluid from the mine to surface. In 2008-9 5 additional wells are being completed for further optimization of fluid extraction. There are 5 extraction pumps currently in use and 3 more anticipated to be in use following completion and installation of wells 34-36. The existing deep-well pump equipment has the flexibility to maintain mine fluid levels between 125 and 250 feet below the surface of the No. 2 shaft.

Each wellhead is equipped with one or more standard pressure gauges and flow meter to monitor the volume and pressure of injection/extraction. The surface elevation for the only injection well is far enough above the fluid level in No. 2 shaft that it often does not register any pressure during operation. The well elevation and the density of the injection and extraction fluid determine to a great extent whether a particular injection well will exhibit positive pressure at the wellhead.

Conditions may exist where there is no positive pressure at any of the mine shafts or wells during below surface operation. The mine is monitored by measuring the fluid level below the surface of the No. 2 shaft. A depth measurement is taken approximately every eight hours with an electrical conductance probe on the end of a wire line.

The injection flow is monitored by one continuous recording flow meter. All injection flow into Sylvite 5 passes through a single flow meter placed in the flow line between the 800 horsepower pump at the brine lake and the wellhead at Well 24 (the only point of injection for the Sylvite 5 cavity).

There is no filtering of the injection fluid.

Injection Pumps - Exhibit 14 titled “UIC Permitted Facilities” for injection and extraction flow lines, flow meter and pump locations.

1. Pump used for pumping tails pond brine water from the dam area and injecting it into Well 24 (Sylvite 5). This is the only pump used for Sylvite 5 Injection.
P-125,  
Location: Tails Lake Dam  
Type = 800 Horsepower, line shaft, vertical turbine  
Name and Model - Johnston, CLC 9 stage  
Capacity = 2400 GPM at 700 feet head.

2. Pump used for injecting tails brine pond water, fresh water or Well 6 water into Well 27 (Sylvite 9). This is the only pump used for Sylvite 9 Injection.  
Location = Well #27 Wellhead  
Type = reciprocating plunger  
Name and model = National Quintuplex Plunger 300Q  
Capacity = 350 GPM at 1300 PSI

Extraction Pumps – All extraction pumps extract from Sylvite 5 only, Sylvite 9 is operated as a pressurized cavity and does not require a pump for extraction. Sylvite 5 pumps are used to lift fluid out of their respective wells and into a pipeline that empties into the solar evaporation ponds.

The following pump is set at 232’ inside Well 6 and is used to lift fluid out of the well and into the surge tank approximately 50 feet away.

Location = Well No. 6  
Type = 300 horsepower, line shaft, Deep well Pump, vertical turbine  
Name and Model - Johnston, CLC 3-stage  
Capacity = 2500 GPM at 200 feet head  
Setting Depth = 232 feet

Location = Inside Well 25  
Type = Electric Submersible, 300 HP  
Name and Model = Baker Hughes WH 550, 17 Stage  
Capacity = 1450 feet of head at 600 GPM  
Setting Depth = 1570 feet

Location = Inside Well 26  
Type = Electric Submersible, 300 HP  
Name and Model = Baker Hughes WG 385, 7 Stage  
Capacity = 538 feet of head at 350 GPM  
Setting Depth = 1090 feet

Location = Inside Well 32  
Type = Electric Submersible, 266 HP  
Name and Model = Baker Hughes WH 585, 13 Stage  
Capacity = 854 feet of head at 650 GPM  
Setting Depth = 1064 feet
Location = Inside Well 33
Type = Electric Submersible, 266 HP
Name and Model = Baker Hughes WH 585, 13 Stage
Capacity = 854 feet of head at 650 GPM
Setting Depth = 1153 feet

Pumps for wells 34 through 36 will be installed within a short amount of time and are the same model as those installed in 32 and 33. Setting depths will also be similar.

d. Water from the Colorado River is pumped to the tailings area where it is used to dissolve salt and potash tailings by direct contact using sprinklers and hoses. The water returns to the brine lake for distribution to the wells for injection or for general use in the production process. Colorado River water is also pumped directly to the plant for general use in potash production. Excess process is also pumped to the brine lake for injection.

Brines injected into the mine originate from three principal sources:

1. Mill Tailings Brine
2. Colorado River Water
3. Environmental Reclaim Brine
4. Brine from the original mine cavity (may be injected into Sylvite 9 cavity).

Mill Tailings Brine - Mill tailings brine is high in NaCl saturation. It is used to pump solid waste NaCl from the mill process to the tailings storage area. The tailings storage area drains into the tails brine storage lake (see pocket aerial photo sheet 1). Excess tails brine is generated during mill operation and from rainfall. Brine is also generated in the tailings area by pumping water from the Colorado River, and running it through sprinklers across the tailings salt to the deposits placed there previously. This brine from the tailings lake is injected into the mine when needed to generate brine to fill the evaporation ponds.

Colorado River Water - Water is pulled from the Colorado River at the river intake facility for use in the plant operation or injection into either Sylvite 5 or 9 cavities.

Environmental Reclaim Brine - The environmental reclaim or scavenger brine system is composed of a series of dams, ponds and catch basins that serve as a collection system for fugitive brines that originate from solar pond leakage and pipeline drains or spills. Water and brine collected in the canyons below the solar ponds are pumped to a lined brine reclaim pond with a 1,200,000-gallon capacity located near the main slurry pit. The reclaimed fluid is pumped to the tailings area for re-injection into the mine or directly to the evaporation ponds for production. Fluid collected below pump stations 4, 5 and 6 and in the vicinity of the plant is
routed to the tails lake for eventual re-injection into the mine using the tails injection pump (see aerial photos in pocket as Exhibit 15 Environmental Reclaim Ponds).

Brine from the original mine cavity - Extraction Brine - Brine is extracted from the solution mine for production purposes. Wells No. 6, 25, 26, 32-36 are used for extraction. Brine is extracted from Well No. 6 with a deep well vertical turbine pump. The extraction brine flows into a surge tank (24 feet diameter x 20 feet, 67,600 gallon capacity, constructed of carbon steel) located near Well No. 6 and pump station No. 4. From the surge tank, the extraction brine is boosted to the solar ponds. Brine from the other extraction wells may either be transported into the same tank as brine from well 6, or diverted directly to the solar ponds.

e. See Plant Area aerial photograph (pocket).

f. The sediment recovered from the mud settling tank near the river intake facility is released back into the river as it has not been treated with any chemicals. Plant Area aerial photos Exhibit 15.

g. Well-associated surface facilities are depicted in the attached diagrams. Updated diagrams are provided with the Technical Report, revised February 17, 2009.

1. UIC Permitted facilities and associated pipelines are included in Exhibit 14.

2. Cross Sections, No. 3 Pond Canyon Collection System (Exhibit 16).

10.2 Surface Installations (Sylvite 9):

a. Three flow meters located at Wells 27H, 28H and 29H monitor the volume of fluid into and out of the Sylvite 9 solution mine cavern.

The mine operates in the following manner:

Below Surface Operation - Mine fluid surface pressure at Well 27 is completely relieved at the extraction Well 28H and in the flow line going to the surge tank at Well 6. The mine fluid level is maintained at full capacity at all times since Sylvite 9 is permitted to operate as a pressurized cavity. The injection pump at Well 27 provides the energy to lift mine fluid out of Well 28 to the surge tank at Well 6. There are no pumps available for lowering the fluid in the solution mine cavity below the surface level.

Each wellhead is equipped with one or more standard pressure gauges. The pressure gauges are not used to operate the system but to monitor the condition of each individual well. Pressures, volumes, fluid levels or flow into this Sylvite 9 cavity do not affect the operation of the Sylvite 5 cavity in any way. Well
elevation, the density of the injection and extraction fluid and the flow rate
determine the amount of pressure at the wellhead. The maximum allowable
surface injection pressure is limited by the UIC Permit. A pressure relief valve is
located downstream of the injection pump at Well 27 which will divert all flow to
the tails lake if the maximum allowable surface injection pressure is exceeded.

In 2005 a second injection well (29H) was completed, providing additional
injection points into the 27H horizontal section. Well 29H is connected to the same
injection pump as 27H.

b. There is no filtering of the Sylvite 9 injection fluid.

c. The injection pump for Sylvite 9 operation is located at the Well 27 wellhead.

11. There are no other subsurface disposal operations in the area.

12. Injection Well Operation

a. Sylvite 5 – Sylvite 5 - The maximum UIC permitted pressure that can be applied
to the Sylvite 5 well cavity at No. 2 Shaft is 1,916 psig. This is the calculated mine
formation breakdown pressure with a 75% safety factor (Exhibit 9). The mine
fluid level is controlled by injection and extraction volumes. The current UIC
permit Part III C (2) limits the mine brine level to 125’ below the casing collar at
the number 2 shaft (elevation 4,018’) or 3,893’ above sea level. Since the elevation
of the base of the Colorado River is 3,928’, the mine level is always below the
level of the Colorado River. The highest likely specific gravity of the brine is 1.26.
The lowest point in the mine is 780 ft above sea level. The highest operating
pressure in sylvite 5 is: (3893-780) x (1.26 x 8.34) x .052 = 1700 psi. This
operating pressure is so far below the pressure necessary for fractures to propagate
within the injection zone that it poses no danger. Injection pressures at the
wellhead are a function of the volume and density of the fluid injected. Currently,
Well 24 is the only point of injection for the Sylvite 5 cavity. The injection well at
this site accepts the injectate brine under a vacuum at rates up to approximately
1,700 gpm. Lower density brines may require some pressure for injection.

b. Sylvite 9 – The maximum allowable surface injection pressure in the Sylvite 9
cavity is limited by the UIC Permit in Section 2.a.b. The maximum pressure
allows for a safety factor of 75% below fracture gradient. Injection pressures are
recorded continuously at the wellhead and a pressure relief valve limits the
pressure under the allowable limit.

c. There is only one point of injection (Well 24) for Sylvite 5; therefore, the
principal flow paths of the injectate within Cane Creek Mine are to all points
within this cavern. Once injected, the lighter fluid travels to areas of the mine that
are highest in elevation. As the fluid absorbs salt and potash it becomes denser
and travels to the lower elevations where it is extracted by the pumps in Wells 6,
The principal flow paths within the Sylvite 9 cavern are determined by the perforations in the 5” tubing injection string hung into Well 27. The 5” injection string is perforated in 500’ – 600’ intervals in the lateral portion of Well 27 and the fluid flows from these perforations to well 28 for extraction. If Well 28 is ever used for injection, the principal flow path will be reversed. Well 29 was constructed in 2005 and is also used for injection. It utilizes a 5.5” casing string to inject fluid at a single point 369’ below the casing into the lateral portion of well 29.

e. The injection and extraction wells currently in operation are subject to mechanical integrity tests.

The approved UIC Permit requires mechanical integrity testing of wells on both a yearly and 5-year basis depending upon the well component. The injection/extraction fluid volume ratios are also continuously monitored.

If a well fails an MIT or is having operational problems (i.e., loss of flow, unexpected pressure or vacuum, injection/extraction ratio out of compliance), the well is taken out of service immediately and reported to the DEQ. The well may be examined using logging procedures, and/or with drill rig equipment. Once any repairs are made to a well, it must pass an approved mechanical integrity test before it can be put back into service.

Proper operation and maintenance of the injection and extraction system is under the supervision of the General Foreman, currently Rick Klein. The injection system is monitored 24 hours a day by personnel working 8-hour shifts. Critical measurements of pressures, mine fluid level and flow rates are checked bi-hourly and recorded (see Exhibit 17 Monitoring Sheet). Wellheads and pipelines are inspected frequently. Maintenance on pumps, pipelines and wells is performed when needed by Moab Salt maintenance personnel or by contractors. The injection system has been in operation since 1970. Nearly 28 years of accumulated experience has been acquired operating and maintaining the existing system.

f. In the event of a well failure or a well that is not repairable, the well will be plugged and abandoned in accordance with the previously approved plugging and abandonment plan unique to each well. If a well is shut-in or taken out of service for any appreciable length of time, the well will be physically disconnected from all sources of brine or water and capped at the surface. If a well needs to be shut-in under emergency conditions, the piping system is designed to take the unexpected pressure. All injection brines can be evacuated from the piping to the tailings lake. In the event the extraction pumping system breaks down or is unavailable, injection of brine into the mine is also discontinued.

14. An updated bond is currently being processed to reflect the updated abandonment cost estimates as of 2009.
UIC Permit Technical Report Exhibit List

Exhibit 1 – Page 2 – Introduction – Process Description

Exhibit 2 – Page 3 – Section 3 – Artificial penetrations within a 2 mile radius

Exhibit 3 – Page 3 – Section 4.a – Delhi-Taylor Well bore schematics

Exhibit 4 – Page 3 – Section 4.c – Chart Tabulating Well Data

Exhibit 5
  • Page 7 – Section 6.c – Two perpendicular cross sections intersecting in the center of Sylvite 9 solution mining cavity.

Exhibit 6 – Page 8 – Section 6.g – Structure contour map of the Sylvite 9 injection zone at the mine property.

Exhibit 7 – Page 8 – Section 6.h - Isopach of Sylvite 5

Exhibit 8 – Page 8 – Section 6.h – Isopach of Sylvite 9

Exhibit 9 – Page 9 – Section 7.1.d – Mine formation breakdown pressure

Exhibit 10 – Page 10 – Section 7.2.c – Sylvite 9 structure contour showing the solution mining boundary extensions of 200 ft. which is the maximum anticipated extent of dissolution.

Exhibit 11 – Page 10 – Section 7.2.d – A report submitted Oct. 10, 2001 by Agapito Associates, Inc. provided the basis for the maximum allowable surface injection pressure as included in our UIC Permit Part III. Section C.2.a,b.

Exhibit 12 – Page 14 – Section 9.1.j – Typical Solution Mining Injection Well Schematic

Exhibit 13 – Page 15 – Section 9.2.a – Typical K-9 Horizontal Well Plan

Exhibit 14 – UIC permitted facilities
  • Page 7 – Section 6.a – The location of all wells and the outline of their solution mining cavity
  • Page 17 – Section 10.1.a – Flow Meters
  • Page 18 – Section 10.1.c – Injection Pumps
  • Page 21 – Section 10.1.g.1 – UIC permitted pipelines

Exhibit 15 – (Prev. 10.1.d) – Surface Topographical Map
  • Page 21 – Section 10.1.d – Environmental Reclaim Ponds
  • Page 21 – Section 10.1.f – River water pump station
Exhibit 16 – Page 21 – Section 10.1.g.3 – Cross Sections, No. 3 Pond Canyon collection system.

Attachment B

Intrepid Potash - Moab, LLC

Moab, Utah

Cane Creek Mine

Plan for Abandonment of
Class III Wells and Mine Shafts
Plugging and Abandonment of Shaft #1
Plugging and Abandonment of Shaft #2
Plugging and Abandonment of Class III Injection Wells
Attachment C

Intrepid Potash - Moab, LLC

Moab, Utah

Cane Creek Mine

Standby Trust Agreement and
Financial Guarantee Bond

(original documents in DEQ Office of Support Services)
Schedule A
Standby Trust Agreement
Cost Estimates
Schedule B
Standby Trust Agreement
Financial Guarantee Bond
Exhibit A
Standby Trust Agreement
Signatures of Designated Persons
Attachment D

Intrepid Potash - Moab, LLC

Moab, Utah

Cane Creek Mine

Well Construction Plans

(As-Built Well Diagrams)

(double click on the icon below to open the As-Built Well Diagrams)
Attachment E

Intrepid Potash - Moab, LLC

Moab, Utah

Cane Creek Mine

Monitoring Protocols

The Intrepid Potash-Moab facilities manager will prepare check lists and accompanying documentation to ensure consistency in performance of all monitoring required by this permit. These documents will be maintained on site and will be reviewed by DWQ staff during the annual facility inspection.
Attachment F

Intrepid Potash - Moab, LLC

Moab, Utah

Cane Creek Mine

Mechanical Integrity Testing (MIT) Protocol
A. Sylvite 5 wells – Intrepid Potash intends to perform a Radioactive Tracer Survey (RTS) on all sylvite 5 wells once every 5 years as a demonstration of no casing leaks (internal MI) and no significant fluid migration behind casing (external MI). A procedure for RTS can be found in Intrepid Potash Mechanical Integrity Testing Procedures (E). To demonstrate internal mechanical integrity in new wells in sylvite 5 prior to operation, a pressure test is completed either:

i. by the cementing contractor during cementing of the last string of casing above clastic 2
ii. with drilling rig equipment before drilling out the float collar, cement and guide shoe, or
iii. with a packer on tubing after drilling out the float collar, cement and guide shoe.

Procedures for all of the above can be found in Intrepid Potash Mechanical Integrity Testing Procedures (A, B, C). Cementing records are sufficient to demonstrate external MI on newly constructed wells based on the following considerations:

i. Approximately the last 800 ft of borehole is drilled in confining layers (salts 2-4 and clastic 1-4) such that upward fluid migration in the borehole would require either poor cementing or dissolution of salt layers.
ii. Saturated salt water drilling fluids are used to minimize formation dissolution while drilling.
iii. The lack of considerable formation dissolution during drilling is demonstrated by caliper logs, which are also used to calculate cement volumes appropriate to borehole volume.
iv. The water phase of the cement slurry is salt water saturated, preventing dissolution of salt layers during cementing.
v. If cement bond logs demonstrate adequate cement bonding, then upward fluid migration is not possible without significant dissolution of confining layers, which is mitigated during drilling and construction practices as discussed above.
vi. As part of the current monitoring program the injection/extraction ratio is continuously recorded and reported quarterly to the DEQ. Any fluid migration out of the mine cavity would immediately be reflected in the injection/extraction ratio, thereby detecting any fluid migration out of the cavern system.

A procedure for cement bond logging can be found in Intrepid Potash Mechanical Integrity Testing Procedures (F) of this document.

B. Sylvite 9 wells – Sylvite 9 wells all contain an interior casing string packed off below the base of clastic 2, full of water. This annulus will be pressurized on all sylvite 9 wells prior to operation and on a yearly basis as an internal MIT. A procedure can be found in Intrepid Potash Mechanical Integrity Testing Procedures (D).

Both casing and cement on sylvite 9 wells extend into the curved portion of the borehole to over 60 degrees off of vertical. Also, at the injection point the well is nearly horizontal and over 400 ft from the vertical portion of the well. These characteristics make it
unlikely that a temperature or radioactive tracer survey would detect upward fluid migration. Therefore, directional components of casing in sylvite 9 wells precludes the use of the MIT methods for external MI described in 40 CFR 146.8 (c)(1). Under paragraph (c)(3) and (4) of the same section, cementing records may be used to demonstrate adequate cement to prevent fluid migration, provided that a monitoring program is in place to verify the absence of such movement.

Cement bond logs exist for all current wells, and will be run for all future wells in order to provide records of adequate cementing. As part of the current monitoring program the injection/extraction ratio is continuously recorded and reported quarterly to the DEQ. All sylvite 9 wells are connected through the closed and pressurized sylvite 9 cavern system. Any fluid migration out of the cavern system would immediately be reflected in the injection/extraction ratio, thereby detecting any fluid migration out of the cavern system.

**Intrepid Potash Mechanical Integrity Monitoring Procedures**

A. Casing Pressure Test with Cementing Contractor (for new sylvite 5 wells)

1. Cement is circulated down the inside of the interior casing and up around the annulus.
2. The cement is followed by a cement wiper plug and an appropriate amount of displacement fluid to fill the inside of the casing. During displacement, pumping pressure is continuously monitored and recorded by the cementing contractor (Halliburton or other). As the cement is displaced by the less dense displacement fluid, the pumping pressure will gradually increase. Once the cement has been circulated completely out of the inside of the casing, the wiper plug will land into a float collar or float shoe. After landing the wiper plug additional displacement fluid can no longer be pumped into the casing and pressure will sharply increase, indicating that the plug has landed and additional pressure is now being applied to the casing.
3. The well casing is now completely full of displacement fluid. Take the last pressure measured to bump the plug before the spike (equal to differential pressure between the displacement fluid column and cement column), and add 100. This is the pressure necessary to create 100 psi of positive pressure between the inside of the casing and the cement-filled borehole. Apply this pressure with cement pump to reach this level and close the pump backflow valve to seal the well. Intrepid’s internal policy recommends adding 500PSI to pressure required to bump the plug for this test (not to exceed 80% of the rated casing burst pressure).
4. Hold this pressure for 45 minutes. Pressure will be continuously recorded electronically by the cementing contractor.
5. After 45 minutes, record final pressure.
6. Bleed off well into a bucket if possible to obtain a volume estimate.
7. If pressure does not vary more than 10% then the well has demonstrated internal mechanical integrity.
8. Have the cement company representative record the results of this test on his official job log.

B. Casing Pressure Test with Drilling Rig Equipment (for new sylvite 5 wells)

1. Allow cement sufficient time to cure.
2. Calculate the necessary surface gauge pressure to achieve at least 100 psi pressure differential between the casing fluid and formation fluid. (Formula and example calculation below at G)
3. Fill the casing completely with fluid and leave static for 12-24 hrs if possible.
4. Before drilling out cement, float collar and guide shoe, trip in drill pipe to near the top of the float collar.
5. Close pressure control equipment (BOP).
6. Pressurize fluid with rig pump to 300 psi minimum (or the greater calculated value from G below) and close the backflow valve on the rig pump.
7. Monitor pressure reading for 45 minutes, recording pressure reading every 5 minutes.
8. After 45 minutes, record final pressure.
9. Bleed off well into a bucket if possible to obtain a volume estimate.
10. Record test results on IADC (International Association of Drilling Contractor’s) form.
11. If pressure does not vary more than 10% in 45 minutes, the well has demonstrated internal mechanical integrity.

C. Casing Pressure Test with Packer (for new sylvite 5 wells)

1. Calculate the necessary surface gauge pressure reading to achieve at least 100 psi pressure differential between the casing and formation. (Formula and example calculation below at G)
2. After drilling out the float collar, cement and guide shoe, lower a packer on tubing to below clastic 2.
3. Expand packer and fill casing completely with fluid.
4. Fluid should be filled into one valve, with another open valve available to allow air to escape.
5. Close pressure control equipment (BOP).
6. Pressurize fluid with rig pump to 300 psi minimum (or the greater calculated value from G below) and close the backflow valve on the rig pump.
7. Monitor pressure reading for 45 minutes, recording pressure reading every 5 minutes.
8. After 45 minutes, record final pressure.
9. Bleed off well into a bucket if possible to obtain a volume estimate.
10. Record test results on IADC (International Association of Drilling Contractor’s) form.
11. If pressure does not vary more than 10% in 45 minutes, the well has demonstrated internal mechanical integrity.
D. Annulus Pressure Test (for wells with a liquid-filled annulus)

1. Calculate the necessary surface gauge pressure reading to achieve at least 100 psi pressure differential between the casing and formation. (Formula and example calculation below at G).
2. If the annulus is not completely full, fill annulus completely with fresh water with a second opening available to allow air to escape.
3. Allow well 12-24 hrs static if possible.
4. Connect to a liquid pressure source.
5. Increase pressure to 300 psi minimum (or the greater calculated value from G below) and immediately disconnect the pressure source, keeping the well head sealed.
6. Monitor pressure reading for 45 minutes, recording pressure reading every 5 minutes.
7. After 45 minutes, record final pressure.
8. Bleed off well into a bucket if possible to obtain a volume estimate.
9. Record test results on IADC (International Association of Drilling Contractor’s) form.
10. If the pressure does not vary more than 10% over 45 minutes then the well has demonstrated internal mechanical integrity.

E. Radioactive Tracer Survey

1. Recording Guidelines:
   i. A collar locator must be run with all logging runs.
   ii. Logging speed and time constant used must be indicated on the log heading.
   iii. Gamma Ray sensitivity must be set so that the tracer can be easily distinguished from normal lithologic “hot spots”.
   iv. Record the type, volume and concentration of each tracer slug.
   v. Record injection rate and pressure during each log pass.
   vi. Show the percentage of fluid loss where detected.
2. Shut down well, move in workover rig and pull pump and/or tubing.
3. Modify system to allow river water to be injected into well.
4. Begin pumping river water until an entire casing volume minimum has been injected.
5. Run a caliper log to establish level of encrustation inside well. If a significant level of encrustation exists, then continue flushing casing with river water or mechanically remove the encrustation and rerun the caliper after the encrustation has been sufficiently decreased.
6. Ensure that the flow rate equals or exceeds the maximum flow rate of the particular well during this test to ensure that normal operating internal casing pressure is achieved. If high flow rates are not practical fresh water may be used to attain normal operating internal casing pressure.
7. Run background gamma log prior to RTS Survey.
8. Load RTS tool to 20 feet below ground surface and begin logging on time drive.
9. Eject a tracer slug.
10. Lower tool to 500 ft below ground, continue logging on time drive until the tracer slug is detected passing the tool.
11. Switch to depth drive, lower tool 100 ft (600 ft below ground) and log up to surface, checking for “hot spots” that indicate a leak in the casing. (internal MI)
12. Lower tool to 500 ft below ground. Return to time drive.
13. Eject a tracer slug and lower tool to 1000 ft.
14. Continue logging on time drive until the slug is detected passing the tool.
15. Switch to depth drive. Lower tool 100 ft (1100 ft below ground) and log up to 25 ft above depth where tracer slug was last ejected, checking for “hot spots” that would indicate a leak in the casing.
16. Repeat steps 12-15 until the entire casing has been logged.
17. **Alternative internal MI:** With the injector tool at 0 ft., inject a tracer slug.
18. Drop the logging tool below the slug and log on depth drive up through the slug until the gamma intensity drops to the same level as below the slug.
19. Repeat step 14 until the slug has passed through the bottom of the wellbore, overlapping log runs to ensure the entire casing is logged.
20. Mechanical integrity is demonstrated if the tracer reading maintains the same area, and velocity is consistent through the casing.
21. **For external MI:** Lower the injector tool to the bottom of the lowest casing shoe and begin logging on time drive.
22. Inject a radioactive slug while keeping the tool stationary at the shoe. Log for 15 minutes.
23. If the tracer is detected moving upwards, switch to depth drive and follow the tracer.
24. If the tracer is not detected moving upwards, move tool to TD, switch to depth drive, and log upwards to see if gamma is detected.
25. Internal MI is demonstrated if no gamma hot spots are detected while logging up after the tracer slug has been detected by the tool. External MI is demonstrated if no gamma hot spots are detected after ejecting a tracer slug near the lowest casing shoe.

F. Cement Bond Log (CBL)

1. Have lubricator on site for use if desired.
2. Allow cement sufficient time to cure (determined by cement type/cement charts)
3. Circulate the hole with a fluid of uniform consistency. Fill hole entirely with fluid.
4. Run a collar locator and gamma ray along with the CBL.
5. Run at least 3 bow-spring or aluminum centralizers.
6. Logging speed should be approximately 30 ft/sec.
7. Record amplitude and travel time. Record amplitude and amplified amplitude on a 5X scale.
8. Log repeat sections.
9. Have logging engineer provide an interpretation of the log data.

The pressure applied at the surface will be at least 300 PSI or the greater of the Test Condition pressures as calculated below.

1. Determine a reasonable value for the weight in pounds/gallon of the fluid in the casing (annulus fluid), the formation, and injection tubing.
2. Determine the necessary surface pressure reading according to the relationships:

Test Condition 1
Applied pressure on the annulus, as measured at the surface, must provide for a positive pressure differential of 100 psi above formation pressure at all depths above the top of the permitted injection zone.

\[ P_{as} + (0.052 \times W_{af} \times D) > 0.052 \times W_{ff} \times D + 100 \]

Test Condition 2
Applied pressure on the annulus, as measured at the surface, must provide for a positive pressure differential of 100 psi above the hydrostatic pressure in the tubing at all depths above the top of the permitted injection zone.

\[ P_{as} + (0.052 \times W_{af} \times D) > (0.052 \times W_{if} \times D) + P_{tsi/s} + 100 \]

Where:
- \( P_{as} \) = annulus pressure reading at surface (psi)
- \( P_{tsi/s} \) = tubing pressure, shut in, at surface (psi)
- \( W_{af} \) = Weight of the annulus fluid (lbs/gal)
- \( W_{ff} \) = Weight of the formation fluid (lbs/gal)
- \( W_{if} \) = Weight of the injection fluid (lbs/gal)
- \( D \) = Depth of packer seat (or lowest extent of pressurized annulus) (ft)

**Example Calculation:**

For a well with an annulus between 9-5/8” and 7” casing filled with fresh water, packer at 3000 ft and saturated salt water injection fluid, not injecting.

\[ P_{tsi/s} = 0 \text{ psi} \]
\[ W_{af} = 8.34 \text{ lbs/gal} \]
\[ W_{ff} = 9.6 \text{ lbs/gal} \]
\[ W_{if} = 10.1 \text{ lbs/gal} \]
\[ D = 3000 \text{ ft} \]
Test Condition 1 Calculation:

\[ Pa/s + (0.052 \times 8.34 \times 3000) > 0.052 \times 9.6 \times 3000 + 100 \]
\[ Pa/s > 1498 - 1301 + 100 \]
\[ Pa/s > 297 \text{ psi} \]

And

Test Condition 2 Calculation:

\[ Pa/s + (0.052 \times 8.34 \times 3000) > (0.052 \times 10.1 \times 3000) + 0 + 100 \]
\[ Pa/s > 1576 - 1301 + 100 \]
\[ Pa/s > 375 \text{ psi} \]

In this example, to achieve over 100 psi positive pressure differential between the annulus liquid and formation fluid requires at least 297 psi at surface, and 375 psi to achieve the same differential between the annulus and injection string. Therefore, the minimum surface pressure gauge reading is 375 psi.
Attachment G

Intrepid Potash - Moab Salt, LLC

Moab, Utah

Cane Creek Mine

Reporting Tables
<table>
<thead>
<tr>
<th>Triggering Event</th>
<th>Time Frame</th>
<th>Permittee Response</th>
<th>Utah DWQ Response</th>
</tr>
</thead>
<tbody>
<tr>
<td>Claims of Confidential Business Information (Part II D)</td>
<td>At the time of submittal</td>
<td>Stamp the words “Confidential Business Information” on each page of submittal</td>
<td>Written Approval/Response</td>
</tr>
<tr>
<td>Permittee becomes aware that he failed to submit any relevant facts or submitted incorrect information in any report to the Executive Secretary. (Part II E (11) (f))</td>
<td>Within 10 days after permittee becomes aware of the event</td>
<td>Submit such facts or information. Submittal must be signed and certified in accordance with UAC R317-7-9.3 (40 CFR 144.32).</td>
<td>Written Acknowledgement of Receipt and Response, if Appropriate</td>
</tr>
<tr>
<td>Construct new injection well (Part III B)</td>
<td>No less than 30 days prior to the commencement of well construction.</td>
<td>Submit individual well plans for each new well to be constructed to the Executive Secretary for review and approval. Well construction may commence only after receipt of written approval from DEQ. Individual well plans must be signed and certified in accordance with UAC R317-7-9.3 (40 CFR 144.32).</td>
<td>Written Approval</td>
</tr>
<tr>
<td>Completion of Well Construction (Part III B)</td>
<td>Within 60 days after the completion of well construction</td>
<td>Submit an &quot;As-Constructed&quot; Well Report signed and certified in accordance with UAC R317-7-9.3 (40 CFR 144.32). Plan must be signed and certified in accordance with UAC R317-7-9.3 (40 CFR 144.32).</td>
<td>Written Acknowledgement of Receipt and Response, if Appropriate (Check for deviations from the approved plan.)</td>
</tr>
<tr>
<td></td>
<td>Within 90 days after the completion of well construction</td>
<td>Submit modified Plan for Abandonment of Class III Wells and Mine Shafts to include plans for new well and a reliable cost estimate to P&amp;A well based on current well condition. Plan must be signed and certified in accordance with UAC R317-7-9.3 (40 CFR 144.32).</td>
<td>Require amendment to Financial Guarantee Bond when contingency is exceeded.</td>
</tr>
<tr>
<td>Any spill, leak or noncompliance of a permit condition that may endanger human health or the environment.</td>
<td>Within 24 hours after the permittee becomes aware of the event</td>
<td>Orally report to Executive Secretary or representative at 801-538-6146 (during normal business hours) or at 801-536-4123 (for reporting at all other times).</td>
<td>Oral Response and Reminder of Written Report</td>
</tr>
<tr>
<td>Triggering Event</td>
<td>Time Frame</td>
<td>Permittee Response</td>
<td>Utah DWQ Response</td>
</tr>
<tr>
<td>------------------------------------------</td>
<td>-----------------------------------------------------------------------------</td>
<td>------------------------------------------------------------------------------------------------------------------------------------------------------</td>
<td>-------------------------------------------------------------</td>
</tr>
<tr>
<td>(Part II E (11) (c))</td>
<td>Within 5 days after the permittee becomes aware of the event</td>
<td>Submit written report including description of the spill, leak or noncompliance and its cause, exact dates and times, steps taken to mitigate the effects, and steps taken or planned to prevent a re-occurrence. If a leak or noncompliance is ongoing, the submission shall indicate the anticipated time it is expected to continue. Report must be signed and certified in accordance with UAC R317-7-9.3 (40 CFR 144.32).</td>
<td>Written Acknowledgement of Receipt and Response, if Appropriate</td>
</tr>
<tr>
<td>Commencement of injection into new well</td>
<td>After receiving written approval from DWQ to commence injection.</td>
<td>Permittee has fulfilled all applicable conditions of this permit pertaining to new injection wells – Part III (C) (6) of the permit</td>
<td>Written Approval to commence injection</td>
</tr>
<tr>
<td>Triggering Event</td>
<td>Time Frame</td>
<td>Permittee Response</td>
<td>Utah DWQ Response</td>
</tr>
<tr>
<td>---------------------------------------------------------------------------------</td>
<td>-------------------------------------------------</td>
<td>------------------------------------------------------------------------------------</td>
<td>--------------------------------------------------------</td>
</tr>
<tr>
<td><strong>Claims of Confidential Business Information (Part II D)</strong></td>
<td>At the time of submittal</td>
<td>Stamp the words “Confidential Business Information” on each page of submittal</td>
<td>Written Approval/Response</td>
</tr>
<tr>
<td><strong>Any spill, leak or noncompliance of a permit condition that may endanger human health or the environment. (Part II E (11) (c))</strong></td>
<td>Within 24 hours after the permittee becomes aware of the event</td>
<td>Orally report to Executive Secretary or representative at 801-538-6146 (during normal business hours) or at 801-536-4123 (for reporting at all other times).</td>
<td>Oral Response and Reminder of Written Report</td>
</tr>
<tr>
<td></td>
<td>Within 5 days after the permittee becomes aware of the event</td>
<td>Submit written report including description of the spill, leak or noncompliance and its cause, exact dates and times, steps taken to mitigate the effects, and steps taken or planned to prevent a re-occurrence. If a leak or noncompliance is ongoing, the submission shall indicate the anticipated time it is expected to continue. Report must be signed and certified in accordance with UAC R317-7-9.3 (40 CFR 144.32).</td>
<td>Written Acknowledgement of Receipt and Response, if Appropriate</td>
</tr>
<tr>
<td><strong>Permittee becomes aware that he failed to submit any relevant facts or submitted incorrect information in any report to the Executive Secretary. (Part II E (11) (f))</strong></td>
<td>Within 10 days after permittee becomes aware of the event</td>
<td>Submit such facts or information. Submittal must be signed and certified in accordance with UAC R317-7-9.3 (40 CFR 144.32).</td>
<td>Written Acknowledgement of Receipt and Response, if Appropriate</td>
</tr>
<tr>
<td><strong>Plugging and Abandonment of Injection Well (Part III D)</strong></td>
<td>No less than 45 days prior to the planned conversion or abandonment of the well (Part III D (1))</td>
<td>Submit written notice of intent to plug and abandon to DWQ including Well Condition Report with supporting documentation and individual plugging and abandonment plans. Well Condition Report must be signed and certified in accordance with UAC R317-7-9.3 (40 CFR 144.32).</td>
<td>Written Approval/Response</td>
</tr>
<tr>
<td></td>
<td>Within 60 days after completion of the plugging and abandonment of the well. (Part III D (4))</td>
<td>Submit a Plugging and Abandonment (“As-Plugged”) Report to DWQ including the certification of accuracy and statement of compliance with approved P&amp;A plan or statement justifying deviation from approved P&amp;A plan. As-Plugged Report must be signed and certified in accordance with UAC R317-7-9.3 (40 CFR 144.32).</td>
<td>Written Acknowledgement of Receipt and Response, if Appropriate</td>
</tr>
<tr>
<td><strong>Emergency Well Conversion or Plugging and Abandonment (Part III D (2))</strong></td>
<td>No less than 24 hours before the emergency action</td>
<td>Orally report to Executive Secretary or representative at 801-538-6146 (during normal business hours) or at 801-536-4123 (for reporting at all other times).</td>
<td>Oral Approval/Response</td>
</tr>
<tr>
<td>Triggering Event</td>
<td>Time Frame</td>
<td>Permittee Response</td>
<td>Utah DWQ Response</td>
</tr>
<tr>
<td>------------------</td>
<td>------------</td>
<td>--------------------</td>
<td>-------------------</td>
</tr>
<tr>
<td>Within 5 days after receiving oral approval from DEQ</td>
<td>Submit a written request for approval of emergency action including justification. Submittal must be must be signed and certified in accordance with UAC R317-7-9.3 (40 CFR 144.32).</td>
<td>Written Approval/Response</td>
<td></td>
</tr>
<tr>
<td>Within 60 days after completion of the emergency action (<strong>Part III D (4)</strong>)</td>
<td>Submit a Plugging and Abandonment (&quot;As-Plugged&quot;) Report to DWQ including the certification of accuracy and statement of compliance with approved P&amp;A plan or statement justifying deviation from approved P&amp;A plan. As-Plugged Report must be signed and certified in accordance with UAC R317-7-9.3 (40 CFR 144.32).</td>
<td>Written Acknowledgement of Receipt and Response, if Appropriate</td>
<td></td>
</tr>
<tr>
<td>Inactive Wells - Cessation of injection activities for 2 years (<strong>Part III D (5)</strong>)</td>
<td>Plug and abandon the injection well unless a variance has been requested and received before the end of the 2 year period</td>
<td>Written Response to Request for Variance</td>
<td></td>
</tr>
<tr>
<td>At the end of the second and fourth year of this permit</td>
<td>Review and evaluate inactive wells to ensure compliance with conditions for allowing inactive wells to remain unplugged. Submit Inactive/Temporarily Abandoned Well Evaluation Report to DWQ signed and certified in accordance with UAC R317-7-9.3 (40 CFR 144.32).</td>
<td>Written Acknowledgement of Receipt and Response, if Appropriate</td>
<td></td>
</tr>
<tr>
<td>Reactivation of Inactive Well (<strong>Part III D (5) (d)</strong>)</td>
<td>No less than 45 days prior to the planned reactivation of an inactive well</td>
<td>Submit written notice of intent to reactivate well to DWQ and demonstrate mechanical integrity of the well in accordance with Part III (F) of this permit.</td>
<td>Written Approval/Response</td>
</tr>
<tr>
<td>Temporary Abandonment/Plugging (<strong>Part III D (5) (b)</strong>)</td>
<td>No less than 45 days prior to the planned temporary abandonment of the well</td>
<td>Submit written notice of intent to temporarily abandon to DWQ including Well Condition Report with supporting documentation and individual temporary plugging plans. Well Condition Report must be signed and certified in accordance with UAC R317-7-9.3 (40 CFR 144.32).</td>
<td>Written Approval</td>
</tr>
<tr>
<td>Within 60 days after completion of the temporary abandonment of the well (<strong>Part III D (4)</strong>)</td>
<td>Submit a Plugging and Abandonment (&quot;As-Plugged&quot;) Report to DWQ including the certification of accuracy and statement of compliance with approved P&amp;A plan or statement justifying deviation from approved P&amp;A plan. As-Plugged Report must be signed and certified in accordance with UAC R317-7-9.3 (40 CFR 144.32).</td>
<td>Written Acknowledgement of Receipt and Response, if Appropriate</td>
<td></td>
</tr>
</tbody>
</table>
### Table of Reporting and Notification Requirements for Plugging and Abandonment

**Utah UIC Permit Number: UTU-19-AP-1C3C2E8; Intrepid Potash, Inc.**

<table>
<thead>
<tr>
<th>Triggering Event</th>
<th>Time Frame</th>
<th>Permittee Response</th>
<th>Utah DWQ Response</th>
</tr>
</thead>
<tbody>
<tr>
<td>At the end of the second and fourth year of this permit <em>(Part III D (5) (c))</em></td>
<td>Review and evaluate temporarily abandoned wells to ensure compliance with conditions for allowing wells to remain temporarily abandoned. Submit Inactive/Temporarily Abandoned Well Evaluation Report to DWQ signed and certified in accordance with UAC R317-7-9.3 (40 CFR 144.32).</td>
<td>Written Acknowledgement of Receipt and Response, if Appropriate</td>
<td></td>
</tr>
<tr>
<td>Reactivation of Temporarily Abandoned Well <em>(Part III D (5) (d))</em></td>
<td>No less than 45 days prior to the planned reactivation of a temporarily abandoned well.</td>
<td>Submit written notice of intent to reactivate well to DWQ and demonstrate mechanical integrity of the well in accordance with Part III (F) of this permit.</td>
<td>Written Approval/Response</td>
</tr>
</tbody>
</table>
# Table of Reporting and Notification Requirements for Mechanical Integrity Testing (MIT)

**Utah UIC Permit Number: UTU-19-AP-1C3C2E8; Intrepid Potash, Inc.**

<table>
<thead>
<tr>
<th>Triggering Event</th>
<th>Time Frame</th>
<th>Permittee Response</th>
<th>Utah DWQ Response</th>
</tr>
</thead>
<tbody>
<tr>
<td>Claims of Confidential Business Information (Part II D)</td>
<td>At the time of submittal</td>
<td>Stamp the words “Confidential Business Information” on each page of submittal</td>
<td>Written Approval</td>
</tr>
<tr>
<td>Permittee becomes aware that he failed to submit any relevant facts or submitted incorrect information in any report to the Executive Secretary. (Part II E (11) (f))</td>
<td>Within 10 days after permittee becomes aware of the event</td>
<td>Submit such facts or information. Submittal must be signed and certified in accordance with UAC R317-7-9.3 (40 CFR 144.32).</td>
<td></td>
</tr>
<tr>
<td>Placing of any existing well into operation (Part III F (2)(a))</td>
<td>Prior to well operation</td>
<td>Demonstration/documentation of MIT</td>
<td>Written Acknowledgement of Receipt and Response, if Appropriate</td>
</tr>
<tr>
<td>Placing of a new well into operation (Part III F (2)(b))</td>
<td>Prior to well operation</td>
<td>Demonstration/documentation of MIT</td>
<td>Written Approval</td>
</tr>
<tr>
<td>Loss of Mechanical Integrity (Part III F (3)(a))</td>
<td>Immediately</td>
<td>Cease operation immediately</td>
<td></td>
</tr>
<tr>
<td>Loss of Mechanical Integrity (Part III F (3)(b))</td>
<td>Immediately</td>
<td>Take steps to prevent losses of mine brine through the leaks caused by high hydrostatic head or pressure</td>
<td></td>
</tr>
<tr>
<td>Loss of Mechanical Integrity (Part III F (3)(d))</td>
<td>Within 15 days after loss of mechanical integrity.</td>
<td>Submit to the Executive Secretary a schedule indicating what will be done to restore mechanical integrity to the well, or if it will be plugged.</td>
<td>Written Acknowledgement of Receipt and Response, if Appropriate</td>
</tr>
<tr>
<td>Loss of Mechanical Integrity (Part III F (3)(e))</td>
<td>Within 90 days after loss of mechanical integrity</td>
<td>Restore mechanical integrity to the well, or plug and abandon the well in accordance with a plugging and abandonment plan approved by the Executive Secretary.</td>
<td>Written Approval</td>
</tr>
<tr>
<td>Loss of Mechanical Integrity which may potentially endanger an USDW and/or the Colorado River and/or (Part III F (3))</td>
<td>Within 24 hours after the permittee becomes aware of the event</td>
<td>Orally report to Executive Secretary or representative at 801-538-6146 (during normal business hours) or at 801-536-4123 (for reporting at all other times).</td>
<td>Oral Response and Reminder of Written Report</td>
</tr>
<tr>
<td>Any spill, leak or noncompliance of a permit condition that may endanger human health or the environment. (Part II E (11) (c))</td>
<td>Within 5 days after the permittee becomes aware of the event</td>
<td>Submit written report including description of the spill, leak or noncompliance and its cause, exact dates and times, steps taken to mitigate the effects, and steps taken or planned to prevent a re-occurrence. If a leak or noncompliance is ongoing, the submission shall indicate the anticipated time it is expected to continue. Report</td>
<td>Written Acknowledgement of Receipt and Response, if Appropriate</td>
</tr>
</tbody>
</table>
### Table of Reporting and Notification Requirements for Mechanical Integrity Testing (MIT)

**Utah UIC Permit Number: UTU-19-AP-1C3C2E8; Intrepid Potash, Inc.**

<table>
<thead>
<tr>
<th>Triggering Event</th>
<th>Time Frame</th>
<th>Permittee Response</th>
<th>Utah DWQ Response</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>MIT Frequency</strong> <em>(Part III F (5)(a))</em></td>
<td>Yearly</td>
<td>For active wells into the original mine cavity (Sylvite 5), annular pressure test (for those wells so equipped)</td>
<td>Written Acknowledgement of Receipt and Response, if Appropriate</td>
</tr>
<tr>
<td></td>
<td>Every 5 years</td>
<td>Test for casing leaks (for those wells NOT equipped to run annular pressure tests) and vertical flow behind casing</td>
<td>Written Acknowledgement of Receipt and Response, if Appropriate</td>
</tr>
<tr>
<td><strong>MIT Frequency</strong> <em>(Part III F (5)(b))</em></td>
<td>Monthly</td>
<td>For active wells into Sylvite 9, annular pressure test</td>
<td>Written Acknowledgement of Receipt and Response, if Appropriate</td>
</tr>
<tr>
<td></td>
<td>Every 5 years</td>
<td>Test for casing leaks and vertical flow behind casing</td>
<td>Written Acknowledgement of Receipt and Response, if Appropriate</td>
</tr>
<tr>
<td><strong>MIT Frequency</strong> <em>(Part III F (5)(c))</em></td>
<td>Prior to new well operation</td>
<td>Prior to placing a new well into operation</td>
<td>Written Acknowledgement of Receipt and Response, if Appropriate</td>
</tr>
<tr>
<td><strong>MIT Frequency</strong> <em>(Part III F (5)(d))</em></td>
<td>Prior to well operation</td>
<td>Following any repair or workover of a well</td>
<td>Written Acknowledgement of Receipt and Response, if Appropriate</td>
</tr>
<tr>
<td><strong>MIT Requests</strong> <em>(Part III F (6))</em></td>
<td>At any time</td>
<td>The Executive Secretary may require an MIT</td>
<td></td>
</tr>
<tr>
<td><strong>MIT Inspections</strong> <em>(Part III F (7))</em></td>
<td>No less than 30 days prior to MIT</td>
<td>Notify DWQ of intent to perform MIT</td>
<td>Written Acknowledgement of Receipt and Response, if Appropriate</td>
</tr>
<tr>
<td><strong>MIT Reporting</strong> <em>(Part III F (8))</em></td>
<td>Within 60 days after completion of MIT</td>
<td>Submit results of MIT.</td>
<td>Written Acknowledgement of Receipt and Response, if Appropriate</td>
</tr>
</tbody>
</table>

Note: MIT must be signed and certified in accordance with UAC R317-7-9.3 (40 CFR 144.32).
<table>
<thead>
<tr>
<th>Triggering Event</th>
<th>Time Frame</th>
<th>Permittee Response</th>
<th>Utah DWQ Response</th>
</tr>
</thead>
<tbody>
<tr>
<td>Operator Change of Address</td>
<td>No less than 15 days prior to the effective date of</td>
<td>Submit written notice to the Executive Secretary</td>
<td>Not Applicable</td>
</tr>
<tr>
<td></td>
<td>the event</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Claims of Confidential Business Information (Part II D)</td>
<td>At the time of submittal</td>
<td>Stamp the words “Confidential Business Information” on each page of</td>
<td>Written Approval</td>
</tr>
<tr>
<td></td>
<td></td>
<td>submittal</td>
<td></td>
</tr>
<tr>
<td>Permit Expiration (Part II E (3)) and (Part III H)</td>
<td>No less than 180 days prior to permit expiration</td>
<td>Submit permit renewal application</td>
<td>Written Approval</td>
</tr>
<tr>
<td></td>
<td>date</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Planned physical alterations or additions to the UIC permitted facilities (Part</td>
<td>No less than 30 days prior to implementing the</td>
<td>Submit written notice to the Executive Secretary</td>
<td>Written Approval</td>
</tr>
<tr>
<td>II E (11) (a))</td>
<td>event</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Any spill, leak or noncompliance of a permit condition that may endanger human</td>
<td>Within 24 hours after the permittee becomes aware</td>
<td>Orally report to Executive Secretary or representative at 801-538-6146</td>
<td>Oral Response and Reminder of Written Report</td>
</tr>
<tr>
<td>health or the environment. (Part II E (11) (c))</td>
<td>of the event</td>
<td>(during normal business hours) or at 801-536-4123 (for reporting at</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>all other times).</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Within 5 days after the permittee becomes aware of</td>
<td>Submit written report including description of the spill, leak or</td>
<td>Written Acknowledgement of Receipt and Response, if</td>
</tr>
<tr>
<td></td>
<td>the event</td>
<td>noncompliance and its cause, exact dates and times, steps taken to</td>
<td>Appropriate</td>
</tr>
<tr>
<td></td>
<td></td>
<td>mitigate the effects, and steps taken or planned to prevent a re-</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>occurrence. If a leak or noncompliance is ongoing, the submission</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>shall indicate the anticipated time it is expected to continue.</td>
<td></td>
</tr>
<tr>
<td>Receipt of this permit (Part II E (11) (g))</td>
<td>Within 30 days after receipt of this permit</td>
<td>Report to the Executive Secretary that the person(s) designated to</td>
<td>Not Required</td>
</tr>
<tr>
<td></td>
<td></td>
<td>implement the requirements of this permit has read and is personally</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>familiar with all terms and conditions of this permit</td>
<td></td>
</tr>
<tr>
<td>Permittee becomes aware that he failed to submit any relevant facts in the</td>
<td>Within 10 days after permittee becomes aware of the</td>
<td>Submit such facts or information. Submittal must be signed and</td>
<td>Written Acknowledgement of Receipt and Response, if</td>
</tr>
<tr>
<td>permit application or submitted incorrect information in a permit application or</td>
<td>event.</td>
<td>certified in accordance with UAC R317-7-9.3 (40 CFR 144.32).</td>
<td>Appropriate</td>
</tr>
<tr>
<td>in any report to the Executive Secretary. (Part II E (11) (f))</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Cessation of injection activities</td>
<td>after 2 years of inactivity</td>
<td>Plug and abandon the injection well unless a variance has been</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>obtained prior to the end of the 2 year period</td>
<td></td>
</tr>
</tbody>
</table>

Page 1 of 4
<table>
<thead>
<tr>
<th>Triggering Event</th>
<th>Time Frame</th>
<th>Permittee Response</th>
<th>Utah DWQ Response</th>
</tr>
</thead>
<tbody>
<tr>
<td>Anticipated Noncompliance (Part II E (11) (b))</td>
<td>As soon as the permittee becomes aware of the event</td>
<td>Give advance notice of any planned change in the permitted facility or activity that may result in a noncompliance with permit requirements.</td>
<td>Written Acknowledgement of Receipt and Response, if Appropriate</td>
</tr>
<tr>
<td>Endangering Noncompliance (Part II E (11) (c))</td>
<td>Within 24 hours after permittee becomes aware of event</td>
<td>Provide oral report of any monitoring data or other information, noncompliance with a permit condition, malfunction of injection system which may cause endangerment to USDW or the Colorado River; also report annual mine cavity brine level tests that show three consecutive drops in brine level.</td>
<td>Oral Response and Reminder of Written Report</td>
</tr>
<tr>
<td></td>
<td>Within 5 days after permittee becomes aware of event</td>
<td>Submit written report describing the endangering noncompliance; its cause; the period of noncompliance, including the exact time and dates; whether or not it has been corrected; the anticipated time it is expected to continue; and steps taken or planned to reduce, eliminate, and prevent a recurrence of the noncompliance.</td>
<td>Written Acknowledgement of Receipt and Response, if Appropriate</td>
</tr>
<tr>
<td>Other Noncompliance (Part II E (11) (d))</td>
<td>Next Quarterly Monitoring Report</td>
<td>Submit written report describing the noncompliance; its cause; the period of noncompliance, including the exact time and dates; whether or not it has been corrected; the anticipated time it is expected to continue; and steps taken or planned to reduce, eliminate, and prevent a recurrence of the noncompliance.</td>
<td>Written Acknowledgement of Receipt and Response, if Appropriate</td>
</tr>
<tr>
<td>Triggering Event</td>
<td>Time Frame</td>
<td>Permitee Response</td>
<td>Utah DWQ Response</td>
</tr>
<tr>
<td>------------------</td>
<td>------------</td>
<td>-------------------</td>
<td>-------------------</td>
</tr>
<tr>
<td><strong>Quarterly Monitoring Reports</strong>&lt;br&gt;(Part II E (11) (e))</td>
<td>1&lt;sup&gt;st&lt;/sup&gt; Qtr (Jan thru March) – April 15&lt;br&gt;2&lt;sup&gt;nd&lt;/sup&gt; Qtr (April thru June) – July 15&lt;br&gt;3&lt;sup&gt;rd&lt;/sup&gt; Qtr (July thru Sept) – October 15&lt;br&gt;4&lt;sup&gt;th&lt;/sup&gt; Qtr (Oct thru December) – January 15</td>
<td>Quarterly reports shall include:&lt;br&gt;1. Injection and Extraction Volumes for Wells into the Original Mine&lt;br&gt;2. Injection and Extraction Volumes for Wells into the Sylvite 9 Solution Mine&lt;br&gt;3. Original Mine Cavity Injection Pressure/Flow Rate/Brine Level&lt;br&gt;4. Injection Pressures and Flow Rates for Wells in the Sylvite 9 Solution Mine&lt;br&gt;5. Injectate Water Quality&lt;br&gt;6. Injection / Extraction Ratio Exceedance Investigation and Corrective Action Report&lt;br&gt;7. Annulus Operating Pressure – Wells Completed in the Sylvite 9 Solution Mine&lt;br&gt;8. Report the results of the continuous monitoring of the brine level in Shaft #2&lt;br&gt;9. Report annual activity to reduce/manage salt loading from evaporation ponds to the local hydrologic system.</td>
<td>Written Acknowledgement of Receipt and Response, if Appropriate</td>
</tr>
<tr>
<td><strong>Renewal of Financial Responsibility</strong>&lt;br&gt;(Part III E (2))</td>
<td>At the time of permit renewal</td>
<td>Demonstrate the adequacy of the surety bond and standby trust agreement to close, plug and abandon all wells not permanently plugged and abandoned by the permittee in compliance with Part III D of this permit.</td>
<td>Written Acknowledgement of Receipt and Response, if Appropriate</td>
</tr>
<tr>
<td><strong>Insolvency of Financial Institution</strong>&lt;br&gt;(Part III E (3))</td>
<td>Within 60 days after either of the following events occurs:&lt;br&gt;a) The institution issuing the trust or financial instrument files for bankruptcy; or&lt;br&gt;b) The authority of the trustee institution to act as trustee, or the authority of the institution issuing the financial instrument, is suspended or revoked.</td>
<td>Submit an alternate demonstration of financial responsibility acceptable to the Executive Secretary</td>
<td>Written Acknowledgement of Receipt and Response, if Appropriate</td>
</tr>
<tr>
<td>Triggering Event</td>
<td>Time Frame</td>
<td>Permittee Response</td>
<td>Utah DWQ Response</td>
</tr>
<tr>
<td>---------------------------------------------------------------------------------</td>
<td>---------------------------------</td>
<td>------------------------------------------------------------------------------------</td>
<td>------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td>Upward fluid migration through well bore of any previously unknown or improperly</td>
<td>Immediately upon permittee</td>
<td>Cease injection until proper plugging of the well can be performed.</td>
<td>Written Acknowledgement of Receipt and Response, if Appropriate</td>
</tr>
<tr>
<td>plugged or unplugged well (Part III G (2))</td>
<td>becoming aware of the event</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Continuation of Expiring Permit (Part III H)</td>
<td>Permit Expiration Date</td>
<td>Provided the permittee has submitted a complete permit renewal application no less</td>
<td>If the permit renewal application was not submitted before 180 days prior to the</td>
</tr>
<tr>
<td></td>
<td></td>
<td>than 180 days prior to the permit expiration date, the conditions of the expired</td>
<td>permit expiration date, the Executive Secretary may choose to take enforcement</td>
</tr>
<tr>
<td></td>
<td></td>
<td>permit may continue in force.</td>
<td>action according to Part III H (3).</td>
</tr>
<tr>
<td>Submittal of Reports</td>
<td></td>
<td>All reports or other information, submitted as required by this permit or requested</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>by the Executive Secretary, shall be signed and certified in accordance with UAC</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>R317-7-9.3 (40 CFR 144.32).</td>
<td></td>
</tr>
</tbody>
</table>