FINAL

UTAH DIVISION OF WATER QUALITY

CLASS III AREA PERMIT

UNDERGROUND INJECTION CONTROL (UIC) PROGRAM

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

Cane Creek Mine
Grand County, Utah

Permit Issued to:

Intrepid Potash - Moab, L.L.C.

April 27, 2015

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PART I. AUTHORIZATION TO CONSTRUCT AND INJECT

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

Intrepid Potash - Moab, LLC
(Hereafter referred to as Intrepid)
P.O. Box 1208
Moab, Utah 84532

is hereby authorized to construct and operate Class III solution mining injection wells in south central Grand County, Utah to extract potash from the Pennsylvanian Paradox Formation. A general location map is included as Attachment A.

The legal description of the area to be included in the UIC area permit follows:

Township 26 South, Range 20 East, SLB&M
- Section 22: All
- Section 23: All
- Section 24: W/2, W/2 of the E/2, SE/4 of the SE/4
- Section 25: Lots 1, 2, N/2, SW/4, NW/4 of the SE/4
- Section 26: All
- Section 27: All
- Section 34: All
- Section 35: All
- Section 36: Lots 2, 3, 4, SW/4 of the NE/4, W/2, SE/4

Township 26 South, Range 21 East, SLB&M
- Section 30: Lots 2, 3, 6
- Section 31: Lots 2, 5, 6

Township 27 South, Range 20 East, SLB&M
- Section 1: All
- Section 2: All

Township 27 South, Range 21 East, SLB&M
- Section 6: Lots 3, 4, 5, 6, 9, 10, 11, 12
- Section 7: Lot 2

Containing 7299.9 acres, more or less
Grand and San Juan Counties, Utah

A map showing the area of review including the existing and proposed Class III solution mining wells and the project area is included as Attachment B.

Whereas Underground Sources of Drinking Water (USDW) had not been identified in the area of the facility at the time this permit became effective, the conditions in this permit are designed to ensure protection of the Colorado River and any USDWs that may be identified in the future.

Injection is explicitly limited to the base of the Clastic 2 where it contacts 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 conditions 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 Director of the Division of Water Quality (hereafter referred to as 'the Director') to inject.

It is typical of salt solution mining operations to use production wells and injection wells interchangeably for at least some period of time. Therefore, this permit will cover both production wells and injection wells.

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 this permit becomes effective. The following are incorporated as enforceable attachments to this permit:

- Attachment A - General Location Map of the Cane Creek Mine, Grand County.
- Attachment B - Map of the UIC Area of Review including the Class III Solution Mining Injection Wells and the Project Area
- Attachment C - Corrective Action Plan for Artificial Penetrations into Injection Zone within Area of Review
- Attachment D - Injection Well Construction Plan with Injection Well Construction Details
- Attachment E - Injection Well Operating Plan and Procedures
- Attachment F - Monitoring, Recording, and Reporting Plan
- Attachment G - Contingency Plan for Well Shut-ins or Well Failures
- Attachment H - Plugging and Abandonment Plan
- Attachment I - Financial Responsibility

This major modification of the original permit 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.**

Any person who violates the Utah Water Quality Act (UWQA), or any permit, rule, or order adopted under it, is subject to the provisions of section UCA 19-5-115 of the UWQA governing violations.

This permit shall become effective **May 1, 2015**

This permit and the authorization to inject shall be issued for the life of the project as described in Part III A – Duration of Permit of this permit unless terminated.

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Walter L. Baker, P.E.
Director
Utah Division of Water Quality

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PART II. GENERAL PERMIT CONDITIONS

A. EFFECT OF PERMIT

The permittee is allowed to engage in underground injection in accordance with the conditions of this permit. The permittee, 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 unless otherwise authorized-by-rule or by another UIC permit. 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 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. 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.

C. CONFIDENTIALITY

In accordance with Utah Code 19-1-306 (Records of the Department of Environmental Quality), Utah Code 63G-2-309 (Confidentiality Claims), and Utah Code 19-5-113 (DWQ Records and Reports Required by Owners/Operators) any information deemed by the permittee to be entitled to trade secret protection submitted to the DWQ 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 DWQ may make the information available to the public without further notice. Claims of confidentiality may be denied by the DWQ according to the procedures detailed in Utah Code 63G-2 and the federal Freedom of Information Act (FOIA). 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.

D. CONDITIONS APPLICABLE TO ALL UIC PERMITS (40CFR144.51)[1]

The following conditions are required for all Class III permits. Specific requirements for implementing these conditions are included in Part III of this permit, as necessary.

1. Duty to Comply (40CFR144.51(a))

   The permittee shall comply with all conditions of this permit. Any permit noncompliance constitutes a violation of the Safe Drinking Water Act and the UWQA and is grounds for enforcement action, permit termination, revocation and re-issuance, modification; or for denial of a permit renewal application; except that the permittee need not comply with the provisions of this permit to the extent and for the duration such noncompliance is authorized in an emergency permit issued in accordance with UAC R317-7-8 (40 CFR 144.34). 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. Duty to Reapply (40CFR144.51(b))

   If the permittee wishes to continue an activity regulated by this permit after the expiration date of this permit, the permittee must apply for and obtain a new permit. The permittee shall submit a complete permit renewal application at least 180 days before this permit expires. While Class III permits are typically issued for the life of the project, unforeseen circumstances may require the permittee to reapply for a permit. Class III well permits shall be reviewed by the Director at least once every five years to determine whether it should be modified, revoked and reissued, or terminated.

3. Need to Halt or Reduce Activity Not a Defense (40CFR144.51(c))

   It shall not be a defense for a permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this permit.

4. Duty to Mitigate (40CFR144.51(d))

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

5. Proper Operation and Maintenance (40CFR144.51(e))

   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

[1] Parenthetical references to the Code of Federal Regulations (CFR) and / or the Utah Administrative Code (UAC) for the UIC Program indicate the requirement for inclusion in the permit.

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

6. Permit Actions

(40CFR144.51(f), 40 CFR 124.5, 40 CFR 144.38, 40 CFR 144.39, 40 CFR 144.40, 40 CFR 144.41)
This permit may be modified, revoked and reissued, or terminated either at the request of any interested person (including the permittee) or upon the Director's initiative. However, permits may only be modified, revoked and reissued, or terminated for the reasons specified in sections a) and b) below. All requests shall be in writing and shall contain facts or reasons supporting the request. The filing of a request for a permit modification, revocation and re-issuance, or termination on the part of the permittee, does not stay any permit condition. This permit may be transferred according to the procedures given in section d).

a) Modify or Revoke and Re-Issue Permits

When the Director receives any information (for example, inspects the facility, receives information submitted by the permittee as required in the permit, receives a request for modification or revocation and reissuance, or conducts a review of the permit file), the Director may determine whether or not one or more of the causes listed in paragraphs (1) and (2) of this section for modification or revocation and reissuance or both exist. If cause exists, the Director may modify or revoke and reissue the permit accordingly, subject to the limitations of paragraph (3) of this section, and may request an updated application if necessary. When a permit is modified, only the conditions subject to modification are reopened. If a permit is revoked and reissued, the entire permit is reopened and subject to revision and the permit is reissued for a new term. If cause does not exist under this section a) or under section c) for minor modifications, the Director shall not modify or revoke and reissue the permit. If a permit modification satisfies the criteria for minor modifications in section c) the permit may be modified without a draft permit or public review. Otherwise, a draft permit must be prepared and other procedures in 40 CFR 124, incorporated by reference into the Utah UIC Program rules (hereafter referred to as ’40 CFR 124’), must be followed.

(1) Causes for modification. For Class III wells the following may be causes for revocation and reissuance as well as modification.

i. Alterations. There are material and substantial alterations or additions to the permitted facility or activity which occurred after permit issuance which justify the application of permit conditions that are different or absent in the existing permit.

ii. Information. The Director has received information. For UIC area permits, this cause shall include any information indicating that cumulative effects on the environment are unacceptable.

iii. New regulations. The standards or regulations on which the permit was based have been changed by promulgation of new or amended standards or regulations or by judicial decision after the permit was issued.

iv. Compliance schedules. The Director determines good cause exists for modification of a compliance schedule, such as an act of God, strike, flood, or materials shortage or other events over which the permittee has little or no control and for which there is no reasonably available remedy. See also paragraph (3) under section c) – Minor Modification of Permit).

(2) Causes for modification or revocation and reissuance. The following are causes to modify or, alternatively, revoke and reissue a permit:

i. Cause exists for termination under section b), and the Director determines that modification or revocation and reissuance is appropriate.

ii. The Director has received notification (as required in the permit, see paragraph (4) under section c) – Minor Modification of Permit) of a proposed transfer of the permit. A permit also may be modified to reflect a transfer after the effective date of an automatic transfer (see paragraph (2) of section d) – Transfer of Permit) but will not be revoked and reissued after the effective date of the transfer except upon the request of the new permittee.

iii. A determination that the waste being injected is a hazardous waste as defined in 40 CFR 261.3 either because the definition has been revised, or because a previous determination has been changed.

(3) Facility siting. Suitability of the facility location will not be considered at the time of permit modification or revocation and reissuance unless new information or standards indicate that a threat to human health or the environment exists which was unknown at the time of permit issuance.

b) Termination of Permit

(1) The Director may terminate a permit during its term, or deny a permit renewal application for the following causes:

i. Noncompliance by the permittee with any condition of the permit;

ii. The permittee's failure in the application or during the permit issuance process to disclose fully all relevant facts, or the permittee's misrepresentation of any relevant facts at any time; or

iii. A determination that the permitted activity endangers human health or the environment and can only be regulated to acceptable levels by permit modification or termination;

(2) The Director shall follow the applicable procedures in 40 CFR 124 in terminating any permit under this section.

c) Minor Modification of Permit

Upon the consent of the permittee, the Director may modify a permit to make the corrections or allowances for changes in the permitted activity listed in this section, without following the procedures of 40 CFR 124. Any permit modification not processed as a minor modification under this section must be made for cause and with 40 CFR 124 draft permit and public notice as required in section a). Minor modifications may only:

(1) Correct typographical errors;

(2) Require more frequent monitoring or reporting by the permittee;

(3) Change an interim compliance date in a schedule of compliance, provided the new date is not more than 120 days after the date specified in the existing permit and does not interfere with attainment of the final compliance date requirement; or

(4) Allow for a change in ownership or operational control of a facility where the Director determines that no other change in the permit is necessary, provided that a written agreement containing a specific date for transfer of permit responsibility, coverage, and liability between the current and new permittee has been submitted to the Director.

(5) Change quantities or types of fluids injected which are within the capacity of the facility as permitted and, in the judgment of the Director, would not interfere with the operation of the facility or its ability to meet conditions described in the permit and would not change its classification.

(6) Change construction requirements approved by the Director pursuant to 40 CFR 144.52(a)(1) (establishing UIC permit conditions), provided that any such alteration shall comply with the requirements of 40 CFR 144 and 40 CFR 146.

(7) Amend a plugging and abandonment plan which has been updated.

d) Transfer of Permit

(1) Transfers by Modification. Except as provided in paragraph (2) of this section, a permit may be transferred by the permittee to a new owner or operator only if the permit has been modified or revoked and reissued (under paragraph (2)(ii) under section a)), or a minor modification made (under paragraph (4) of section c)) to identify the new permittee and incorporate such other requirements as may be necessary under the Safe Drinking Water Act.

(2) Automatic Transfers. As an alternative to transfers under paragraph (1) of this section, any UIC permit for a well not injecting hazardous waste or injecting carbon dioxide for geologic sequestration may be automatically transferred to a new permittee if:

i. The current permittee notifies the Director at least 30 days in advance of the proposed transfer date referred to in paragraph (2)(ii) of this section;

ii. The notice includes a written agreement between the existing and new permittee containing a specific date for transfer of permit responsibility, coverage, and liability between them, and the notice demonstrates that the following financial responsibility requirements of 40 CFR 144.52(a)(7) will be met by the new permittee:

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

(A) The well has been plugged and abandoned in accordance with an approved plugging and abandonment plan and submitted a plugging and abandonment report; or

(B) The well has been converted; or

(C) The transferor of a permit has received notice from the Director that the owner or operator receiving transfer of the permit, the new permittee, has demonstrated financial responsibility for the well.

The permittee shall show evidence of such financial responsibility to the Director by the submission of a surety bond, or other adequate assurance, such as a financial statement or other materials acceptable to the Director.

iii. The Director does not notify the existing permittee and the proposed new permittee of intent to modify or revoke and reissue the permit. A modification under this paragraph may also be a minor modification under section c) – Minor Modification of Permit. If this notice is not received, the transfer is effective on the date specified in the agreement mentioned in paragraph (2)(ii) of this section.

7. <u>Property Rights (40CFR144.51(g))</u>

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

8. Duty to Provide Information (40CFR144.51(h))

   The permittee shall furnish to the Director within a time specified, any information which the Director may request to determine whether cause exists for modifying, revoking and re-issuing, or terminating this permit, or to determine compliance with this permit. The permittee shall also furnish to the Director upon request, copies of records required to be kept by this permit.

9. Inspection and Entry (40CFR144.51(i))

   The permittee shall allow the Director, 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 must be 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 the SDWA and / or UWQA any substances or parameters at any location.

10. Monitoring and Records (40CFR144.51(j))

    a) Samples and measurements taken for the purpose of monitoring shall be representative of the monitored activity.

    b) The permittee shall retain records of all monitoring information, including the following:

       (1) Calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation, copies of all reports required by this permit, and records of all data used to complete the application for this permit, for a period of at least 3 years from the date of the sample, measurement, report, or application. This period may be extended by request of the Director at any time; and

       (2) The nature and composition of all injected fluids until three years after the completion of any plugging and abandonment as appropriate. The Director may require the owner or operator to deliver the records to the Director at the conclusion of the retention period.

    c) 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) The date(s) analyses were performed;

(4) The names of individual(s) who performed the analyses;

(5) The analytical techniques or methods used; and

(6) The results of such analyses.

11. Signatory Requirements (40CFR144.51(k))

All reports or other information, submitted as required by this permit or requested by the Director, shall be signed and certified as follows:

a) Applications. All permit applications shall be signed as follows:

(1) For a corporation: by a responsible corporate officer. For the purpose of this section, a responsible corporate officer means;

i. A president, secretary, treasurer, or vice president of the corporation in charge of a principal business function, or any other person who performs similar policy- or decision-making functions for the corporation, or

ii. the manager of one or more manufacturing, production, or operating facilities employing more than 250 persons or having gross annual sales or expenditures exceeding $25 million (in second-quarter 1980 dollars), if authority to sign documents has been assigned or delegated to the manager in accordance with corporate procedures.

Note:
DEQ does not require specific assignments or delegations of authority to responsible corporate officers identified in 40 CFR 144.32(a)(1)(i). DEQ will presume that these responsible corporate officers have the requisite authority to sign permit applications unless the corporation has notified the Director to the contrary. Corporate procedures governing authority to sign permit applications may provide for assignment or delegation to applicable corporate positions under 40 CFR 144.32(a)(1)(ii) rather than to specific individuals.

(2) For a partnership or sole proprietorship: by a general partner or the proprietor, respectively; or

(3) For a municipality, State, Federal, or other public agency: by either a principal executive officer or ranking elected official. For purposes of this section, a principal executive officer of a Federal agency includes: (i) The chief executive officer of the agency, or (ii) a senior executive officer having responsibility for the overall operations of a principal geographic unit of the agency (e.g., Regional Administrators of EPA).

b) Reports. All reports required by permits and other information requested by the Director shall be signed by a person described in section a), or by a duly authorized representative of that person. A person is a duly authorized representative only if:

(1) The authorization is made in writing by a person described in paragraph a) of this section;

(2) The authorization specifies either an individual or a position having responsibility for the overall operation of the regulated facility or activity, such as the position of plant manager, operator of a well or a well field, superintendent, or position of equivalent responsibility. (A duly authorized representative may thus be either a named individual or any individual occupying a named position); and

(3) The written authorization is submitted to the Director.

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

d) Certification. Any person signing a document under section a) or b) shall make the following certification:

"I CERTIFY UNDER PENALTY OF LAW THAT THIS DOCUMENT AND ALL ATTACHMENTS WERE PREPARED UNDER MY DIRECTION OR SUPERVISION IN ACCORDANCE WITH A SYSTEM DESIGNED TO ASSURE THAT QUALIFIED PERSONNEL PROPERLY GATHER AND EVALUATE THE INFORMATION SUBMITTED BASED ON MY INQUIRY OF THE PERSON OR PERSONS WHO MANAGE THE SYSTEM, OF THOSE PERSONS DIRECTLY RESPONSIBLE FOR GATHERING THE INFORMATION, THE INFORMATION SUBMITTED IS, TO THE BEST OF MY KNOWLEDGE AND BELIEF, TRUE, ACCURATE, AND COMPLETE. I AM AWARE THAT THERE ARE SIGNIFICANT PENALTIES FOR SUBMITTING FALSE INFORMATION, INCLUDING THE POSSIBILITY OF FINE AND IMPRISONMENT FOR KNOWING VIOLATIONS."

12. Reporting Requirements (40CFR144.51(l))

All requirements for reporting the following items are specified in Part III (H) of the permit.

a) Planned Changes
The permittee shall give written notice to the Director, as soon as possible, of any planned physical alterations or additions to the UIC-permitted facility. Notification of planned changes on the part of the permittee does not stay any permit condition.

b) Anticipated Noncompliance
The permittee shall give advance notice to the Director of any planned changes in the permitted facility or activity that may result in noncompliance with permit requirements. Notification of anticipated noncompliance on the part of the permittee does not stay any permit condition.

c) Permit Transfers
This permit is not transferable to any person except in accordance with section d) of Permit Actions – Transfer of Permit. The Director may require modification or revocation and re-issuance of the permit to change the name of the permittee and incorporate such other requirements as may be necessary under the Safe Drinking Water Act and / or the UWQA.

d) Monitoring
All reporting requirements of monitoring results shall be reported at the intervals specified in Part III (H) of this permit.

e) Compliance Schedule
All reports of compliance or noncompliance with, or any progress reports on, interim and final requirements contained in any compliance schedule specified in Part III (B) of this permit shall be submitted no later than 30 days following each schedule date as specified in Part III (H) of this permit.

f) Endangering Noncompliance
The permittee shall report to the Director 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 a USDW, or

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

(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.

g) Other Noncompliance
The permittee shall report all instances of noncompliance not reported under 12d) (Monitoring Reports), 12e) (Compliance Schedule Reports), or 12f) (Endangering Noncompliance Monitoring) of this section in the next Monitoring Report. 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.

h) Other Information

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

13. Requirements Prior to Commencing Injection (40CFR144.51(m))

a) For new injection well authorized by individual permit, a new injection well may not commence injection until construction is complete, and

(1) The permittee has submitted notice of completion of construction to the Director; and

(2) Either of the following:

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

ii. The permittee has not received notice from the Director of his or her intent to inspect or otherwise review the new injection well within 13 days of the date of the notice in section a), in which case prior inspection or review is waived and the permittee may commence injection. The Director shall include in his notice a reasonable time period in which he shall inspect the well.

b) For new injection wells authorized by an area permit under UAC R317-7-7 (40 CFR 144.33), all requirements prior to commencing injection are specified in Part III (E) of the permit.

14. Notification Prior to Conversion or Abandonment. (40CFR144.51(n))

The permittee shall notify the Director at such times as the permit requires before conversion or abandonment of the well or in the case of area permits before closure of the projects.

15. Plugging and Abandonment Requirements. (40CFR144.51(o))

A Class III permit shall include, conditions for developing a plugging and abandonment plan that meets the applicable requirements of UAC R317-7 to ensure that plugging and abandonment of the well will not allow the movement of fluids into or between USDWs. If the plan meets the plugging and abandonment requirements of UAC R317-7, the Director shall incorporate it into the permit as a permit condition. Where the review of the plan submitted in the permit application indicates the plan is inadequate, the Director may require the applicant to revise the plan, prescribe conditions meeting the requirements of this paragraph, or deny the permit. For purposes of this paragraph, temporary or

intermittent cessation of injection operations is not abandonment. All requirements for implementing the approved plugging and abandonment plan are specified in Part III (J) of this permit.

16. Plugging and Abandonment Report. (40CFR144.51(p))

    All requirements for submitting a plugging and abandonment report are specified in Part III (H) of this permit.

17. Duty to Establish and Maintain Mechanical Integrity. (40CFR144.51(q))

    a) The owner or operator of a Class III well shall establish prior to commencing injection or on a schedule determined by the Director, and thereafter maintain mechanical integrity as defined in 40CFR146.8.

    b) When the Director determines that a Class III well lacks mechanical integrity pursuant to 40CFR146.8, written notice of this determination shall be given to the owner or operator. Unless the Director requires immediate cessation, the owner or operator shall cease injection into the well within 48 hours of receipt of the Director's determination. The Director may allow plugging of the well pursuant to the requirements of UAC R317-7 or require the permittee to perform such additional construction, operation, monitoring, reporting and corrective action as is necessary to prevent the movement of fluid into or between USDWs caused by the lack of mechanical integrity. The owner or operator may resume injection upon written notification from the Director that the owner or operator has demonstrated mechanical integrity pursuant to 40CFR146.8.

    c) The Director may allow the owner/operator of a well which lacks internal mechanical integrity pursuant to Part III (I)(1)(a) of this permit to continue or resume injection, if the owner or operator has made a satisfactory demonstration that there is no movement of fluid into or between USDWs.

PART III. SPECIFIC PERMIT CONDITIONS

A. DURATION OF PERMIT
(R317-7-9.5 and 40CFR144.36)

This UIC Class III Solution Mining permit shall be issued for the life time of the project. The Director of the Utah Division of Water Quality (hereafter referred to as 'the Director') shall review this permit once every five (5) years to determine whether it should be modified, revoked and re-issued, terminated, or undergo minor modification according to the requirements of Part II (D)(6) of this permit.

B. COMPLIANCE SCHEDULE
(40CFR144.53)

Intrepid must address each of the following conditions within the time period indicated for each item. Failure to do so may result in the termination of the permit according to Part II(D)(6)(b) of this permit.

1. Construction Plan

   Intrepid shall submit for the Director's approval a revised Construction Plan, which meets the requirements of Part III (D) of this permit, for all Class III injection wells, any production well that may be used for injection, and any stratigraphic test well. The Plan shall be submitted within 90 days of the effective date of this permit modification but before construction of any new injection well.

2. Operating Plan

   Intrepid shall submit for the Director's approval a revised Operating Plan which meets the requirements of Part III (F) of this permit, for all injection wells including production wells that may be used for injection. The Plan shall be submitted within 90 days of the effective date of this permit modification but before the construction of any new injection well. Intrepid shall include new operating protocols to address the use of the Sylvite 5 mine for excess brine storage.

3. Monitoring, Recording and Reporting Plan

   Intrepid shall submit for the Director's approval a revised Monitoring, Recording and Reporting Plan, which meets the requirements of Part III (G and H) of this permit, for all injection wells including production wells that may be used for injection. The Plan shall be submitted within 90 days of the effective date of this permit modification but before construction of any new injection well. Intrepid shall include new monitoring, recording and reporting protocols to address the use of the Sylvite 5 mine for excess brine storage.

Intrepid shall include with the monitoring, recording and reporting plan a piping and instrumentation diagram (P&ID) for all fluid movement into and out of the wells, sampling points, valves, etc.

4. Plugging and Abandonment Plan

   Intrepid shall submit for the Director's approval a revised Plugging and Abandonment Plan, which meets the requirements of Part III (J) of this permit, to include all injection wells, production wells that may be used for injection and not previously addressed in earlier Plans. The Plan shall be submitted within 90 days of the effective date of this permit but before plugging and abandonment

5. Installation of Continuous Monitoring System

   Intrepid shall install a continuous monitoring system to collect injection pressure, injection rate, injection volume, injection temperature, extraction rate, extraction volume, extraction temperature for all caverns.

   a) Monitoring Equipment Installation

      Intrepid shall have the monitoring equipment of the continuous monitoring system installed no later than 1 year after the effective date of this permit. A report of the achievement of this interim task shall be submitted to the Director no later than 30 days after deadline for completing this task.

   b) Continuous Data Logging

      Intrepid shall have the database of the continuous monitoring system operational and be collecting continuous data no later than 2 years after the effective date of this permit. A report of the achievement of this interim task shall be submitted to the Director no later than 30 days after deadline for completing this task.

C. CORRECTIVE ACTION
(40CFR144.52(2). 40CFR144.55, 40CFR146.7)

Intrepid shall identify all artificial penetrations into the permitted injection zones for the solution mining operation that lie within the 2-mile radius area of review of the project area. For such wells which are improperly sealed, completed, or abandoned, Intrepid shall submit a Corrective Action Plan consisting of such steps or modifications as are necessary to prevent movement of fluid into underground sources of drinking water (USDWs) and/or into the Colorado River. The approved and enforceable Corrective Action Plan, if required, is included as Attachment C of this permit.

As of the effective date of this permit or the date the permit was last reviewed, a corrective action plan was not required.

D. CONSTRUCTION REQUIREMENTS
(R317-7-10.1(B) and 40CFR146.32)

1. Class III Injection Well Construction Standards

Each well shall be constructed according to the requirements for Class III wells set forth in R317-7-10.1(B) and 40CFR146.32 details of which are included in the following permit conditions.

2. Construction Plan

The approved and enforceable Construction Plan is included as Attachment D of this permit.

3. Changes to the Construction Plan

Changes to the approved Construction Plan must be approved by the Director as a minor modification of the permit according to Part II (D)(6)(c)(6) of this permit. No such changes may be physically incorporated into construction of the well or the development of the cavern prior to approval of the modification by the Director. All changes must comply with UAC R317-7 and those sections of 40CFR144 and 40CFR146 incorporated by reference in the state rule.

4. Casing and Cement

Regulatory Reference: All new Class III wells shall be cased and cemented to prevent the migration of fluids into or between underground sources of drinking water. The Director may waive the cementing requirement for new wells in existing projects or portions of existing projects where there is substantial evidence that no contamination of underground sources of drinking water would result. It is the permittee's responsibility to provide such evidence to the Director. The casing and cement used in the construction of each newly drilled well shall be designed for the life expectancy of the well. The permittee shall consider the following factors in designing a casing and cementing program for the well:

(1) Depth to the injection zone;

(2) Injection pressure, external pressure, internal pressure, axial loading, etc.;

(3) Hole size;

(4) Size and grade of all casing strings (wall thickness, diameter, nominal weight, length, joint specification, and construction material);

(5) Corrosiveness of injected fluids and formation fluids;

(6) Lithology of injection and confining zones; and

(7) Type and grade of cement.

The following requirements pertaining to the cement and casing shall apply:

a) Only new casing shall be installed.

b) Surface and intermediate casing strings shall be used to protect USDWs above the uppermost mine.

c) All casings shall be cemented to protect USDWs and other subsurface resources.

d) A minimum of one cemented casing shall be set across all non-salt formations.

e) Appropriate cement shall be used for cementing across salt formations.

f) Centralizers shall be used on all cemented casing strings and shall be placed to optimize the proper placement of cement in casing-borehole annulus.

g) Boreholes shall be conditioned prior to running cement.

5. Tubing / Packer

All wells operated in pressurized mode shall be constructed to inject/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 inside the tubing string which is connected to the packer if desired.

6. Logging and Testing

Regulatory Reference: Appropriate logs and other tests shall be conducted during the drilling and construction of new Class III wells. A descriptive report interpreting the results of such logs and tests shall be prepared by a knowledgeable log analyst and submitted to the Director. The logs and tests appropriate to each type of Class III well shall be determined based on the intended function, depth, construction and other characteristics of the well, availability of similar data in the area of the drilling site and the need for additional information that may arise from time to time as the construction of the well progresses. Deviation checks shall be conducted on all holes where pilot holes and reaming are used, unless the hole will be cased and cemented by circulating cement to the surface. Where deviation checks are necessary they shall be conducted at sufficiently frequent intervals to assure that vertical avenues for fluid migration in the form of diverging holes are not created during drillings.

All logging and test results must be made available to DWQ upon request.

The following geophysical logs and tests must be performed during construction of each Class III injection well:

a) Cement Evaluation Logs and Background Gamma Ray Logs shall be run on each casing string placed directly adjacent to bare formations.

b) Background 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.

c) Casing Inspection Logs (ultrasonic or electromagnetic flux) shall be run on last cemented casing seated at the top of the injection zone (base of Clastic 2) from casing seat to surface. Multi-arm casing inspection logs may be run in the deviated portion of wells into Sylvite 9.

d) Casing Pressure Test according to Part III(I)(9)(a) of this permit.

7. Injection Zone Characterization

a) Where the injection zone is a formation which is naturally water-bearing the following information concerning the injection zone shall be determined or calculated for new Class III wells or projects:

(1) Fluid pressure;

(2) Fracture pressure; and

(3) Physical and chemical characteristics of the formation fluids.

b) Where the injection formation is not a water-bearing formation, only the fracture pressure must be submitted.

c) The approved and enforceable Formation Testing Program is included in the Construction Plan in Attachment D of this permit.

8. Well Stimulation Program

If the operator intends to stimulate the well to clean the well bore, enlarge channels, and increase pore space in the interval to be injected thereby enhancing the injectivity of the well, a Well Stimulation Program must be prepared for the Director's approval and included in the Construction Plan in Attachment D of this permit. Well stimulation commonly refers to hydraulic fracturing, acid fracturing, and matrix acidification. Well stimulation does not include the process of solution mining the potash ore which includes under-reaming, freshwater injection to enlarge the boreholes being drilled, and other drilling and solution mining activities.

9. Monitoring Wells

Other than the use of Shaft #2 to measure fluid levels in the Sylvite 5 mine, no monitoring wells are required by this permit.

10. Additional Construction Requirements

a) New Well Construction Plan - No less than 30 days prior to the planned construction of a new well, the permittee shall submit individual plans, which meet the requirements of this section, 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 Director.

b) New Cavern - No less than 90 days prior to drilling new wells for the creation of a new cavern, Intrepid shall submit for the Director's approval a new

geomechanical analysis of mine site and revised construction, operating, monitoring and plugging and abandonment plans to address the new cavern(s).

c) New Stratigraphic Wells (Core Holes) – No less than 30 days prior to the planned construction of a new stratigraphic well, the permittee shall submit individual plans, which meet the requirements of this section, for each new stratigraphic well to be constructed, for review and approval by the Director. Stratigraphic well construction may begin only after receipt of written approval from the Director.

E. REQUIREMENTS PRIOR TO SOLUTION MINING (40CFR146.34(b))

In accordance with Part II (D)(13) of this permit, the following requirements must be met prior to the commencement of solution mining:

1. Well Completion Report

The operator shall submit for the Director's review an injection well completion report consisting of:

a) All available logging and testing data on the well that is relevant to mechanical integrity of the well and presence or absence of a USDW (casing pressure test data, casing inspection logs, cement evaluation logs, radioactive tracer test logs, spontaneous potential logs, downhole fluid tester data, etc.;

b) Results of mechanical integrity testing for each new well;

c) Actual maximum injection pressure and injection flow rate;

d) Results of the formation testing program;

e) Actual solution mining procedures;

f) Status of all wells requiring corrective action within the area of review, if applicable;

g) Detailed 'As-Built' Well Schematic including:

(1) Casing details including size, weight, grade and setting depths,

(2) Cement details including type, special formulations, calculated volumes, actual pumped volumes, and yield (cubic feet / sack),

(3) Formation horizons, and

(4) Groundwater horizons.

h) Explanation and justification for any deviations from approved plan.

2. Director's Approval to Commence Solution Mining

   Within 14 days after receipt of the well completion report, the Director shall provide written notice denying or granting approval to commence solution mining.

F. OPERATING REQUIREMENTS
(R317-7-10.2(A))

1. Class III Injection Well Operation Standards

   Operating requirements for the drilling and solution mining of each well are set forth in R317-7-10.2(A) details of which are included in the following permit conditions.

2. Operating Plan

   The approved and enforceable Operating Plan that meets all the operating requirements of this section is included as Attachment E of this permit.

3. Maximum Allowable Surface Injection Pressure (MASIP)

   Except during well stimulation, the maximum allowable surface injection pressure (MASIP) at the wellhead shall be calculated

   a) to ensure that pressure in the injection zone does not initiate new fractures or propagate existing fractures in the confining zones; and

   b) to ensure that pressure in the mines does not cause migration of injectate or formation fluids into an USDW; and

   c) to ensure that pressure in the mines does not cause migration of injectate or formation fluids into the Colorado River.

4. Borehole – Casing Annulus Injection Prohibited

   Injection between the outermost casing protecting USDW's and the well bore is prohibited.

5. Additional Operating Requirements

   a) Injection Formations - Injection shall be limited to the base of Clastic 2 where it contacts the Salt 3 zone of the Paradox Formation and below, down to and including the Sylvite 9 salt zone.

   b) Injectate Fluid Limitations – Injection fluid is limited to:

      (1) Colorado River water, and

      (2) Brine from the Tailings Lake, and

      (3) Brine from the Sylvite 5 mine, and

(4) Brine from Sylvite 9 mine, and

(5) Brine recovered from environmental reclaim ponds.

c) Fluid Levels in Shaft #2 – The fluid level in Shaft #2 shall be maintained below the bottom of the Colorado River channel. To this end, the depth of the fluid level in Shaft #2 as measured from the casing collar shall not be less than 125 feet. If in the future it is determined that this depth is not below the bottom of the Colorado River channel, the 125-ft depth will be increased.

d) Injection / Extraction Ratios – During the time when Colorado River water is injected, the injection / extraction ratio shall not exceed 1.08. During the time when brine is injected, the injection / extraction ratio shall not exceed 1.02.

G. MONITORING AND RECORDING REQUIREMENTS (R317-7-10.3(B), 40CFR144.54, and 40CFR146.34)

1. Class III Injection Well Monitoring and Recording Standards

   Monitoring and recording requirements for the drilling and solution mining of each well are set forth in R317-7-10.3(B) and 40CFR144.54 details of which are included in the following permit conditions.

2. Utah UIC Quality Assurance Project Plan (QAPP)

   All monitoring, recording, and reporting of environmental data for the UIC Program shall comply with the most current revision of the Utah UIC QAPP.

3. Monitoring, Recording and Reporting Plan

   The approved and enforceable Monitoring, Recording and Reporting Plan that meets all the monitoring and recording requirements of this section is included as Attachment F of this permit.

4. Monitoring Equipment and Methods

   Regulatory Reference: All monitoring equipment shall be properly selected, installed, used, and maintained according to the manufacturer's specifications so as to yield data which are representative of the monitored activity. All monitoring methods shall be properly selected and implemented at appropriate intervals and frequency so as to yield data which are representative of the monitored activity. Documentation verifying, if applicable, the proper selection, installation, use, and maintenance of monitoring equipment and the proper implementation of monitoring methods shall be made available to the Director upon request.

5. Injectate Characterization

   Regulatory Reference: The permittee shall monitor the nature of injected fluids with sufficient frequency to yield representative data on its characteristics. The permittee shall provide qualitative analysis and ranges in concentrations of all

monitored constituents, listed below, of injected fluids. Whenever the injection fluid is modified to the extent that this analysis is incorrect or incomplete, a new analysis shall be provided to the Director. The permittee may request confidentiality in accordance with Part II C of this permit. If the information is proprietary the permittee may, in lieu of the ranges in concentrations, choose to submit maximum concentrations which shall not be exceeded. In such a case the permittee shall retain records of the undisclosed concentrations and provide them upon request to the Director as part of any enforcement investigation.

Intrepid shall monitor the water quality of the injectate at least quarterly or more frequently if the source of the injectate changes. The water quality of the injectate shall be analyzed for the following constituents:

a) Inorganics: Potassium

b) Acid Soluble Metals (unfiltered sample): Arsenic, Chromium, Selenium, Zinc

c) Field Measurements: pH, Temperature, Specific Conductivity

6. Injection Pressure, Injection Rate, and Injection Volume

Regulatory Reference: The permittee shall monitor the injection pressure and either the injection rate or injection volume semi-monthly, or metering and daily recording of injected and produced fluid volumes as appropriate.

Intrepid shall continuously monitor the injection pressure, injection rate, injection volume, injection temperature, extraction rate, extraction volume, extraction temperature for all caverns.

7. Mechanical Integrity Test (MIT)

Mechanical integrity testing shall be conducted according to Part III (I) of this permit.

8. Injection Zone Fluid Level

Regulatory Reference: The permittee shall monitor the fluid level in the injection zone no less frequently than semi-monthly, where appropriate. Injection zone fluid level monitoring shall be representative of the level during normal operations.

Intrepid shall monitor continuously the fluid level in Shaft #2.

9. Manifold Monitoring

Regulatory Reference: The permittee may monitor its Class III injection wells on a field or project basis rather than an individual well basis by manifold monitoring. Manifold monitoring may be used in cases of facilities consisting of more than one injection well, operating with a common manifold. Separate monitoring systems for each well are not required provided the owner/operator

demonstrates that manifold monitoring is comparable to individual well monitoring.

Intrepid does not intend to implement manifold monitoring.

10. Additional Monitoring and Recording Requirements

As of the effective date of this permit or the date the permit was last reviewed, additional permit conditions for monitoring and recording were not required.

H. REPORTING REQUIREMENTS (R317-7-10.4(B) and 40 CFR 144.54)

1. Quarterly Monitoring Reports

a) Schedule for Submitting Quarterly Monitoring Report

Quarter		Report Due On:
1st Quarter	Jan 1 – Mar 31	Apr 15
2nd Quarter	Apr 1 – Jun 30	July 15
3rd Quarter	Jul 1 – Sep 30	Oct 15
4th Quarter	Oct 1 – Dec 31	Jan 15

b) Content of Quarterly Monitoring Reports

Monitoring data for the following shall be included in the quarterly monitoring reports:

(1) Injectate Characterization
(2) Injection Pressure - daily average
(3) Injection and Extraction Rates, Volumes, and Temperature - daily average
(4) Injection Zone Fluid Level (Shaft #2) - daily average
(5) Monitoring Wells, if applicable
(6) Manifold Monitoring, if applicable
(7) Noncompliance Not Previously Reported – Such 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.
(8) Other Required Monitoring

2. Endangering Noncompliance Reporting

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

a) 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:

(1) Any monitoring or other information that indicates any contaminant may cause an endangerment to a USDW, or

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

b) 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.

3. Planned Changes

The permittee shall give written notice to the Director, as soon as possible, of any planned physical alterations or additions to the UIC-permitted facility. Notification of planned changes on the part of the permittee, does not stay any permit condition.

4. Anticipated Noncompliance

The permittee shall give advance notice to the Director of any planned changes in the permitted facility or activity that may result in noncompliance with permit requirements. Notification of anticipated noncompliance on the part of the permittee, does not stay any permit condition.

5. Permit Transfers

This permit is not transferable to any person except in accordance with Part II (D)(6)(d) of this permit. The current permittee shall notify the Director at least 30 days in advance of the proposed transfer date. Notification shall comply with the requirements in Part II(D)(6)(d) of this permit.

6. Compliance Schedule Reporting

Reports of compliance or noncompliance with, or any progress reports on, interim and final requirements contained in any compliance schedule specified in Part III B of this permit shall be submitted no later than 30 days following each schedule date.

7. Mechanical Integrity Reporting

   a) Mechanical Integrity Demonstration - The permittee shall submit the results of any MI demonstration within 60 days after completion of the test. The permittee shall include in the report, a detailed description of the tests and the methods used to demonstrate MI. In the case of MI failure, the permittee shall also describe in detail what and when steps were taken to reestablish MI.

   b) Loss of Mechanical Integrity –

      (1) In the event of a mechanical integrity failure which may potentially endanger an USDW, report to the Director verbally within 24 hours followed by submission of a written report within 5 days.

      (2) Within 15 days after loss of MI, submit to the Director a schedule indicating what will be done to restore MI to the well, or if it will be plugged.

8. 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 Director. 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 P&A Plan(s) previously submitted to, and all conditions of approval provided by, the Director; or

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

9. Additional Reporting Requirements

   a) Permit Review Report

      Within 30 days after effective date of this permit, the permittee shall report to the Director that the person(s) responsible for implementing this permit has read and is personally familiar with all terms and conditions of this permit.

   b) Electronic Reporting

      In addition to submittal of the hard copy data, the permittee shall submit the required monitoring data in an Excel spreadsheet.

I. MECHANICAL INTEGRITY
(R317-7-10.3(B) and 40CFR146.8)

1. Class III Injection Well Mechanical Integrity Standards

Mechanical integrity testing requirements for each Class III well are set forth in 40CFR146.8 details of which are included in the following permit conditions:

An injection well has mechanical integrity (MI) if there is:

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

b) No significant fluid movement into an USDW through vertical channels adjacent to the injection well bore (external MI).

2. Mechanical Integrity Testing (MIT) Methods

The following methods are allowed for demonstrating internal and external mechanical integrity of Class III injection wells:

a) Internal MI

(1) **Standard Annulus Pressure Test (SAPT) -** For Wells Equipped with Tubing and Packer: Following an initial casing pressure test (see Part III(I)(9)(a) – Casing Pressure Tests below), monitoring of the tubing-casing annulus pressure with sufficient frequency to be representative, as determined by the Director, while maintaining an annulus pressure different from atmospheric pressure measured at the surface;

(2) **Standard Annulus Monitoring Test (SAMT)** – For Wells Equipped with Tubing and Packer

(3) **Radioactive Tracer Survey (RTS)** – Allowed by Federal Register Notice Volume 52, No. 181; Friday, September 18, 1987; Pages 35324 to 35326 and as revised by Federal Register Notice Volume 52, No. 237; Thursday, December 10, 1987; Pages 35324 to 35326. The timed-run method of running the RTS is the only method approved by EPA to demonstrate MI. The velocity-shot method is not.

(4) **Water-Brine Interface Test (W-BIT)** – For Class III Salt Solution Mining Wells Only. Allowed by Federal Register Notice Volume 57, No. 7; Friday, January 10, 1992; Pages 1109 to 1112. Method, procedures and limitations for implementing the test must follow those described in the FR Notice.

(5) **"ADA" Pressure Test**

b) External MI

(1) **Temperature Survey**

(2) **Noise Log**

(3) **Oxygen Activation Method (OAL)** – Final approval for use in Federal Register Notice Volume 56, Number 22; Friday, February 1, 1991, Pages 4063 to 4065.

(4) **Radioactive Tracer Survey (RTS)** - Allowed by Federal Register Notice Volume 52, No. 181; Friday, September 18, 1987; Pages 35324 to 35326 and as revised by Federal Register Notice Volume 52, No. 237; Thursday, December 10, 1987; Pages 35324 to 35326. The timed-run method of running the RTS is the only method approved by EPA to demonstrate MI. The velocity-shot method is not. The RTS may only be used to demonstrate external MI when the USDW is directly above the injection zone but separated from it by an impermeable confining zone.

(5) **Cementing Records + Monitoring Program** – If the nature of the casing precludes the use of the logging methods above, then cementing records may be used to demonstrate external MI provided the monitoring program required by Part III (G) of this permit is designed to verify the absence of significant fluid movement into an underground source of drinking water through vertical channels adjacent to the injection well bore.

c) The Director may allow the use of a test to demonstrate mechanical integrity other than those listed in a) and b) above with the written approval of the EPA Region 8 Administrator (Administrator). To obtain approval, the Director shall submit a written request to the Administrator, which shall set forth the proposed test and all technical data supporting its use. The Administrator shall approve the request if it will reliably demonstrate the mechanical integrity of wells for which its use is proposed. Any alternate method approved by the Administrator shall be published in the **Federal Register** and may be used in all States unless its use is restricted at the time of approval by the Administrator.

d) In conducting and evaluating the tests enumerated in this section or others to be allowed by the Director, the owner or operator and the Director shall apply methods and standards generally accepted in the industry. When the owner or operator reports the results of mechanical integrity tests to the Director, he shall include a description of the test(s) and the method(s) used. In evaluating the MIT results, the Director shall review monitoring and other test data submitted since the previous evaluation.

e) The Director may require additional or alternative tests if the results presented by the owner or operator under d) above are not satisfactory to the Director to demonstrate that there is no movement of fluid into or between USDWs resulting from the injection activity.

3. <u>Mechanical Integrity Demonstration Plan</u>

The permittee shall prepare a detailed plan to demonstrate MI to be included in the approved and enforceable Monitoring, Recording and Reporting Plan in Attachment F of the permit. In preparing a plan, which includes MI tests or

demonstration methods allowed by the Director, the permittee shall apply methods and standards generally accepted in the industry for conducting and evaluating the tests (40CFR146.8(e)).

4. Mechanical Integrity Demonstration Frequency

   The permittee shall demonstrate MI for each injection well / cavern according to Part III (J)(2) above:

   a) Before solution mining commences;
   b) Once every 5 years after the initial demonstration,
   c) Following any repair or workover of a well involving the cemented casings, prior to placing it back into operation.

5. Prohibition Without Demonstration

   The permittee shall not commence injection operation of any new well without:

   a) Prior demonstration of MI, and
   b) Receipt of Director written approval of the MI demonstration.

6. Loss of Mechanical Integrity

   If the permittee or the Director determines that a well fails to demonstrate MI the permittee shall:

   a) Cease operation of the well immediately, and
   b) Take steps to prevent losses of brine into USDWs or the Colorado River, and
   c) If the mechanical integrity failure may potentially endanger an USDW and/or the Colorado River, report to the Director verbally within 24 hours and submit a written report within 5 days according to Part III (H)(2) of this permit, and
   d) Within 15 days after loss of mechanical integrity, submit to the Director a schedule indicating what will be done to restore mechanical integrity to the well, or if it will be plugged, and
   e) Within 90 days after loss of MI, restore MI or plug and abandon the well in accordance with a plugging and abandonment plan approved by the Director, and
   f) The permittee may resume operation of the well after demonstration of MI and receiving written approval from the Director.

7. Mechanical Integrity Demonstration Requests

   With just cause, the Director may at any time require, by written notice, the permittee to demonstrate MI of a well.

8. Mechanical Integrity Demonstration Inspections

The permittee shall allow the Director, or his representative, to observe any or all MI demonstrations. The permittee shall notify the Director, in writing, of its intent to demonstrate MI, no less than 30 days prior to the intended demonstration.

9. Additional MIT Requirements

a) Casing Pressure Test

In order to determine the integrity of casing strings set in the well, the operator shall perform a hydrostatic pressure test before drilling out any casing string, before suspending drilling operations, or before completing the well, to the lesser of

(1) the maximum anticipated pressure to be contained at the surface,

(2) one psi/ft of the last casing string depth, or

(3) 70% of the minimum internal yield pressure of any casing subject to the hydrostatic pressure test.

b) Internal Mechanical Integrity Exception

According to 40CFR144.51(q)(3), the Director may allow the owner/operator of a well which lacks internal mechanical integrity (Part III (I) (1) (a) of this permit) to continue or resume injection, if the owner or operator has made a satisfactory demonstration of external mechanical integrity (that is, that there is no movement of fluid into or between USDWs.) Such proposals of satisfactory demonstration shall be reviewed and approved or denied on an individual basis.

J. PLUGGING AND ABANDONMENT REQUIREMENTS
(40CFR146.10 and R317-7-10.5)

1. Requirement for Plugging and Abandonment Plan

The permittee shall develop a plugging and abandonment plan (hereafter, the P&A Plan) for the Class III solution mining wells as required by Part II D(15) of this permit. The approved P&A Plan shall become a permit condition of this permit and be incorporated into the permit as Attachment H.

2. Notice of Plugging and Abandonment

The permittee shall notify the Director 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 in the existing P&A Plan. 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 salt formation, as determined from cement bond logs run at the time of well construction or just prior to well abandonment.

(5) Any supporting data or test results supporting the conclusions of the well condition report shall be attached to the report.

b) Individual Plugging and Abandonment Plan
The permittee shall also submit an individual P&A Plan for each well to be plugged and abandoned. In coordination with the Well Condition Report, this individual P&A Plan shall modify and supersede previous P&A Plans, as necessary, to ensure adequate plugging and abandonment of the well.

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

3. 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 Director 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 Director approval of emergency well conversion or abandonment, with appropriate justification, within five (5) working days after receiving oral approval.

c) The Director 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 Director 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 P&A Plan.

4. Plugging and Abandonment

The permittee shall plug and abandon the well(s) consistent with R317-7-10.5, as provided for in the P&A Plan, and any conditions issued by the Director in approval of the individual P&A Plans required by this permit.

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), unless the permittee requests and receives a variance from this requirement from the Director 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 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 Director.

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, for Director approval.

(3) Emplacement of a bridge plug below the lowermost leak in the casing, if any, or at a depth required by the P&A Plan, or at a depth as directed by the Director.

(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 P&A Plan and 40 CFR 146.10.

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

c) 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 Director, and

(2) Demonstration of mechanical integrity to the Director, as required by this permit, and

(3) Receipt of Director written approval of mechanical integrity demonstration and approval to reactivate the well.

K. FINANCIAL RESPONSIBILITY
(R317-7-9.1(24) and 40CFR144.52)

1. Demonstration of Financial Responsibility

The permittee is required to maintain financial responsibility and resources to close, plug, and abandon all wells and mine shafts referenced in the approved Plugging and Abandonment Plan (Attachment H), 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 included in Attachment I of this permit.

2. Renewal of Financial Responsibility

   Every five (5) years, the permittee shall demonstrate the adequacy of the financial assurance instrument to close, plug and abandon all wells not permanently plugged and abandoned by the permittee in compliance with the plugging and abandonment requirements of this permit.

3. Insolvency Financial Responsibility

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

   a) The institution issuing the trust or financial assurance 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 assurance instrument is suspended or revoked.

L. ADDITIONAL CONDITIONS (40CFR144.52)

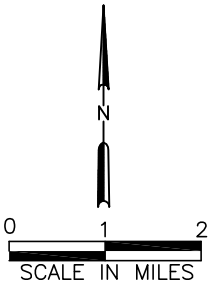
The Director shall impose on a case-by-case basis such additional conditions as are necessary to prevent the migration of fluids into underground sources of drinking water.

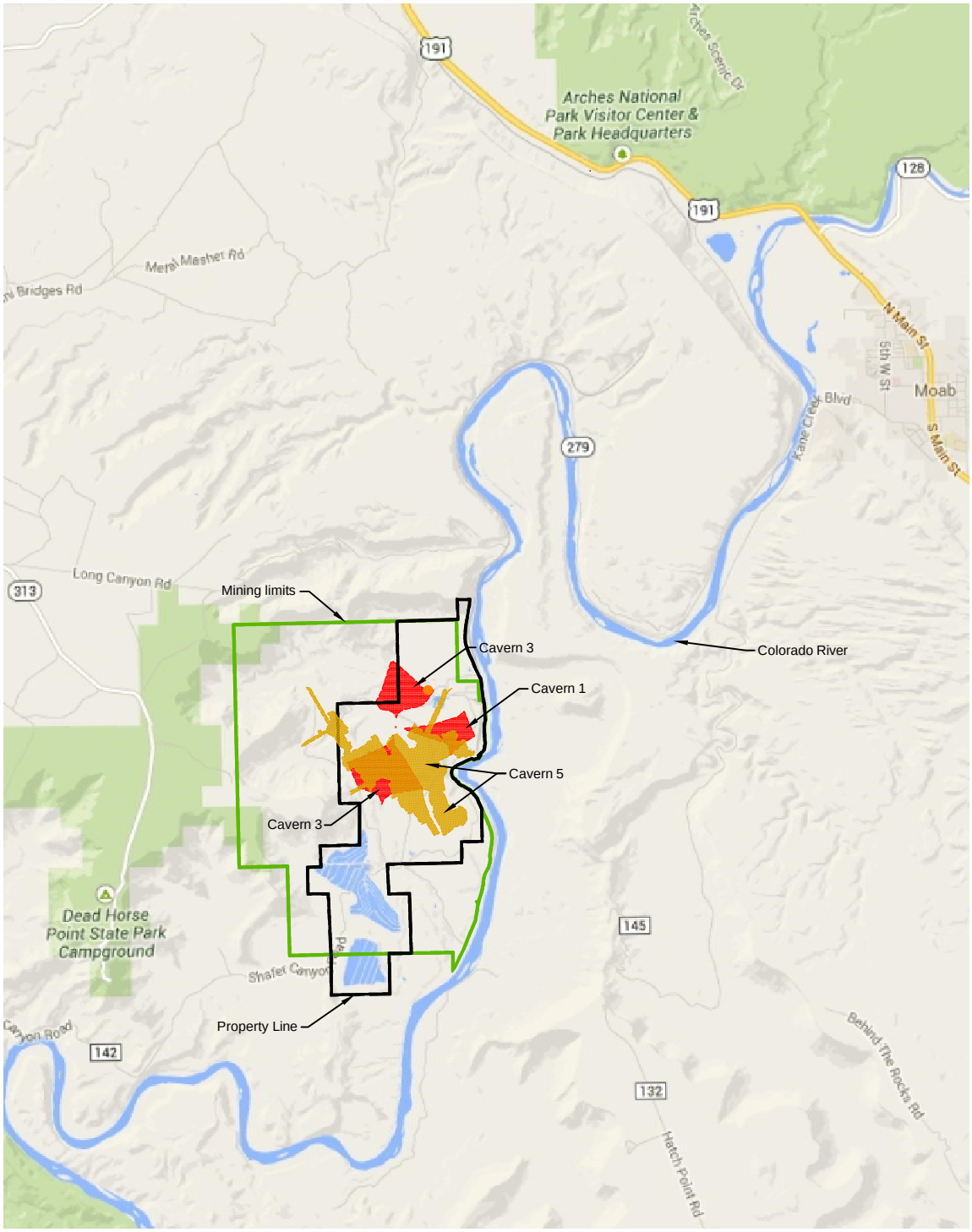
As of the effective date of this permit or the date the permit was last reviewed, additional permit conditions were not required.

M. ATTACHMENTS

Attachment A

General Location Map of the Cane Creek Mine,
Grand County





INTREPID POTASH

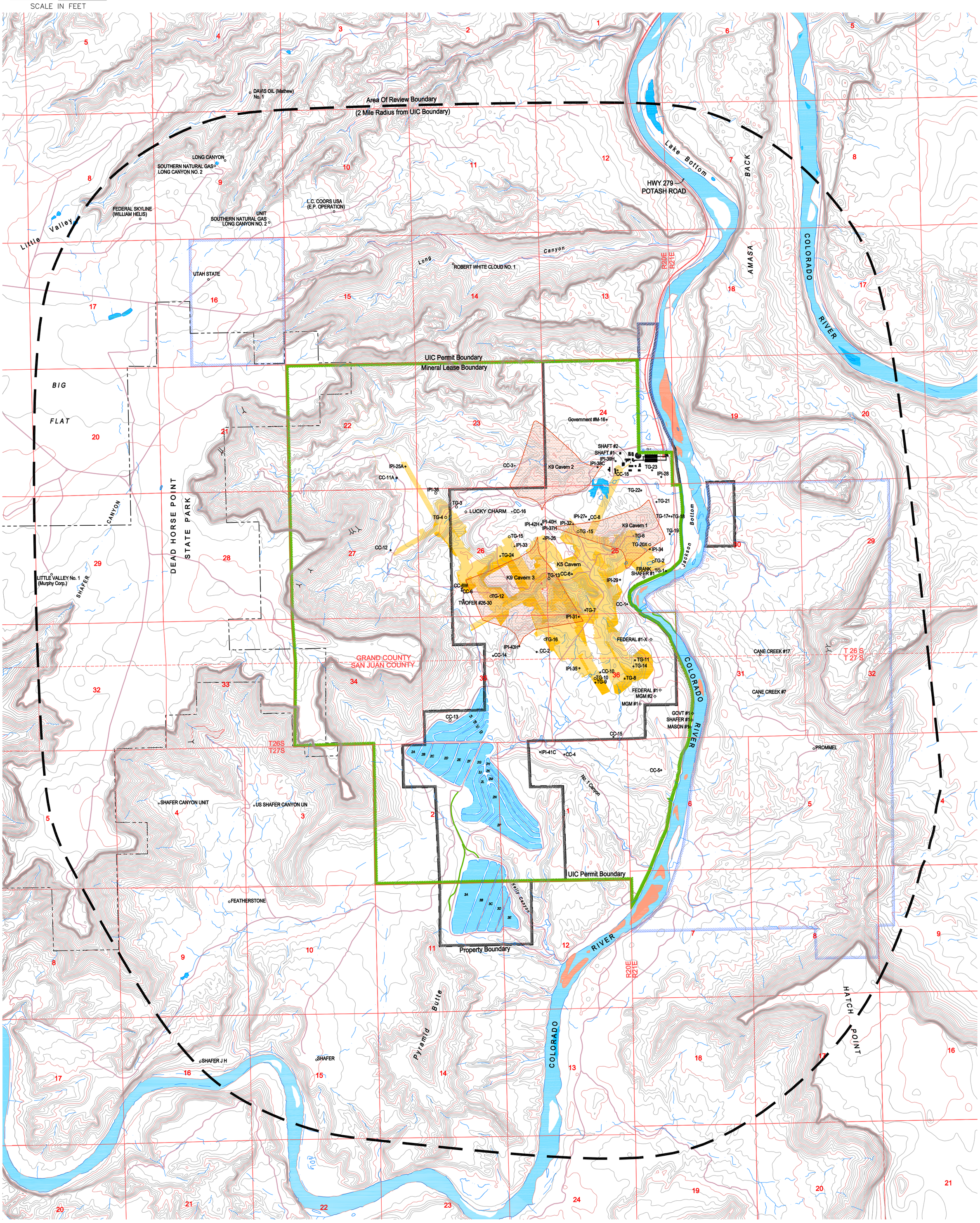
DATE 9-22-13
DWN GRH
APP
REV
PROJECT NO.
UIC-001-001

FIGURE 1
INTREPID POTASH
MOAB, UTAH
UIC PERMIT
SITE LOCATION

D:\Intrepid\Overal Site Maps\UIC Permit Drawings\Figures 8x11.dwg

Attachment B

Map of the UIC Area of Review including the Class III Solution Mining Injection Wells and the Project Area



Site Plan Explanation

- Active Potash Injection/Extraction Well
- Abandoned Potash Injection/Extraction Well
- Gas & Oil Well
- Property Boundary
- Mineral Lease & UIC Boundary
- Recent Mineral Leases
- Area of Review
- Rail Road Tracks
- Cavern 1, 2 & 3
- Cavern 5 - Original Mine Limits
- Cavern 5 - Estimated 2013 Dissolution Limits
- 40' Contour Interval (MSL)
- Existing Road
- Adits (Mine Entrance)

Base Map Source Information from USGS 7.5 minute Quadrangle maps:

- Trough Springs Canyon, UT, Quad 038109d5
- Schafer Basin, UT, Quad 038109d6
- Musselman Arch, UT, Quad 038109d7
- Moab, UT, Quad 038109e5
- Gold Bar Canyon, UT, Quad 038109e6
- The Knoll, UT, Quad 038109e7

INTREPID POTASH

DATE 3-26-14
DWN. GRH
APPR. CDF
PROJECT NO. IPMO-001.001

UIC PERMIT
INTREPID POTASH – MOAB, LLC
AREA OF REVIEW
TOPOGRAPHY

Drawing No.
1

Attachment C

Corrective Action Plan for Artificial Penetrations into Injection Zone within Area of Review

(at the time this permit renewal was issued, there were no wells within the Area of Review requiring corrective action)

Attachment D

Injection Well Construction Plan with
Injection Well Construction Details

ATTACHMENT D—INJECTION AND EXTRACTION WELL CONSTRUCTION PLAN WITH CONSTRUCTION DETAILS

Permit Condition Reference: Part III.D.2.

This attachment comprises the approved and enforceable construction plan for injection and extraction wells, and for stratigraphic test wells (core holes). IPM currently operates wells in the 5th ore zone (Sylvite 5) and the 9th ore zone (Sylvite 9). In addition, core holes are advanced for evaluating the geology.

The designs submitted and discussed in this section are considered minimum designs. As the well field is expanded with new wells, each well is designed for the objectives of that operation. The new design takes into account the implementation of previous well drilling and construction programs. Intrepid works with many service providers (e.g. Halliburton, Weatherford, Baker Hughes, etc.) to continually advance the designs of the wells to increase longevity, efficiency, and protection of the environment. All wells constructed since 2000 have been cemented from total depth to surface to mitigate external corrosion.

Prior to drilling new wells, a proposed well schematic and an abandonment plan will be submitted to DEQ for review and approval.

1. CONSTRUCTION OF SYLVITE 5 INJECTION AND EXTRACTION WELLS

Wells in the 5th ore zone (Sylvite 5) are currently constructed into the original open mine works. Presented below are the designs for those wells. Intrepid intends to consider drilling horizontal wells in the ore zone outside of the original mine works. The construction for those wells is discussed separately. A typical Sylvite 5 well diagram is included as Figure 4 of the Technical Report submitted as part of the application for this permit (2013).

1.1. TOTAL DEPTH

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.

1.2. PRESSURES AND AXIAL LOADING

1.2.1. Injection Pressure

Well 24 is the only injection well in Sylvite 5, 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, in the approved and enforceable Operation Plan (Attachment E).

1.2.2. 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' msl, casing depths ranging from 800-1200-ft, and fluid densities of 9.3-10.0 lbs/gal, the maximum external pressure ranges from 1,302 to 1,608 psi with completely evacuated casing.

1.2.3. 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 0.0374 psi/ft, or 120 psi for a 3,300-ft deep well.

1.2.4. Axial Loading

The maximum load on the exterior casing, using a buoyancy correction for 10.0-ppg drilling fluid, is 77,942-pounds for a typical string length of 2,300-ft. The interior string

is run after cementing the exterior string and is typically 1,000-ft long, giving an axial load of 19,486-lbs.

The casing string described in section 1.5 is well within its capacities concerning the above pressures and load.

1.3. BOREHOLE SIZE

Borehole size typically ranges from 20-inch for the surface casing, 15" to12-¾" where the exterior (surface) casing is set, 8-¾" where the interior (intermediate) casing is set, and 5-7/8" to 6-1/8" for the open hole completion into the mine workings.

1.4. COMPLETION

Wells into the Sylvite 5 mine cavity are completed with an open-hole section below the lowest casing string into the Sylvite 5 mine cavity. This open-hole section extends from Clastic 4 into the mine cavity in Sylvite 5.

1.5. TYPICAL CASING STRINGS

Permit Condition Reference: Part III.D.4, Part III.D.4 (a)

Only new casing shall be installed in wells. The typical casing string for wells in Sylvite 5 is described below.

1.5.1. Conductor Casing

Conductor casing is 10-¾" - 20" line pipe, ¼-inch wall, with setting depth ranging from 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-ft of solid bedrock. New wells constructed in Colorado River alluvium, identified as stratigraphic units Qu and QTu on Figure 2 of the 1985 Huntoon Report, will be constructed such that the surface casing extends significantly into bedrock. The annulus between the drill hole and the surface casing is cemented back to the surface.

1.5.2. Surface Casing

Permit Condition Reference: Part III.D.4 (b)

Surface casing is 9-5/8" 40-pound, J-55 or K-55, 0.395-inch wall, 8 round thread, American Petroleum Institute (API) standard, setting from the surface to about 2,300-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.

1.5.3. Intermediate Casing

Permit Condition Reference: Part III.D.4 (b)

7" 23#, J-55 or K-55, 0.317-inch wall, 8 round threads, LTC, API Standard, (or higher grade) set from approximately 200' above the bottom of the 9-5/8" casing to about 3,300 feet or into Clastic 4. This casing is cemented from the base of Clastic 2 (or lower) to the top of the 200-ft overlap. This creates a 200-ft sealed overlap between the two strings of casing.

1.6. INJECTION ZONE

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.

1.7. TYPICAL CEMENTING PROCEDURES

Halliburton or other reputable cement service companies are contracted to provide cement, equipment and personnel.

Cementing the surface casing requires circulating cement down the inside of the casing, out the shoe and up the annulus. Cement excess of 120 to 150% of calculated cement volume may be necessary for the primary lift. Lost circulation material (LCM) may be added to the cement mixture; however, residual LCM may be present from drilling and may not be needed. The cement company may pump a top out cement if the primary cement does not come to surface. Typically a tremie pipe method is used for the top off cement due to lower cost and simplicity.

Intermediate casings and or liners are cemented by pumping the cement slurry down the inside of the casing, through the shoe and up the annulus. Cement excess is typically lower in this section due to increased wellbore stability and less loss circulation. The excess for this calculated cement volume is 10% minimum. A liner top packer at the top of the 7-inch casing is engaged after cementing, isolating the backside of the 7-inch and the 9-5/8-inch x 7-inch annulus. Excess is cement reverse circulated out of the hole and back to surface.

Specific Cementing Procedures for specific casings are described below.

Permit Condition Reference: Part III.D.4 (c)

1.7.1. Conductor, 20-inch

- Annular volume between 26-inch hole and casing = .0.2681 bbl/lin.ft

- Volume of cement required = depth (ft) * 0.2681bb/ft. If cement does not circulate to surface, ready-mix is to be poured until visible at surface
- Cement Type = Ready-Mix cement, 15 lbs/gal. Slurry wt.
- Equipment: None, open ended

1.7.2. Surface Casing, 9-5/8-inch

- Annular volume between 14-3/4-inch hole and casing = 0.1214 bbl/ft
- Volume of cement required = depth (ft) * 0.1214 bbl/ft. Increase this by 10% excess minimum
- Spacers (before and after cement) – Reactive spacers, may consist of one or two pumped in recommended sequence. Halliburton (HES) uses CaCl and a proprietary product called Super Flush. Other cement service companies offer similar reactive products and may be used instead of HES products
- Cement details - Type VERSACEM or similar; 11-16 lbs/gal Cement type & weight vary with advancements in cement technology
- Minimum equipment: double float system consisting of a float collar and float shoe; centralizers; rubber cementing top plug; Weld-A; tremie pipe for top out cement

1.7.3. Intermediate Casing or Liner, 7-inch

- Volume between 8-1/2-inch hole and casing = 0.0118 bbl/ft
- Volume of cement required = measured depth from base of surface casing to shoe (may need to include rat hole) in ft. * 0.0118 bbl/ft. Increase the volume by 10% excess minimum
- Volume between 9-5/8-inch casing and intermediate casing = 0.0282 bbl/ft
- Volume of cement required = footage of overlap into 9-5/8-inchch casing * 0.0282 bbl/ft
- Typical Cement Type = Class G, 12.0 to 17.0 lbs/gal or recommended weight from cement service company
- Equipment: float collar; float shoe; landing collar; plug holder bushing; drill pipe pump down plug; Type #1 liner wiper plug

1.7.4. Centralizers

Permit Condition Reference: Part III.D.4 (d), (e), (f)

Centralizers will be used on all cemented casing strings to optimize proper placement of cement in the casing-borehole annulus. New wells will 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. Any casing string that is placed in or below the salt will have centralizers installed on every third joint of casing to the surface above the bottom three joints.

1.8. INJECTIVITY TEST

Demonstration that the bore hole is in communication with the mine cavity will be by pumping fluid into the well and monitoring the pressure and flow rate.

1.9. TYPICAL LOGGING

1.9.1. Deviation Surveys

Permit Condition Reference: Part III.D.6

Deviation surveys are collected either by running single or multi-shot tools or by directional drilling tools. Borehole deviation surveys are taken at a minimum of 500-ft intervals throughout drilling operations.

1.9.2. Open Hole Caliper Log

A borehole caliper log will be run, it will be used to determine cement volumes. After the volume indicated from the caliper log is evaluated the cement excess will be increased by 10-percent as a minimum.

1.9.3. Gamma Ray Log

Permit Condition Reference: Part III.D.6 (a)

At a minimum, this log will be run for the entire vertical portion of the well, from total depth to surface.

1.9.4. Cement Bond Log

This log is run after cementing of each vertical casing string to ensure adequate cement placement and provide records thereof.

1.9.5. Temperature Survey

Permit Condition Reference: Part III.D.4 (b)

This log will provide a baseline temperature profile from surface to a point where the survey tool starts to fall into the curve of the horizontal well.

1.9.6. Injection Zone

Typically the injection zone is not cored in the 5th ore zone, since the well is being installed into the open mine works. However, the 5th ore zone may be cored at any time the opportunity exists. No core samples can be obtained from the injection zone. Ore zone composition is well documented from previous conventional mining.

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

1.10. FRACTURE PRESSURE

The fracture pressure was calculated based on records of Texas Gulf wells 19, 20 and 21, which were hydraulically fractured. A fracture gradient was calculated at 1.31 psi/ft. The depth to the injection zone varies from 2,624-ft to 3,284-ft. Therefore, using a safety factor of 25%, the fracture pressure (assuming that injection occurs at the top of the permitted injection zone) ranges from 2,582 to 3,231 psi.

2. CONSTRUCTION OF SYLVITE 5 HORIZONTAL INJECTION/EXTRACTION WELLS

All new Class III wells drilled in Sylvite 5 will 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 the surface to below the permitted injection zone. Wells are subject to MIT tests conforming to CFR 146.8 prior to operation. A typical Sylvite 5 well diagram is included as Figure 4 in the Technical Report (2013).

2.1. TOTAL DEPTH

Total measured depth of the Sylvite 5 horizontal wells ranges from 2,700 feet to 3,300. Any future wells into the Sylvite 5 ore body would have very similar true vertical depth (TVD) depths to existing wells.

2.2. PRESSURES AND AXIAL LOADING

2.2.1. Injection pressure

Injection pressure will be set according to the parameters set forth in Part III.F.2.

2.2.2. External pressure

Hydrostatic pressure from formation salt water is representative of the external pressure exerted on the casing strings. Given a maximum depth of 3,200' TVD with fluid densities ranging from 9.5-10.5 lbs/gal, the external pressure ranges from 1,580 – 1,747 psi with completely evacuated casing. These calculated pressures are results from the following formula below:

*Hydrostatic Pressure = mud weight (MW) ppg * depth (TVD) ft * 0.052*

Note: TVD is true vertical depth and 0.052 is a conversion factor allowed when using the units of feet, ppg and psi.

2.2.3. Internal pressure

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

2.2.4. Axial Loading

The maximum load on 9-5/8-inch 40-lb surface casing with no buoyancy correction for 10.5-ppg mud is 108,000 lbs. This is for a string length of 2700 ft. The body yield (916,000 lbs) and joint strength (727,000 lbs) is compared and the smaller of the two values is used for casing selection. The surface casing string intended for use is well within its capacities concerning the above pressures and load.

2.3. BOREHOLE SIZE

Conductor borehole size may range from 24-inch to 30-inch with depths ranging from 30-ft to 600-ft. Setting depth is determined by penetration into and through the alluvium and 20-ft of solid bedrock. The surface hole ranges from 14-3/4-inch to 12-1/4-inch with depths starting at the base of the conductor and complete into Salt 2. The short vertical and curve are typically 8-3/4-inch or 8-1/2-inch and start from the base of the surface casing shoe to 3000-ft to 3800-ft in total measured depth. The horizontal legs are typically 6-inch and may achieve footages ranging from 4000-ft to 8500-ft in total depth. Borehole size may change due to wellbore instability and or unforeseen drilling complications. Drilling issues typically arise during large diameter surface drilling.

2.4. COMPLETION

Sylvite 5 injection wells are complete when the injection wellhead is fully installed and plumbed for solution mining operations. Typical wellhead configurations consist of a SOW starter flange for the 9-5/8-inchch surface casing, a casing head for the 7-inch MIT string, a tubing head for the 4-1/2-inch injection string and a swedge that ties in the 1-inch fresh water dilution string.

2.5. TYPICAL CASING STRINGS

Permit Condition Reference: Part III.D.4, Part III.D.4 (a)

The typical casing strings used in horizontal wells in Sylvite 5 is described below

2.5.1. Conductor Casing

Conductor Casing 10 ¾-inch to 20-inch 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.

2.5.2. Surface Casing

Permit Condition Reference: Part III.D.4 (b)

9-5/8-inch 40# to 47# L-80 (different grades may be used but L-80 is typical) casing set in Salt 4. Cement to surface recommended cement slurries adjacent to bare formations. Typical cement programs for the Moab Cane Creek Mine AOR consist of one or more spacers, a lead cement and tail cement.

2.5.3. Casing Liner

7-inch 29-lb L-80 (may use different grade) casing liner hung off 9-5/8-inch surface casing. This string lines the wellbore from the base of the surface casing to the base of Clastic 4. The casing string is cemented using HES or other service provider.

2.5.4. MIT Casing

7-inch 26-lb or 29-lb L-80 (may use different grade) casing set at surface and run to the top of the polished bore receptacle (PBR) which is on top of the 7-inch casing lining the curve section. The MIT casing will have a seal assembly that slides into the PBR. Some wells maybe constructed using a swell packer assembly at the bottom MIT casing string. The MIT casing string is not cemented.

2.5.5. Injection/Extraction Tubing

Permit Condition Reference: Part III.D.5

The injection tubing is typically 4-1/2-inch 11.60-lb L-80 tubing that is inserted into the lateral. The tubing is either installed near the base of the 7-inch casing line cemented in the curve section or is run up to the end of the lateral. Not cemented.

Fresh Water Injection Tubing – 1-inch (1.315-inch OD) 1.72-lb J-55 set at surface and run to the base of the curve or farther out into the lateral but still within the 4-1/2" injection/extraction string. This string prevents the 4-1/2-inch strings from salting-off.

2.5.6. 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. The casings mentioned above reflect the current configuration in use. Technology may allow additional for modification

2.6. INJECTION ZONE

The injection zone is a horizontally drilled cavity in the Sylvite 5 zone of the Paradox formation. Clastic and salt intervals of the Paradox formation overlie and underlie Sylvite 5.

2.7. TYPICAL CEMENTING PROCEDURES

Halliburton or other reputable cement service companies are contracted to provide cement, equipment and personnel.

Cementing the surface casing requires circulating cement down the inside of the casing, out the shoe and up the annulus. Cement excess of 20% to 50% or more of calculated cement volume may be necessary for the primary lift. LCM may be added to the cement mixture; however, residual LCM may be present from drilling and may not be needed. The cement company may pump a top out cement if the primary cement does not come to surface. Typically a tremie pipe method is used for the top off cement due to lower cost and simplicity.

Intermediate casings and or liners are cemented by pumping the cement slurry down the inside of the casing, through the shoe and up the annulus. Cement excess is typically lower in the Salt sections of the borehole due to increased wellbore stability and less loss circulation. The excess for this calculated cement volume is typically 10% minimum. A liner top packer at the top of the 7-inch casing is engaged after cementing, isolating the backside of the 7-inch and the 9-5/8-inch x 7-inch annulus. Excess cement is reverse circulated out of the hole and back to surface.

Specific Cementing Procedures for specific casings are described below.

Permit Condition Reference: Part III.D.4 (c)

2.7.1. Conductor, 20-inch

- Annular volume between 26-inch hole and casing = .0.2681 bbl/lin.ft
- Volume of cement required = depth (ft) * 0.2681bb/ft. If cement does not circulate to surface, ready-mix will be poured until visible at surface
- Cement Type = Ready-Mix cement, 15 lbs/gal. Slurry wt

- Equipment: None, open ended

2.7.2. Surface Casing, 9-5/8-inch

- Annular volume between 14-3/4-inch hole and casing = 0.1214 bbl/ft
- Volume of cement required = depth (ft) * 0.1214 bbl/ft. Increase this by 10% excess minimum
- Spacers (before and after cement) – Reactive spacers, may consist of one or two pumped in recommended sequence. Halliburton (HES) uses CaCl and a proprietary product called Super Flush. Other cement service companies offer similar reactive products and may be used instead of HES products
- Cement details - Type VERSACEM or similar; 11-16 lbs/gal Cement type & weight vary with advancements in cement technology
- Minimum equipment: double float system consisting of a float collar and float shoe; centralizers; rubber cementing top plug; Weld-A; tremie pipe for top out cement

2.7.3. Intermediate Casing or Liner, 7-inch

- Volume between 8-1/2-inch hole and casing = 0.0118 bbl/ft
- Volume of cement required = measured depth from base of surface casing to shoe (may need to include rat hole) in ft. * 0.0118 bbl/ft. Increase the volume by 10% excess minimum
- Volume between 9-5/8-inch casing and intermediate casing = 0.0282 bbl/ft
- Volume of cement required = footage of overlap into 9-5/8-inchch casing * 0.0282 bbl/ft
- Typical Cement Type = Class G, 12.0 to 17.0 lbs/gal or recommended weight from cement service company
- Equipment: float collar; float shoe; landing collar; plug holder bushing; drill pipe pump down plug; Type #1 liner wiper plug

2.7.4. Centralizers

Permit Condition Reference: Part III.D 4 (d), (e), (f)

Centralizers will be used on all cemented casing strings to optimize proper placement of cement in the casing-borehole annulus. New wells will 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. Any casing string that is placed in or below the salt will have centralizers installed on every third joint of casing to the surface above the bottom three joints.

2.8. INJECTIVITY TEST

If a horizontal well drilled in Sylvite 5 the well that intersects the original 5th ore zone open mine works the well will be tested for connectivity by pumping fluid into the well and monitoring the pressure and flow rate. If a standalone cavern is being developed. Connectivity can only be

demonstrated when the second well is drilled into a first well, since the first well is not connected to another well yet.

2.9. TYPICAL LOGGING

Permit Condition Reference: Part III.D.6

2.9.1. Deviation Surveys

Deviation surveys are collected either by running single or multi-shot tools or by directional drilling tools. Borehole deviation surveys are taken at a minimum of 500-ft intervals throughout drilling operations.

2.9.2. Open Hole Caliper Log

If a borehole caliper log is run, it will be used to determine cement volumes. After the volume indicated from the caliper log is evaluated the cement excess will be increased by 10-percent as a minimum.

2.9.3. Gamma Ray Log

Permit Condition Reference: Part III.D.6 (a)

At a minimum, this log will be run for the entire vertical portion of the well, from total depth to surface.

2.9.4. Cement Bond Log

This log is run after cementing of each vertical casing string to ensure adequate cement placement and provide records thereof.

2.9.5. Temperature Survey

Permit Condition Reference: Part III.D.6 (b)

This log will provide a baseline temperature profile from surface to a point where the survey tool starts to fall into the curve of the horizontal well.

2.9.6. Injection Zone

Typically the coring is not conducted during construction of horizontal wells. However, the 5th ore zone may be cored at any time the opportunity exists. Typically a pilot hole will be drilled out of the bottom of the surface casing vertically to the top of Salt 5. Then core runs are made till the interval has been sampled. This vertical hole is then abandoned with cement and the curve for the horizontal well is drilled from a kick-off point in the vertical hole as appropriate. No core samples can be obtained from the

injection zone. Ore zone composition is well documented from previous conventional mining and additional data for the newly developed area.

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

2.10. FRACTURE PRESSURE

The fracture pressure was calculated based on records of Texas Gulf wells 19, 20 and 21, which were hydraulically fractured. A fracture gradient was calculated at 1.31 psi/ft. The depth to the injection zone varies from 2,624-ft to 3,284-ft. Therefore, using a safety factor of 25%, the fracture pressure (assuming that injection occurs at the top of the permitted injection zone) ranges from 2,582 to 3,231 psi.

3. CONSTRUCTION OF SYLVITE 9 INJECTION/EXTRACTION WELLS

All existing and new Class III wells in Sylvite 9 will 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 the surface to below the permitted injection zone. Wells are subject to MIT tests conforming to CFR 146.8 prior to operation. A typical Sylvite 9 well diagram is included as Figure 5 (Technical Report, 2013).

3.1. TOTAL DEPTH

Total measured depth of the Sylvite 9 horizontal wells ranges from 6,000 to over 8,000 feet. 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.

3.2. PRESSURES AND AXIAL LOADING

3.2.1. Injection pressure

Injection pressure will be set according to the parameters set forth in Part III.F.2.

3.2.2. External pressure

Hydrostatic pressure from formation salt water is representative of the external pressure exerted on the casing strings. Given a maximum depth of 4,000' TVD with fluid densities ranging from 9.5-10.5 lbs/gal, the external pressure ranges from 1,976 – 2,184

psi with completely evacuated casing. These calculated pressures are determined from the following formula below:

*Hydrostatic Pressure = mud weight (MW) ppg * depth (TVD) ft * 0.052*

Note: TVD is true vertical depth and 0.052 is a conversion factor allowed when using the units of feet, ppg and psi.

3.2.3. Internal pressure

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

3.2.4. Axial Loading

The maximum load on 9-5/8-inch 40-lb surface casing with no buoyancy correction for 10.5-ppg mud is 120,000 lbs. This is for a string length of 3000 ft. The body yield (916,000 lbs) and joint strength (727,000 lbs) is compared and the smaller of the two values is used for casing selection. The surface casing string intended for use is well within its capacities concerning the above pressures and load.

3.3. BOREHOLE SIZE

Conductor borehole size may range from 24-inch to 30-inch with depths ranging from 30-ft to 600-ft. Setting depth is determined by penetration into and through the alluvium and 20-ft of solid bedrock. The surface hole ranges from 14-3/4-inch to 12-1/4-inch with depths starting at the base of the conductor and complete into Salt 4. The short vertical and curve are typically 8-3/4-inch or 8-1/2-inch and start from the base of the surface casing shoe to 3800-ft to 4500-ft in total measured depth. The horizontal legs are typically 6-inch and may achieve footages ranging from 4000-ft to 8500-ft in total depth. Borehole size may change due to wellbore instability and or unforeseen drilling complications. Drilling issues typically arise during large diameter surface drilling.

3.4. COMPLETION

Sylvite 9 injection wells are complete when the injection wellhead is fully installed and plumbed for solution mining operations. Typical wellhead configurations consist of a slip on and weld (SOW) starter flange for the 9-5/8-inch surface casing, a casing head for the 7-inch MIT string, a tubing head for the 4-1/2-inch injection string and a swedge that ties in the 1-inch fresh water string.

3.5. TYPICAL CASING STRINGS

Permit Condition Reference: Part III.D.4, Part III.D.4 (a)

The typical casing strings used in horizontal wells in Sylvite 9 is described below

3.5.1. Conductor Casing

Conductor Casing 10 ¾-inch to 20-inch 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.

3.5.2. Surface Casing

Permit Condition Reference: Part III.D.4 (b)

9-5/8-inch 40# to 47# L-80 (different grades may be used but L-80 is typical) casing set in Salt 4. Cement to surface recommended cement slurries adjacent to bare formations. Typical cement programs for the Moab Cane Creek Mine AOR consist of one or more spacers, a lead cement and tail cement.

3.5.3. Casing Liner

7-inch 29-lb L-80 (may use different grade) casing liner hung off 9-5/8-inch surface casing. This string lines the wellbore from the base of the surface casing to the base of Clastic 8. Cemented.

3.5.4. MIT Casing

The MIT casing is comprised of 7-inch 26-lb or 29-lb L-80 (may use different grade) casing set at surface and run to the top of the polished bore receptacle (PBR) which is on top of the 7-inch casing lining the curve section. The MIT casing will have a seal assembly that slides into the PBR. Some wells may use a swell packer assembly on the base of the MIT casing string. Not cemented.

3.5.5. Injection/extraction Tubing

Permit Condition Reference: Part III.D.5

The injection tubing is typically 4-1/2-inch 11.60-lb L-80 tubing that is inserted into the lateral. The tubing is either installed near the base of the 7-inch casing line cemented in the curve section or is run up to the end of the lateral. Not cemented.

Fresh Water Injection Tubing – 1-inch (1.315-inch OD) 1.72-lb J-55 set at surface and run to the base of the curve. This string prevents the 4-1/2-inch strings from salting-off.

3.5.6. 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. The casings mentioned above reflect the current configuration in use. Technology may allow additional for modification.

3.6. INJECTION ZONE

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.

3.7. TYPICAL CEMENTING PROCEDURES

Halliburton or other reputable cement service companies are contracted to provide cement, equipment and personnel.

Cementing the surface casing requires circulating cement down the inside of the casing, out the shoe and up the annulus. Cement excess of 20 to 50% of calculated cement volume may be necessary for the primary lift. LCM may be added to the cement mixture; however, residual LCM may be present from drilling and may not be needed. The cement company may pump a top out cement if the primary cement does not come to surface. Typically a tremie pipe method is used for the top off cement due to lower cost and simplicity.

Intermediate casings and or liners are cemented by pumping the cement slurry down the inside of the casing, through the shoe and up the annulus. Cement excess is typically lower in this section due to increased wellbore stability and less loss circulation. The excess for this calculated cement volume is 10% minimum. A liner top packer at the top of the 7-inch casing is engaged after cementing, isolating the backside of the 7-inch and the 9-5/8-inch x 7-inch annulus. Excess cement reverse circulated out of the hole and back to surface.

Specific Cementing Procedures for specific casings are described below.

Permit Condition Reference: Part III.D.4 (c)

3.7.1. Conductor, 20-inch

- Annular volume between 26-inch hole and casing = .0.2681 bbl/lin.ft
- Volume of cement required = depth (ft.) * 0.2681bb/ft. If cement does not circulate to surface, ready-mix will be poured until visible at surface
- Cement Type = Ready-Mix cement, 15 lbs/gal. Slurry wt
- Equipment: None, open ended

3.7.2. Surface Casing, 9-5/8-inch

- Annular volume between 14-3/4-inch hole and casing = 0.1214 bbl/ft
- Volume of cement required = depth (ft) * 0.1214 bbl/ft. Increase this by 10% excess minimum
- Spacers (before and after cement) – Reactive spacers, may consist of one or two pumped in recommended sequence. Halliburton (HES) uses CaCl and a proprietary product called Super Flush. Other cement service companies offer similar reactive products and may be used instead of HES products
- Cement details - Type VERSACEM or similar; 11-16 lbs/gal Cement type & weight vary with advancements in cement technology
- Minimum equipment: double float system consisting of a float collar and float shoe; centralizers; rubber cementing top plug; Weld-A; tremie pipe for top out cement

3.7.3. Intermediate Casing or Liner, 7-inch

- Volume between 8-1/2-inch hole and casing = 0.0118 bbl/ft
- Volume of cement required = measured depth from base of surface casing to shoe (may need to include rat hole) in ft. * 0.0118 bbl/ft. Increase the volume by 10% excess minimum
- Volume between 9-5/8-inch casing and intermediate casing = 0.0282 bbl/ft
- Volume of cement required = footage of overlap into 9-5/8-inchch casing * 0.0282 bbl/ft
- Typical Cement Type = Class G, 12.0 to 17.0 lbs/gal or recommended weight from cement service company
- Equipment: float collar; float shoe; landing collar; plug holder bushing; drill pipe pump down plug; Type #1 liner wiper plug

3.7.4. Centralizers

Permit Condition Reference: Part III.D.4 (d), (e), (f)

Centralizers will be used on all cemented casing strings to optimize proper placement of cement in the casing borehole annulus. New wells will have centralizers installed on the bottom three joints of the surface casing and on the bottom three joints of a casing string that is placed in or below the salt. Any casing string that is placed in or below the salt will have centralizers installed on every third joint of casing to the surface above the bottom three joints.

3.8. INJECTIVITY TEST

Demonstration that the bore hole is in communication with the mine cavity will be by pumping fluid into the well and monitoring the pressure and flow rate.

3.9. TYPICAL LOGGING

Permit Condition Reference: Part III.D.6

3.9.1. Deviation Surveys

Deviation surveys are collected either by running single or multi-shot tools or by directional drilling tools. Borehole deviation surveys are taken at a minimum of 500-ft intervals throughout drilling operations.

3.9.2. Open Hole Caliper Log

If a borehole caliper log is run, it will be used to determine cement volumes. After the volume indicated from the caliper log is evaluated the cement excess will be increased by 10-percent as a minimum.

3.9.3. Gamma Ray Log

Permit Condition Reference: Part III.D.6

At a minimum, this log will be run for the entire vertical portion of the well, from total depth to surface.

3.9.4. Cement Bond Log

This log is run after cementing of each vertical casing string to ensure adequate cement placement and provide records thereof.

3.9.5. Temperature Survey

Permit Condition Reference: Part III.D.6 (b)

This log will provide a baseline temperature profile from surface to a point where the survey tool starts to fall into the curve of the horizontal well.

3.9.6. INJECTION ZONE

Typically the coring is not conducted during construction of horizontal wells. However, the 5th and 9th ore zones may be cored at any time the opportunity exists. Typically a pilot hole will be drilled out of the bottom of the surface casing vertically to the top of Salt for an ore zone. Then core runs are made till the interval has been sampled. This vertical hole is then abandoned with cement and the curve for the horizontal well is drilled from a kick-off point in the vertical hole as appropriate.

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

3.10. FRACTURE PRESSURE

Permit Condition Reference: Part III section C.2 (a) and (b)

The same fracture pressure gradient applies as described for Sylvite 5. The fracture pressure was calculated based on records of Texas Gulf wells 19, 20 and 21, which were hydraulically fractured. A fracture gradient was calculated at 1.31 psi/ft. The depth to the injection zone varies from 23,657-ft to 4,389-ft. Therefore, using a safety factor of 25%, the fracture pressure (assuming that injection occurs at the top of the permitted injection zone) ranges from 3,108 to 4,319-psi. In addition, the current UIC permit requires use of a gradient of 0.85 psi/ft where the cavern is below or within 500-ft of the Sylvite 5 mine cavity.

4. EXPLORATION CORE HOLES

Permit Condition Reference: Part III.D.10 (c)

Exploration core holes are occasionally drilled to collect information on the depth, thickness, and grade of ore in the area. Typically, core holes are regulated by the Utah DOGM. However, in a cooperative process, Intrepid submits the proposed core hole schematic to both DEQ and DOGM. Since DEQ makes frequent site visits and oversees the well programs, core hole drilling is primarily overseen by DEQ. Plans for new core holes will be submitted to DWQ at least 30 days prior to commencement of construction.

Permit Condition Reference: Part III.D.4 (g)

Core holes are typically plugged and abandoned at the completion of well drilling and geophysical logging. Core holes will be conditioned before running cement.

5. NOTE ON CORROSIVENESS OF INJECTED FLUIDS

The nature of this operation, which uses a salt brine for injection, the fluid is corrosive to metal. However, 40-years of operational experience has demonstrated that the most severe corrosion of well casing and surface pipelines is caused by the extraction brine. In addition, surface moisture

along pipelines is also corrosive to the pipeline metals. Especially where the pipelines are in contact with soils that hold moisture. The most severe corrosion occurs where air is either entrained in the fluid or exposed to casing materials.

6. INJECTION ZONE CHARACTERIZATON

Permit Condition Reference: Part III.D.7 (c)

This section comprises the approved and enforceable construction plan for formation testing.

Characterization of the injection zone will focus on determining fluid (pore) pressures (if present) and fracture pressures/gradients. The primary injection zone is the Sylvite ore in the salt sections. The salt is considered to have extremely low permeability and fluids are typically not present. However, the lateral borehole occasionally comes in contact with the overlying clastic unit. Fluids can be present in the clastic units (beds of anhydrite, siltstone, dolomite, and shale). IPM will evaluate the clastic unit above each ore zone when drilling.

IPM intends to evaluate fracture pressure and fluid pressure by petrophysical analysis of wireline geophysical data as well as review published literature. The primary goal is to design a casing and mud weight program to minimize the chance of accidently breaking down the formation as well as identifying maximum injection pressures. Drill stem tests (DST) such as a leak-off test, limit test, or formation integrity tests may be conducted to augment the analysis.

Characterization of naturally occurring fluids within the injection zone will be addressed by reviewing readily available literature. Sampling of formation fluids is very difficult, especially from low permeability rocks such as those in the clastic cycle. Even though some downhole wireline deployed tools are available, typically they are used for off shore drilling platform environments and collect small volumes of fluid. These methods are very expensive and are primarily calibrated to evaluating hydrocarbons.

Attachment E

Injection Well Operating Plan and Procedures

ATTACHMENT E—INJECTION AND EXTRACTION WELL OPERATING PLAN AND PROCEDURES

Permit Condition Reference: Part III.F.2.

This attachment comprises the approved and enforceable operating plan and procedures for operating the injection and extraction wells. It also provides operating procedures for the evaporation ponds and the associated brine distribution network of pumps, pipelines, surge tanks, salt tailings pond, and environmental reclaim ponds, sumps and other structures at the mine site. These components comprise the UIC permitted facilities. The locations of these components are shown on Drawing 7 of the Technical Report submitted with the application for this permit (2013).

1. CAVERN SYSTEM OVERVIEW

Injection and extraction wells are operated in four separate and unconnected caverns located in two ore zones. The Sylvite 5, or 5th ore zone, is the original mine cavern. The Sylvite 9, or 9th ore zone, is comprised of three caverns. Brine that is near saturation with sodium chloride is pumped through an injection well into a cavern, where it dissolves potassium chloride and is subsequently discharged through extraction wells. Extraction wells withdraw brine from the mine cavities either by submersible pumps in Sylvite 5, or by the pressure of the injection pumps in the three Sylvite 9 Caverns. Extracted fluid, containing high concentrations of potassium chloride and sodium chloride, is pumped to the solar evaporation ponds where it is concentrated by solar energy. The salt and potassium crystals that precipitate out of the brine in the solar ponds are harvested by scrapers and loaders and transported as a slurry via a pipeline to the mill for processing.

The injection and extraction pumps are not continuously operated, but rather are turned on and off based on the needs of the solar evaporation process and the saturation level of a particular cavern or well, and to maintain injection/extraction ratios under the limits established in this permit. The pumper staff is on site 24-hours-a-day inspecting, maintaining, monitoring and documenting well field operations. Intrepid maintains a training and quality assurance plan for the operations and monitoring of the process. Critical measurements of pressures, mine fluid level and flow rates are checked approximately bi-hourly and recorded, as described in the Monitoring, Recording and Reporting Plan. Maximum operating flow rates and typical pumping rates, volumes and injection pressures based on multi-year averages are shown in Table 7 (Technical Report, 2013) for all operating wells.

2. OPERATION OF ORIGINAL MINE CAVERN (SYLVITE 5)

The location of the wells into the 5th ore zone and ore bed structure is shown on Figure 2 (Technical Report, 2013). Well 24 is the primary injection well into the original mine cavern and typically injects on a vacuum, although lower density brines may require some pressure for injection. Brine extracted from Sylvite 9 is occasionally injected through Well 6 to allow for storage of KCl-rich brine during periods of low evaporation. Injection at Well 6 is by gravity flow. The other wells in Sylvite 5 are extraction wells, which are operated at different times and rates to optimize the solar evaporation process. When Well 24 is operated at injection rates over 1,500-gpm small amounts of pressure due to pipe restriction are present at the wellhead. 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. Therefore, mine fluid surface pressure is completely relieved at the extraction wells and the mine fluid level is normally maintained at a depth between 140-ft and 250-ft below the reference point at Shaft Number 2 (Drawing 1 and Drawing 2, Technical Report, 2013). The permitted minimum depth to fluid in No. 2 shaft is 125 ft.

2.1. INJECTION PRESSURE

Permit Condition Reference: Part III.F.3 and Part III.F.5(c)

A report submitted October 10, 2001 by Agapito Associates, Inc. (Appendix A of Technical Report, 2013) provides the basis for the maximum allowable surface injection pressure (see Exhibit 11 of Appendix A). The fracture pressure was calculated based on records of Texas Gulf wells 19, 20 and 21, which were hydraulically fractured. A fracture gradient was calculated at 1.31 psi/ft. The depth to the injection zone varies from 2,624-ft to 3,284-ft. Therefore, using a safety factor of 25%, the fracture pressure (assuming that injection occurs at the top of the permitted injection zone) ranges from 2,582 to 3,231 psi. Applying another safety factor of 25% results in a maximum pressure that can be applied to the Sylvite 5 cavern as measured at the No. 2 Shaft is 1,916 psig. Pressure in the

shaft is a factor of depth and specific gravity of the fluid. At even the highest expected specific gravity of fluid in the shaft, the fluid level in the shaft associated with this pressure would be above the ground surface. So it is physically impossible to exceed the permitted pressure in Sylvite 5. Therefore, the mine fluid level is controlled by injection and extraction volumes to maintain a water level below 3,983-ft msl, which is 125-ft below the casing collar at the number 2 shaft, which has a ground surface elevation of 4,018-ft msl. Since the elevation of the base of the Colorado River is 3,928-ft near the mill facility, the mine level is always below the level of the Colorado River.

3. OPERATION OF SYLVITE 9 CAVERNS

IPM operates three (3) separate caverns in Sylvite 9. The Sylvite 9 caverns were created by drilling intersecting boreholes with horizontal directional drilling technology. The locations of the caverns are shown on Drawings 1 and 2 (Technical Report, 2013). The location of the wells into the 9th ore zone and ore bed structure is shown on Drawing 6. Injection and extraction wells for each cavern are summarized below.

Cavern	Injection Wells	Extraction Wells
1	27, 29, 37	28
2	40	39
3	43	42

Natural gas fired brine heaters are used to heat the lake brine (using heat exchanger technology) which is pumped into the injection well with a quintiplex pump. The typical injection rate into Sylvite 9 caverns ranges from 200 to 400-gpm (Table 7, Technical Report, 2013). The quintiplex pump installed near the wellhead creates the hydraulic pressure to push the injection fluid down the injection well, through the intersecting laterals and out the extraction well to the surge storage tank at Well 6, where it is eventually comingled with brine from Sylvite 5 and pumped to the solar evaporation ponds. There are three pumps at the Well 6 surge tank that pump the brine to the solar ponds.

3.1. INJECTION PRESSURES

Permit Condition Reference: Part III.F.3

The same fracture gradient and safety factor applies to Sylvite 9 as is used for Sylvite 5 (1.31 psi/ft and 25%, respectively). However, a safety factor of 35% is applied to caverns below or within 500 ft of the Sylvite 5 cavern. This applies to caverns 1 and 3. Therefore the fracture gradients used for determining maximum injections pressures are 0.98 psi/ft for Cavern 2 and 0.85 psi/ft for Caverns 1

and 3. The cavern depths range from 3,657 ft to 4,389 ft in wells 27H, 28H and 29H, giving a range of fracture pressures from 3,108 psi to 4,301 psi. Another safety factor of 25% is applied to these fracture pressures to obtain the maximum injection pressures for each cavern. These calculations are summarized below.

Sylvite 9 Cavern	Formation Fracture Gradient (psi/ft)	Safety Factor 1	Applied Fracture Gradient (psi/ft)	Cavern Depth-min (ft)	Safety Factor 2	Max Injection Pressure (psi)
1	1.31	35%	0.85	3657	25%	2743
2	1.31	25%	0.98	4399	25%	3299
3	1.31	35%	0.85	3825	25%	2869

Each wellhead is equipped with one or more standard pressure gauges for monitoring the conditions at each well. Pressures, volumes, fluid levels or flow into one cavity do not affect the operation of the other cavities in any way. Well elevation, the density of the injection and extraction fluid and the flow rate determine the amount of pressure at each wellhead. A pressure relief valve is located downstream of the injection pump at each injection well to prevent injection at pressures in excess of the limits set in this permit.

3.2. OPERATION OF SYLVITE 9 CAVERN 1

The principal flow path within Sylvite 9 Cavern 1 is determined by the perforations in the 5-inch tubing injection string hung into Well 27. The 5-inch injection string is perforated in 500 to 600-ft intervals in the lateral portion of Well 27 and the fluid flows from these perforations into the cavern and finally toward well 28 for extraction. If Well 28 is ever used for injection, the principal flow path would be reversed. Well 29 was constructed in 2005 and is also used for injection. It utilizes a 5.5-ft casing string to inject fluid at a single point 369' below the bottom of the 9-5/8" casing into the lateral portion of well 29.

3.3. OPERATION OF SYLVITE 9 CAVERN 2

Flow in Cavern 2 is down Well 40H, through the 4-1/2" injection string installed in Lateral 7, the westernmost lateral, and extends out into Lateral 4 sidetrack 1 of Well 39H.

Well 40H failed an MIT test performed on May 17, 2013. In July 2013, Intrepid requested and was granted a variance from MIT requirements based on operation of the well with an enhanced barrier system. The enhanced barrier system utilizes the 9-5/8" by 7" annulus and an additional annulus between the 4-1/2" injection string and the 7" casing. Both annuli are continuously pressurized at 100-psi with freshwater such that any loss in pressure will be automatically replaced with additional freshwater. Since the leakage from the MIT annulus is very small, the possibility exists that the leak may heal. If Well 40H can pass an MIT it will be returned to the normal MIT testing program for as long as it can continue to pass an MIT, then returned to this modified method should it fail again.

3.4. OPERATION OF SYLVITE 9 CAVERN 3

Flow in Cavern 3, is down well 43 through the 4-1/2" injection string installed in Lateral 7. A cast iron bridge plug was set at 4,900-ft. The 4-1/2" casing was perforated 40 times from 4900-ft to 4890'. Another 40 perforations from 4890-ft to 4880-ft, and finally another 40 perforations from 4880-ft to 4870-ft. Each perforation was approximately 0.69-in diameter.

4. INJECTION FORMATIONS

Permit Condition Reference: Part III.F.4

IPM constructs wells so the annulus between the outermost casing string and the borehole wall (formation) are filled with cement. IPM does not intend to inject or allow salt water into this annulus. However, as part of the enhanced protective barrier in Well 40, freshwater is injected into the MIT annulus which may possibly be leaking out into the formation (or the freshwater injected into this MIT annulus, may actually be leaking past the MIT packer at the bottom of the 7-inch MIT casing string.

Permit Condition Reference: Part III.F.5 (a)

Wells constructed into the 5th ore zone have surface casing installed to the base of Salt 2. Then a 7-inch casing string is installed inside of the 9-5/8" down into the 5th ore zone. The 7-inch overlaps the 9-5/8" by approximately 200-ft. Each casing string is pressure tested during installation to confirm the casing string has MI.

The potash 9 wells have an additional casing string not present in Sylvite 5 wells extending from the permitted injection zone (salt 3) to surface, which creates a fluid filled annulus which can be pressurized for MIT tests.

5. INJECTATE FLUID SOURCES

Permit Condition Reference: Part III.F.5 (b)

The source of all fluids used in the solution mining process is the Colorado River. Brines injected into the mine caverns originate from the following principal sources: freshwater from the river, tailings lake brine, brine re-injected from the mine cavities, environmental reclaim brine, and minor amounts of process water and brine from the mill transferred to the tailings pond. These sources are further discussed below. The injected fluid is not filtered. Prior to injection into Sylvite 9, the brine is heated to temperatures up to approximately 200°F.

5.1. COLORADO RIVER WATER

Colorado River water is diverted from the river at the intake facility shown on Drawing 7. The water is diverted into two systems: 1) for use in the mill and 2) to the B-line which is used in the field. The 2-inch flush water lines are connected to the B-line system. Typically, river water is pumped to the tailings area through the B-line where it is used to dissolve salt and potash tailings by direct contact using sprinklers and hoses. The water that runs off the salt tailings pile returns to the tails lake for later distribution to the wells for injection or for general use in the production process. River water is also used in the plant operation. Occasionally river water is injected into either Sylvite 5 or 9 cavities for special purposes, such as undercutting new laterals or to flush salt deposits that have formed in the well casing annuli. The extraction wells installed in the 9th ore zone have dilution strings that inject approximately 5 to 8–gpm of freshwater into the brine to dilute the brine so it does not crystalize out when the brine cools as the brine flows to the surface and plugging the extraction tubing.

5.2. TAILINGS LAKE

The mill tailings pond contains water that has a high concentration (near saturation) of NaCl. Brine from the pond is used as the primary injection fluid into the 5th and 9th ore zones and as a fluid to pump waste NaCl solids from the mill process to the tailings lake area for storage. The principal sources of water in the tailings lake are discharge from the mill and runoff from the tailings storage area (see Drawing 7 of Technical Report, 2013) and from the river water intake. Brine is created from spraying fresh river water, and from precipitation, on the salt in the storage area. Additionally, brine is generated during mill operation that is pumped to the lake.

5.3. RE-INJECTED BRINE

Brine is extracted from the solution mine primarily for production purposes. Brine flows from extraction wells into the evaporation ponds either directly or by way of a carbon steel surge tank (67,600 gallon capacity). The surge tank is located near Well No. 6 and pump station No. 4. Occasionally surplus brine from the tank is re-injected in the mine caverns.

5.4. PROCESS WATER AND EXCESS BRINE

Surplus process water and brine is also pumped to the tailings lake for later injection.

5.5. ENVIRONMENTAL RECLAIM BRINE

The environmental reclaim or scavenger brine system is composed of a series of small dams, ponds and catch basins that serve as a collection system for fugitive brines that originate from solar pond leakage, mill tailings pond, and pipeline drains or spills. There are six major scavenger pond locations (Drawing 7, Technical Report, 201)). Brine collected in these ponds is sent to the evaporation ponds or to the tailings lake for injection into the mine caverns.

6. INJECTION/EXTRACTION RATIOS

Permit Condition Reference: Part III.F.5 (d)

As described in the Monitoring, Recording and Reporting plan, the injection/extraction ratio for each cavern is calculated from continuously recorded flow meters on injection and extraction wells. These data are reported quarterly to DWQ. 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.

High injection/extraction ratios may indicate possible fluid introduction outside of the approved injection zone. If the injection/extraction ratio exceeds 1.08 when injecting Colorado River water, or 1.02 for all other injected fluids, for 14 consecutive days IPM shall conduct an investigation as to the cause within 72 hours. If the investigation indicates leakage, appropriate corrective actions will be taken without delay. Such actions may include, but is not limited to, lowering the brine level in the appropriate mine cavern.

7. OPERATION OF THE SOLAR PONDS

The objective for operating the solar ponds is to maximize the precipitation of potassium crystals out of the brine. This is accomplished by monitoring the chemistry of the brine in each individual pond cell. When the concentration of potassium in the brine decreases below saturation the brine

will no longer precipitate potassium crystals. Brine is transferred from one pond to another by either pumps or siphoning, depending on hydraulic head differences.

8. FRESHWATER AND BRINE DISTRIBUTION PIPELINES AND PUMPS

Fluids are distributed around the site via pipelines and pumps. The primary fluids are freshwater from the Colorado River and brines from various sources. In addition to the pumping and pipeline system, there are a series of catchment ponds and dams on site. These systems of pumps, pipelines, and catchments comprise the permitted UIC facilities.

8.1. PUMPING SYSTEM

The size, type, and setting depth for the submersible extraction pumps installed in the 5th ore zone extraction wells are summarized on Table 4. The injection pumps for the 9th ore zone are also summarized on Table 4. The various pumps for distributing the freshwater and various brine around the well field, to the solar ponds, and from the solar ponds to the mill are summarized in Table 5. The locations of the pumps are shown on Drawing 7 (Technical Report, 2013).

8.2. PIPELINES

Pipelines are used to transport the following fluids:

8.2.1. River Water

The river water distribution system consists of: 1) the feed line to the mill process system, 2) the B-line to the mill tailings pond, and 3) 2-inch poly-lines that are installed to each well to supply water to flush out salt accumulations in the well.

8.2.2. Tailings (Lake) Brine

Water from the tails lake is pumped to two locations: 1) to well 24 for injection into the 5th ore zone original mine works and to 2) the lake brine distribution tank located near Well 27H. The lake brine distribution tank supplies water for injection to the 9th ore zone wells, 27H, 29H (a back-up injection well), 37H, 40H, and 43H.

8.2.3. Extraction Brine

Brine removed from the wells is piped either to: 1) the surge tank at pump station 4 or directly into the solar line going to the solar evaporation ponds.

8.2.4. Slurry Line

The salt and potassium crystals that are removed from the solar ponds by the scrapers are transferred to one of two slurry pits for pumping back to the mill feed slurry tank via one 10-inch steel line. Multiple booster pumps are located along this line.

8.2.5. Recycle Line

The recycle line is brings sodium and potassium saturated brine to the slurry pits to be mixed with the harvested salts from the solar pond to create a slurry that can be pumped to the mill.

8.3. ENVIRONMENTAL RECLAIM BRINE PONDS AND STRUCTURES

Shallow scavenger ponds are located around the site and are used to collect minor leaks and spills from the solar ponds, surge tanks, and pipelines. The shallow ponds locations are shown on Drawing 7 (Technical Report, 2013). The collected brine is called "environmental reclaim brine" and it is pumped back to either to the solar ponds as brine to be harvested or to the tailings lake to be used as injection brine. There are seven main areas for scavenger ponds. Details for each environmental reclaim pond are discussed below:

8.3.1. East Catch Pond

The scavenger pond for the mill is located on the east side of state Highway 279 (Potash Road), across from the packaging and loading facility. Brine is collected from several areas around the mill facility.

8.3.2. Tailings Lake Toe Pond

A small pond captures seepage from the tailings lake dam. Reclaimed brine is pumped directly back to the tailings lake. Brine is also removed from a fracture in the area near Well 27 and pumped to the tails lake. That location is labeled TP-4.

8.3.3. 4-station

Brine captured around 4-station is transferred back into the surge tank at 4-station.

8.3.4. Number 1 Canyon

Brines that leak from the solar ponds and flow toward the north are caught in a series of sumps and French drains below the steep cliffs and pumped into a lined pond. There is also a second pond along the main haul road that is used to collect brines drained

from the pipelines. Occasionally the freshwater pipelines have brine introduced into them to keep the lines from freezing during the winter. After the cold periods, the lines are drained into the catchment where the brine is pumped back to the Number 1 Canyon pond. Water and brine from this pond is pumped to the main pit scavenger pond.

8.3.5. 3-Pit

There are two pits above Kelly Canyon. Brine from these two pits are transferred to a scavenger pond at the #3 slurry pit (3-pit). Brine is then pumped from the 3-pit scavenger pond to the main pit scavenger pond.

8.3.6. Kelly Canyon

There are two major brine reclaim structures located in Kelly Canyon. The Kelly Canyon dam is higher in the canyon and the Mobley dam is lower. Brine captured by the Mobley dam is pumped into the Kelly Canyon dam where it is then pumped to the 3-pit scavenger pond.

8.3.7. Main Pit Scavenger

Water and brine collected in the various scavenger ponds around the solar ponds is pumped to the lined brine reclaim pond at the main slurry pit. This pond has a 1,200,000-gallon capacity. Brine from here can be pumped directly into one for the following solar pond cells 1A,1B, 1C, 1D, 2H, 2K, 2N, and 2E.

Attachment F

Monitoring, Recording, and Reporting Plan

ATTACHMENT F—MONITORING, RECORDING AND REPORTING PLAN

1. OVERVIEW

Intrepid Potash—Moab's monitoring program was designed to track and control the injection and extraction fluids, well conditions, and the fluid distribution system. The monitoring program consists of the following major components:

- Monitoring injection and extraction well flow rates, volumes, temperatures, and pressures. The pumpers record the data in the field on preprinted forms (Figure 6 of Technical Report, 2013).

- Collecting river water quality and brine chemistry samples for laboratory analysis. Samples collected from the wells are analyzed on site. Samples collected from the Colorado River are submitted to a third-party analytical laboratory for analysis.

- Conducting MIT tests annually and every 5 years.

The results of monitoring are reported to the DEQ in Quarterly UIC reports.

1.1. INJECTION/EXTRACTION VOLUMES, PRESSURES, AND TEMPERATURES

The principal component of IPM's monitoring program consists of monitoring the flow rates, volumes, temperatures, and pressures at each well. Injection and extraction brine flow rate,

volume, pressure, and temperature are monitored at each well head, except for Well 24. Locations of flow meters are shown on Drawing 7 (Technical Report, 2013).

1.1.1. 5th Ore zone Monitoring

The flow of brine being injected into the 5th ore zone, through Well 24, is monitored by one continuous recording flow meter installed in the flow line between the 800-horsepower pump at the mill tails pond and the Well 24 wellhead. Well 24 is the only injection well for the Sylvite 5 cavity. Sylvite 5 extraction wells are equipped with totalizing flow meters, pressure transducer, and thermal probe. A three-pen chart recorder provides a chart of these parameters. The pumpers change the charts as necessary. Intrepid is currently working on going to electronic data recorders for all the wells. Once the electronic data recording system is in place, the 3-pen chart recorders will be phased out.

Pressure in the Sylvite 5 original mine cavity is measured by the mine fluid level at Shaft Number 2, measured by an electric conductance probe and by a continuously recording pressure transducer data logger.

1.1.2. 9th Ore zone Monitoring

Sylvite 9 wells are equipped with three trace recorders that continuously recording injection pressure, temperature, and flow rate. Injection and extraction volumes are measured at the well head. A three-pen chart recorder provides a chart of these parameters. The pumpers change the charts as necessary. Intrepid is currently working on going to electronic data recorders for all the wells. Once the electronic data recording system is in place, the 3-pen chart recorders will be phased out.

1.1.3. Pumpers

Mine staff responsible for pump operations "pumpers" are on site 24-hours-a-day working in 12-hr shifts. Pumpers observe all operating wells approximately every two hours to ensure correct operating parameters (flow rate, injection pressure, and annular pressure). The Pumpers record flow total volumes, flow rate, operating hours, and injection pressure for each well every 12 hours on "Pumper's Report" (Figure 6, Technical Report, 2013).

After each shift these reports are turned in and entered in to the mine's database on a daily basis (during the normal 5-day work week). Quarterly monitoring conforming to the requirements of UIC Permit Part II (E) (11) (e) are produced from this database. The pumpers also inspect pipelines and pumps for issues. They repair minor leaks. The mine has a staff of welders and mechanics that can complete most all repairs to pipelines and surface pumps.

1.2. INJECTATE WATER QUALITY MONITORING

Mine laboratory staff collects samples from various systems to monitor brine grades. The primary sampling locations are: 1) mill tailings pond 2) operating wells, and upstream and downstream Colorado River water. Samples of the injection fluid are collected at the 800-hp pump on the tailings pond dam. The injection fluids have been sampled routinely since 1985. These samples are analyzed in the onsite laboratory. Samples from the Colorado River are submitted to a state certified environmental laboratory for analysis of sodium and potassium. The injection fluid analytical results are summarized on Table 8 (Technical Report, 2013).

The injection brines are composed of the soluble element of the injections zone and are compatible with the formation and formation fluids.

1.3. MECHANICAL INTEGRITY MONITORING

Mechanical Integrity testing (MIT) requirements are defined by the UIC permit Part III (F). Mechanical integrity is defined in 40 CFR 146.8. Mechanical Integrity Testing Protocols for approved MIT methods are detailed in Section. MIT are conducted annually. Intrepid intends to conduct the tests in the first or fourth quarter each year. The fourth or first quarter allows repair work to the wells to be made before the next summer's evaporation season when the demand for well brine is at its highest level.

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.

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.

1.4. QUARTERLY UIC REPORTING

A UIC report is submitted quarterly to the DEQ. The UIC report contains a summary of the data collected during the monitoring programs, ongoing well maintenance or abandonment, as well as drilling activities. The injection and extraction volumes and ratios are summarized in tables and included in the quarterly UIC report.

2. MECHANICAL INTREGRITY DEMONSTRATION PLAN

2.1. MIT PROTOCOLS

This section provides the protocols necessary for the demonstration of mechanical integrity (MIT) for Class III Injection Wells, as required by UAC R317-7-10.3 B (3) and 40 CFR 146.8. An injection well has mechanical integrity if, for the purposes of the Cane Creek Mine UIC program:

- There are no leaks in the casing, tubing or packer
- There is no significant fluid movement through vertical channels behind the casing.
- The absence of significant fluid movement from the original mine cavity (Sylvite 5) or the Sylvite 9 solution mine caverns into any overlying waters of the state of Utah, including the Colorado River.

Generally, the cementing records, when the well is constructed, provide the documentation for verifying the outside MIT. Periodically MIT are conducted to be demonstrated MI on the outside of the casing and on the inside. MIT testing on annual basis provides verification of mechanical integrity that the casing string is not leaking. Every 5 years, an additional MIT test is conducted to verify the outside mechanical integrity, which was originally verified by the cementing records is still valid.

2.2. WELL CONSTRUCTION TYPES CORRELATED TO DIFFERENT MIT TESTING PROCEDURES

Intrepid currently has two types of wells, which are listed below. The Permit specifies the frequency of testing and the MIT testing method based on the type of well (which ore zone it was constructed in and for which purpose). Currently there are no horizontal wells in the 5th ore zone. When they are constructed, they will be tested according to the MIT procedures specified for wells constructed in the 9th ore zone.

2.2.1. 5th Ore Zone

Wells constructed in the 5th ore zone (Sylvite 5/potash 5) which intersect the original open mine works. In general, the 5th ore zone is a cavern that is open to the atmosphere and is operated by pumping water into the cavern and using submersible pumps to remove the fluid from the cavern. The fluid level in the open mine works is kept below the Colorado River.

2.2.2. 9th Ore Zone

Wells constructed in the 9th ore zone (Sylvite 9/Potash 9). Wells in the 9th ore zone are pressurized at the surface by the pumps that inject the fluid. This injection pressure is what forces fluid from the cavern at the extraction well.

2.2.3. Future 5th Ore Zone Wells

Intrepid plans to create new caverns in the 5th ore zone by horizontal drilling techniques. These new caverns will be operated similar to the 9th ore zone caverns. Therefore, there MIT testing methods will be the same as the other 9th ore zone wells.

2.2.4. Sylvite 5 wells – Constructed in the Original Open Mine Works

The current UIC permit (Part III F (5) (a)) requires testing for casing leaks (internal MI) every year and for vertical flow behind casing (external MI) once every five years.

Intrepid Potash intends to use temperature logs 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). Part III F (4) (a) (b) of the UIC permit allows either a temperature or a radioactive tracer survey (RTS) as an MIT method for both internal and external MI. A procedure for conducting the temperature log can be found below as Method H. A procedure for RTS can be found below as Method E. To demonstrate internal mechanical integrity in new wells in Sylvite 5 prior to operation, a pressure test is completed by one of the following methods:

a) By the cementing contractor during cementing of the last string of casing above clastic 2
b) With drilling rig equipment before drilling out the float collar, cement and guide shoe, or
c) With a packer on tubing after drilling out the float collar, cement and guide shoe.

Procedures for all of the above can be found as MIT procedures A, B, C and these procedures are provided below. Cementing records are sufficient to demonstrate external MI on newly constructed wells based on the following considerations:

a) Approximately the last 800-ft of borehole is drilled in confining layers (salts 2 through 4 and clastic 1 through 4) such that upward fluid migration in the borehole would require either poor cementing or dissolution of salt layers.
b) Saturated salt water drilling fluids are used to minimize formation dissolution while drilling.
c) The lack of considerable formation dissolution during drilling is demonstrated by caliper logs, which are also used to calculated cement volumes appropriate to borehole volume. The caliper volume is increased when ordering cement.
d) The water phase of the cement slurry is designed to minimize salt dissolution during cementing. Intrepid and DEQ recently met with Halliburton to discuss

recent advances in cement slurry mixture advances that are considered best practices.

e) 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. A procedure for cement bond logging can be found in MIT testing procedure Method F, below.

f) 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.

2.2.5. Sylvite 9 wells and New Caverns in the 5th ore zone created by horizontal drilling

Sylvite 9 wells and any new caverns constructed in the 5th ore zone will be created by horizontal drilling. These new wells will contain an interior casing string packed off below the base of clastic 2, full of water. The MIT annulus is between this interior casing string (known as the MIT string) and the primary casing that has been cemented in. This MIT annulus will be pressurized on all Sylvite 9 wells prior to operation for testing and on a yearly basis as an internal MIT. A procedure can be found in MIT procedure Method F, provided below.

Both casing and cement on Sylvite 9 wells extend into the curved portion of the borehole to over 60 degrees off- of-vertical. In addition, 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, if 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 calculated from continuously recorded flow meters on injection and extraction wells. The Injection/extraction ratio is tabulated bi-weekly 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.

3. MECHANICAL INTEGRITY TESTING PROTOCOLS

The methods for conducting MITs for casing leaks is defined in 40 CFR 146.8(b). In general, those methods include:

- Monitoring of tubing-casing annulus pressure with sufficient frequency to be representative. Since Intrepid currently uses continuous chart recorders and is planning to convert to electronic digital data records. Either of these two data collection methods will meet this requirement.

- Pressure test with liquid or gas

Methods for conducting MIT's for significant fluid movement on the outside of the casing include:

- Temperature and noise (sonic).
- Cement records.

3.1. METHOD A - CASING PRESSURE TEST WITH CEMENTING CONTRACTOR (FOR NEW SYLVITE 5 WELLS)

3.1.1. Cement is circulated down the inside of the interior casing and up around the annulus.

3.1.2. 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.

3.1.3. 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).

3.1.4. Hold this pressure for 45 minutes. Pressure will be continuously recorded electronically by the cementing contractor.

3.1.5. After 45 minutes, record final pressure.

3.1.6. Bleed off well into a bucket if possible to obtain a volume estimate.

3.1.7. If pressure does not vary more than 10% then the well has demonstrated internal mechanical integrity.

3.1.8. Have the cement company representative record the results of this test on his official job log.

3.2. METHOD B - CASING PRESSURE TEST WITH DRILLING RIG EQUIPMENT (FOR NEW SYLVITE 5 WELLS)

3.2.1. Allow cement sufficient time to cure.

3.2.2. 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)

3.2.3. Fill the casing completely with fluid and leave static for 12-24 hrs. if possible.

3.2.4. Before drilling out cement, float collar and guide shoe, trip in drill pipe to near the top of the float collar.

3.2.5. Close pressure control equipment (BOP).

3.2.6. 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.

3.2.7. Monitor pressure reading for 45 minutes, recording pressure reading every 5 minutes.

3.2.8. After 45 minutes, record final pressure.

3.2.9. Bleed off well into a bucket if possible to obtain a volume estimate.

3.2.10. Record test results on IADC (International Association of Drilling Contractor's) form.

3.2.11. If pressure does not vary more than 10% in 45 minutes, the well has demonstrated internal mechanical integrity.

3.3. METHOD C - CASING PRESSURE TEST WITH PACKER (FOR NEW SYLVITE 5 WELLS)

3.3.1. Calculate the necessary surface gauge pressure reading to achieve at least 100 psi pressure differential between the casing and formation. (Formula and example calculations are described in Method G, below).

3.3.2. After drilling out the float collar, cement and guide shoe, lower a packer on tubing to below clastic 2.

3.3.3. Expand packer and fill casing completely with fluid.

3.3.4. Fluid should be filled into one valve, with another open valve available to allow air to escape.

3.3.5. Close pressure control equipment (BOP).

3.3.6. 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.

3.3.7. Monitor pressure reading for 45 minutes, recording pressure reading every 5 minutes.

3.3.8. After 45 minutes, record final pressure.

3.3.9. Bleed off well into a bucket if possible to obtain a volume estimate.

3.3.10. Record test results on IADC (International Association of Drilling Contractor's) form.

3.3.11. If pressure does not vary more than 10% in 45 minutes, the well has demonstrated internal mechanical integrity.

3.4. METHOD D - ANNULUS PRESSURE TEST (FOR WELLS WITH A LIQUID-FILLED ANNULUS)

3.4.1. 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).

3.4.2. If the annulus is not completely full, fill annulus completely with fresh water with a second opening available to allow air to escape.

3.4.3. Allow well 12-24 hrs. static if possible.

3.4.4. Connect to a liquid pressure source.

3.4.5. 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.

3.4.6. Monitor pressure reading for 45 minutes, recording pressure reading every 5 minutes.

3.4.7. After 45 minutes, record final pressure.

3.4.8. Bleed off well into a bucket if possible to obtain a volume estimate.

3.4.9. Record test results on IADC (International Association of Drilling Contractor's) form.

3.4.10. If the pressure does not vary more than 10% over 45 minutes then the well has demonstrated internal mechanical integrity.

3.5. METHOD E - RADIOACTIVE TRACER SURVEY

Radioactive tracer survey (RTS or RATs) is a technology originally developed in the 1930's for locating flow behind casing strings and is useful for analyzing casing mechanical integrity. Generally, either "slug tracking" or "velocity shot" methods are used for leak detection.

3.5.1. Recording Guidelines:

a) A collar locator must be run with all logging runs.
b) Logging speed and time constant used must be indicated on the log heading.
c) Gamma ray sensitivity must be set so that the tracer can be easily distinguished from normal lithologic "hot spots".
d) Record the type, volume and concentration of each tracer slug.
e) Record injection rate and pressure during each log pass.
f) Show the percentage of fluid loss where detected.

3.5.2. Shut down well, move in work over rig and pull pump and/or tubing.

3.5.3. Modify system to allow river water to be injected into well.

3.5.4. Begin pumping river water until an entire casing volume minimum has been injected.

3.5.5. Run 1

a) 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.
b) 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, water may be used to attain normal operating internal casing pressure.

3.5.6. Run 2

a) Run background gamma log prior to RTS Survey.

3.5.7. Run 3A – Method A Internal Mechanical Integrity

a) Load RTS tool to 20 feet below ground surface and begin logging on time drive. Centralize the RTS tool.
b) Eject a tracer slug.
c) Lower tool to 500 ft. below ground, continue logging on time drive until the tracer slug is detected passing the tool.
d) Switch to depth drive, lower tool 100 f1"(600 ft. below ground) and log up to surface, checking for "hot spots" that indicate a leak in the casing. (internal MI)
e) Lower tool to 500 ft. below ground. Return to time drive.
f) Eject a tracer slug and lower tool to 1,000 ft.
g) Continue logging on time drive until the slug is detected passing the tool.
h) 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.
i) Repeat steps 12-15 until the entire casing has been logged.
j) When logging up through any radioactive tracer slug, always log a reasonable distance above the released slug as a check for secondary peaks because the movement of secondary peaks may indicate some sort of inconsistency. When doing tracer loss surveys, record the times the slugs are logged so a timed slug analysis can also be performed.

3.5.8. Run 3B– Method B Internal Mechanical Integrity

a) With the injector tool at 0 ft., inject a tracer slug.
b) 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.
c) Repeat step 14 until the slug has passed through the bottom of the wellbore, overlapping log runs to ensure the entire casing is logged.
d) Mechanical integrity is demonstrated if the tracer reading maintains the same area, and velocity is consistent through the casing.

3.5.9. Run 4–External Mechanical Integrity

a) Lower the injector tool to the bottom of the lowest casing shoe and begin logging on time drive.
b) Inject a radioactive slug while keeping the tool stationary at the shoe. Log for 15 minutes. .
c) If the tracer is detected moving upwards, switch to depth drive and follow the tracer.
d) 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.
e) 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.

3.6. METHOD F - CEMENT BOND LOG (CBL)

3.6.1. Have lubricator on site for use if desired (optional).

3.6.2. Allow cement sufficient time to cure (determined by cement type/cement charts and or recommendations by the cementing contractor, such as Halliburton)

3.6.3. Circulate the hole with a fluid of uniform consistency. Fill hole entirely with fluid.

3.6.4. Run a collar locator and gamma ray along with the CBL.

3.6.5. Run at least 3 bow-spring or aluminum centralizers.

3.6.6. Logging speed should be approximately 30 ft. per sec.

3.6.7. Record amplitude and travel time. Record amplitude and amplified amplitude on a 5X scale.

3.6.8. Log repeat sections.

3.6.9. Have logging engineer provide an interpretation of the log data.

3.7. METHOD G - CALCULATION FOR ESTABLISHING TEST CONDITIONS FOR STANDARD STATIC ANNULUS PRESSURE TEST.

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

Determine a reasonable value for the weight in pounds/gallon of the fluid in the casing (annulus fluid), the formation, and injection tubing.

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.
Pals + (0.052 x Waf X D) > 0.052 X Wffx 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.
Pals + (0.052 x Waf X D) > (0.052 X Wif X D) + Ptsils + 100

Where:

Pals = annulus pressure reading at surface (psi)
Ptsils = tubing pressure, shut in, at surface (psi)
Waf = Weight of the annulus fluid (lbs/gal)
Wff = Weight of the formation fluid (lbs/gal)
Wif = Weight of the injection fluid (lbs/gal)
D = Depth of packer seat (or lowest extent of pressurized annulus) (£1)

Example Calculation:
For a well with an annulus between 9-5/8" and 7" casing filled with fresh water, packer at 3000 £1 and saturated salt water injection fluid, not injecting.
Ptsils = 0 psi
Waf = 8.34lbs/gal
Wff == 9.6 lbs/gal
Wif= 10.1 lbs/gal
D = 3000 £1
Test Condition 1 Calculation:
Pals + (0.052 x 8.34 x 3000) > 0.052 x 9.6 x 3000 + 100
Pals>1498-1301+100
Pals> 297 psi

And

Test Condition 2 Calculation:
Pals + (0.052 x 8.34 x 3000) > (0.052 x 10.1 x 3000) + 0 + 100
Pals> 1576 - 1301 + 100
Pals> 375 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. Calculation G was prepared for all existing Sylvite 9 wells and is presented on Table 7 (Technical Report, 2013).

3.8. METHOD H – TEMPERATURE LOG FOR EXTERNAL MIT

4. PIPING AND INSTRUMENTATION DIAGRAM

Attachment G

Contingency Plan for Well Shut-ins or Well Failures

Contingency Plan

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.

Attachment H

Plugging and Abandonment Plan

ATTACHMENT H—PLUGGING AND ABANDONMENT PLAN

This attachment provides an overview of well plugging and abandonment (P&A) programs and procedures, and is incorporated in the UIC permit as a permit condition as required by Part II.D.15 of the permit. A summary of well plugging and abandonment history to date is included. The generic abandonment procedure was developed based on Utah abandonment regulations as well as consultation with a reputable well cementing contractor. Abandonment plan schematics for all operating wells along with schematics for abandoning the two mine shafts are provided in Appendix C of the Technical Report submitted with the application for this permit (2013). A third party cost estimate was obtained for well and shaft abandonment. These costs were used to calculate the financial surety bond for well abandonment in the event of financial failure.

1. WELL PLUGGING AND ABANDONMENT HISTORY

The history of well abandonment was largely compiled from mine records. Wells within the area of review (AOR) are summarized in Table 3. Following is a list of known abandoned wells within the UIC boundary.

1.1. OIL WELLS

There are 10 oil wells drilled inside the UIC boundary.

1.2. CANE CREEK COREHOLES

Abandonment of the Cane Creek core holes 1 through 19 were conducted at the time they were drilled. Plugging and abandonment information is shown on the well table and is provided in Appendix C of the Technical Report.

1.3. TEXAS GULF WELLS

Texas gulf drilled Wells TG-1 through TG-16 were drilled in the years 1970 to 1975. Additional wells TG-17 to TG-23 were drilled later. Many wells were drilled in faulted areas and had problems with loss of mechanical integrity.

1.3.1. Well TG-1

This well was drilled in 1970, but did not enter the mine. It was used in the test well program and plugged and abandoned in 1989.

1.3.2. Wells TG-2, TG-8, TG-13, and TG-14

These wells were used for injection but developed leaks. Well TG-2 was plugged and abandoned in 1975. Wells TG-8, TG-13 and TG-14 were plugged in 1988.

1.3.3. Wells TG-3 and TG-9

These wells were drilled for injection but missed the mine. Well TG-3 was used for six months in 1974 in the test well program. It was plugged and abandoned in 1989. Well TG-9 was never used and was plugged and abandoned in 1989.

1.3.4. Wells TG-7 and TG-11

These wells were drilled for injection and did enter the mine, but encountered problems and were temporarily plugged. Well TG-7 was initially plugged in 1971 and the pugging and abandonment was completed in 1988. TG-11 had a bridge plug and some cement set in place in 1971. Plugging and abandonment was completed in 1989.

1.3.5. Well TG-4 and TG-10

These wells were used for injection, but developed problems. These wells were plugged in 1988. Cane Creek #10 was drilled in 1960 as a test well and was plugged and abandoned in 1989.

1.3.6. Well TG 12, TG-16, and TG-20

These wells failed mechanical integrity tests early in 1989 and were plugged and abandoned that same year.

1.3.7. Well TG-17, TG-18, TG-19, TG-21, TG-22, and TG-23

These wells were drilled outside the mine and were used in the test well program. Well TG-19 was plugged and abandoned in 1988. Wells TG-21, TG-22, TG-23 were plugged in 1989. TG-17 and TG-18 were plugged and abandoned in 1993.

1.3.8. Well TG-5 and TG-15

These wells were used for injection and plugged and abandoned in 1996 and 1995, respectively, because they failed mechanical integrity tests.

1.3.9. Well TG-6

This well is still operating as one of the 5th ore zone extraction wells.

2. PLUGGING AND ABANDONMENT REQUIREMENTS

Permit Condition Reference: Part III.J.2

When the decision to plug a well is made, a final plan will be submitted to the DEQ prior to actual abandonment operations and it may be different than the plan set forth below due to changes in the condition, well configuration, or other recommendations based on improvements in plugging techniques. Plugging and abandonment plans are required by UAC R317-7-9.1 D (23) C.

2.1. TECHNICAL SPECIFICATIONS FOR PLUGGING WELLS

2.1.1. Plugging with Cement

In accordance with UAC R317-7-10.5, wells to be abandoned will be plugged with cement in a manner which will not allow the movement of fluid either into or between underground sources of drinking water. Prior to the placement of the cement plug, the

well will be allowed to reach a state of static equilibrium, as indicated by the mud weight being equalized top to bottom. This will be accomplished either by circulating the mud in the well at least once, or by a comparable method prescribed by the Division.

As reported by Peter W. Huntoon (1985), there are no USDWs within a two-mile radius of the facility. Class III wells at the permitted facility will be cemented from a retainer set below the permitted injection zone to surface. This should prevent fluid migration in the wellbore whether USDWs are present or not.

2.1.2. Plugging method

Placement of cement plugs will be accomplished by one of the following methods:

- balance method,
- dump bailer method,
- two plug method, or
- an alternative approach approved by the DEQ.

3. WELL PLUGGING AND ABANDONMENT PROCEDURES

The following is a general procedure for the plugging and abandonment for the wells currently in operation. Wells that are taken out of service and are scheduled for abandonment will be physically disconnected from sources of brines or water and capped at the surface. Intrepid intends to conduct abandonment procedures that meet or exceed industry standards. Prior to conducting plugging and abandonment procedures Intrepid will contact reputable well cementing companies and seek current procedures.

3.1. THE GENERAL PROCEDURE FOR ABANDONMENT CONSISTS OF THE FOLLOWING:

3.1.1. Notify DWQ of intent to plug and abandon no later than 45 days in advance

Permit Condition Reference: Part III.J.2 (a)

The notice will include a well condition report discussing the well's most recent MIT results, the location of any leaks or perforations in the casing, the location of any vertical migration of fluids, the adequacy of the casing cement bonding across the salt formation as determined from cement bond logs. Any data or results available supporting the conclusion of the well condition report will also be provided.

The notice will also include an individual abandonment plan for each well to be abandoned that will supersede any previous P&A plans. An anticipated schedule for the abandonment operations will be included so a DEQ representative may observe if they desire.

3.1.2. Calculate cement volumes

All cement volumes use 10-percent excess per 1,000-ft of depth, both inside and outside; or use 100-percent excess outside casing, 50-ft excess inside casing and 50-ft excess for a casing annulus, whichever is greater. The stabilizing wellbore fluid will be at least 9.5 ppg produced brine, sufficient to balance all exposed formation pressures. All cement will be Class B ASTM Type III, mixed at 15.6-ppg yielding approximately 1.18-cubic ft/sack for plugs below 5,000-ft and, mixed at 14.8-ppg yielding approximately 1.32 cubic ft/sack for plugs above 5,000-ft. The exact cement formula may change based upon consultation with professional cementing companies.

3.1.3. Prepare location for rig and other equipment

Access to location may require dirt work prior to rig arrival. IPM may use the existing reserve pit or dig a small earthen pit for well returns and cement wash up. The rig tie down anchors will be tested.

3.1.4. Move in and rig up a daylight workover rig with the necessary ancillary equipment

IPM will conduct a safety meeting for all personnel on location. Work to be completed includes: nipple up relief line and blow down well; kill with produced brine as necessary to meet specifications, Nipple down wellhead and nipple up blow out preventer (BOP), and test the BOP.

3.1.5. Review Cement Bond Log

If necessary a cement bond log will be run to verify cement conditions behind the casing. If significant zones of poor quality cement are identified, the zone will be perforated and squeezed. If the well is required to be squeezed, IPM will work with the cementing contractor to develop a plan that meets current best practices. This may require infiltration/injection rate tests. Cement squeeze jobs will be continued until there is a 100-ft zone of cement outside the casing.

3.1.6. Circulate the well to achieve static equilibrium as required by UAC R317-7-10.5 C.

3.1.7. Remove all uncemented tubing and / or casing strings above Clastic 2 zone

Note that the sylvite 9 wells all have 7-inch 26-pound per foot casing that is stung into a packer or polished bore receptacle. This casing will have to be removed.

3.1.8. Pressure test casing to 1,000-psi

If casing does not test then spot or tag subsequent plugs as appropriate.

3.1.9. Trip in with bit and scraper with 2-7/8" tubing on power swivel with pit and pump

3.1.10. Trip in with cement retainer and set at specified depth below Clastic 2

3.1.11. Un-sting from cement retainer, circulate 2 hole volumes to balance fluid densities

3.1.12. Tremie

With tremie pipe near bottom fill hole approximately 1/2 full with 14.5-ppg Ready-Mix cement using the balance-plug method with 20% excess over casing volume

3.1.13. Pull tremie pipe 600 ft above top of cement plug and wait 4-6 hrs

3.1.14. After WOC trip in hole and tag cement to verify plug location

3.1.15. Calculate next cement volume

3.1.16. Fill hole to surface with Ready-Mix with tremie at top of first plug

3.1.17. Trip out tremie pipe, and top off hole for displacement of pipe volume

3.1.18. Demobilize rig and equipment.

3.1.19. Cut off surface and production casing below ground level

3.1.20. Install dry-hole marker with well number and survey information

3.1.21. Submit final abandonment plan to DEQ

Based on specific well condition for approval.

4. MINE SHAFT PLUGGING AND ABANDONMENT PROCEDURES

There are two shafts into the 5th ore zone; Shaft Number 1, which has the tall concrete head frame, and Shaft Number 2, which was reconstructed as a "well" to be used as a ventilation shaft into the 5th ore zone. Schematics of the two shafts are provided in Appendix C of the Technical Report.

4.1. ABANDONMENT PLAN – SHAFT NUMBER 1

The 22-ft diameter shaft was filled with salt by pumping the salt slurry from the mill into the shaft over a two week period in 1972. The original abandonment plan for the shaft was modified in 2003. Note the original abandonment schematic is included in Appendix C only for reference to depths and shaft construction details, not abandonment procedures.

The plan specifies for the salt to be removed (or added if necessary) to the depth of approximately 22-ft below the elevation of the bottom of the Colorado River, which is estimated to be 126-ft below ground level. The actual depth will be evaluated at the time of abandonment. A 44-ft thick concrete plug will be placed in that interval from 126-ft to 82-ft. Then 50-ft of gravel or fine grain soils readily available from on-site locations, will be placed on into the remaining shaft top of the concrete plug to approximately 3 to 5 feet below the surface. The gravel and soils will be capped with concrete with an observation port into the gravel portion to monitor for settling (and addition of material). The shaft will be monitored for 5 years and refill if necessary.

4.2. ABANDONMENT PLAN – SHAFT NUMBER 2

Shaft Number 2 is used to measure the brine level in the 5th or zone. A schematic of Shaft Number 2 is included in Appendix C of the Technical Report. The plugging and abandonment of the shaft will consist of the following steps:

4.2.1. Remove all tubing and measuring equipment

4.2.2. Measure to verify the shaft is open to at least 2,650-ft

4.2.3. Place gravel into the shaft, filling it to an elevation at least above 2,650-ft msl

4.2.4. Place a 100-ft thick cement plug

The cement will be API Class B cement with a density of approximately 120-pounds be ft3.

4.2.5. Fill the shaft with gravel and/or cement to 3 to 5 feet below ground level.

4.2.6. Place metal cap and observation port into the gravel below the surface cement

The observation port will be used to monitor the gravel for settling. If the gravel has settled, the port will allow access to add more gravel to keep the level at the concrete surface plug.

4.2.7. The gravel level will be monitored through the observation port for 5-years.

5. PLUGGING AND ABANDONMENT COST ESTIMATES

IPM prepared and supplied bid packages to selected contractors. The bid package contained the procedures specified above and the schematics of each well and shaft that needs abandonment from Appendix C of the Technical Report. The contractors provided written cost estimates for this work. Those contractor prepared cost estimates are supplied in Appendix D of the Technical Report. Additional details are provided below.

5.1. WELL PLUGGING AND ABANDONMENT COST

IPM obtained a cost estimate for plugging and abandoning the wells. Those costs for plugging and abandoning one well is shown on Table 10 of the Technical Report (2013). The typical cost per well is approximately $69,530. Halliburton provided a cost estimate for cement retainers. A cement retainer will cost approximately $5,000 for a 7-inch casing and approximately $10,000 for a 9-5/8" casing. Cement and cementing services for each well will cost approximately $74,168. The total amount for all the wells was provided to DWQ as part of the application for this permit, and is approximately $1,428,576.

5.2. SHAFT PLUGGING AND ABANDONMENT COST

The contractor supplied cost estimate for plugging and abandoning the two shafts were provided to DWQ as part of the application for this permit. The total cost for plugging the two shafts is approximately $281,322.

Attachment I

Financial Responsibility

The updated Standby Trust Agreement along with the updated Schedule A and the Associated Financial Guarantee Bond are housed in the DEQ's Office of Support Services.

These document shall be updated every five years from the effective date of this permit renewal:

6. FINANCIAL SURETY TRUST BOND

A financial surety trust bond was obtained from Western Surety Company, effective January 8, 2015. The bond was obtained by submitting the cost estimates as summarized on Tables 10, 11, and 12 of the technical report (2013), along with the plugging and abandonment procedures and bid packages. The total amount for plugging and abandoning the 16 operating wells and the two open mine shafts is 1,709,898. A copy of the surety trust bond has been provided to DWQ (see Attachment I of this permit).

Intrepid Potash – Moab, LLC
P.O. Box 1208
Moab, UT 84532
435.259.1204
435.259.7100 fax

July 23, 2015

Woodrow Campbell, PE
Utah Division of Water Quality
195 North 1950 West
Salt Lake City, UT 84116-4879

Re: Intrepid Potash-Moab, LLC, UIC Permit Attachments
UIC Permit Number UTU-19AP-1C3C2E8

Dear Mr. Campbell,

Pursuant to Part III, Section B of the UIC permit effective May 1, 2015, Intrepid Potash—Moab, LLC (IPM) is submitting the following documents for your review and approval as enforceable plans to be attached to the above-mentioned permit:

- Operating Plan
- Construction Plan with Well Construction Details
- Plugging and Abanment Plan
- Monitoring, Recording and Reporting Plan

The Monitoring, Recording and Reporting (MRR) Plan describes the procedures currently followed for monitoring and reporting. As you are aware, the permit issued in May 2015 describes additional monitoring and reporting requirements, including installation of a continuous monitoring system for each cavern. It also provides a compliance calendar for completion of these requirements. As this system is installed and made operational, the procedures described in the MRR plan will change and the plan will be updated at that time. Moreover, the permit also calls for a piping and instrumentation diagram to be included as part of the MRR plan. Work on that diagram is not complete so it will be provided to DWQ when the MRR Plan is updated.

IPM appreciates the opportunity to work with DWQ on this matter. If you have any questions please call me at (435-259-1282).

Sincerely,

Chad Harris, PE
Environmental Coordinator

cc: Brandon Bartosh, Rick York, Craig Fanshier

Enclosures