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, 2023

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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, SE/4, W/2 of the NE/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 7379.9 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 Clastic 9, upon the express conditions that Intrepid 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 '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

Attachment J - Expected Changes Due to Injection

Attachment K - Mechanical Integrity Demonstration Protocols

Attachment L - Two Fer 26-30 (API 43-019031452) Oil and Gas Well Rework Report

This major modification of the original permit is based upon representations made by Intrepid and other information contained in the administrative record. **It is the responsibility of Intrepid 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 **April__, 2023.**

This permit and the authorization to inject shall be issued for 5 years as described in Part III A – Duration of Permit of this permit unless terminated prior to the expiration date or renewed.

John Mackey.
Director
Utah Division of Water Quality

PART II. GENERAL PERMIT CONDITIONS

A. EFFECT OF PERMIT

Intrepid is allowed to engage in underground injection in accordance with the conditions of this permit. Intrepid, 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 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 Intrepid 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 Intrepid 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 Intrepid.

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))

   Intrepid 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 Intrepid 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 Intrepid wishes to continue an activity regulated by this permit after the expiration date of this permit, Intrepid must apply for and obtain a new permit. Intrepid shall submit a complete permit renewal application at least 180 days before this permit expires. 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 Intrepid 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))

   Intrepid 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))

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

[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.

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 Intrepid) 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 Intrepid, 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 Intrepid 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 force majeure, labor strike, flood, or materials shortage or other events over which Intrepid 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 Intrepid.

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 Intrepid with any condition of the permit;

ii. Intrepid's failure in the application or during the permit issuance process to disclose fully all relevant facts, or Intrepid'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 Intrepid, 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 Intrepid;

(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 Intrepid 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 Intrepid 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 Intrepid 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 Intrepid if:

i. The current Intrepid 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 Intrepid 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 Intrepid:

Intrepid, 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 Intrepid, has demonstrated financial responsibility for the well.

Intrepid 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 Intrepid and the proposed new Intrepid 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. Property Rights (40CFR144.51(g))

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

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

Intrepid 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. Intrepid 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))

Intrepid 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 Intrepid'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) Intrepid 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
Intrepid 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 Intrepid does not stay any permit condition.

b) Anticipated Noncompliance
Intrepid 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 Intrepid 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 Intrepid 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
Intrepid 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 Intrepid 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 Intrepid 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
Intrepid 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 Intrepid 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, Intrepid shall submit such facts or information within 10 days after becoming aware of the failure to submit relevant facts.

13. <u>Requirements Prior to Commencing Injection (40CFR144.51(m))</u>

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

(1) Intrepid 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. Intrepid 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 Intrepid 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))

Intrepid 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 Intrepid 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 five (5) years. 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. <u>Construction Plan</u>

   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. <u>Operating Plan</u>

   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.

3. <u>Monitoring, Recording and Reporting Plan</u>

   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.

6. Financial Responsibility and Guarantee

   Within 6 months of renewal of this permit, Intrepid Potash will provide financial guarantee information, which meets the requirements of Part III (K) of this permit.

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 Intrepid'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. Intrepid 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, Intrepid 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, Intrepid 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 (40_CFR_146.34(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 9 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), 40_CFR_144.54, and 40_CFR_146.34)

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: Intrepid shall monitor the nature of injected fluids with sufficient frequency to yield representative data on its characteristics. Intrepid 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. Intrepid may request confidentiality in accordance with Part II C of this permit. If the information is proprietary Intrepid may, in lieu of the ranges in concentrations, choose to submit maximum concentrations which shall not be exceeded. In such a case Intrepid 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: Intrepid 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)

   MITs shall be conducted according to Part III (I) of this permit.

8. Injection Zone Fluid Level

   Regulatory Reference: Intrepid 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: Intrepid 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 monitor-ing 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

Intrepid 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 Intrepid 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 Intrepid 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

Intrepid 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 Intrepid, does not stay any permit condition.

4. Anticipated Noncompliance

Intrepid 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 Intrepid, 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 Intrepid 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 - Intrepid shall submit the results of any MI demonstration within 60 days after completion of the test. Intrepid shall include in the report, a detailed description of the tests and the methods used to demonstrate MI. In the case of MI failure, Intrepid 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, Intrepid 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, Intrepid 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, Intrepid shall submit the required monitoring data in an Excel spreadsheet.

I. MECHANICAL INTEGRITY
(R317-7-10.3(B) and
40_CFR_146.8)

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**

(6) **Water-Brine Interface Test (W-BIT)** – For Sylvite 5 and 9 Class III Salt Solution Mining Wells only.

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>

Intrepid 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, Intrepid shall apply methods and standards generally accepted in the industry for conducting and evaluating the tests (40CFR146.8(e)).

4. Mechanical Integrity Demonstration Frequency

   Intrepid 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

   Intrepid 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 Intrepid or the Director determines that a well fails to demonstrate MI Intrepid 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) Intrepid 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, Intrepid to demonstrate MI of a well.

8. Mechanical Integrity Demonstration Inspections

   Intrepid shall allow the Director, or his representative, to observe any or all MI demonstrations. Intrepid 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 40_CFR_144.51(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 (40_CFR_146.10 and R317-7-10.5)

1. Requirement for Plugging and Abandonment Plan

   Intrepid 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

   Intrepid 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
      Intrepid 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
Intrepid 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) Intrepid will seek oral approval from the Director for emergency well conversion or abandonment no less than 24 hours prior to the emergency action.

b) Intrepid 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 Intrepid from its responsibility to comply with the conditions of this permit, including requirements of the P&A Plan.

4. Plugging and Abandonment

Intrepid 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 Intrepid shall plug and abandon the well(s), unless Intrepid 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 Intrepid 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 Intrepid 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
40_CFR_144.52)

1. Demonstration of Financial Responsibility

Intrepid 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. Intrepid must secure updated bonding in a form satisfactory to DWQ and submit to DWQ within 60 days of permit issue.

2. <u>Renewal of Financial Responsibility</u>

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

3. <u>Insolvency Financial Responsibility</u>

   Intrepid 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
(40_CFR_144.52)

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

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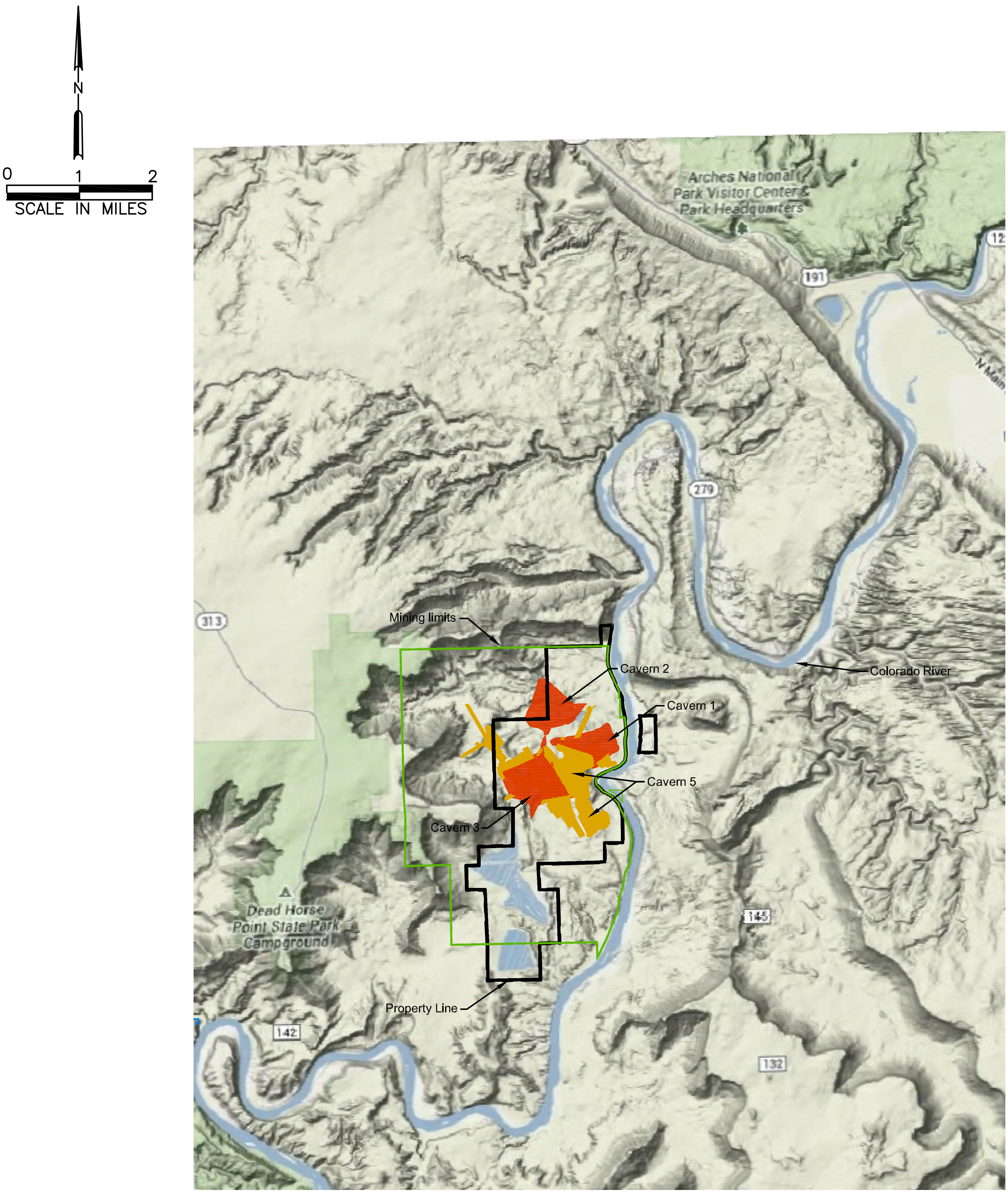
Attachment A

General Location Map of the Cane Creek Mine,
Grand County



INTREPID

DATE 11-30-22
DWN GRH
APP
REV
PROJECT NO.
UIC-001-001

FIGURE 1
INTREPID POTASH
MOAB, UTAH
UIC PERMIT
SITE LOCATION

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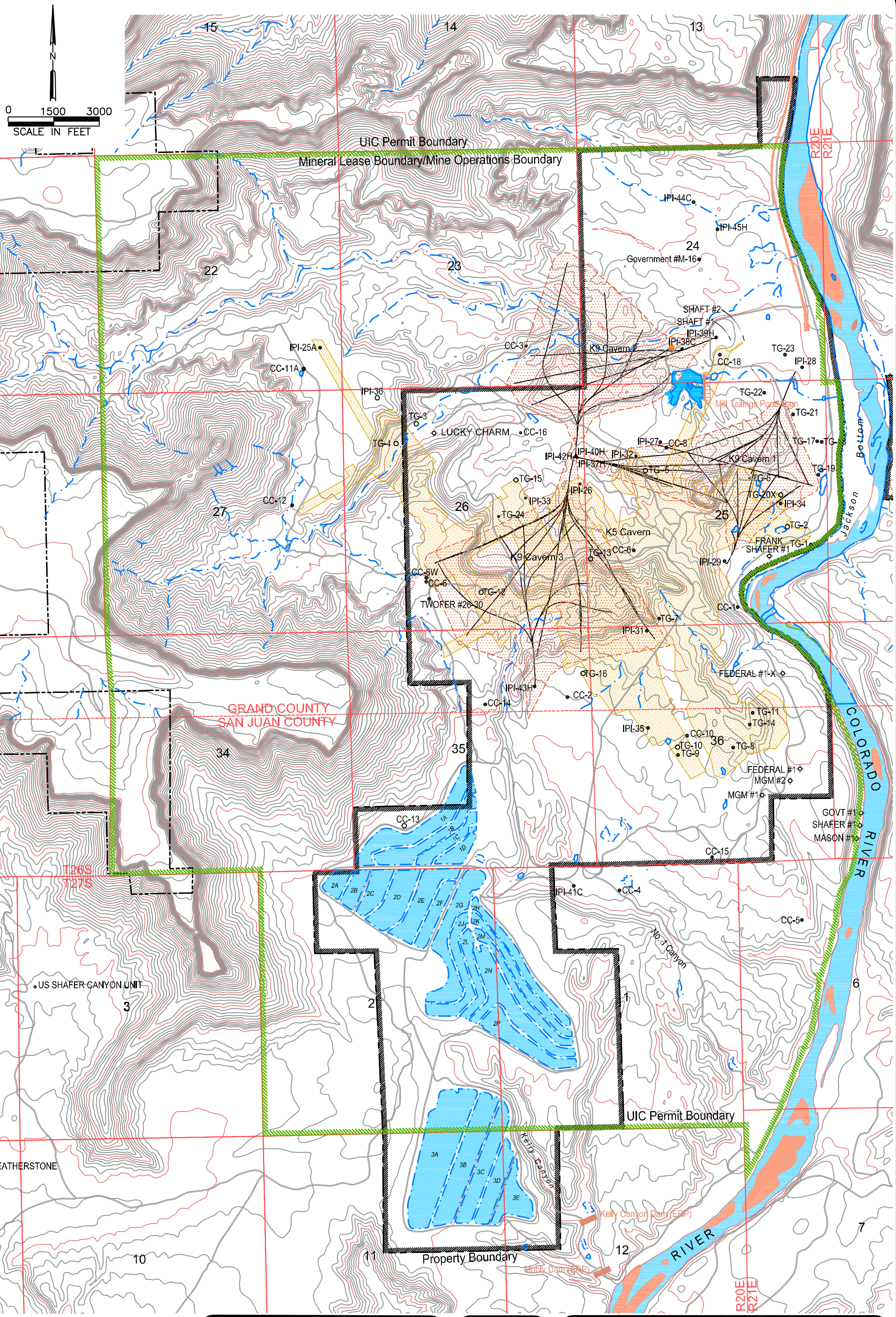
Attachment B

Map of the UIC Area of Review including the Class III Solution Mining Injection Wells, Including the Two Fer 26-30 Well (API 43-019031452) and the Project Area



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INTREPID

DATE	11-30-22
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REV	
PROJECT NO.	UIC-001-001

FIGURE 2
INTREPID POTASH
MOAB, UTAH
UIC PERMIT
SITE OVERVIEW

Attachment C

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

3.2 Corrective Action Plan - Part D

Well abandonment records for the wells in the area of review that penetrate the injection zone were compiled and reviewed. Well abandonment is further discussed in Section 8. Intrepid has reviewed the readily available records of the wells located on site (within the facility operating boundary). All wells within the AoR have been properly plugged according to DEQ requirements or sufficiently removed from solution mining operations to pose no concerns. Abandonment reports and/or schematics have previously been submitted to DEQ for all wells plugged on the property and in the AoR, and were approved in the 2015 UIC permit. No information has identified other artificial penetrations that would restrict injection pressures. Therefore, a corrective action plan is not required to be included with this review. However, if a previously unidentified well is discovered a corrective action plan will be prepared that considers known construction information and additional information acquired during well condition assessment and well plugging and abandonment activities.

Attachment D

Injection Well Construction Plan with
Injection Well Construction Details

5 INJECTION AND EXTRACTION WELL CONSTRUCTION PLANS - PART G

Construction specifications for each type of well are provided in this section. The following construction specifications were written to specifically address the individual points of UAC R317-7-10.1(B), which governs construction of Class III injection wells. Currently there are seven vertical wells completed to extract brine form the 5th ore zone (Sylvite 5) and eight wells constructed to extract brine from horizontally constructed caverns in the 9th ore zone (Sylvite 9). Wells IPM 30 and IPM 45H will be added in the near future. In addition, coreholes are advanced for evaluating the geologic conditions.

As the well field is expanded with new wells, each well is designed for the objectives of that operation. The new design considers the implementation of previous well drilling and construction programs and advancements in drilling and well construction technology. 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 to protect the environment. All wells constructed since 2000 have been cemented from total depth to surface to mitigate external corrosion. Construction specifications for each type of well are discussed in this section.

The folded nature of the geology due to the Cane Creek Anticline and the ductile nature of salts combined with a complex surface topography produces a wide range of depths to the target ore zones. A summary of well depths and major casing strings are summarized on Table 5. Well depth ranges from approximately 2,992 to 3,556-ft deep for wells constructed to access the 5th ore zone, while wells constructed to access the 9th ore zone range from 3,623-ft to 4,385-ft in true vertical depth. The minimum depth for a well constructed in each ore zone was used to calculate maximum allowable surface injection pressure, external pressure, internal pressure, axial loading for this renewal. The designs discussed in this section are considered minimum designs.

When new wells are planned the estimated depths will be used to calculate the pressures and loads and the casing program reviewed and submitted with the schematic and abandonment plans for new wells. Wells that are completed in multiple zones will use the lessor depth for determining maximum injection pressures.

5.1 Construction of Sylvite 5 Injection/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 may 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.

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

Intrepid may drill horizontal wells into the 5th ore zone in the future. Construction stresses are similar to vertical wells. The well design will be similar to horizontal wells constructed in the 9th ore zone.

5.1.1 Total Depth and Depth to Injection Zone

Total vertical depth of existing wells (Table 5) constructed to access the 5th ore zone varies from 2,995 to 3,556-feet. The depth of any new injection wells would likely be within the range of existing well depths. The top of the injection zone is the base of Clastic 2 where it contacts Salt 3. The depth to the base of Clastic 2 in both Sylvite 5 and 9 wells currently operating varies from 2,345 to 3,624-ft, as shown on Table 5. Wells already completed comprise a variety of the well designs. The well design described below is similar to the most recently completed wells. The typical Sylvite 5 well construction is shown on Figure 4. Future wells are likely to follow the same design.

5.1.2 Injection Pressure, External Pressure, Internal Pressure, Axial loading

i. Injection pressure – Intrepid may operate all wells constructed in Sylvite 5 as injection and extraction wells. Well 24 is the primary injection well for the open mine works in Sylvite 5, and typically injects at a negative pressure. Since 2018, Intrepid has been storing brine produced from the 5th and 9th ore zones in the original mine works during the winter months. Wells 32 and 34 are the primary wells used for injecting brine for storage. However, as Intrepid continues to collect and evaluate operations data, additional Sylvite 5 wells may be included for both injection and extraction.

The fluid level in the Sylvite 5 cavern is measured at Shaft 2 (Drawing 1). The minimum depth to fluid is 125-ft bgs, as specified in the current UIC permit, which corresponds to 3,893-ft msl. Fluid level in the mine cavity is kept at a minimum of 35-ft below the base of the Colorado River. This creates a hydraulic gradient into the mine cavity. The original mine works itself are not operated in a pressurized state.

ii. External pressure – Hydrostatic pressure from formation saltwater is representative of the external pressure exerted on the casing strings. These calculated pressures are results from the following formula:

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

*(*0.052 is a conversion factor allowed when using the units of feet, ppg and psi)

- **Operating Wells.** The maximum depth of for all casing strings is the top of Sylvite 5, which for operating wells, is 3,544 -ft in Well MS-25 TVD with fluid densities ranging from 9.5-10.5 lbs/gal, the external pressure ranges from 1,717 to 1,898 psi with completely evacuated casing.

- **Potential Future Wells.** Sylvite 5 at corehole 44C (which is the farthest to the north of the anticline) is 3,824-ft. Fluid density will range from 1,889 to 2,088-psi.

iii. Internal pressure – Internal pressure is equal to the hydrostatic pressure inside the casing string and should be equal to the external pressure. During pumping, denser brine from the mine workings could fill the interior casing. Given a density difference of 0.7 lbs/gal, this would create a pressure differential between external and internal pressures of 0.0374 psi/ft, or 143 psi for a 3,824-ft deep well.

iv. Axial loading – The maximum load on the exterior casing varies with casing size. Typical casing types, other than shallow casings installed as conductors or for unstable drilling conditions, range from 9-5/8-inch 40-pound/ft casing used for the surface casing and 7-inch 23-pound/ft casing is used as an intermediate casing string. The buoyancy correction for 10.0-ppg drilling fluid is not used for these calculations. Since the buoyancy factor is not used it is considered an extra safety factor. Casing data is obtained from the Baker Hughes Tech Facts Engineering Handbook (publication date not available).

- The longest string of surface casing is 2,720-ft used in Well MS-25. The maximum load on the 9-5/8-inch 40-lb surface casing in this well with no buoyancy correction for 10.5-ppg mud is 108,800 lbs. The body yield for J55 casing is 916,000 lbs and the joint strength is 727,000 lbs. These two numbers are 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.

- The longest string of intermediate casing used in vertical wells is 1,245-ft used in Well MS-25. The maximum load on the 7-inch 23-lb intermediate casing in this well with no buoyancy correction for 10.5-ppg mud is 28,635-lbs. The body yield for 7-inch 23-lb casing (366,000-lbs) and the joint strength is (313,000-lbs) are 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.

- The intermediate casing string for a horizontal well will be longer because it will have to extend through both the vertical and the curve sections of the borehole to the base of Clastic 8. The length of this casing string could range up to 1,900-ft.

Twenty-nine (29) pound casing is often used in the curved section to accommodate the additional internal wear on the casing from drilling laterals due to the drill string from rotating as it lays on the bottom side of the casing. The maximum load on the 7-inch 29-lb intermediate casing in this well, with no buoyancy correction for 10.5-ppg mud, is 55,000-lbs. The body yield for 7-inch 29-pound casing is 676,000 lbs and the joint strength is 587,000-lbs are 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.

The casing strings described below in section 5.1.5 is well within its capacities concerning the above pressures and load.

5.1.3 Borehole Sizes

Borehole sizes are based on the casing planned to be installed. Sizes for downhole hammers, tricones, and PDC bits vary. Often a long borehole will use multiple bit sizes. Sometimes larger diameter bits such as 13-1/2 through 15" are not available and the bit is selected on availability. If practical, the bit program will utilize slightly smaller diameters as the depth of the borehole is advanced when one bit wears out. The surface casing borehole sizes are selected to allow a small diameter (~1.315-inch) string of tubing to be inserted down the backside (between the casing and the borehole wall) as a tremie pipe to allow additional cement to be pumped into the annulus to bring the cement to the surface, when the top of the primary cement job doesn't come to the surface. Borehole size may also change due to wellbore instability or other unforeseen drilling complications. Drilling issues typically arise during large diameter surface drilling.

The range of typical borehole sizes are summarized below:

- Conductor casing - 20 to 24-inch.
- Surface casing - 15 to 12-1/4-inch.
- Intermediate casing – 8-3/4-inch.
- Drilling for open hole completion into the mine or ore zone - 5-7/8 to 6-1/8-inch.

5.1.4 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 typically extends from Clastic 4 into the mine cavity in Sylvite 5.

5.1.5 Casing Strings (Typical)

The typical casing string is discussed below.

Conductor Casing – 10-¾ - 20” line pipe, ¼-inch wall, setting depth 30 to 600 feet depending on well location. The setting depth is unique to each well. The main criteria for determining this surface casing depth is when the surface hole has penetrated through the alluvium and into at least 20-ft of solid bedrock. The current permit requires that “new wells constructed in Colorado River alluvium, identified as stratigraphic units Qu and QTu on Figure 2 of the 1985 Huntoon Report, shall be constructed in accordance with the additional requirement that the surface casing extends significantly into bedrock”. The annulus between the drill hole and the surface casing is cemented back to the surface.

Surface Casing – 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 groundwater corrosion.

Intermediate Casing - 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.

Additional Casing for Horizontal Wells - MIT Casing – 7-inch 26 to 29-lb L-80 (or similar grade) casing set at surface and run to approximately 150-ft to 200-ft above the bottom of the 9-5/8” surface casing. When used, the intent is to set the MIT string into the permitted injection zone with enough room above the base of the 9-5/8” to allow room for repairs to the MIT string. The bottom of the 7” MIT casing string is constructed using one of several types of sealing assemblies. The sealing assembly creates the annulus between the 9-5/8” surface casing and the 7” MIT string which is used for MIT testing. Typically, injection wells use a swell packer assembly while extraction wells use polished bore receptacles (PBR) or swell packers (such as recently used in wells IPI-27, 37, and 43). As well designs and available seal technologies are improved Intrepid may modify the design to take advantage of the improvements. Any design changes will be submitted with the request to drill new wells. The MIT casing string is not cemented in. The backside of the MIT string is filled with freshwater and 2% corrosion inhibitor.

5.1.6 Injection Zone

The injection zone for Sylvite 5 is from the base of Clastic 2 to the base of Salt 9. Intrepid primarily injects into 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 string. 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.

5.1.7 Typical Cementing Procedures

Halliburton or other reputable cement service companies are contracted to provide cement, equipment, and personnel for the primary cement job. When additional cement is required after the primary cement job, the drilling contractor runs tremie pipe and pumps ready mix cement from a local firm to bring cement to surface. Cement designs continue to evolve so the exact weight and mixtures will change. Intrepid strives to use these technological advancements to provide high quality cement around the casing strings.

Cementing the surface casing requires circulating cement down the inside of the casing, out the casing 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 by the drilling contractor for the top off cement due it's 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. The amount of excess cement required for the cement job 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-in casing is engaged into the 9-5/8" casing after cementing, isolating the backside of the 7-inch (the annular space between the 9-5/8-inch casing and the 7-inch casing) and below where the 7-inch casing is in the open borehole). Excess cement is then reverse circulated out of the hole and back to surface.

Details for cementing specific casings are listed below:

i. Conductor 18 - 24"

- Annular volume between 26-in hole and casing = 0.2681 bbl/lin-ft.
- Volume of cement required = depth (ft) * 0.2681bb/ft. If cement is not circulated to surface, ready-mix will be poured until visible at surface.
- Cement Type = Ready-Mix cement, 12.5 to 15 lbs/gal. Slurry weight.
- Equipment: Float equipment is not required. Cement is added via tremie pipe inserted into the borehole between the casing and casing. A plug of cement is often added to the inside of the casing, to prevent the cement installed in the annulus from flowing up into the casing.

ii. <u>Surface Casing, 9-5/8"</u>

- Annular volume between 14-3/4-in hole and casing = 0.1214 bbl/ft.
- Volume of cement required = depth (ft) * 0.1214 bbl/ft. Increase this by 10% to 25% excess minimum. The amount of excess depends on the location of the well at the site. The closer the well is to the crest of the anticline, or highly fracture areas the

excess amount is increased. Wells farther from the crest, such as Well 39 and corehole 44, cement was circulated to the surface on the primary cement job.

- Spacers (before and after cement) – Reactive spacers, may consist of one or two pumped in recommended sequence. Halliburton (HES) uses calcium chloride 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

iii. Intermediate Casing or Liner, 7"

- Volume between 8-1/2-in hole and casing = 0.0118 bbl/ft.
- Volume of cement required = measured depth from base of surface casing to shoe (may need to include a rat hole) in ft. * 0.0118 bbl/ft. Increase the volume by 10% excess minimum.
- Volume between 9-5/8-in casing and intermediate casing = 0.0282 bbl/ft
- Volume of cement required = footage of overlap into 9-5/8-inch 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

iv. Centralizers

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.

v. Injectivity Test

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

5.1.8 Typical Logging

The following geophysical logs are used to log the open borehole prior to running casing and cementing.

1. Deviation Surveys. Deviation surveys are collected during the drilling process either by running single or multi-shot tools, or by the measurement while drilling tools.

Borehole deviation surveys are taken at a minimum of 500-ft intervals throughout drilling operations.

2. Open Hole Caliper Log. A borehole caliper log will be run to determine cement volumes. After the volume indicated from the caliper log is evaluated the cement excess will be increased by a minimum of 10-percent. In the upper borehole where the 9-5/8” casing is set, the excess cement specified is based on the fractured nature of the Cutler and Honaker Trail formations. Near the crest of the anticline, excess varies from 20 to greater than 50-percent. On the flanks of the anticline, 25-percent excess has been sufficient to cement the casing into the borehole to the surface.

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

The following geophysical logs are run after the casing has been cemented in place. Typically, the logs are done after drilling the next section.

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

2. Temperature Survey. This log will provide a baseline temperature profile from surface to just above the open mine works or to a point where the survey tool starts to fall into the curve of the horizontal well. The survey will take place at least 48-hours after the well completion activities have been completed.

3. Injection Zone

    a. Measurement of bottom hole pressure is not required but can be determined from surface pressure gauge and density of fluid in well column.

    b. Temperature log may be run but is not necessary.

5.1.9 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 by Agapito Associates Inc. (Appendix A). The maximum allowable surface injection pressure (MASIP) for the Sylvite 5 cavern was calculated by applying an additional 60% safety margin to the fracture gradient and using the depth at shaft 2 (2,700-ft bgs) as the shallowest point to the cavern. Therefore, the MASIP is 1,415-psi (Table 4).

5.2 Construction of Sylvite 9 Injection/Extraction Wells

Class III wells in Sylvite 9 are constructed to conform with UAC R317-7-10.1 B (1), which states: "All new Class III wells shall be cased and cemented to prevent the migration of fluids into or between underground sources of drinking water." Although there are no USDWs within two miles of the facility, all wells are cased and cemented from surface to below the permitted injection zone to protect the environment. 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. Coreholes are shown on Figure 7 (discussed in Section 5.6). Single well where injection and extraction are operated in a single well is shown on Figure 7. Currently all the wells in Sylvite 9 are constructed as horizontal wells with laterals that intersect the boreholes of laterals drilled from other Sylvite 9 horizontal wells. IPI-30 (Two Fer) is scheduled for conversion to a Sylvite 9 well in 2023.

Intrepid may in the future drill vertical Sylvite 9 wells. The pressures and loads calculated below are valid for both horizontal and vertical wells. The design assumes all the weight is placed on the casing in a vertical position. However, in horizontal wells the casing weight is somewhat supported by the casing centralizers as they lay on the bottom of the borehole in the curve section

5.2.1 Total Depth

Total measured depths of the Sylvite 9 horizontal wells, including the horizontal lateral range 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.

5.2.2 Injection pressure, External Pressure, Internal Pressure, Axial Loading

i. Injection pressure – Intrepid may operate all wells constructed in Sylvite 9 as injection and extraction wells. Wells 27, 37, 40, and 43 are the primary injection well for the caverns in Sylvite 9. The maximum allowable surface pressure for the three caverns range from 3,085 to 3,798-psi and are shown on Table 4.

ii. External pressure – Hydrostatic pressure from formation saltwater is representative of the external pressure exerted on the casing strings and is calculated using the same formula for the Sylvite 5 wells described in Section 5.1. The maximum depth for all casing strings is the top of Sylvite 9, which for operating wells, is 4,329-ft TVD in Well 39. The calculated pressures with fluid densities range from 9.5-10.5 lbs/gal, the external pressure ranges from 2,138 to 2,363-psi with completely evacuated casing.

iii. 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.

<u>iv. Axial loading</u> – The maximum load on the exterior casing varies with casing size. Typical casing types, other than shallow casings installed as conductors or for unstable drilling conditions, range from 9-5/8-inch 40-pound/ft casing used for the surface casing to 7-inch 29-pound/ft used as an intermediate casing string. The buoyancy correction for 10.0-ppg drilling fluid is not used in the calculation, as an extra safety factor. Casing data is obtained from the Baker Hughes Tech Facts Engineering Handbook (publication date not available).

- The depth for the surface casing in Sylvite 9 wells is greater than the Sylvite 5 wells because of the MIT string. The longest string of surface casing is 4,513-ft, used in Well IPI-39. The MIT string is designed to extend approximately 150 to 200-feet into the injection zone to allow for repair procedures in the future. The maximum load on the 9-5/8-inch 40-lb surface casing in this well with no buoyancy correction for 10.5-ppg mud is 180,520-lbs. The body yield for J55 casing is 916,000 lbs and the joint strength is 727,000 lbs. The smaller of the two values (727,000 lbs) is used for casing selection. The surface casing string intended for use is well within its capacities concerning the above pressures and load.

- The intermediate casing string for a horizontal well will be longer because it will have to extend through both the vertical and the curve sections of the borehole to the base of Clastic 8. The length of this casing string could range up to 1,900-ft. Twenty-nine (29) pound casing is often used in the curved section to accommodate the additional internal wear on the casing from drilling laterals due to the drill string from rotating as it lays on the bottom side of the casing. The maximum load on the 7-inch 29-lb intermediate casing in this well, with no buoyancy correction for 10.5-ppg mud, is 55,000-lbs. The body yield for 7-inch 29-pound casing is 676,000 lbs and the joint strength is 587,000-lbs are 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.

The casing strings described below in section 5.15 are well within its capacities concerning the above pressures and load.

5.2.3 Borehole Size

Borehole sizes are based on the casing planned to be installed. Sizes for downhole hammers, tricones, and PDC bits vary. Often a long borehole will use multiple bit sizes. Sometimes larger diameter bits such as 13-1/2 through 15” are not available and the bit is selected on availability. If practical, the bit program will utilize slightly smaller diameters when one bit wears out. The borehole sizes are selected to allow a small diameter (~1.315-inch) string of tubing to be inserted down the backside (between the casing and the borehole wall) as a tremie pipe to allow additional cement to be pumped into the annulus to bring the cement to the surface, when the top of the primary cement job doesn’t come to the surface. Borehole size may change due to wellbore instability and or unforeseen drilling complications. Drilling issues typically arise during large diameter surface drilling.

The range of typical borehole sizes are summarized below:

- Conductor casing – 24 to 32-inch.
- Surface casing – 15 to 12-1/4-inch.
- Intermediate casing, vertical and curve sections – 8-3/4-inch.
- Open hole completion into the mine or ore zone – 6 to 8-1/2”-inch.

5.2.4 Casing String (Typical)

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.

Surface Casing – 9-5/8-inch 40-pound/ft to 47-pound/ft L-80 (may use different grade but L-80 is typical) casing set in Salt 4. Cement to surface using 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.

Casing Liner – 7-inch 29-pound/ft L-80 (or similar 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 and is cemented. The top of the 7” casing extends ~150 to 200-ft up into the 9-5/8” surface casing.

MIT Casing – 7-inch 26-pound/ft to 29-pound/ft L-80 (or similar grade) casing set at surface and run to approximately 150-ft to 200-ft above the bottom of the 9-5/8” surface casing. The intent is to set the MIT string into the permitted injection zone with enough room above the base of the 7” to allow room for repairs to the MIT string. The bottom of the 7” MIT casing string is constructed using one of several types of sealing assemblies. The sealing assembly creates the annulus between the 9-5/8” surface casing and the 7” MIT string which is used for MIT testing. Typically, injection wells use a swell packer assembly while extraction wells use polished bore receptacles (PBR). Injection Well IPI-40 uses a seal assembly and a PBR for the MIT system. As well designs and available seal technologies are improved Intrepid may modify the design to take advantages of the improvements. Any design changes will be submitted with the request to drill new wells. The MIT casing string is not cemented in. The annulus between the 7” MIT string and the 9-5/8” surface casing is filled with freshwater containing ~2% corrosion inhibitor.

Injection Tubing – 7-inch 11.60-lb L-80 tubing set at base of Clastic 2 or lower with an annular packer to provide a sealed annulus which may be pressurized for mechanical integrity testing. The injection tubing is not cemented in.

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.

Other casings – Hole conditions such as loss of 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 described above reflect the current configuration in use. New technology may allow additional for modification of these configurations.

5.2.5 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 similar hydrological characteristics, namely that they are confining layers and are not fluid bearing.

5.2.6 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. 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 its 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-in 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.

Details for cementing specific casings are listed below.

i. Conductor 20"

- Annular volume between 26-in hole and casing = 0.2681 bbl/lin-ft.
- Volume of cement required = depth (ft) * 0.2681bb/ft. If cement is not circulated 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.

ii. Surface Casing, 9-5/8"

- Annular volume between 14-3/4-in 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 calcium chloride 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.

iii. Intermediate Casing or Liner, 7"

- Volume between 8-1/2-in 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-in casing and intermediate casing = 0.0282 bbl/ft
- Volume of cement required = footage of overlap into 9-5/8-inch 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.

iv. Centralizers

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.

v. Injectivity Test

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

5.2.7 Typical Logging

The following geophysical logs are used to log the open borehole prior to running casing and cementing.

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. Open Hole Caliper Log. A borehole caliper log will be run to determine cement volumes. After the volume indicated from the caliper log is evaluated the cement excess will be increased by at least 10-percent. The upper borehole where the 9-5/8" casing is set, the excess cement specified is based on the fractured nature of the Cutler and Honaker Trail formations. Near the crest of the anticline, excess varies from 20 to greater than 50-percent. On the flanks of the anticline, 25-percent excess has been sufficient to cement the casing into the borehole to the surface.

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

The following geophysical logs are run after the casing has been cemented in place. Typically, the logs are done after drilling the next section.

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

2. Temperature Survey. 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. Temperature surveys will be run after at least 48-hours following completion activities.

3. Injection Zone

    a. Measurement of bottom hole pressure is not required but can be determined from surface pressure gauge and density of fluid in well column.

    b. Temperature log may be run but is not necessary.

5.2.8 Fracture Pressure

The same fracture pressure gradient applies as mentioned in Section 5.1.9 of this document. The fracture gradient of 1.31-psi/ft is reduced by a typical 10% safety factor. IPM has also applied an additional 15 to 25% safety factor to the fracture gradient for Sylvite 9 caverns. Sylvite 9 caverns that are below or within 500-ft (horizontally) of the Sylvite 5 cavern are reduced a total of 35% (10% typical safety factor plus the additional 25% safety factor) which is a gradient of 0.85 psi/ft. The 0.85 psi/ft fracture gradient will be used for Sylvite 9 Caverns 1 and 3. A 0.98 psi/ft fracture gradient is calculated using a total safety factor of 25% (10% typical safety factor plus the additional 15% safety factor) for Sylvite 9, Cavern 2, because it not directly under the cavern in Sylvite 5. The ranges of maximum allowable injection pressures for each cavern are shown on Table 4. The lowest maximum injection pressure for each cavern is summarized below (note the shallowest casing shoe depth (in TVD) for the wells constructed in the cavern was used for this summary).

- Cavern 1, well IPM-28H is 3,734-psi
- Cavern 2, well IPI-40H is 4,229-psi
- Cavern 3, well IPI-43H is 3,210-psi
- Cavern 4, Well IPI-45H is 4,488-psi.

Currently the surface pumps for the Sylvite 9 caverns are limited to approximately 1,500 to 2,000-psi. The injection pressures may be increased when pumping freshwater to overcome the increased weight of pumping saltwater up the extraction annulus.

5.3 Injection Well Construction Details (Part H)

Typical well construction for Sylvite 5 and Sylvite 9 wells are shown on Figures 4 and 5, respectively. Prior to drilling a new well, a proposed well construction schematic, abandonment plan, and well location coordinates will be submitted to DWQ for review and approval. After the well is drilled and completed, a well construction report will be submitted that contains the actual well construction details, geophysical logs, and MIT testing data.

5.4 Corrosiveness of Injected Fluids

By 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.

5.5 Hydrocarbon Blankets

IPM is evaluating the use of a hydrocarbon blanket in some of its vertical solution mining wells. Hydrocarbon blankets are a common method to prevent the collapse of rock in the roof of a cavern directly around the casing. A minimal amount of hydrocarbon is added through the annulus. The pressure of the annulus is monitored to track the amount of oil in the cavern. The hydrocarbon blanket will be added through an annulus of a string of steel casing. IPM commissioned Agapito Associates, Inc. to evaluate the regulatory framework for allowing hydrocarbon blankets. Their findings and recommendations are provided in

Appendix F. Agapito states *"The use of a roof blanket for the UIC regulated wells at the Intrepid Potash-Moab facility is not prohibited by state or federal regulations. Based on industry experience, the use of a roof blanket is recommended to limit the vertical extent of solution mining to the permitted injection zones and maintain wellbore integrity"*. Based on this IPM will include the use of a hydrocarbon blanket with the submittal for a well that will use this technique. IPM plans to convert well 30 (Two-Fer) into a vertical solution mining well that will use a hydrocarbon blanket. The preliminary design is presented on Figure 8.

5.6 Exploration Core Holes

Exploration coreholes are occasionally drilled to collect information on the depth, thickness, and grade of ore in the area. Typically, coreholes are regulated by the Utah DOGM. However, in a cooperative process, Intrepid submits the proposed corehole schematic to both DEQ and DOGM. Since DEQ makes frequent site visits and oversees the well programs, corehole drilling is primarily overseen by DEQ. A typical schematic for exploratory coreholes is shown on Figure 6. Coreholes are typically plugged and abandoned at the completion of well drilling and geophysical logging.

IPM may consider converting coreholes into vertical solution mining wells. The design will be submitted at the time the corehole is being permitted.

Attachment E

Injection Well Operating Plan and Procedures

6 WELL AND SOLAR POND OPERATION PLAN AND PROCEDURES - PART I

This section comprises the operating plan and procedures for the injection and extraction wells. It also provides an overview of the 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 brine related structures at the mine site. These components comprise the UIC permitted facilities. The locations of these components are shown on Drawing 7.

6.1 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. Three caverns are constructed in the Sylvite 9, or 9th ore zone. 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 forcing fluid through 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 using 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 system has been in operation since 1970. Over 50-years of accumulated experience has been acquired operating and maintaining the existing system. 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 KCl concentration of a particular cavern or well. Maximum operating flow rates and typical pumping rates, volumes and injection pressures based on multi-year averages are shown in Table 9 for all operating wells. 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 by 1) the pumpers approximately bi-hourly and recorded (See Section 7 - Monitoring, Recording and Reporting Plan) and 2) by the continuous monitoring system called OSIsoft PI historical data system (see Section 6.12). Wellheads and pipelines are inspected frequently. Maintenance on pumps, pipelines and wells is performed when needed by Intrepid maintenance personnel or by contractors.

Additional information on monitoring, record keeping, chart records are discussed in Section 7. Proper operation and maintenance of the injection and extraction system is under the supervision of the production manager.

6.2 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 and Drawing 1. 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 into the Sylvite 5 cavern through the various wells such as Well 32 and Well 34 to allow for storage of KCl-rich brine during periods of low evaporation and are later pumped to the ponds during the high evaporation season. Injection into these wells is by gravity flow. The other wells in Sylvite 5 are primarily operated as extraction wells but are also used as injection wells to store brine. The wells are operated at different times and rates to optimize brine grades and utilization of 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 this 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). The permitted minimum depth to fluid in No. 2 shaft is 125-ft below ground surface (3,893-ft msl).

6.2.1 Injection Pressure

The maximum injection pressure for the Sylvite 5 cavern is 1,415-psi and is discussed in sections 4.1 and 5.1.9. These calculations are summarized on Table 4. Future wells will also use this same rationale to determine maximum injection pressure.

6.3 Operation of Sylvite 9 Caverns

Intrepid 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. 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 1 consists of wells 27, 28, 29 and 37. Wells 27, 29 and 37 are used for injection. Well 28 is the extraction well.

- Cavern 2 consists of Well 39 (extraction) and Well 40 (injection).
- Cavern 3 consists of Wells 42 (extraction) and Well 43 (injection).
- Cavern 4 consists of Well 45 (injection/extraction - dual completion)

Natural gas fired brine heaters are used to heat the lake brine (using heat exchanger technology), which then 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 9). 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 two pumps at the Well 6 surge tank that pump the brine to the solar ponds.

6.3.1 Injection Pressure

The same fracture gradient and safety factor used for Sylvite 5 (1.31 psi/ft) applies to Sylvite 9. The maximum injection pressure for the Sylvite 9 cavern is 3,893-psi and is discussed in sections 4.1 and 5.2.8. Sylvite These calculations are summarized on Table 4. Future wells will also use this same rationale to determine maximum injection pressure.

Each wellhead is equipped with one or more standard pressure gauges for monitoring the conditions at each well. Pressures, volumes, fluid levels or flow in 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 the permit. Moreover, the pumps currently in use at IPM have a maximum injection pressure of only 1,500 psi.

6.3.2 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 as a backup well to Well 28 and could also be used for injection. It utilizes a 5.5-in 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. Well 37, added in 2012, is also used as an injection well in this cavern.

6.3.3 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 western most 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 according to 40 CFR 144.51(q)(3) as specified in the mine' current UIC permit, 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. A copy of the letter from DWQ approving the variance and Intrepid's letter requesting the variance is provided in Appendix E.

6.3.4 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 4,900-ft to 4,890'. Another 40 perforations from 4,890-ft to 4,880-ft, and finally another 40 perforations from 4,880-ft to 4,870-ft. Each perforation was approximately 0.69-in diameter. Extraction occurs at Well 42.

6.3.5 Operation of Sylvite 9 Cavern 4

Flow in Cavern 4 will be down well 45 through the 4-1/2" injection string installed in a Lateral. Extraction will occur up the annulus between the 7" MIT/curve casing and the 4-1/2" injection string. Injection will begin with freshwater and will be converted to salt water for selective potash mining at some time in the future.

6.4 Source of Injection Fluids

The source of all fluids used in the solution mining process originates from the Colorado River. River water is diverted from the Colorado River at the river intake facility (shown on Figure 2 and Drawing 1). Brines injected into the mine (either the 5^{th} or 9^{th} ore zone) originate from the following principal sources: 1) mill tailings brine, 2) environmental reclaim brine, 3) brine from the original mine cavern (may be injected into a Sylvite 9 cavern), 4) brine from the Sylvite 9 caverns may be injected into the Sylvite 5 wells, and 5) minor amounts of brine or water from the mill that are transferred into the tailings pond. These sources are further discussed below. The injected fluid is not filtered.

- **Colorado River Water**. Colorado River water is diverted from the river at the intake facility shown on Figure 2 and Drawing 1. The water is diverted into two systems: 1) for use in the mill and 2) to the 10-inch diameter B-line which is used in the field. The 2-inch flush water lines which are run to each well 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 brine lake (also called the Mill Tailings Pond) for distribution to the wells for injection 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, MIT tests, or to flush salt deposits that have formed in the well casing annuluses. 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 plug the extraction tubing.

- **Mill Tailings Pond.** 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 solid waste NaCl from the mill process to the tailing's storage area. The tailings storage area drains into the tails brine pond (or storage lake) (see Drawing 7). Additional brine is created from the process of spraying Colorado River water onto the solid salt tailings as explained above. Additional mill tails brine is generated during mill operation and from rainfall. This brine from the tailing's lake is injected into the caverns when needed to generate brine to fill the evaporation ponds. The principal source of water in the tailings pond is from either the discharge from the mill or from runoff from the tailing's dissolution process discussed above.

- **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).

- **Brine from the original mine cavity.** Brine is extracted from the solution mine primarily for production purposes. Brine flows from extraction wells into either:

    - A carbon steel surge tank (24-feet in diameter, 20-feet tall, and contains approximately 67,600 gallons at capacity). The surge tank is located near well TGS-6 (plugged and abandoned December 2019) and pump station No. 4. From the surge tank, the extraction brine is boosted to the solar ponds. Occasionally this brine is injected into the 9th ore zone caverns.

    - Is directly diverted to the solar ponds

- Excess process water/brine is also pumped to the brine lake.

- **Brine from Sylvite 9 Caverns.** Intrepid takes some of the brine from the caverns constructed in Sylvite 9 and reinjects it into the cavern in Sylvite 5 for storage. Typically, this occurs during winter when the evaporation rate in the solar ponds is low.

The lake brine can be heated to temperatures up to 200-degrees before being injected into the 9th ore zone injection wells (currently Well 27, 29, 37, 40, and 43). In addition, Well 42 may be operated as an injection well if desired because it is located near the injection equipment for Well 37 and 40.

6.5 Injection Brine Chemistry

Samples of the brine that is being injected into either the 5th or 9th ore zones are collected daily and submitted to the on-site laboratory for analysis, where they are analyzed by ion couple plasma (ICP) and x-ray fluorescence. Water quality samples are collected quarterly from the river and submitted to a certified laboratory for analysis. Ranges of concentrations in milligrams per liter (mg/L) of all constituents of injection fluids are displayed in Table 10. Injection fluid analytical data has been submitted to DWQ on a quarterly basis since 1985.

The injection fluids are very compatible for the intent of dissolving salts within the Sylvite 5th and 9th formation and formation fluids. The injection brines are almost entirely composed of the soluble elements of the injection zone. There is also trace amounts of flotation chemical introduced to the injection brine via the plant tailings stream. Fresh water injected from the Colorado River is also compatible for solution mining with the formation.

6.6 Injection/Extraction Ratios

As described in the Monitoring, Recording and Reporting plan (Section 7), 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 in an area outside of the approved injection zone. If the seven-day weighted average injection/extraction ratio exceeds 1.08 when injecting Colorado River water, or 1.02 for all other injected fluids, for 14 consecutive days Intrepid shall investigate 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.

In 2019 Intrepid began using a seven-day weighted average injection/extraction (I/E) ratio to attenuate the effect of startup and shutdown of wells on the daily I/E ratio as described in the fourth quarter 2018 quarterly report. The weighted average is a more accurate representation of the effects of mine activities on the conditions in the cavern because the effects of days of partial well usage are less pronounced. Intrepid will continue using this more representative measure of mine activities.

6.7 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 cell of the ponds. When the concentration of potassium in the brine decreases (after it was saturated) the brine will no longer precipitate potassium crystals. Brine is then transferred from one pond to another by either pumps or siphoning, depending on hydraulic head differences.

6.8 Operation in Conformity with Permitting Conditions

Well operating parameters include typical average flow rates, daily volumes, injection pressures as well as maximum operating flow rates and injection pressures are summarized on Table 9.

6.9 Fresh Water and Brine Distribution Pipelines and Pumps

Fluids are distributed around the site via pipelines and pumps (Drawing 7). 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.

6.9.1 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 6. The surface installed injection pumps for the 9th ore zone are also summarized on Table 6. The various pumps for distributing the freshwater and various brine around the well field and environmental reclaim system to the solar ponds and from the solar ponds to the mill are summarized in Tables 7 and 8. They can be divided into five categories: 1) river water intake and distribution, 2) mill tailings pond, 3) field pumps, 4) well submersible pumps and well injection pumps (several styles), and 5) slurry pumps. The locations of the pumps are shown on Drawing 7.

6.9.2 Pipelines

There are over 10-miles of pipelines located on the site. The primary types of pipelines are to transport the following fluids:

- **River Water.** The river water distribution system consists of: 1) the feed line to the mill process system, 2) the 10-inch diameter B-line to the mill tailings pond, and 3) 2-inch diameter poly-lines that are installed to each well to supply water to flush out salt accumulations in the well.

- **Mill Tailings Pond (Lake) Brine.** Water from the tails pond 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, 37H, 40H, and 43H.

- **Extraction Brine.** Brine removed from the wells is piped to either: 1) the surge tank at pump station 4 or, 2) directly into the "solar" line going to the solar evaporation ponds.

- **Slurry Line.** The salt and potassium crystals that are removed from the solar ponds by the earth moving scrapers, are transferred to one of two pits, where potassium- and sodium salt-saturated brine is added to produce a slurry. The slurry is then pumped back to the mill feed slurry tank via one 10-inch diameter HDPE. Multiple booster pumps are located along this line.

- **Recycle Line.** The recycle line 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.

Reinjection of brine utilizes existing pipelines. The function of the piping network is occasionally temporarily modified for MIT testing and drilling needs.

6.9.3 Environmental Reclaim Brine Ponds and Structures

Shallow scavenger ponds are located around the site and are used to collect minor spills and leaks from the solar ponds, surge tanks, and pipelines. The shallow ponds locations are shown on Drawing 7. The collected brine is called "environmental reclaim brine" and it is pumped back to either 1) to the solar ponds as brine to be harvested or, 2) to the mill tailings pond to be used as injection brine. There are seven main areas for scavenger ponds. Details for each environmental reclaim pond are discussed below:

- **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.

- **Tailings Toe Pond.** A small pond captures leakage from the mill tailings pond dam. Reclaimed brine is pumped directly to the mill tailings pond. Brine is also removed from a fracture in the area near Well 27. That location is labeled TP-4. Brine is transferred to the tailings pond.

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

- **Number 1 Canyon.** Brines that leak from the solar ponds and flow toward the north are caught in a series, sumps, and French drains below the steep cliffs. There is a 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 one canyon ponds. This pond is pumped to the main pit scavenger, located by the main slurry pit.

- **3-Pit.** There are two pits above Kelly Canyon. Brine from these two pits are transferred to a scavenger pond at 3-pit (slurry pit). Brine is then pumped from the 3-pit scavenger pond to the 2E pond.

- **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 a series of sumps in the Mobley dam is pumped into the Kelly Canyon dam where it is then pumped to the 3-pit scavenger.

- **Main Pit Scavenger.** The main pit scavenger is located near the main slurry pit and has a capacity of 1,200,000 gallons. It is used primarily for freshwater storage. The stored freshwater is used to flush 25 Well and for processing during the winter months.

6.10 Well Field Data Collection and Piping Diagram

Intrepid has implemented a commercially available continuous monitoring system called OSIsoft PI historical data system, which allows data to be captured at remote sites then transmitted via hard wired connection or Wi-Fi and stored in a robust database. The database can then be accessed and analyzed to evaluate well field and process mill operations. The system is used to monitor injection and extraction wells, pump stations, and mill.

The system provides real time monitoring of instantaneous flow, flow totalizing, temperature, and pressure at all the injection and extraction wells. A programable logic controller (PLC) system is installed at each well, which stores the data on the processor level so that if communication is interrupted the totalizing still occurs without the need of communications. The frequency that data is recorded is based on either: 1) using exception deviation (a change of more than a certain percentage or absolute value) or, 2) compression deviation (an average of consistent data).

Data is transmitted from the PLC to the historical data servers located at the mine's office. Backup servers are located at Intrepid's operations in Wendover, Utah and the corporate headquarters in Denver, Colorado. Intrepid's servers are collective servers, the data is being stored in two different locations as it is read from the processors. Those servers are backed up daily.

The data is translated into a uniform structure for combining, comparing, and analyzing data. The data is tabulated in a historical database. The database can be viewed using the OSIsoft platform. Mine personnel can access the database from their office computer, laptop, tablet, or smart phone. The OSIsoft system allows state of the art visualization software. Data can be exported for use in other software such as Microsoft© Excel©. The system is optimized for fast and efficient data delivery, the PI System accesses decades' worth of important historical data and consolidates it with current real-time data.

Each primary injection well (Well 24, Well 27, Well 32, Well 34, Well 37, Well 40, and well 43) has the following data collection parameters: instantaneous flow rate, total volume, temperature, and pressure. Wells used primarily for extraction (Well 25, Well 26, Well 28, Well 33, Well 35, Well 39, and Well 42) record data for instantaneous flow, flow totalizing and temperature. If the use of a well is modified to include both injection and extraction, flow, pressure, and temperature will be monitored for both the injection and extraction. Additional pressure gauges are installed to provide easily accessible displays of injection pressures.

Fluid samples are collected from sample ports on each extraction well. These samples are submitted to the onsite laboratory for analysis and compilation in a historical database.

The alignment of major pipelines, pumps, and flow meters are shown on Drawing 7. Along each pipeline corridor, there may be multiple brine related pipelines. For example, the line going to the solar pond actually has three main lines (brine, recycle brine, and slurry) plus a freshwater line.

Data from this system is used to calculate the injection/extraction ratio using a seven-day average.

Attachment F

Monitoring, Recording, and Reporting Plan

7 MONITORING, RECORDING, AND REPORTING PLAN -PART J

Intrepid's monitoring program was designed to provide representative data of the monitored systems 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 are monitored using the OSIsoft PI described in Section 6.10. In addition, the pumpers record the data in the field on preprinted forms (Figure 6).

- 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 certified analytical laboratory.

- Conducting well MIT tests annually and every 5 years.

The results of monitoring are reported to the DWQ in Quarterly UIC reports. Other records such as calibration and maintenance records are created and stored as required.

7.1 Injection/Extraction Volumes, Pressures, and Temperatures

The principal component of Intrepid'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. Well 24 is monitored at the pump located in the injection flow line approximately ½-mile to the north from the well head. Locations of flow meters are shown on Drawing 7. The mine's field staff, informally known as "pumpers" work 24-hours a day observing well operations. The pumpers record well operating parameters on preprinted forms, shown on Figure 9.

So as to yield data which are representative of the monitored activity as require by 40 CFR 144.51(j)), a seven-day weighted average for recording and reporting of injection/extraction ratios was implemented. The continuous monitoring system provide reliable parameter tracking at small time intervals, which allows the seven-day weighted average be calculated.

7.1.1 5th Ore zone Monitoring

The flow of brine being injected into the 5th ore zone, through Well 24, is monitored by one continuously 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 primary injection well for the Sylvite 5 cavity. The other wells are used primarily as injection wells as needed. Wells 32 and 34 are used to inject brine into the cavern to store brine. Typically, the flow is injected into the pump column or directly into the well. Sylvite 5 extraction wells are equipped with totalizing flow meters, a pressure transducer, and a thermal probe.

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. Data is summarized for reporting daily averages for submittal in the quarterly UIC report. The fluid level is required to be not less than 125-ft below ground surface at Shaft 2.

7.1.2 9th Ore Zone Monitoring

Sylvite 9 wells are also monitored by the PI system. Sylvite 9 wells are equipped with totalizing flow meters, a pressure transducer (injection wells only), and a thermal probe.

7.2 Injectate Water Quality Monitoring

Mine laboratory staff collect samples from various systems to monitor brine grades. The primary sampling locations are: 1) mill tailings pond 2) operating wells, and 3) Colorado river water (mine's intake system, upstream and downstream). 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 also are submitted to a certified environmental laboratory for analysis by method SW 6010C. Surface water samples are collected from the Colorado River water at the intake and are analyzed for total (unfiltered) arsenic, chromium, potassium, selenium, sodium, and zinc. Samples collected up and downstream from the Colorado River are analyzed for sodium and potassium. The injection fluid analytical results are summarized on Table 10. The injection brines are composed of the soluble element of the injections zone and are compatible with the formation and formation fluids. Water quality field parameters of pH, temperature, and conductivity are measured in the field at the time the samples are collected.

Laboratory results and field water quality parameters are summarized and presented in the quarterly UIC reports submitted to DWQ.

7.2.1 Pumpers

Mine staff responsible for pump operations, known as 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 a “Pumper’s Report” form (Figure 9).

After each shift these reports are turned in and entered into the mine’s database daily (during the normal 5-day work week). 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 other repairs to pipelines and surface pumps.

7.3 Mechanical Integrity Monitoring

Mechanical Integrity testing (MIT) requirements are defined by the UIC permit. Mechanical integrity is defined in 40 CFR 146.8. MIT protocols for approved MIT methods are detailed in Section 10.

MIT’s on Sylvite 5 wells are conducted every 5 years. MIT’s on Sylvite 9 wells 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 highest.

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 DWQ. The well may be examined using troubleshooting logic (utilizing monitoring pressures on the injection string and annuli), logging procedures, downhole cameras, 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 placed 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 tailing’s lake. In the event the extraction pumping system breaks down or is unavailable, injection of brine into the mine is also discontinued.

7.4 Quarterly UIC Reporting

A UIC report is submitted quarterly to DWQ. The UIC report contains a summary of the data collected during the monitoring programs, ongoing well maintenance or abandonment, MIT tests, as well as drilling activities.

The quarterly report contains 1) the physical, chemical, and other relevant characteristics of injected fluid: 2) observations of daily average injection pressure, rate, and temperature; 3) the results of any on-site groundwater monitoring, and 4) the daily injection and extraction volumes and I/E ratios.

Attachment G

Contingency Plan for Well Shut-ins or Well Failures

8 CONTINGENCY PLAN, PLUGGING AND ABANDONMENT PLAN, AND FINANCIAL RESPONSIBILITY

This section provides plans for plugging and abandoning the wells, and calculations for preparing the financial surety bond. The financial assurance package is provided in Appendix D. The package contains the standby trust agreement, Schedule A (cost estimate), Schedule B (Financial Guarantee Bond), and exhibit A (company officer signatures). IPM is currently revising the entire package to reflect changes such as "Water Quality Board" to Division of Water Quality, change of "Executive Secretary" to Director. The Financial Guarantee Bond is currently being updated to the amounts calculated for plugging and abandoning the current wells, shafts, and the two new wells (Well IPI-45H and IPI-30 [Two Fer] planned.

The Financial Guarantee Bond will be a total of both the wells and shaft plugging costs. The total cost as of August 2022, including the two new wells (IPM-30 and IPM-45H) is $2,143,895.

8.1 Contingency Plan - Part K

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 most recently 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 tailing's lake. In the event the extraction pumping system breaks down or is unavailable, injection of brine into the mine is also discontinued. Prior to plugging and abandoning a well, a well condition report will be prepared and submitted to the DWQ for final approval of the plugging and abandonment plan.

Attachment H

Plugging and Abandonment Plan

8.2 Plugging and Abandonment Plan - Part L

The history of plugging and abandonment along with plans and procedures for plugging and abandonment plans are discussed in Section 8.2.1.

This section provides an overview of well plugging and abandonment programs. 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 Halliburton, 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. A third-party cost estimate was obtained for well and shaft abandonments (Appendix D). These costs were used to calculate the financial surety bond for well abandonment upon financial failure.

8.2.1 Well Plugging and Abandonment History

The history of well abandonment was largely compiled from mine records. Wells within the AoR are summarized in Table 3.

Oil Wells. There are ten oil and gas wells inside the UIC boundary. These oil wells are summarized on Table 3. One well, Two Fer has been plugged back and is being planned to be converted to a vertical solution mining well with a hydrocarbon blanket. Nine wells were plugged and abandoned. Plugged and abandonment schematics for four wells which were close to the operation are provided in Appendix C.

Cane Creek Coreholes. Abandonment of the Cane Creek coreholes 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.

Texas Gulf Wells. Texas Gulf Wells TG-1 through TG-16 were drilled between 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.

- Well TG-1 was drilled in 1970 but was completed approximately 165-ft outside the mine perimeter. It was used from 1975 as a test well program to evaluate up dip solution mining and was plugged in 1989.
- Wells TG-2, TG-8, TG-13, and TG-14 were used for injection but developed leaks. Well TG-2 was plugged in 1975. Wells TG-8, TG-13 and TG-14 were plugged in 1988.
- Well TG-3 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 in 1989.
- Well TG-6 was drilled in 1972 and used for injection into the mine. It developed a separation in the casing and plugging and abandonment was completed in 2019.
- Wells TG-7 was 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.
- Well TG-8, TG-9, TG-10, and TG-11 were drilled to vent air from the mine while the cavern was filling with water. TG-8 was plugged in 1989. TG-9 missed the mine and was abandoned prior to 1981. TG-11 had a bridge plug and some cement set in place in 1971. Plugging was completed in 1989.
- Well TG-4 and TG-10 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 in 1989.

- Well TG-5 was used for injection until 1977 when it was abandoned.

- Well TG-12 was originally drilled as both a vent well and was also used for injection. TG-13 was drilled as a monitoring well for brine samples to be collected to evaluate solution mining performance. TG-16 was drilled as an injection well. Well TG-12, TG-16, and TG-20 failed MITs early in 1989 and were plugged that same year

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

- Well TG-15 was used for injection and plugged in 1995. Well TG-5 was used for injection and was plugged in 1996. Both of these wells were plugged because they failed mechanical integrity tests.

8.2.2 Plugging and Abandonment Requirements

When the decision to abandon a well is made, a final plan which will include a well condition assessment will be submitted to DWQ prior to actual abandonment operations. The plan may differ from 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. Technical specification for plugging these wells will be in conformance with the following:

- UAC R317-7-10.5 A requires that Class I Non-hazardous and Class III wells, shall be plugged with cement in a manner which will not allow the movement of fluid either into or between underground sources of drinking water. As reported by Peter W. Huntoon (1985), there are no USDWs within a two-mile radius of the facility. However, Class III wells at the permitted facility will be cemented from a retainer set below the permitted injection zone to surface. It is expected this will prevent fluid migration in the wellbore whether USDWs are present or not.

- The plugging method will be one of the methods allowed by UAC R317-7-10.5 B(1), which consist of 1) the balance method, 2) dump bailer method, 3) two plug method or 4) alternative approach approved by DWQ.

Individual Plugging and Abandonment Plan. Intrepid will 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 well condition assessment will contain the following: 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 and 5) any supporting data or test results supporting the conclusions of the well condition report shall be attached to the report.

8.3 Well Plugging and Abandonment Procedures

Currently there are seven operating wells into the 5th ore zone and eight wells into the 9th ore zone. There are no open coreholes at this time since they are typically plugged and abandoned after drilling activities have been completed. 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 or scheduled for abandonment will be physically disconnected from sources of brines or water and capped at the surface. A list of those wells that require plugging are summarized on Table 11 and 13. Abandonment plans for each well is provided as a schematic in Appendix C. The estimated cement volume for all the wells requiring abandonment is summarized on Table 13.

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. The general procedure for abandonment consists of the following:

- A final abandonment plan will be submitted for approval for each well or group of wells to DWQ 45-days before abandonment activities begin. Plans will be based on specific well conditions, construction specifications, and geology. An anticipated schedule for the abandonment operations will be included so a DWQ representative may observe if desired. 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.

- Calculation of cement volumes. All cement volumes use 20-percent excess, both inside and outside. 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, such as Halliburton.

- Preparation of the location for rig and other equipment. Access to location may require dirt work prior to rig arrival. The existing reserve pit, environmental brine reclaim structures, or a small earthen pit and line with plastic sheeting will be used for collection of well returns and cement wash up. Rig tie down anchors will be tested.

- Rigging up a daylight workover rig with the necessary ancillary equipment. Conduct safety meeting for all personnel on location. Nipple up relief line and blow down well; kill with produced brine as necessary to meet specifications. Nipple down wellhead and nipple-up the blow out preventer (BOP). Test BOP. Comply with all DOGM, BLM, and Intrepid safety rules and regulations.

- Intrepid will review the well construction information and evaluate the cement bond log. If necessary, a CBL 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, Intrepid will work with the cementing contractor to develop a plan that meets current best practices. This may include performing infiltration/injection rate tests. Cement squeeze jobs will be continued until there is a 100-ft zone of cement outside the casing.

- Circulate the well to sufficiently achieve static equilibrium (see Abandonment Procedure 8.) as required by UAC R317-7-10.5 C.

- 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. Tubing in the laterals of the Sylvite 9 caverns typically cannot be removed. Tubing will be either backed off and removed.

- Pressure test the casing to 1,000-psi. If casing does not pass this pressure test, then spot or tag subsequent plugs as appropriate.

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

- Un-sting from cement retainer and circulating two hole volumes to balance fluid densities.

- Fill the casing with the tremie pipe near the bottom to approximately 1/2 full with 14.5-ppg Ready-Mix cement using the balance-plug method with 20% excess over casing volume. Pull tremie pipe 600 ft above top of cement plug and waiting on cement (WOC) 4-6 hrs.

- WOC to set-up, then trip down and tag cement to verify plug location and calculate next cement volume. Filling hole to surface with Ready-Mix with tremie at top of first plug.

- Tripping out tremie pipe and topping off hole for displacement of pipe volume.

- Rigging down the rig and demobilizing rig and equipment.
- Cutting off surface and production casing below ground level and installing a dry-hole marker with well number and survey information.
- Submitting final abandonment plan to DEQ based on specific well condition for approval.

8.4 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. Shaft Number 2 was constructed as a "well" to be used as ventilation shaft into the 5th ore zone. Schematics of the two shafts are provided in Appendix C.

8.4.1 Abandonment Plan – Shaft Number 1

The 22-ft diameter shaft was previously filled with salt by pumping a 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 2003 plan specifies for the salt to be removed (or added if necessary) to a 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 plug of cement 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. It will be capped with concrete and an observation port installed into the gravel portion for monitoring for settling (and addition of material). The shaft will be monitored for 5 years and refilled if necessary.

8.4.2 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. The plugging and abandonment of the shaft will consist of the following steps:

- Remove all tubing and measuring equipment.
- Measure the shaft to confirm it is open to at least 2,650-ft.
- Place gravel into the shaft, filling it to an elevation at least above 2,650-ft msl.

- Place a 100-ft thick cement plug. The cement will be API Class B cement with a density of approximately 12.0-pounds per cubic foot (ft^3).

- Fill the remaining shaft with gravel or cement, or a combination of the two, to approximately 3 to 5 feet below ground level.

- Construct a metal cap and observation port into the gravel portion 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.

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

8.5 Plugging and Abandonment Cost Estimates

Intrepid prepared and submitted bid packages for P&A plans 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. The contractors provided written cost estimates for this work. This cost estimate is supplied in Appendix D. Additional details are provided in the sections below.

8.5.1 Well Plugging and Abandonment Cost

Intrepid obtained a cost estimate for plugging and abandoning the wells. Those rig costs for plugging and abandoning one well is show on Table 12. Additional costs for casing crew, bridge plugs/cement retainers, and cement are provided on Table 13. The typical cost to plug and abandon a typical well in 2020 is approximately 147,995. There are 17 operating wells which require plugging and abandonment, the total amount for all the wells is approximately $1,839,152 , which is summarized on Table 13.

8.5.2 Shaft Plugging and Abandonment Cost

The contractor supplied cost estimate for plugging and abandoning the two shafts are providing in Appendix D and is summarized on Table 14. The total cost for plugging the two shafts is approximately $304,743.

8.5.3 Total Well and Shaft Plugging and Abandonment Cost

The Financial Guarantee Bond will be a total of both the wells and shaft plugging costs. The total cost as of August 2022, including the two new wells (IPM-30 and IPM-45H) is $2,143,895.

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

8.6 Financial Responsibility - Part M Financial Assurance

The financial assurance package for the mine is composed is a Standby Trust Agreement (STA) and financial guarantee bond and standby trust agreement 2016 provided in Appendix D. The trustee for the STA is U.S. Bank National Association. The Financial Guarantee Bond (also known as a surety bond) is issued by Argonaut Insurance Company. This bond amount was recently increased (August 2022) to cover the cost of plugging and abandoning the new Well 45H and Well 30 (the Two Fer) from an oil and gas well to a solution mining well. The bond will be updated by submitting the cost estimates as summarized on Tables 12, 13, and 14, along with the plugging and abandonment procedures and bid packages provided in Appendix C, upon completion of these permit modifications. The total amount of for plugging and abandoning the 17 operating wells and the two open mine shafts is $2,143,895. A financial Guarantee Bond sufficient to cover the cost estimates for all existing wells and the new well along with shaft plugging, and abandonments is provided in Appendix D. Cost estimates for the plugging and abandonment work was obtained through a bidding process and are provided with the well and shaft schematics in Appendix D.

Attachment J

Expected Changes Due to Injection

9 EXPECTED CHANGES DUE TO INJECTION - PART O

The injection zone extends from the base of Clastic 2 through the Evaporite 9 member to the base of Clastic 9. Currently Intrepid is actively injecting into the 5th and 9th ore zones (Sylvite 5/Potash 5 and Sylvite 9/Potash 9). The upper unit is the original open mine works in the 5th ore zone. Currently there is only one cavern in the 5th ore zone that is being injected into. The artificially created underground caverns in the 9th ore zone created by horizontal drilling are in the lower portion of the injection zone. Currently there are three caverns in the 9th ore zone. Intrepid plans to continue creating new caverns in both the 5th and 9th ore zones.

9.1 Expected Changes in Potash 5 Cavern

The current targeted injection zones (Sylvite 5 and Sylvite 9) are impermeable layers within the Paradox Formation that do not contain formation fluid; therefore, the expected changes due to injection do not include changes related to native fluid displacement. The main change expected due to injection is the creation of brine filled void spaces due to dissolution of potash and salt minerals.

Dissolution in the open mine works in the 5th ore zone will continue as long as solution mining activities continue. Dissolution will stop unless a supply of fluid, undersaturated in sodium chloride and or potassium chloride, is pumped into the injection zone. Sump areas where saturated potash solutions cannot be drained or be replenished with fresh unsaturated brines will stop their solution mining activity. A meaningful average yearly dissolution rate cannot be calculated with the data available from wells and tons extracted. However, the average annual dissolution rate can be estimated from past production rate data. This estimate of the dissolution rate for the ongoing mining operation has been used to evaluate the horizontal extent of the caverns. The methodology is discussed below.

Estimate of Lateral Dissolution. Yearly tons of dissolved solids markedly decreased from 1984 through 2003 averaging just 105,000 tons/year with a high of 168,000 tons in 1988 and a low of 49,000 tons in 1998. From 1980 through 2003, the mine yielded an average of 420,000 tons/year of dissolved solids consisting principally of potassium and sodium chlorides. Recently (2010 through 2019), the tons of dissolved material ranged from 408,000 to 596,000. Yearly wall dissolution rates using 420,000-tons will give a more than acceptable margin of error in calculating the expected extent of void space in the Potash 5 cavern. The original entryways were normally cut 8 feet high. For a total entry length of 150 miles, the amount of vertical wall area is calculated as:

- 150-miles x 5,280-ft/mile x 8-ft = 6,336,000 ft^2

The volume of solids dissolved is calculated as:

- 420,000-tons/yr. x 15.3-ft^3/ton = 6,426,000-ft^3/yr

The average annual wall dissolution rate equals:

- 6,426,000-ft^3yr / 6,336,000-ft^2 = 1.101-ft/yr

The above calculation assumes no cavity roof or floor dissolution, and therefore, constitutes a maximum average horizontal dissolution rate. For a project life of 90 years (1971-2061, the mine's outermost perimeter is projected to expand approximately 50 feet horizontally beyond the original entry boundary. Dissolution rates are also dependent on solution saturation. Since injection fluids are generally slightly under-saturated with NaCl, dissolution rates in the vicinity of injection wells could be greater than the average. Because of the inaccessibility of the solution mine cavity, no direct measurements of dissolution rates can be made.

Abandoned wells drilled outside the original Potash 5 mining cavern may never be intersected by the Potash 5 cavern during the anticipated operations lifetime. No intersection will be made with those wells where there is no point of extraction that is lower than the point where the well penetrates the potash ore. Evaluation of the potential for the mine cavity to expand into an open or improperly plugged hole drilled outside the original mine entries has involved monitoring the open wells near the mine cavity. The two holes considered most likely to intersect the mine cavity are solution mining well Nos. 1,9 and 3.

- Well No. 9 is approximately 160-feet from the nearest mine entry and the closest outside well to an injection well, Well No. 10 (see Figure 8 in the Huntoon report). Upon completion, the well was hydraulically fractured in an unsuccessful attempt to achieve a connection with the mine. Well No. 9 was monitored on a regular basis until June 1986 at which time it was permanently plugged. Well No. 10 was also plugged in May 1986. The mine cavity never intersected Well No. 9 in 15-plus years of mining before it was plugged and abandoned in January 9, 1989 (Appendix D).

- Well No. 1 was drilled 130-feet outside the nearest mine entry and repeated attempts to make a connection through hydraulic fracturing were unsuccessful. Well No. 1 is remote from any active injection well. In 1975, Well No. 1 was fitted with a tubing string inside the casing and operated as a solution mining experiment independent of the mine. After ten years of intermittent operation, Well No. 1's cavity had not connected with the mine. Well No. 1 was plugged and abandoned December 19, 1989 (Appendix D).

- Well No. 3, which is located 240 feet from the nearest mine entry, was also operated for a short period as an independent test. Well No. 3's cavity never intersected the mine. it was plugged and abandoned on January 25, 1989 (Appendix D).

Based on the information presented above, a horizontal distance of approximately 250 feet from the original mine perimeter is considered the limit or critical distance beyond which the mine cavity will not progress during the expected life of the project. This value is five times greater than the calculated average of 50 feet.

In the future Intrepid plans to create new solution mining caverns in the 5th ore zone using the same technology that was used to create the caverns in the 9th ore zone. Therefore, the dissolution estimates of horizontally drilled caverns in the 5th would be the same as reported for the dissolution rate for caverns in the 9th ore zone, which is discussed below.

The estimated boundary of the dissolution of the 5th ore zone is shown on Drawing 5.

9.2 Expected Changes in Potash 9 Caverns

Injection into Cavern 1 in the 9th ore zone began in 2002. Injection into Cavern 2 began in February 2012. Injection into Cavern 3 began in November 2013.

The best data for evaluating the actual dissolution rate of the 9th ore zone is the connections of Well 37 laterals 1, 2, and 4 to Well 29H during actual drilling. Additional estimates can be based on estimates from undercutting of target laterals and then intersecting those laterals. The general estimate can be developed using a mass balance approach. Where the weight of the extracted fluid minus the weight of the injected fluid is the mass of salt and potash dissolved. The estimated boundary of the dissolution of the 9th ore zone is shown on Drawing 6.

9.3 Critical Distance

Critical distance from the solution mine cavity is defined as the maximum horizontal distance that the cavity wall can progress to some point outside the original mine entry at the time solution mining operations permanently cease. The distance from the 5th or 9th ore zone solution mining caverns are shown on Table 3 The critical distance is shown on the structural contour map for each ore zone on Drawings 5 and 6. The plugging and abandonment of the wells within the critical distance are evaluated for completeness to prevent injected brine from migrating to the surface through improperly abandoned wells.

Intrepid has used the average annual dissolution rate, calculated above, and an estimated project completion date of at least 2060. The critical distance will be re-evaluated during each permit review every 5 years.

<u>5th Ore zone (Sylvite 5/Potash 5).</u> Based on the information presented above, the horizontal distance of approximately 300 feet from the original mine perimeter is considered the limit or critical distance beyond which the mine cavity will not progress during the expected life of the project. The 300-ft is six times greater than the calculated amount of the mine workings expansion of 50 feet in 90-years.

<u>9th Ore zone (Sylvite 9/Potash 9).</u> Based on information provided above, a general estimate of 300-feet is also appropriate for the caverns in Sylvite 9.

Critical distance poses little concern since all wells within the UIC boundary have been properly plugged according to DEQ regulations. Please note that most of the wells on site were intentionally drilled into the mine cavern for the purpose of active solution mining.

Attachment K

Mechanical Integrity Demonstration Protocols

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10 MECHANICAL INTEGRITY DEMONSTRATION 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 146.31 to 146.34. MI has an internal and external requirement. According to 40 CFR 146.8(b), an injection well has mechanical integrity if, for the purposes of the Cane Creek Mine UIC program:

- There is no significant leak in casing, tubing, or packer, and (internal mechanical integrity), and
- There is no 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 external MI. Periodically, MIT's are conducted to demonstrate MI on the outside of the casing and on the inside. Every 5 years, a test is conducted to validate the outside mechanical integrity originally verified by the cementing records. The approved methods for demonstrating MI are listed in section 10.2. In addition, EPA Region 8 has approved temperature logging for internal mechanical integrity (attachment 1) which has been adopted by Utah DWQ. Annual internal MI testing (annulus pressure tests) provides verification of mechanical integrity that the casing string is not leaking.

10.1 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 5^{th} ore zone. When they are constructed, they will be tested according to the MIT procedures specified for wells constructed in the 9^{th} ore zone.

- **5^{th} Ore Zone.** Wells constructed in the 5^{th} ore zone (Sylvite 5/Potash 5) which intersect the original open mine works. In general, the 5^{th} 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.

- **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.

- **Future 5th Ore Zone Wells.** Intrepid may create new caverns in the 5th ore zone by horizontal drilling techniques. These new caverns will be operated similarly to the 9th ore zone caverns. Therefore, there MIT testing methods will be the same as the other 9th ore zone wells.

10.1.1 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 issued May 2015 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:

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

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

1) 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.

2) Saturated saltwater drilling fluids are used to minimize formation dissolution while drilling.

3) The lack of considerable formation dissolution during drilling is demonstrated by caliper logs, which are also used to calculate cement volumes appropriate to borehole volume. The caliper volume is increased when ordering cement.

4) The water phase of the cement slurry is designed to minimize salt dissolution during cementing. Intrepid and DWQ has been in discussion with Halliburton on recent advances in cement slurry mixture advances that are considered best practices.

5) 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.

6) 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.

10.1.2 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 5^{th} 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. The procedure can be found as 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 away 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). As stated in 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 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.

10.2 Mechanical Integrity Testing Protocols

The methods for conducting MITs for casing leaks (Internal MI) 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. Intrepid currently uses continuous electronic digital data recorders, which meet this requirement.

- Pressure test with liquid or gas

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

- Temperature and noise (sonic).

- Radioactive Tracer Survey (RTS).

- Cement records.

10.2.1 Method A - Casing Pressure Test with Cementing Contractor (for new Sylvite 5 wells)

1) Cement is circulated down the inside of the interior casing and up around the annulus.
2) The cement is followed by a cement wiper plug and an appropriate amount of displacement fluid to fill the inside of the casing. During displacement, pumping pressure is continuously monitored and recorded by the cementing contractor. As the cement is displaced by the less dense displacement fluid, the pumping pressure will gradually increase. Once the cement has been circulated completely out of the inside of the casing, the wiper plug will land into a float collar or float shoe. After landing the wiper plug additional displacement fluid can no longer be pumped into the casing and pressure will sharply increase, indicating that the plug has landed, and additional pressure is now being applied to the casing.
3) The well casing is now completely full of displacement fluid. Take the last pressure measured to bump the plug before the spike (equal to differential pressure between the displacement fluid column and cement column) and add 100. This is the pressure necessary to create 100 psi of positive pressure

between the inside of the casing and the cement-filled borehole. Apply this pressure with cement pump to reach this level and close the pump backflow valve to seal the well. Intrepid's internal policy recommends adding the lesser of 500 psi or 80% of the rated casing burst pressure, to pressure required to bump the plug for this test.

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

5) After 45 minutes, record final pressure.

6) Bleed off well into a bucket, if possible, to obtain a volume estimate.

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

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

10.2.2 Method B - Casing Pressure Test with Drilling Rig Equipment (for new Sylvite 5 wells)

1) Allow cement sufficient time to cure.

2) Calculate the necessary surface gauge pressure to achieve at least 100 psi pressure differential between the casing fluid and formation fluid. (Formula and Example calculation below at G)

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

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

5) Close pressure control equipment (BOP).

6) Pressurize fluid with rig pump to 300 psi minimum (or the greater calculated value from G below) and close the backflow valve on the rig pump.

7) Monitor pressure reading for 45 minutes, recording pressure reading every 5 minutes.

8) After 45 minutes, record final pressure.

9) Bleed off well into a bucket, if possible, to obtain a volume estimate.

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

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

10.2.3 Method C - Casing Pressure Test with Packer (for new Sylvite 5 wells)

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

10.2.4 Method D - Annulus Pressure Test (for wells with a liquid-filled annulus)

1) Calculate the necessary surface gauge pressure reading to achieve at least 100 psi pressure differential between the casing and formation. (Formula and example calculation below at G).
2) If the annulus is not completely full, fill annulus completely with fresh water with a second opening available to allow air to escape.
3) Allow well 12-24 hours to be static if possible.
4) Connect to a liquid pressure source.
5) Increase pressure to 300 psi minimum (or the greater calculated value from G below) and immediately disconnect the pressure source, keeping the well head sealed.
6) Monitor pressure reading for 45 minutes, recording pressure reading every 5 minutes.

7) After 45 minutes, record final pressure.

8) Bleed off well into a bucket, if possible, to obtain a volume estimate.

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

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

10.2.5 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.

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.

2) Shut down well, move in workover rig and pull pump and/or tubing.

3) Modify system to allow river water to be injected into well.

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

<u>Run 1</u>

1) 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.

2) 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.

<u>Run 2</u>

1) Run background gamma log prior to RTS Survey.

Run 3A – Method A Internal Mechanical Integrity

1) Load RTS tool to 20 feet below ground surface and begin logging on time drive. Centralize the RTS tool.
2) Eject a tracer slug.
3) Lower tool to 500 ft below ground, continue logging on time drive until the tracer slug is detected passing the tool.
4) 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)
5) Lower tool to 500 ft below ground. Return to time drive.
6) Eject a tracer slug and lower tool to 1,000 ft.
7) Continue logging on time drive until the slug is detected passing the tool.
8) 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.
9) Repeat steps 12-15 until the entire casing has been logged.
10) 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.

Run 3B– Method B Internal Mechanical Integrity

1) With the injector tool at 0 ft., inject a tracer slug.
2) 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.
3) Repeat step 14 until the slug has passed through the bottom of the wellbore, overlapping log runs to ensure the entire casing is logged.
4) Mechanical integrity is demonstrated if the tracer reading maintains the same area, and velocity is consistent through the casing.

Run 4–External Mechanical Integrity

1) Lower the injector tool to the bottom of the lowest casing shoe and begin logging on time drive.
2) Inject a radioactive slug while keeping the tool stationary at the shoe. Log for 15 minutes.

3) If the tracer is detected moving upwards, switch to depth drive and follow the tracer.

4) 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.

5) 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.

10.2.6 Method F - Cement Bond Log (CBL)

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

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

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

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

5) Run at least 3 bow-spring or aluminum centralizers.

6) Logging speed should be approximately 30 ft per sec.

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

8) Log repeat sections.

9) Have logging engineer provide an interpretation of the log data.

10.2.7 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. The test pressure and variable inputs are summarized on Table 15.

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

2) Determine the necessary surface pressure reading according to the relationships:

<u>Test Condition 1</u>

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.

$$Pals + (0.052 \times Waf \times D) > 0.052 \times Wff \times D + 100$$

Test Condition 2

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

$$Pals + (0.052 \times Waf \times D) > (0.052 \times Wif \times D) + Ptsils + 100$$

Where:

Pals = annulus pressure reading at surface (psi)
Ptsils = tubing pressure, shut in, at surface (psi)
Waf = Weight of the annulus fluid (lbs/gal)
W_{ff} = 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)

Example Calculation:

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

Ptsils = 0 psi
Waf = 8.34lbs/gal
Wff == 9.6 lbs/gal
Wif= 10.1 lbs/gal
D = 3000 ft

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 15.

10.2.8 Method H – Temperature Log for MIT

IPM requests that temperature logging be included as a method for conducting internal and external MIT test for vertical wells. IPM conducted temperature logging of wells IPI-32 and IPI-33 in February 2013, using the EPA Region 8 temperature logging procedures for mechanical integrity (Appendix G). IPM has conducted a review of the regulatory framework and EPA research documents. The review is provided in Appendix F. To support IPM's request, a demonstration of temperature logging was conducted on TGS-6 prior to it being plugged and abandoned in December 2019. The logging clearly showed the casing parting at 2,466-ft. The temperature logging report from the TGS-6 demonstration is included in Appendix G.

IPM's demonstration showed that temperature logging is an effective method for conducting internal and external MI testing for wells constructed in Sylvite 5 and Sylvite 9. Therefore, IPM is requesting this waiver from the Director to allow for this use of temperature logging to conduct internal and external MI testing on Sylvite 5 and Sylvite 9 wells. The basis for such a waiver is found in 40 CFR 144.16, which states that when injection does not occur into, through or above an USDW, the Director may authorize a well or project with less stringent requirements for area of review, construction, mechanical integrity, operation, monitoring, and reporting than required in 40 CFR part 146 or § 144.52 to the extent that the reduction in requirements will not result in an increased risk of movement of fluids into an underground source of drinking water. The site has been classified as not having a USDW, so this criterion is satisfied. Since IPM's temperature logging demonstration was successful, and because temperature logging is a petroleum industry standard for evaluating casing leaks, the method still provides a stringent test for proving internal and external mechanical integrity of a well, so the waiver should be granted.

IPM has a long operational history and temperature logs have been collected for most of the wells constructed since 2000. Temperature data is also available from some older wells in paper format. Temperature data is collected digitally from each injection and extraction well. This extensive data set and the in-house capability to run multiple logs, a robust data set will be built which will allow well integrity to be thoroughly evaluated.

The proposed procedure for using temperature logging for MIT is:

1. Let well stand idle for at least 24-hrs.

2. Run baseline log to measure geothermal gradient.

3. Start injection into the well with fluid that is significantly different temperature than the bottom hole temperature. The temperature should be 10-degrees warmer or colder than the temperature range on the background log.

    a. Allow flow rates to stabilize, which takes about 15 minutes to 1-hour.

    b. Logging while injecting is a preferred step but not required.

    c. Inject at least three times the casing volume.

4. Begin Recovery logging runs.

    a. Start the first logging run immediately after injection is complete.

    b. Logging runs are based on the amount of time the well was previously actively injecting. The longer the injection period, the recovery logs are run at longer time intervals.

    c. Each logging run should go into the top of the injection zone.

5. Log at a speed of approximately 30-ft per minute or less

6. Log down if possible.

7. Logging intervals are still undergoing evaluation. IPM envisions that multiple passes will be made in the first two days, then at 24-hour intervals for the following two days. This will provide logs over a 96-hour period, which is part of the EPA Region 8 guideline. When a sufficient set of data has been collected for each well, a logging schedule will be developed and submitted to DWQ.

8. The final log report will include lithology information, gamma log, background and logging run temperatures, and differential temperature traces.

Attachment L

Two Fer 26-30 (API 43-019031452)

Oil and Gas Well Rework Report

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

November 20, 2021

Mr., Dusty Earley, PhD, PG
Utah Division of Water Quality
PO Box 144870
Salt Lake City, UT 84114-4870

Re: Intrepid Potash-Moab, LLC, Plan to Convert the Two Fer 26-30 Oil and Gas well to Solution Mining Well
UIC Permit Number UTU-19AP-1C3C2E8

Dear Mr. Earley,

Intrepid Potash-Moab, LLC (IPM) has prepared this letter to notify the Utah Division of Water Quality (DWQ) of our intention is to convert the existing Two Fer 26-30 (API 43-019031452) oil and gas well to a Class III solution mining well and incorporate it into the mine's Underground Injection Control (UIC) permit. The well is currently owned by Intrepid Oil and Gas, LLC (IOG). The well was plugged back to approximately 4,070-ft in May 2021. The Sundry report that was filed with DOGM outlining the plug back procedure and their approval is in Attachment 1. Attachment 2 contains a survey plot for the well. The Sundry report filed with DOGM documenting the actual plug back operation is included in Attachment 3.

IPM plans to perforate the casing in the two potash zones, Potash 5 (K5) and Potash 9 (K9) in two phases. First, K9 will be perforated and the well placed into production. After the well has been in production for several years, the K5 zone will be perforated. Water will be circulated down the casing annulus, where it will flow out into the formation through the perforations, then back into the well and up the extraction string.

The Two Fer well is located near Moab Utah on private property owned by IPM. The coordinates for the well are: Latitude 38.50675 and Longitude 109.68400. The well is located in the northeast quarter of the southeast quarter of section 26, township 26 south, range 20 east Salt Lake principle meridian and baseline. A survey plot of the well locations is provided in Attachment 2.

This letter provides an overview of: 1) the regulatory handoff between Utah Department of Natural Resources (DNR), Division of Oil, Gas, and Mining (DOGM)(oil and gas program) to the Utah DNR DWQ, and the DNR DOGM minerals program, 2) the review of well integrity and cementing information, 3) description of the plugging back operations and 4) solution mining conversion. Schematics for the program are provided in Figures 1 through 6. Figure 1 shows the original "as built" well schematic. Figure 2 is a schematic showing the actual plug back details. Figure 3 shows the proposed perforations and tubing for the final well conversion. Figure 4 shows the details of the perforations. Figure 5 shows the process for undercutting the perforation zones with freshwater during the insertion of the 3-1/2" tubing string. Figure 6 provides a final plugging and abandonment schematic.

REGULATORY FRAMEWORK

There are two regulatory components: 1) the well and 2) the pad. Currently the well and pad are under the regulatory oversight of DOGM's oil and gas program. They have authority over the well and well pad up to when the well is plugged back. DOGM has approved the Sundry notice IOG submitted for the plug back program and for the regulatory authority of the well to be transferred to the DWQ under the mine's UIC permit (Attachment 3). Once the well is plugged back, IPM will acquire the well and the pad from IOG. The regulatory oversight of the pad will changeto DOGM, mining program for final pad reclamation. Cost for pad reclamation will then be incorporated into the mine's reclamation bond (currently in process). Once the well has been acquired by IPM, IOG can request for the bond to be released. The well will be incorporated into the mine's UIC permit and bonds.

WELL INTEGRITY SUMMARY

The primary indicators of well integrity are the cement bond log and pressure tests. Cementing records are provided in Attachment 4 and are summarized below:

- The 9-5/8" casing was cemented with 1,325 sacks (555-bbls) of Cement Lite II which was circulated to the surface. The cement weighed 15.8-pounds per gallon. After the primary cement job was complete, the cement fell back overnight and an additional 550-sacks (143-bbls) of Cement Lite II was placed in the annulus through a tremie pipe. The cement for the "top job" was circulated to surface. Apparently a CBL was not run on the 9-5/8".

- The 7" casing was cemented in with 760 sacks (193 bbls) of Type V cement. The top of cement is at 50-ft. A cement bond log (CBL) is available for 7" casing. Bonding appears good.

A pressure test was conducted on the 9-5/8" casing before it was drilled out (Attachment 5). The 7" casing was also pressurized to 1,000-psi and held. The 7" casing was again pressure tested during the plug back operation in May 2021, using a cement retainer was sat at 6,236-ft. The 7" casing was pressured up to 950-psi and pressure held for 20-minutes. A representative from the Utah Division of Oil Gas and Mining, Oil and Gas program was on site for the duration of the test.

PLUG BACK AND CONVERSION

The scope of work is divided into two phases: 1) the plug back and 2) the conversion to a solution mining well. Additional testing will occur during both phases of work. The tasks required in each phase are as follows:

<u>Phase 1 – Plug Back Operations</u>

- A DOGM representative observed the plugging back operations. The plug back process is described on the sundry notice (Attachment 1 and 3).

- The work over contractor Drake Well Services from Farmington New Mexico was used for the plug back activities.

- An additional pressure test was conducted during the plugging back program. A blow out preventor (BOP) will be installed on the wellhead. After the cement retainer was set at 6,239-ft the work string (2-7/8" tubing) will be disconnected, the BOP was closed around the tubing, and the well was pressure test to approximately 950-psi. Stable pressure was monitored and documented for 20-minutes. After the well was plugged back the work-over contractor move off-site. The wellhead was secured, and the cement allowed to set.

Phase 2 – Conversion to Solution Mining

- The plug backed well has been allowed to equilibrate since May 2021.

- A MIT test will be conducted on the 7" casing before the conversion process begins.

- Intrepid will also run a baseline temperature log, gamma, caliper log, and full wave sonic log using its Mount Sopris wireline system down to 3,000-ft. Which is approximately 236-ft into the injection zone allowed under the UIC permit (Figure 2). The allowable injection zone specified in the mine's UIC permit is the base of Clastic 2/top of Salt 3 to the base of Salt 10. The contact of the Clastic 2 and Salt 3 is at 2,766-ft.

- The CBL was not run on the 9-5/8" casing. To evaluate the cement behind the 9-5/8" casing, through the 7-inch casing a wireline company (Jet West, of Farmington New Mexico) will conduct a logging program consisting of the two logging groups:

    - A background temperature log will be run to the top of the cement plug at 4,070-ft to map the geothermal profile. Normally the temperature log is run after the well is constructed. But, since this well is now essentially constructed for the UIC program and the new perforations are at 3,123-ft and 3,951-ft, approximately 357-ft below the top of the allowable injection zone (base of Clastic 2/Top of Salt 3)(Figure 2), the addition of the perforations will not change the background temperature profile. In addition, the workover contractor will begin installing the 3-1/2" extraction string right after the perforations have been shot, which would not provide the 48-hour time for the temperature profile to equilibrate.

    - A sector bond log will be run to evaluate the 9-5/8" cement. It is often difficult to evaluate cement behind another string of casing, in this case the 7". However, a qualitative evaluation can be conducted by running the log twice. Once under static pressure and the second under 1,000-psi. This combined with the cementing records for the 9-5/8" casing will provide confirmation on zonal isolation.

    - The solution mining of the K5 and K9 zones will be accomplished by perforating the 7" casing across the thickness of each potash zone. The wireline contractor will then perforate the casing with 6 to 10-shots per foot in the two potash zones then a Enhanced

Energy gas gun (Attachment 6) will be deployed to “rubbilize” the salts in the area adjacent to the well casing perforations.

- The workover contractor will mobilize to the site.

- A 3-1/2” string of tubing will be installed as an extraction string. When the 3-1/2” tubing is installed, lowering will pause for approximately 12 hours at each potash zone so freshwater can be pumped down the tubing and it will exit the 3-1/2” tubing sideways through perforations cut into the 3-1/2” tubing. The water jetted out the 3-1/2” string will help clean up the perforations and fractures to help ensure hydraulic connection with the potash. After each zone has been flushed and undercut the tubing will be lowered to approximately 5 to 10-ft above the top of the plug back cement.

- A 1.315-inch diameter dilution string will then be installed into the 3-1/2”.

SCHEDULE

IOG performed phase 1, the plug back operations, in May 2021. Phase 2 is planned for 2022, pending DWQ approval.

IPM appreciates the opportunity to work with DWQ’s Underground Injection Control Program on this matter. If you have any questions, please call me at (435) 259-1282.

Sincerely,

Chad Harris

Chad Harris, PE
Environmental Manager

Enclosures: Figures 1 through 6
Attachments 1 through 6

cc: Craig Fanshier, Brandon Bartosh, Rick York

Figure 1
Two-Fer 26-30 As Built Well Construction Schematic
API # 43-019-31452
Intrepid Oil and Gas, LLC

Purpose: Well drilled for oil and gas production. Minimal production since completion. Scheduled for Plugging & Abandonment.

Ground Elevation: 4,540		KB +20.2'	*Note: Depths are relative to the kelly bushing, which is 22.1 feet above ground surface, except for the 40-foot of 24" hole and 20" conductor pipe which were set relative to ground surface.*
Lat. 38.50675	Long. 109.68400		
Spudded: 10/28/2005	Completed 9/14/2010		
Legal: NE 1/4 of SE 1/4, section 26, township 26 south, range 20 east			

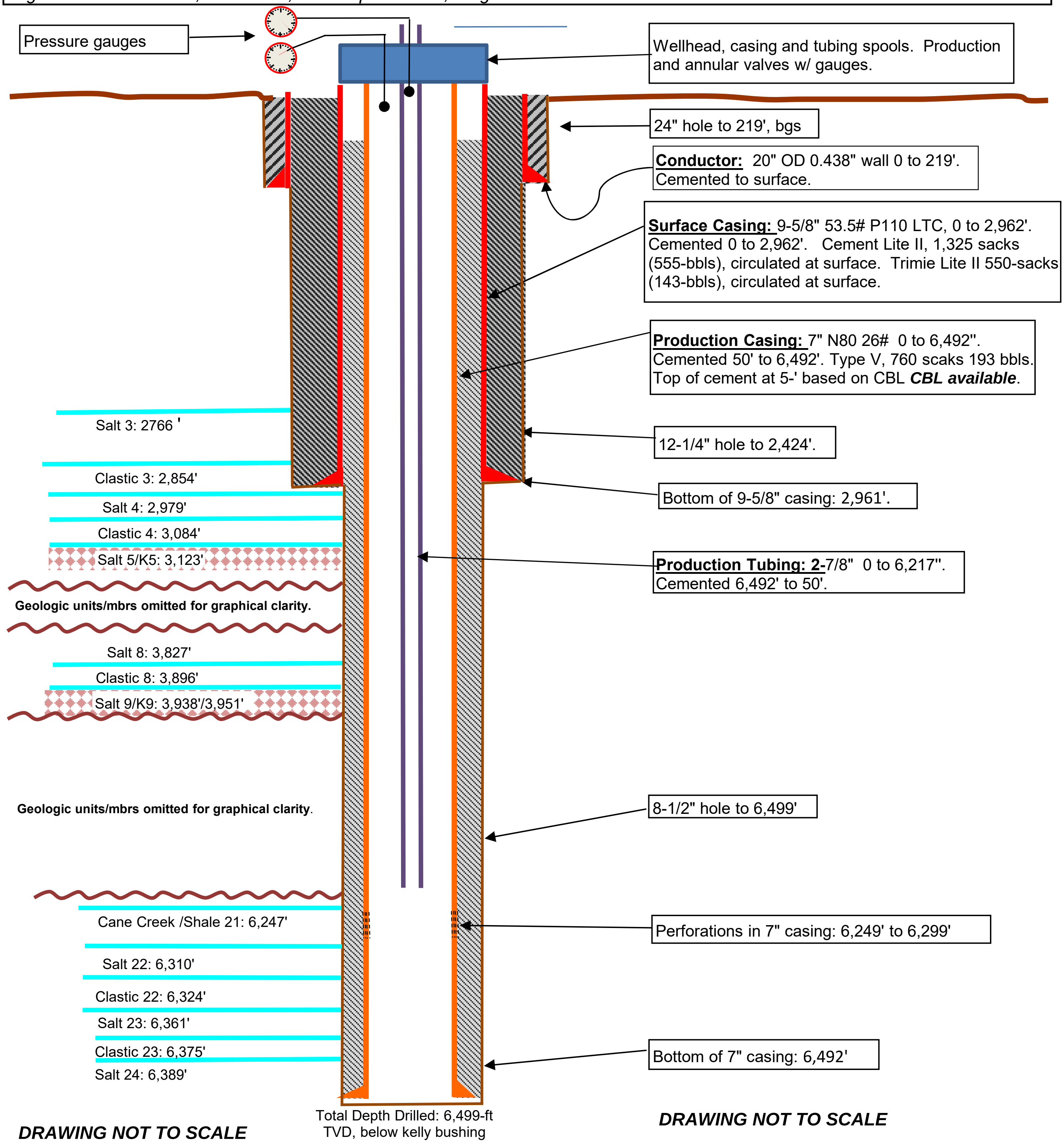

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Figure 2
Two-Fer 26-30
Actual Plug Back Schematic
API # 43-019-31452
Intrepid Oil and Gas, LLC

Purpose: Well drilled for oil and gas production. Minimal production since completion. Scheduled for Plugging & Abandonment.

Ground Elevation: 4,540		KB +20.2'	*Note: Depths are relative to the kelly bushing, which is 22.1 feet above ground surface, except for the 40-foot of 24" hole and 20" conductor pipe which were set relative to ground surface.*
Lat. 38.50675	Long. 109.68400		
Spudded:	Completed 9/14/2010		
Legal: NE 1/4 of SE 1/4, section 26, township 26 south, range 20 east			

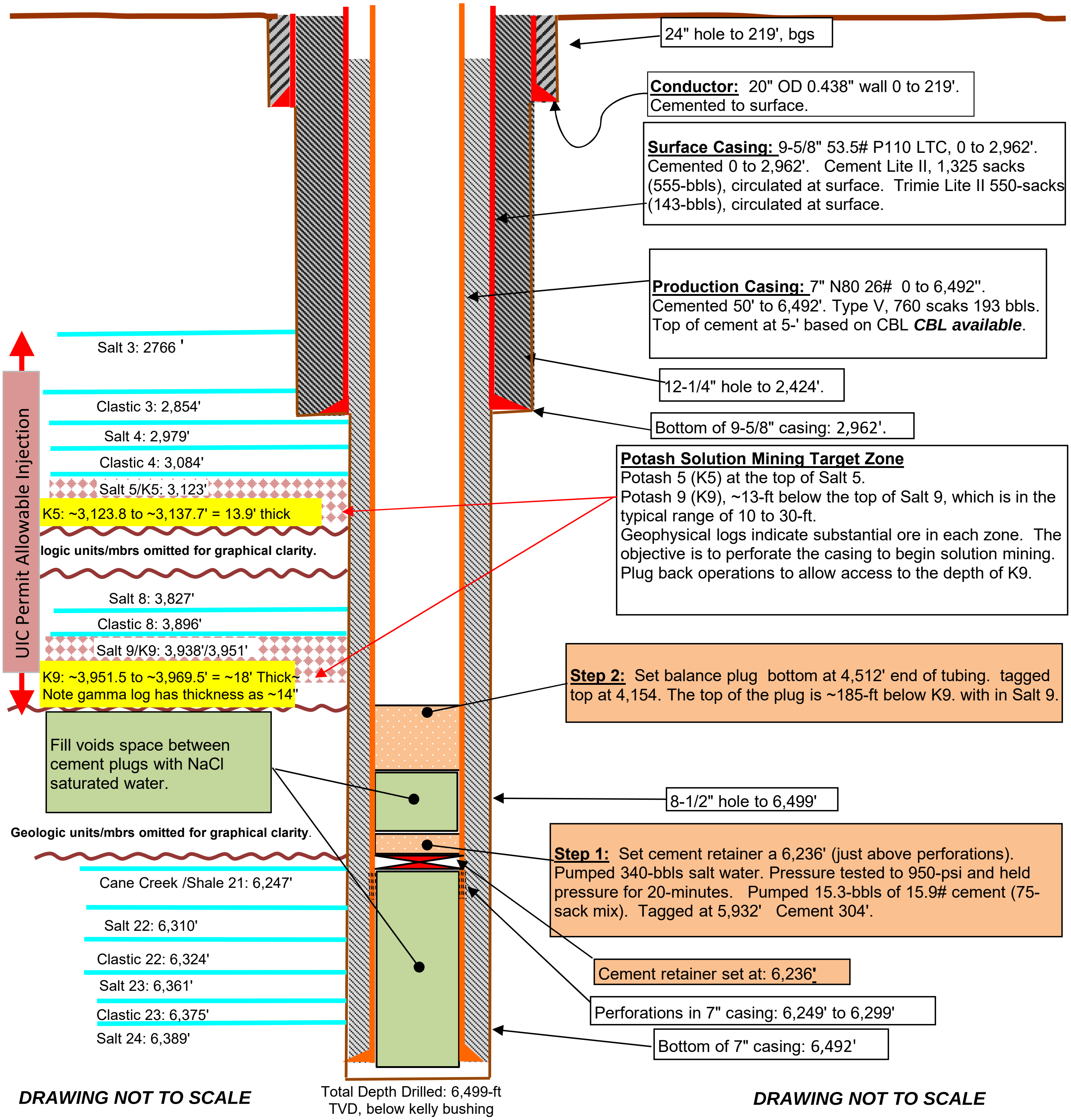

Figure 3
Two-Fer 26-30
(API # 43-019-31452)
Proposed Vertical Solution Mining Well Schematic
Intrepid Potash-Moab, LLC

Purpose: Well drilled for oil and gas production. Will plug back and convert to solution mining

Ground Elevation: 4,540		KB +20.2'	*Note: Depths are relative to the kelly bushing, which is 22.1 feet above ground surface, except for the 40-foot of 24" hole and 20" conductor pipe which were set relative to ground surface.*
Lat. 38.50675	Long. 109.68400		
Spudded:	Completed 9/14/2010		
Legal: NE 1/4 of SE 1/4, section 26, township 26 south, range 20 east			

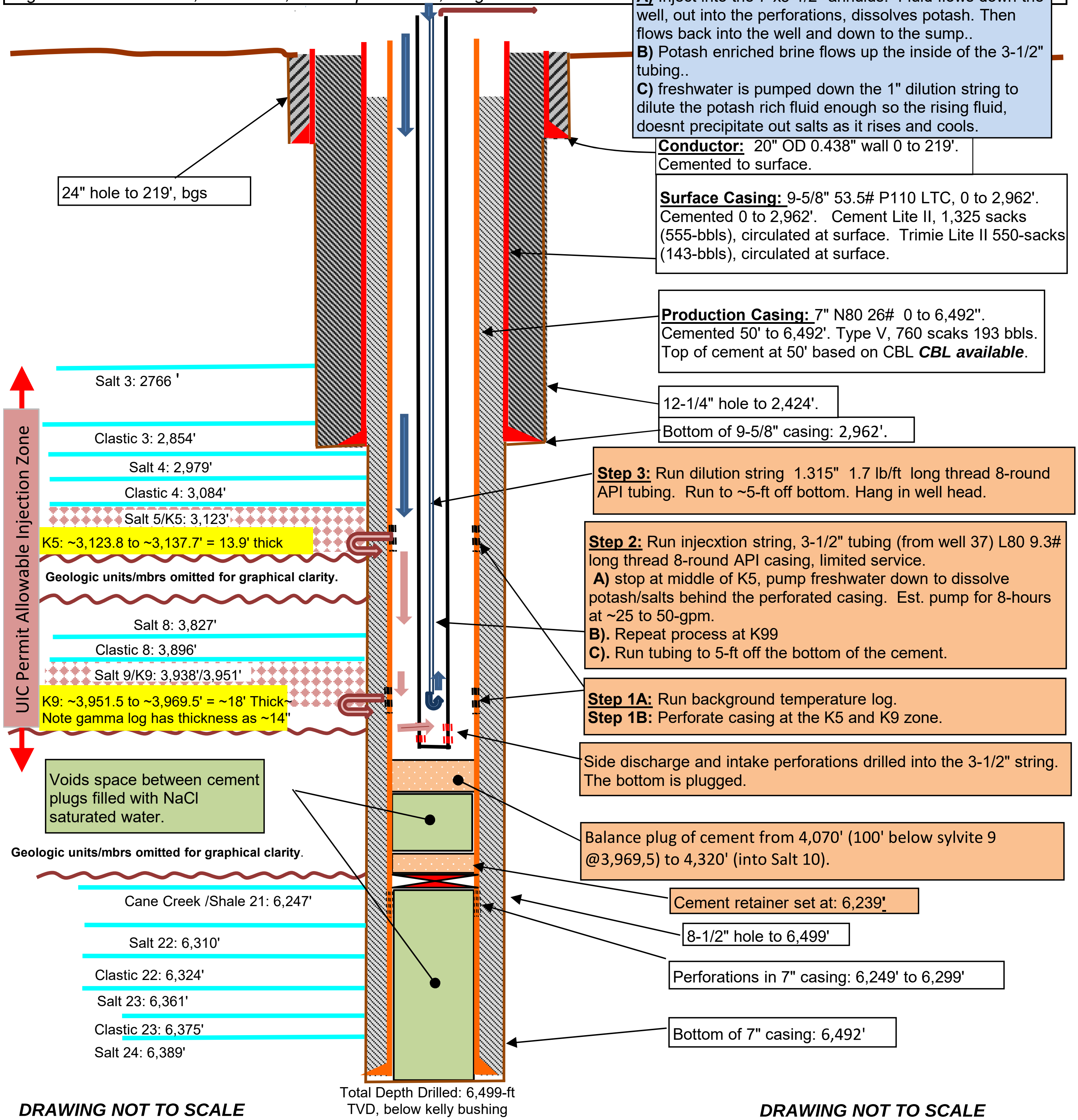

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Figure 4
Two-Fer 26-30
Vertical Solution Mining Well Details
Intrepid Potash-Moab, LLC

All Information is Confidential and Proprietary

Purpose: Well drilled for oil and gas production. Will plug back and convert to solution mining.

Ground Elevation: 4,540		KB +20.2'	*Note: Depths are relative to the Kelly bushing, which is 22.1 feet above ground surface, except for the 40-foot of 24" hole and 20" conductor pipe which were set relative to ground surface.*
Lat. 38.50675	Long. 109.68400		
Spudded:	Completed 9/14/2010		
Legal: NE 1/4 of SE 1/4, section 26, township 26 south, range 20 east			

Detail Schematic of Potash Zones and Well Components for Vertical Well Solution Mining

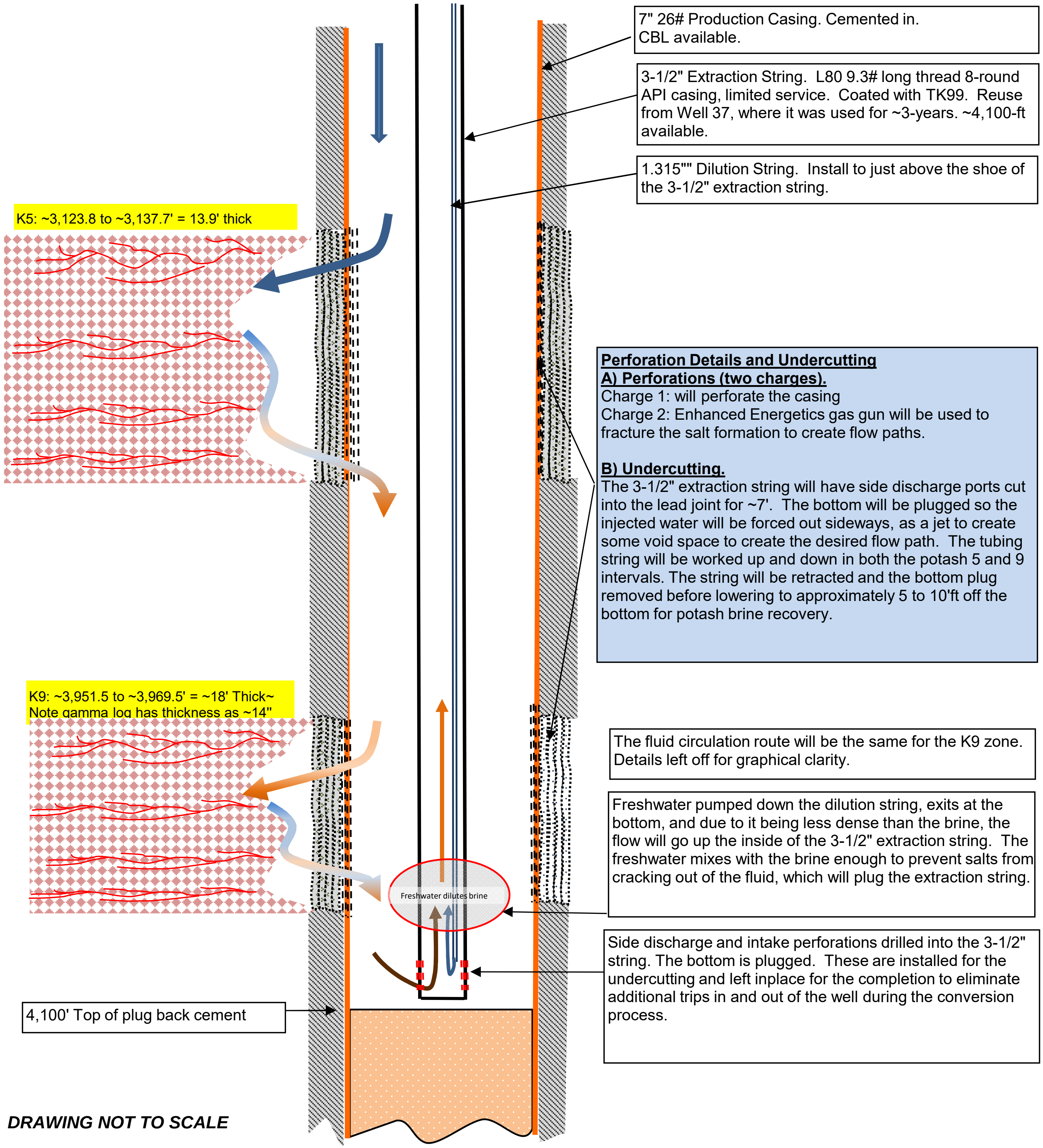

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Figure 5
Two-Fer 26-30
Vertical Solution Mining Well Undercutting Details
Intrepid Potash-Moab, LLC

All Information is Confidential and Proprietary

Purpose: Well drilled for oil and gas production. Will plug back and convert to solution mining.

Ground Elevation: 4,540		KB +20.2'	*Note: Depths are relative to the Kelly bushing, which is 22.1 feet above ground surface, except for the 40-foot of 24" hole and 20" conductor pipe which were set relative to ground surface.*
Lat. 38.50675	Long. 109.68400		
Spudded:	Completed 9/14/2010		
Legal: NE 1/4 of SE 1/4, section 26, township 26 south, range 20 east			

Detail Schematic of Potash Zones and Well Components for Vertical Well Solution Mining

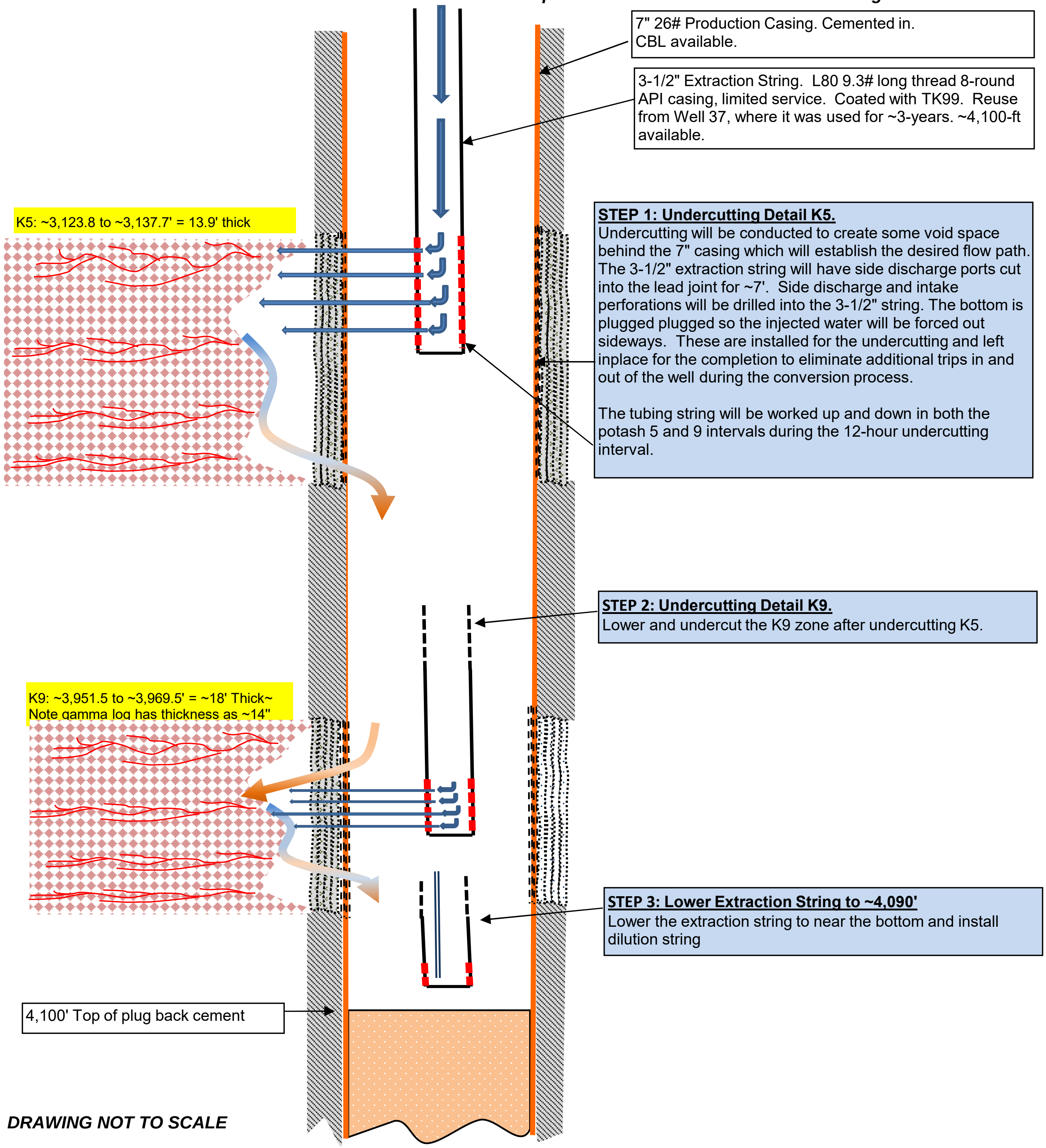

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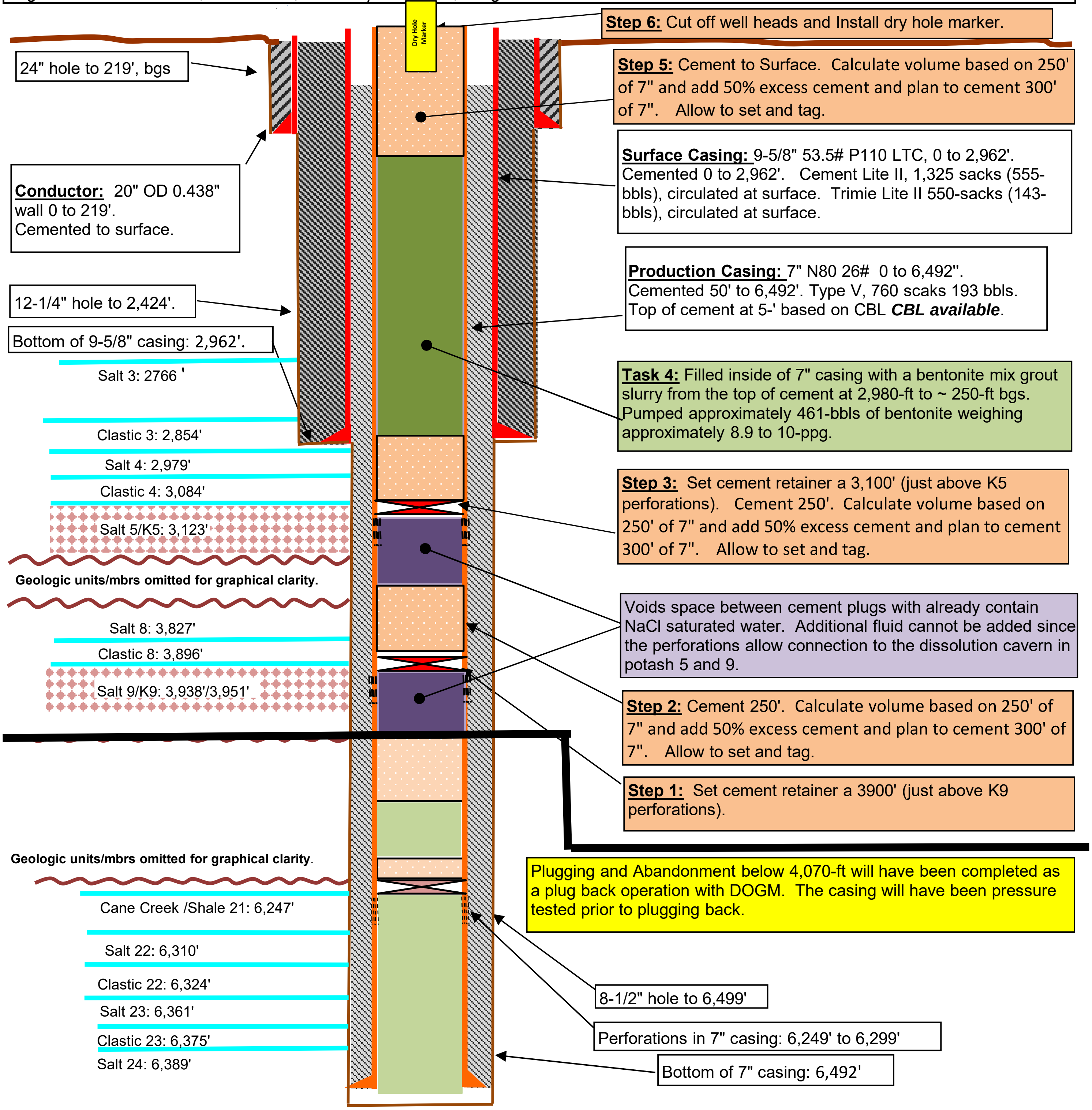
Figure 6
Two-Fer 26-30
(API # 43-019-31452)
Final Proposed Plugging and Abandonment Schematic
Intrepid Potash-Moab, LLC

Purpose: Well drilled for oil and gas production. Minimal production since completion. Scheduled for Plugging & Abandonment.

Ground Elevation: 4,540	KB +20.2'		*Note: Depths are relative to the kelly bushing, which is 22.1 feet above ground surface, except for the 40-foot of 24" hole and 20" conductor pipe which were set relative to ground surface.*
Lat. 38.50675	Long. 109.68400		
Spudded:	Completed 9/14/2010		
Legal: NE 1/4 of SE 1/4, section 26, township 26 south, range 20 east			



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Total Depth Drilled: 6,499-ft TVD, below kelly bushing

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Fact Sheet and Statement of Basis
Temperature Logging MIT Waiver
UIC Permit Number UTU-19-AP-1C3C2E8
February 2023

Intrepid Potash
Moab, Utah

<u>Location:</u> **Moab, Utah**	**<u>Operator:</u>** **Intrepid Potash**
<u>Facility Contact:</u> **Todd Stubbs** **Intrepid Potash – Moab, LLC** **PO Box 1208** **Moab, Utah**	**<u>Regulatory Contact:</u>** **Porter Henze** **Utah Department of Environmental Quality** **Division of Water Quality** **UIC Program** **195 North 1950 West** **Salt Lake City, UT 84116** pkhenze@utah.gov **Tel. 385-566-7799**

Purpose of the Statement of Basis and Fact Sheet

The Utah Division of Water Quality ("DWQ") has prepared this Fact Sheet and Statement of Basis ("FSSOB") pursuant to a request from Intrepid Potash – Moab LLC ("Intrepid") for waiver to allow Temperature Logging Mechanical Integrity Testing (MIT) to test for internal mechanical integrity under 40 CFR § 144.16 – Waiver of Requirement by Director. Pursuant to Utah Admin. Code R317-7 *et. seq*. and federal regulations in Title 40 of the Code of Federal Regulations ("CFR") incorporated by R317-7-1, the purpose of this FSSOB is to briefly describe the principal facts and the significant factual, legal, methodological and policy questions considered in by the Director in preparing the waiver, which the Director intends to approve. To meet these objectives, this FSSOB contains:

- Background information on the waiver request and names and telephone numbers of contacts for additional information (listed on the first page of this FSSOB above);
- A description of the Waiver review process and public participation;
- A brief description of the type of Faculty and activity which is the subject of the waiver; and
- Basis for a Waiver of Standards

Waiver Process

<u>Application and Review</u>

In January 2023, Intrepid submitted an Underground Injection Control ("UIC") Permit Review and Technical Report which included a request for a temperature logging MIT waiver permit application for the Sylvite 5 and Sylvite 9 wells. *See* DWQ-2023-001129. DWQ reviewed this request and previously submitted documents.

Public Participation

The waiver was prepared by the DWQ for public notice and public comment. Public comments were accepted by DWQ for 30 days following the first day of public notice in the local newspaper that serves the affected community. Public Comment ran from March 3 to April 3, 2023. No comments were received

Description of Permitted Facility

Intrepid operates the Cane Creek Mine (the "Mine") in Grand and San Juan Counties, under UIC Class III Solution Mining Permit number UTU-19-AP-1C3C2E8, issued by DWQ on May 6, 2015. Currently the Mine is primarily focused on solution mining to produce the primary products of Potassium salt (potash) and sodium Chloride (common salt). The Mine utilizes a salt brine which is injected into various caverns and boreholes, dissolving potassium rich salts, and extracted through another well. The solution is pumped to solar evaporation ponds, allowing the salts to recrystallize and precipitate out as a layer at the bottom of the shallow solar ponds. The salts are then collected and processed as various potash products.

Description of Activity

UIC class III wells are required to be regularly tested for mechanical integrity under 40 CFR § 146.8 and permit requirements. Two types of tests are required, internal and external. Intrepid requested a waiver to include temperature logging, a test approved for external tests, to also be sufficient for internal tests for two UIC Class III wells, Sylvite 5 and 9.

A temperature log MIT test involves allowing a well standing idle for at least 24 hours to establish geothermal gradient. A fluid with a significantly different temperature than the bottom hole temperature is then injected. The change in temperature is monitored to determine if there is a compromise in the well. Methods for can be found in the 2022 December Technical Report and in McKinley's Temperature, Radioactive Tracer, and Noise Logging for Injection Well Integrity[2].

Basis for a Waiver of Standards

Under 40 CFR § 144.16, the Director may authorize a well to alter requirements for mechanical integrity tests to the extent that the change will not result in an increased risk of movement of fluids into an underground source of drinking water ("USDW"). To fulfill the requirement, Intrepid submitted a 1985 Memo[3] from the Department of Health determining that there is no USDW within the boundaries of the Crane Creek mine, indicating there is no risk of fluid movement into a USDW. Intrepid also submitted a justification memo[4] for temperature logging and a demonstration of temperature logging for leak detection on one of their Wells[5]. Several EPA documents support that under certain situations, temperature

1 McKinley, R.M., July 1994, Temperature, Radioactive Tracer, and Noise Logging for Injection Well Integrity

2 Morton, Loren, 1985, Texasgulf USDW study and results of field trip of August 1, 1985, State of Utah Department of Health.; DWQ-1985-001401

3 Cady, Candace, July 2020, Temperature Logging for Part 1, Internal Mechanical Integrity; DWQ-2020-03001

4 Fanshier, Craig, 2020, Demonstration of Temperature Logging for Mechanical Integrity Testing in TGS-6; DWQ-2020-03002

logging can be used to fulfill the internal requirement of Mechanical Integrity tests, such as how temperature logging method is used in Class II Mechanical Integrity Tests[6] and how Temperature Logging can be used to detect leaks in the casing[7]. The director agrees that the evidence provided satisfies 40 CFR § 144.16 and approves this waiver.

5 Nielsen, D.M. and Aller, Linda; July 1984, Methods for Determining Mechanical Integrity for Class II Injection Wells, EPA 600/2-84-121
6 Geraghty and Miller, April 1980, Mechanical Integrity Testing of Injection Wells, prepared for the US EPA Office of Drinking Water under Contract No. 68-01-5971.