FINAL

UTAH WATER QUALITY BOARD

CLASS III AREA PERMIT

UNDERGROUND INJECTION CONTROL (UIC) PROGRAM

UIC Permit Number: UTU-27-AP-9232389

Millard County, Utah

Minor Permit Modification Issued to:

NGL Supply Terminal Solution Mining, LLC
6965 Union Park Center Suite 270
Midvale, UT 84047

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PART I. AUTHORIZATION TO CONSTRUCT AND INJECT

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

NGL Energy Partners LP (NGLEP),
NGL Supply Terminal Solution Mining, LLC
6965 Union Park Center Suite 270
Midvale, UT 84047

is hereby authorized to construct and operate Class III solution mining injection wells in a Project Area centered approximately at 39^{o} 29' 39" latitude 112^{o} 36' 20" longitude, NAD83, located in the S 1/2 of Sec. 23 and the N 1/2 of Sec. 26, T 15 S, R 7 W; SLB&M in Millard County, Utah. A general location map is included as Attachment A.

The intent of the solution mining activity to be conducted under this permit is to create underground hydrocarbon storage (natural gas liquids) caverns in a salt deposit that has been tectonically thickened. This permit implements requirements, as established by the state and federal UIC regulations, for constructing the wells; logging and testing the wells; establishing and maintaining mechanical integrity of the wells and caverns; monitoring, recording and reporting; well and cavern closure and abandonment; and financial assurance to cover closure. Regulatory authority for each of these activities is shared, to varying degrees, with the Utah Division of Oil, Gas and Mining (DOGM). However, once the underground hydrocarbon storage caverns are developed to their full permitted capacity and employed in storing product, the operation of the storage caverns will be regulated by DOGM in accordance with the DOGM Board Order issued to Magnum, predecessor to NGLEP, and filed on March 31, 2014. Details of the shared regulatory authority during well/cavern construction and development and transfer of regulatory authority from DWQ to DOGM for operation of each well/cavern system for product storage will be captured in a Memorandum of Understanding (MOU) between the two agencies.

According to the Solution Mining Plan for the natural gas liquid (NGL) storage caverns, each NGL storage cavern will have a maximum permitted capacity of 2,110,000 barrels of open cavern volume corresponding to a natural gas liquid storage space of 2 million barrels. The final cemented casing will be set a depth of no less than 200 feet below the top of the salt structure, and the roof of the cavern will be established at a depth no less than 100 feet below the setting depth of the last cemented casing. The maximum diameter of each NGL cavern is intended to be approximately 200 feet and the open height approximately 800 feet.

The Project Area, defined in the permit application, is located west of the intersection of Highway 174, also known as Brush-Wellman Road, and Jones Road; approximately 3 ½ miles east-northeast of Sugarville, Utah and 9 miles north of Delta, Utah. The Project Area is the surface projection of the maximum extent within the salt structure in which caverns can be created. The western boundary of the Project Area is defined "by the surface projection of a main north-south trending fault identified at a depth of 3,000 feet during seismic testing and the drilling of exploratory well MH-1." The southern and eastern boundaries are defined "by the downward dip of the salt structure at 3,000 feet." The northern boundary is defined by "a desired offset [of the Project Area] from existing and future high voltage power lines paralleling Brush-Wellman Road." A map showing the facility property boundary, the Project Area, and Area of Review, and the proposed injection wells is included as Attachment B.

The legal description of the Project Area within which the construction of Class III solution mining wells may occur follows:

> Commencing at the Southwest corner of Section 23, Township 15 South, Range 7 West, Salt Lake Meridian; thence South 89°31'51" East 80.78 feet along section line to the POINT OF BEGINNING; thence North 00°44'34" East 597.47 feet; thence North 22°12'14" West 222.88 feet to a point on section line; thence continuing in Section 22, T15S, R7W, SLM North 22°12'14" West 208.71 feet; thence North 00°34'02" East 28.16 feet; thence North 89°59'50" East 79.78 feet to a point on section line; thence continuing in said Section 23 North 89°59'50" East 16.31 feet; thence South 47°45'57" East 1538.32 feet; thence continuing in Section 26, T15S, R7W, SLM South 47°45'57" East 492.21 feet; thence South 00°05'21" East 1183.00 feet; thence South 67°45'22" West 65.70 feet; thence South 72°08'22" West 759.72 feet to a point on a non-tangent curve to the right having a radius of 4216.45 feet and a chord that bears North 32°18'22" West 394.08 feet; thence along said curve a distance of 394.22 feet; thence North 80.27 feet; thence West 44.50 feet to a point on a non-tangent curve to the right having a radius of 4216.45 feet and a chord that bears North 20°19'16" West 1182.28 feet; thence along said curve a distance of 1186.18 feet; thence North 00°44'34" East 258.55 feet to the POINT OF BEGINNING. Contains 2549435 square feet or 58.527 acres, more or less.

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

Attachment A - General Location Map of the NGLEP NGL Storage Project, Millard County.

Attachment B - Map of the NGLEP NGL Storage Project 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 - Construction and Cavern Development Plan

Attachment E - Monitoring, Recording, and Reporting Plan

Attachment F - Well and Cavern Closure and Abandonment Plan

Attachment G - Financial Responsibility

This major modification of the original permit is based upon representations made by the permittee and other information contained in the administrative record. **It is the responsibility of the permittee to read and understand all provisions of this permit.**

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

This permit shall become effective **February 17, 2015**

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

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

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 **February 17, 2015**

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

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

PART II. GENERAL PERMIT CONDITIONS

A. EFFECT OF PERMIT

The permittee is allowed to engage in underground injection in accordance with the conditions of this permit. The permittee, authorized by this permit, shall not construct, operate, maintain, convert, plug, abandon or conduct any other injection activity in a manner that allows the movement of fluid containing any contaminant into underground sources of drinking water (USDW), if the presence of that contaminant may cause a violation of any primary drinking water standard under the Utah Public Drinking Water Administrative Rules, UAC R309-200 and 40 CFR Part 141, or may otherwise adversely affect the health of persons. Any underground injection activity not specifically authorized in this permit is prohibited unless otherwise authorized-by-rule or by another UIC permit. Compliance with this permit does not constitute a defense to any action brought under the Utah Water Quality Act (UWQA) Title 19, Chapter 5 Utah Code Annotated 1953, or any other common or statutory law or regulation. Issuance of this permit does not authorize any injury to persons or property, any invasion of other private rights, or any infringement of State or local law or regulations. Nothing in this permit shall be construed to relieve the permittee of any duties under applicable regulations.

B. SEVERABILITY

The provisions of this permit are severable. If any provision of this permit or the application of any provision of this permit to any circumstance is held to be invalid, the application of such provision to other circumstances and the remainder of this permit shall not be affected thereby.

C. CONFIDENTIALITY

In accordance with Utah Code 19-1-306 (Records of the Department of Environmental Quality), Utah Code 63G-2-309 (Confidentiality Claims), and Utah Code 19-5-113 (DWQ Records and Reports Required by Owners/Operators) any information deemed by the permittee to be entitled to trade secret protection submitted to the UWQB pursuant to this permit may be claimed as confidential by the submitter. Any such claim must be asserted at the time of submission by stamping the words "Confidential Business Information" on each page containing such information. If no claim is made at the time of submission, the UWQB may make the information available to the public without further notice. Claims of confidentiality may be denied by the UWQB according to the procedures detailed in Utah Code 63G-2 and the federal Freedom of Information Act (FOIA). Claims of confidentiality for the following information will be denied as per UAC R317-7-9.7:

1. The name and address of the permittee.

2. Information that deals with the existence, absence or level of contaminants in drinking water.

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

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

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

   The permittee shall comply with all conditions of this permit. Any permit noncompliance constitutes a violation of the Safe Drinking Water Act and the UWQA and is grounds for enforcement action, permit termination, revocation and re-issuance, modification; or for denial of a permit renewal application; except that the permittee need not comply with the provisions of this permit to the extent and for the duration such noncompliance is authorized in an emergency permit issued in accordance with UAC R317-7-8 (40 CFR 144.34). Such noncompliance may also be grounds for enforcement action under the Utah Solid and Hazardous Waste Act (USHWA), Title 19, Chapter 6, Utah Code Annotated 1979.

2. Duty to Reapply (40CFR144.51(b))

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

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

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

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

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

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

   The permittee shall at all times properly operate and maintain all facilities and systems of treatment and control (and related appurtenances) which are installed or used by the permittee to achieve compliance with the conditions of this permit. Proper operation and maintenance includes effective performance, adequate funding, adequate operator staffing and training, and adequate laboratory and

[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.

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

6. Permit Actions

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

a) Modify or Revoke and Re-Issue Permits

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

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

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

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

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

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

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

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

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

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

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

b) Termination of Permit

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

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

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

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

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

c) Minor Modification of Permit

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

(1) Correct typographical errors;

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

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

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

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

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

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

d) Transfer of Permit

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

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

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

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

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

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

(B) The well has been converted; or

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

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

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

7. 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))

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

9. <u>Inspection and Entry (40CFR144.51(i))</u>

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

   a) Enter upon the permittees 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. <u>Monitoring and Records (40CFR144.51(j))</u>

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

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

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

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

   c) Records of monitoring information shall include:

      (1) The date, exact place, and time of sampling or measurements;

      (2) The individual(s) who performed the sampling or measurements;

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

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

      (5) The analytical techniques or methods used; and

(6) The results of such analyses.

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

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

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

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

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

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

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

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

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

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

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

(2) The authorization specifies either an individual or a position having responsibility for the overall operation of the regulated facility or activity,

such as the position of plant manager, operator of a well or a well field, superintendent, or position of equivalent responsibility. (A duly authorized representative may thus be either a named individual or any individual occupying a named position); and

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

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

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

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

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

Specific requirements for reporting the following items are included in Part III of the permit.

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

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

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

d) Monitoring
Monitoring results shall be reported at the intervals specified in Part III of this permit.

e) Compliance Schedule Reports
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.

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

(1) Twenty-four Hour Reporting
Endangering noncompliance information shall be provided orally within 24 hours from the time the permittee becomes aware of the circumstances. Such reports shall include, but not be limited to, the following information:

i. Any monitoring or other information that indicates any contaminant may cause an endangerment to a USDW, or

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

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

g) Other Noncompliance
The permittee shall report all instances of noncompliance not reported under 12d) (Monitoring Reports), 12e) (Compliance Schedule Reports), or 12f) (Endangering Noncompliance Monitoring) of this section in the next Monitoring Report. The reports shall contain a description of the noncompliance and its cause, the period of noncompliance, including exact dates and times, and if the noncompliance has not been corrected, the anticipated time it is expected to continue; and steps taken or planned to reduce, eliminate, and prevent recurrence of the noncompliance.

h) Other Information
When the permittee becomes aware of a failure to submit any relevant facts in the permit application or submitted incorrect information in a permit application or in any report to the Director, the permittee shall

submit such facts or information within 10 days after becoming aware of the failure to submit relevant facts.

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

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

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

(2) Either of the following:

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

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

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

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

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

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

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

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

Requirements for submitting a plugging and abandonment report are specified in Part III of this permit.

17. <u>Duty to Establish and Maintain Mechanical Integrity. (40CFR144.51(q))</u>

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

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

c) The Director may allow the owner/operator of a well which lacks internal mechanical integrity pursuant to 40CFR146.8(a)(1) 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 a period to include that time required to complete the solution mining of each underground hydrocarbon storage cavern to the permitted capacity, to demonstrate mechanical integrity of the well/cavern system, and to effect the transfer of control from the Utah Division of Water Quality (DWQ) to the Utah Division of Oil, Gas and Mining (DOGM) for regulatory oversight of the operation and maintenance of the underground hydrocarbon storage facility.

The Director of the Division of Water Quality (hereafter '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 conditions of Part II (D)(6) of this permit.

B. COMPLIANCE SCHEDULE
(40CFR144.53)

NGLEP 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. Geomechanical Analysis of CW#5

   NGLEP shall submit a geomechanical stability analysis of the current configuration of CW#5 to determine whether further solution mining to increase its capacity would be mechanically sound and technically feasible.

   The analysis shall be submitted within 150 days of the effective date of this permit modification.

2. Financial Responsibility

   NGLEP shall submit evidence of adequate resources acceptable to the Director and the Director of the Division of Oil, Gas and Mining (hereafter 'the Director of DOGM'), if applicable; to implement the approved closure and abandonment plan required by this permit.

   Within 150 days of the effective date of this permit modification, NGLEP shall submit evidence of adequate resources to plug and abandon CW#5 and CW#6.

   Prior to the commencement of drilling additional cavern wells, NGLEP shall submit evidence of adequate resources to plug and abandon the additional cavern well.

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

As of the effective date of this permit modification no wells have been identified within the area of review for the NGLEP NGL Storage Project that require corrective action.

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

1. <u>Well Construction and Cavern Development Standards</u>

Each well shall be constructed and each cavern developed according to the requirements for Class III injection wells as set forth in R317-7-10.1(B) and 40CFR146.32 and according to those generally held to be standards by the underground hydrocarbon storage industry as follows and where applicable:

- *Common Practices – Gas Cavern Site Characterization, Design, Construction, Maintenance, and Operation, SMRI Research Report RR2012-03*
- *Recommended Practice for the Design of Solution-Mined Underground Storage Facilities – API Recommended Practice 1114,* API, July 2007
- *Recommended Practice on the Operation of Solution-Mined Underground Storage Facilities – API Recommended Practice 1115 (R2012)*, API, October 2012
- *Canadian Standard Association, CWA Z341 Series 14 – Storage of hydrocarbons in underground formations, April 2014*

Additionally, the requirements in the approved Application for a Permit to Drill (APD) issued by DOGM must be met, if applicable.

2. <u>Construction and Cavern Development Plan</u>

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

3. <u>Changes to the Construction and Cavern Development Plan</u>

Changes to the approved Construction and Cavern Development 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. To facilitate the minor modification of the permit to incorporate changes to the Construction and Cavern Development Plan, NGLEP will send DWQ courtesy copies of all sundry notices sent to DOGM.

4. <u>Casing and Cement</u>

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

(1) Depth to the injection zone;

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

(3) Hole size;

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

(5) Corrosiveness of injected fluids and formation fluids;

(6) Lithology of injection and confining zones; and

(7) Type and grade of cement.

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

a) Only new casing shall be installed.

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

c) All casings shall be cemented to surface.

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

e) A minimum of two cemented casing strings shall be set in the salt body.

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

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

h) Boreholes shall be conditioned prior to running cement.

i) Joints of last cemented casing shall be gas tight to prevent leakage of gaseous product and/or gaseous blanket material.

5. <u>Logging and Testing</u>

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.

The following geophysical logs and tests must be performed during construction of each well/cavern system:

a) Cement Evaluation Log shall be run according to Part III (H) of this permit.

b) Casing Inspection Log (ultrasonic or electromagnetic flux) shall be run on last cemented casing, from casing seat to surface, before installing leaching strings.

c) Hydrostatic pressure and nitrogen/brine interface tests according to the methods and schedule in Part III (H) of this permit.

d) Inclination and directional surveys starting at 500’ taken 500’ thereafter. Deviation control shall be implemented to maintain the verticality of the well to a maximum of 1.5 degrees average inclination from the vertical at the top of the salt, with no more than 2 degrees or less at any depth.

6. 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 (determined on MH-1); 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) NGLEP shall include in the Construction and Cavern Development Plan a description of the method for determining the top of the salt body.

d) NGLEP shall submit for Director’s approval a Formation Testing Program to determine the fracture pressure of the salt at the last cemented casing seat. The approved and enforceable Formation Testing Program is included in the Construction and Cavern Development Plan in Attachment D of this permit.

7. 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 and Cavern Development Plan in Attachment D of this permit.

8. Monitoring Wells

   No monitoring wells are required by this permit. However, ground water monitoring is addressed in the approved Operating Plan included in the DOGM Board Order issued to Magnum, predecessor to NGLEP, and filed on March 31, 2014.

9. Leaching String

   a) For well/cavern systems constructed after CW#6, NGLEP shall select an appropriate blanket/brine interface tool and appropriate leaching string pair such that the depth of the blanket/brine interface can be confirmed periodically during solution mining of the cavern and such that a sonar survey can be obtained through both leaching strings to monitor the development of the cavern. If NGLEP is unable to obtain sonar surveys through both leaching strings, the inner leaching string shall be removed so that a sonar survey can be obtained.

   b) The joints of the outer hanging leaching string shall be gas tight so as to prevent the loss of the gaseous blanket material or gaseous product.

10. Cavern Configuration, Spacing, and Standoff Requirements

    Each cavern shall be developed, spaced, and set back from the boundary of the salt body (standoff) to maintain mechanical integrity of the caverns, the salt web (the in-situ mass separating adjacent underground caverns and caverns and the edge of the salt body), and the overburden during all modes of cavern development, operation and abandonment for the lifetime of the facility.

    NGLEP shall maintain optimal S:D ratios for the stability of the cavern storage field, where S is the distance between the centers of two caverns or between a cavern and the edge of the salt body and D is the average of the maximum diameter of the two caverns.

Following are the permitted capacities for each NGL cavern:

Cavern	Product Type	Permitted Cavern Capacity (Open Cavern Volume, barrels)	115% of Permitted Cavern Capacity
CW#5	Natural Gas Liquid	2,110,000	2,426,500
CW#6	Natural Gas Liquid	2,110,000	2,426,500
CW#7	Natural Gas Liquid	2,110,000	2,426,500
CW#8	Natural Gas Liquid	2,110,000	2,426,500
CW#9	Natural Gas Liquid	2,110,000	2,426,500
CW#10	Natural Gas Liquid	2,110,000	2,426,500
CW#11	Natural Gas Liquid	2,110,000	2,426,500

11. Requirements Prior to Solution Mining

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

a) Well Completion Data / Report

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

(1) All available logging and testing data on the well;

(2) Primary cement calculations and evidence of cement returns to surface;

(3) Results of satisfactory demonstration of mechanical integrity;

(4) Actual maximum injection pressure and injection flow rate;

(5) Results of the formation testing program, if applicable;

(6) Actual solution mining procedures;

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

(8) Detailed 'As-Built' Well Schematic including:

i. Casing details including size, weight, grade and setting depths,

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

iii. Formation horizons,

iv. Ground water horizons,

v. Pilot hole.

b) DWQ Director's Approval to Commence Solution Mining

Within 7 days after receipt of the well completion report, the Director shall provide written notice denying or granting approval to commence injection.

c) Compliance with DOGM Rules and Orders

NGLEP shall comply with all administrative rules and orders of DOGM prior to the commencement of solution mining.

12. Cavern Development

The Construction and Cavern Development Plan (Attachment D) shall address all modes of cavern development NGLEP intends to implement. This includes complete development to permitted capacity before initial product storage and various scenarios of re-leaching of existing caverns. Maintaining the geomechanical stability of the cavern network must be the first priority in developing and implementing an operating plan for cavern development. Cavern shape shall be controlled by maintaining the blanket material, controlling the water injection rate, controlling the locations of the water injection and brine removal, and controlling the salinity of injected water. Control of cavern development shall be facilitated by the use of computer simulations appropriate to the mode of cavern development.

The following conditions shall apply:

a) The NGL caverns shall be completely developed to permitted capacity within 3 years after the commencement of cavern solution mining, and

b) Hanging strings shall be removed after each solution mining phase, and

c) Sonar surveys of the cavern, cavern floor and cavern roof shall be conducted after each solution mining phase and before commencement / re-commencement of product storage, and

d) Nitrogen/brine interface MIT shall be conducted according to Part III (H) after each solution mining phase and before commencement / re-commencement of product storage, and

e) Submittal of well/cavern completion report required by Part III (G)(1) after each solution mining phase and before commencement / re-commencement of product storage, and

f) Written approval from the Director of DWQ to commence / re-commence product storage shall be required.

g) Approval from the Director of DOGM to commence / re-commence product storage shall be required.

13. Maximum Allowable Operating Pressure Gradient (MaxAOPG)

Except during well stimulation, the maximum allowable operating pressure gradient (MaxAOPG) shall be calculated to assure that pressure in the injection zone during injection does not initiate new fractures or propagate existing fractures in the injection zone. In no case shall the injection pressure initiate fractures in the confining zone or cause the migration of injection or formation fluids into an USDW.

Based on the geomechanical analysis of the salt formation in the MH-1 exploratory well, the upper limit of operating pressures is 0.92 psi/ft of depth to the last cemented casing seat. However, NGLEP shall provide additional protection by operating at pressure gradients below 0.92 psi/ft of depth as follows:

a) The typical operating pressure gradient of a cavern will be 0.55 psi/ft of depth to the last cemented casing seat.

b) The maximum allowable operating pressure gradient (MaxAOPG) will not be greater than 0.75 psi/ft of depth to the last cemented casing seat. At no time will the caverns be subjected to pressures above this pressure gradient including pressure pulsations and during abnormal operating conditions.

c) The maximum allowable test pressure gradient will not exceed 0.85 psi/ft of depth to the last cemented casing seat.

14. Minimum Allowable Operating Pressure Gradient (MinAOPG)

The permittee shall maintain a minimum operating pressure gradient during the creation and operation of each cavern that is protective of the integrity of the wells, caverns, salt web, and overburden. NGLEP shall maintain a MinAOPG of 0.25 psi/ft of depth based on the geomechanical analysis of the salt formation.

15. Borehole – Casing Annulus Injection Prohibited

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

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

1. Well and Cavern Monitoring and Recording Standards

Monitoring and recording requirements for the drilling and solution mining of each well/cavern are set forth in R317-7-10.3(B) and 40CFR144.54 and those generally held to be standards by the underground hydrocarbon storage industry as follows and where applicable:

- *Common Practices – Gas Cavern Site Characterization, Design, Construction, Maintenance, and Operation, SMRI Research Report RR2012-03*
- *Recommended Practice for the Design of Solution-Mined Underground Storage Facilities – API Recommended Practice 1114,* API, July 2007
- *Recommended Practice on the Operation of Solution-Mined Underground Storage Facilities – API Recommended Practice 1115 (R2012),* API, October 2012
- *Canadian Standard Association, CWA Z341 Series 14 – Storage of hydrocarbons in underground formations, April 2014*

Additionally, the monitoring and recording requirements for the drilling of each well in the approved Application for a Permit to Drill (APD) issued by DOGM must be met, if applicable. Monitoring and recording requirements for hydrocarbon storage shall be set by DOGM once the well / cavern system has been released from the Class III UIC permit.

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

   The approved and enforceable Monitoring, Recording and Reporting Plan is included as Attachment E of this permit.

3. <u>Monitoring Equipment and Methods</u>

   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.

4. <u>Injectate Characterization</u>

   The permittee shall monitor the nature of injected fluids with sufficient frequency to yield representative data on its characteristics. The permittee shall provide qualitative analysis and ranges in concentrations of all constituents of injected fluids. Whenever the injection fluid is modified to the extent that this analysis is incorrect or incomplete, a new analysis shall be provided to the Director. The applicant may request confidentiality in accordance with Part II C of this permit. If the information is proprietary an applicant may, in lieu of the ranges in concentrations, choose to submit maximum concentrations which shall not be exceeded. In such a case the applicant shall retain records of the undisclosed concentrations and provide them upon request to the Director as part of any enforcement investigation.

NGLEP shall submit a complete chemical analysis of the solution mining media (injectate) every two years. The sample shall be taken during a period of active solution mining.

5. Mechanical Integrity Testing (MIT)

   Mechanical integrity testing shall be conducted according to the methods and schedule in Part III (H) of this permit.

6. Cavern Development Monitoring

   The following must be monitored during cavern development:

   a) NGLEP shall monitor the shape of the cavern, by sonar surveys, during development to ensure a stable shape and configuration is achieved, and

   b) NGLEP shall maintain the location of the blanket/brine interface. It is not sufficient to estimate the depth of the interface from the volume of blanket material injected. NGLEP shall perform periodic wireline surveys to confirm the location of the blanket/brine interface with increased frequency when the solution mining mode is switched from direct to reverse. If the interface cannot be confirmed by wireline surveys, solution mining must stop immediately until the interface can be re-established and confirmed.

   c) NGLEP shall conduct daily monitoring of flow rate of injected water, saturation level of injected water, pressure of injected water, temperature of injected water, flow rate of produced brine, saturation level of produced brine, pressure of produced brine, temperature of produced brine, pressure of blanket, volume of blanket, temperature of blanket.

7. Weekly Brine Analysis

   NGLEP shall conduct weekly or more frequently as needed, analysis of the produced brine for at least magnesium (Mg) and potassium (K) to identify zones of highly soluble salts. If highly soluble zones are identified, adjustment of the solution mining process may be necessary.

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

1. Quarterly Monitoring Reports

   a) Schedule for Submitting Quarterly Monitoring Report

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

b) Content of Quarterly Monitoring Reports

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

(1) Periodic Injectate Characterization
(2) Daily cavern development monitoring data
(3) Weekly Brine Analysis
(4) Wireline logs for all blanket/brine interface confirmations
(5) Sonar surveys for all cavern shape and configuration verification
(6) 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.
(7) Other Required Monitoring

2. Endangering Noncompliance Reporting

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

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

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

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

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

3. Planned Changes

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

4. Anticipated Noncompliance

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

5. Permit Transfers

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

6. Compliance Schedule Reporting

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

7. Mechanical Integrity Reporting

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

   b) Loss of Mechanical Integrity –

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

      (2) Within 14 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. Closure and Abandonment (“As-Plugged”) Report

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

   a) A statement that the well was plugged in accordance with the Closure and Abandonment Plan(s) previously submitted to, and all conditions of approval provided by, the Director; or

b) If the actual closure and abandonment differed from the approved plan(s), a statement and diagrams defining the actual closure and abandonment and why the Director should approve such deviation. Any deviation from the previously approved individual 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. <u>Permit Review Report</u>

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

10. <u>Electronic Reporting</u>

In addition to submittal of the hard copy data, the permittee shall submit the required monitoring data in the electronic format specified by the Director.

G. REQUIREMENTS PRIOR TO PRODUCT STORAGE

1. <u>Well / Cavern Completion Report</u>

The operator shall submit to DOGM and to the DWQ Director, for review a well / cavern completion report at the end of each solution mining phase consisting of:

a) All available logging and testing data on the well/cavern system not previously submitted with the well completion report;

b) Results of mechanical integrity testing for well/cavern system;

c) Detailed ‘As-Built’ well/cavern schematic including any changes made to the original well ‘As-Built’ schematic;

d) Sonar survey of the cavern including floor and roof surveys;

2. <u>Director’s Approval to Commence Product Storage</u>

Within 7 days after receipt of the well / cavern completion report, the Director shall provide written notice denying or granting approval to commence product storage.

3. <u>Compliance with DOGM Rules and Orders</u>

NGLEP shall comply with all administrative rules and orders of DOGM prior to the commencement of product storage.

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

1. Class III Injection Well Mechanical Integrity Standards

   Mechanical integrity testing requirements for each Class III well are set forth in R317-7-10.3(B) and 40CFR146.8. Additionally, the mechanical integrity requirements for each well in the approved Application for a Permit to Drill (APD) issued by DOGM must be met.

   All injection wells shall have and maintain mechanical integrity (MI) consistent with the requirements of 40 CFR 146.8. An injection well has 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 testing methods shall be employed to demonstrate MI of the well / cavern system:

   a) Internal MI

      (1) Hydrostatic Pressure Test

      The hydrostatic pressure test shall be conducted according to R649-3-7.4 – Well Control, Pressure Tests as follows:

      i. Last two cemented casings in salt at the time of construction

      ii. Casing seat of last cemented casing after drilling 20’ into salt

      (2) Nitrogen/Brine Interface Test

      The nitrogen/brine interface test shall be conducted according to UIC Guidances UIC-3-14, 15, 16, and 17 as follows:

      i. Last cemented casing string before commissioning the cavern

      ii. Last cemented casing string after workover involving last cemented casing

      iii. Last cemented casing string every 5 years after initial test

   b) External MI

      (1) Nitrogen/Brine Interface Test

      i. Well/pilot hole before solution mining of cavern commences

      ii. Well/cavern before commissioning the cavern

      iii. Well/cavern every 5 years after initial test

      (2) Cement Records

Primary cement records for each cemented casing string obtained during construction of each well.

(3) Cement Evaluation Logs

Conducted on surface, all intermediate and production casings after WOC of 72 hours and after attaining a compressive strength of 500 psi unless an appropriate cement evaluation tool is not available for the larger diameter casings in which case an alternative logging program shall be proposed by the permittee.

3. Mechanical Integrity Demonstration Plan

The permittee shall prepare a detailed plan to demonstrate MI to be included in the approved and enforceable Monitoring, Recording and Reporting Plan in Attachment E of the permit. In preparing a plan, which includes MI tests or demonstration methods allowed by the Director, the permittee shall apply methods and standards generally accepted in the industry for conducting and evaluating the tests (40CFR146.8(e)).

4. Prohibition Without Demonstration

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

a) Prior demonstration of MI, and

b) Receipt of Director written approval of the MI demonstration.

5. Loss of Mechanical Integrity

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

a) Cease operation of the well immediately, and

b) Take steps to prevent losses of brine into USDWs, and

c) 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.

d) The permittee may resume operation of the well after demonstration of MI and receiving written approval from the Director.

6. Mechanical Integrity Demonstration Requests

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

7. Mechanical Integrity Demonstration Inspections

The permittee shall allow the Director, or his representative, to observe any or all MI demonstrations. The permittee shall notify the Director, in writing, of its intent to demonstrate MI, no less than 14 days prior to the intended demonstration.

I. WELL AND CAVERN CLOSURE AND ABANDONMENT (40CFR146.10 and R317-7-10.5)

If a well or well/cavern system is required to be plugged and abandoned before it has been transferred to DOGM for regulatory oversight for operation and maintenance, NGLEP shall submit for the Director's approval a comprehensive plan for cavern evacuation, decommissioning and well abandonment that meets the requirements that are generally held to be closure and abandonment standards by the underground hydrocarbon storage industry. The approved closure and abandonment plan shall become an enforceable attachment (Attachment F) to this permit.

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

1. <u>Demonstration of Financial Responsibility</u>

   The permittee is required to maintain financial responsibility and resources to close, plug, and abandon all wells and well/cavern systems. This requirement is demonstrated by submission of evidence of financial responsibility acceptable to the Director and, if applicable, to the Director of DOGM to implement the approved well and cavern closure and abandonment plan (Attachment F) required by this permit. Evidence of adequate financial assurance is included in Attachment G of this permit.

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

   Every five (5) years, the permittee shall demonstrate the adequacy of the financial assurance instrument to close, plug and abandon all well/cavern systems not permanently closed and abandoned by the permittee in compliance with the closure and abandonment requirements of this permit.

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

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

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

   b) The authority of the institution issuing the financial assurance instrument is suspended or revoked; or

   c) In the case a Certificate of Deposit (CD) is used to demonstrate financial responsibility, the CD is determined to be insufficient to cover well closure, plugging and abandonment; or

   d) In the case a Certificate of Deposit (CD) is used to demonstrate financial responsibility, the CD is suspended or revoked.

K. ADDITIONAL CONDITIONS (40CFR144.52)

1. Geomechanical Analysis

Once each NGL cavern has been solution mined to its full permitted capacity the cavern will continue to grow due to product displacement with less than fully saturated brine. Where S equal the distance between the centers of the two caverns and D equals the average of the maximum diameter of the two caverns, NGLEP shall perform a geomechanical analysis of the cavern field to verify the geomechanical stability of the caverns, salt web and overburden when either of the following occurs:

a) When the S:D ratio falls below 2:1 for any NGL cavern and adjacent pillar or edge of the salt body, or

b) When the S:D ratio falls below 4:1 for any NG cavern and adjacent pillar or edge of the salt body, or

c) When the open cavern volume of any cavern exceeds the permitted cavern capacity by 15%.

NGLEP shall be required to take appropriate action if the results of the analysis indicate such action is necessary.

Attachment A

General Location Map of the NGLEP NGL Storage Project, Millard County

PUBLIC COPY

FILE NAME:193 – CLYDE SNOW SS\29.220 – 09 CLASS III PERMIT\CAD\MAP 1 – GENERAL LOCATION MAP.DWG FILE DATE: 10.2.2009 12:32:02 (CAH)

HANSEN ALLEN & LUCE INC ENGINEERS

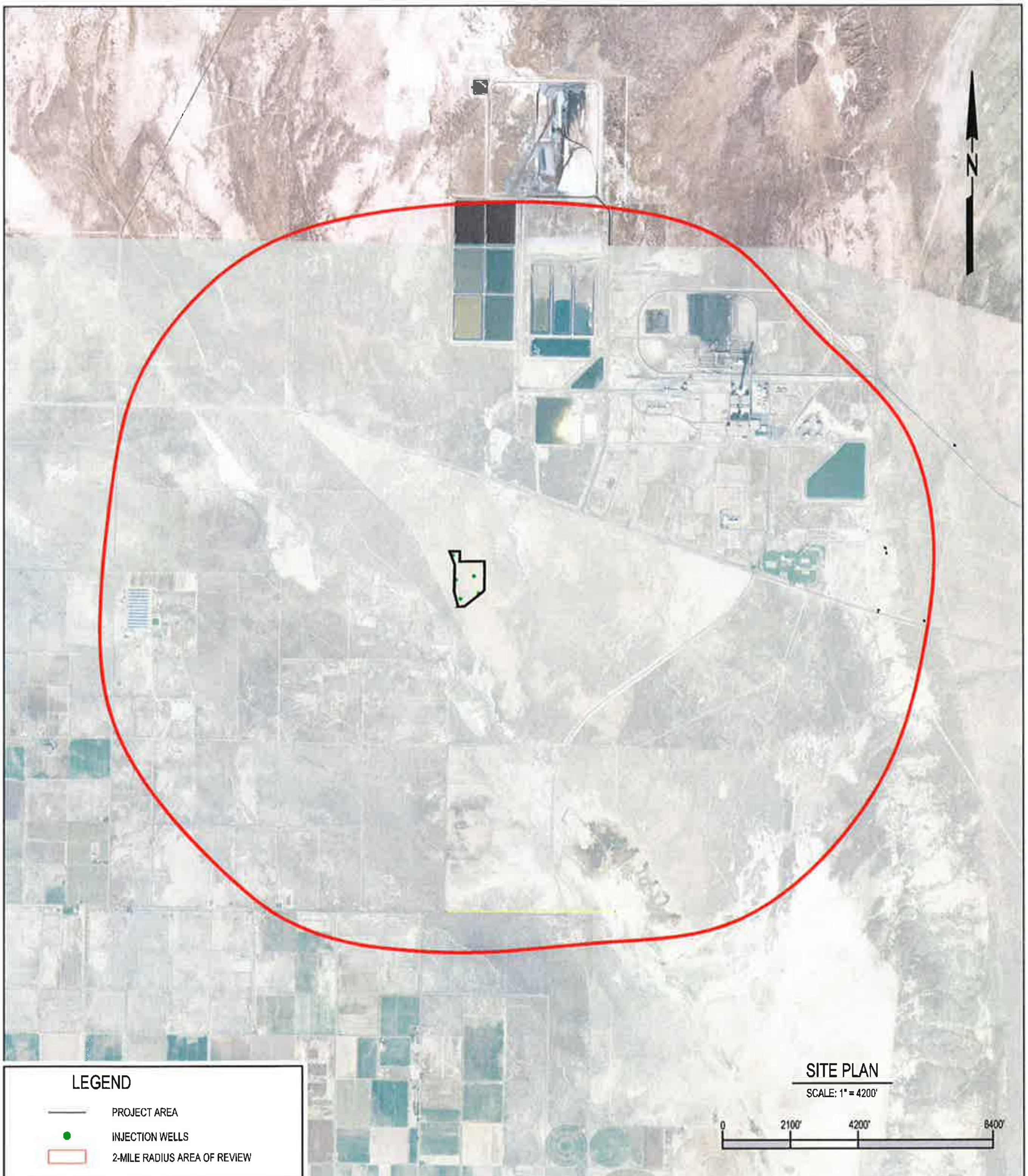
GENERAL LOCATION MAP

FIGURE 1

03/04

Attachment B

Map of the NGLEP NGL Storage Project Area of Review including the Class III Solution Mining Injection Wells and the Project Area



LEGEND

PROJECT AREA

INJECTION WELLS

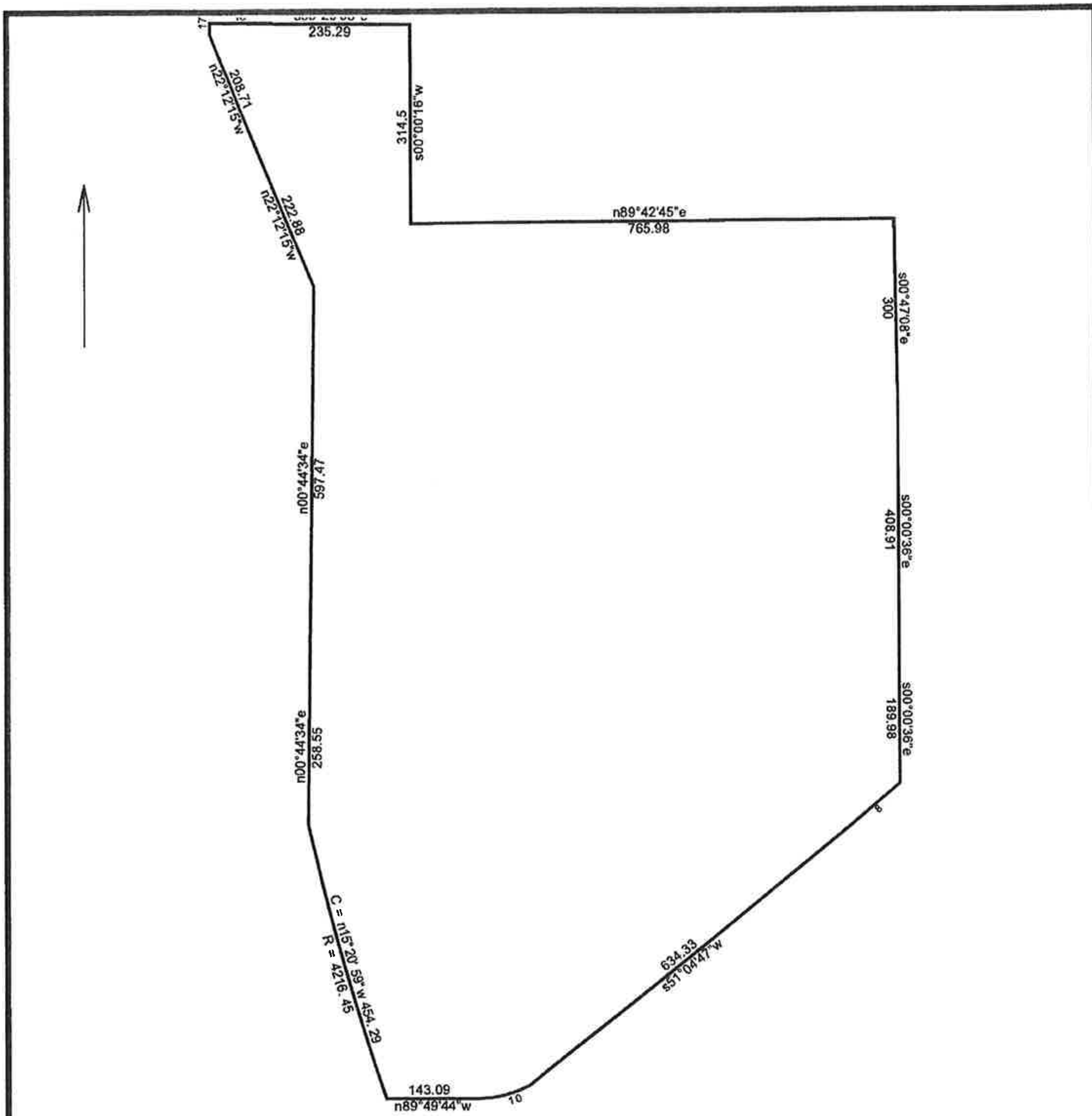
2-MILE RADIUS AREA OF REVIEW

CLASS III AREA PERMIT
UNDERGROUND INJECTION CONTROL (UIC PROGRAM)
UIC PERMIT #UTU-27-AP-9232389
ATTACHMENT B

SHEET NAME:
MAGNUM NGLs SOLUTION MINING LLC

MAGNUM NGLs
3165 E. MILLROCK DR, SUITE 330
HOLLADAY, UTAH 84121
PHONE: (801) 993-7001

DATE:	08/04/2014	SURVEYED BY:	SUNRSIE	SHEET NO:
DATE DRAWN:	08/04/2014	DRAWN BY:	LMR	1
SCALE:	1"=4200'	REVISED:	TJ	



9/11/2014

Scale: 1 inch= 215 feet | File:

Tract 1: 27.6198 Acres, Closure: s02.2012w 0.02 ft. (1/275869), Perimeter=5041 ft.

01 /n00.1823e 1013.34
02 s89.2953e 235.29
03 s00.0016w 314.5
04 n89.4245e 765.98
05 s00.4708e 300
06 s00.0036e 408.91
07 s00.0036e 189.98
08 s49.2854w 124.07
09 s51.0447w 634.33
10 Rt, r=174.52, chord=s76.0723w 84.72
11 n89.4944w 143.09
12 Rt, r=4216.45, chord=n15.2059w 454.29
13 n00.4434e 258.55
14 n00.4434e 597.47
15 n22.1215w 222.88
16 n22.1215w 208.71
17 n00.3402e 17.69
18 s89.2953e 79.82

MAGNUM NGLs SOLUTION MINING, LLC UIC BOUNDARY

Commencing at Southwest corner of Section 23; Township 15 South, Range 7 West, Salt Lake Meridian; thence North 00°18'23" East 1013.34 feet along section line to the POINT OF BEGINNING; thence South 89°29'53" East 235.29 feet; thence South 00°00'16" West 314.50 feet; thence North 89°42'45" East 765.98 feet; thence South 00°47'08" East 300.00 feet; thence South 00°00'36" East 408.91 feet to a point on section line; thence continuing in Section 26, T15S, R7W, SLM, South 00°00'36" East 189.98 feet; thence South 49°28'54" West 124.07 feet; thence South 51°04'47" West 634.33 feet to a point on a non-tangent curve to the right having a radius of 174.52 feet and a chord that bears South 76°07'23" West 84.72 feet; thence along said curve a distance of 85.58 feet; thence North 89°49'44" West 143.09 feet to a point on a non-tangent curve to the right having a radius of 4216.45 feet and a chord that bears North 15°20'59" West 454.29 feet; thence along said curve a distance of 454.51 feet; thence North 00°44'34" East 258.55 feet to a point on section line; thence continuing in said Section 23, North 00°44'34" East 597.47 feet; thence North 22°12'15" West 222.88 feet to a point on section line; thence continuing in Section 22, T15S, R7W, SLM, North 22°12'15" West 208.71 feet; thence North 00°34'02" East 17.69 feet; thence South 89°29'53" East 79.82 feet to the POINT OF BEGINNING. Contains 1203114 square feet or 27.620 acres, more or less.

PROFESSIONAL LAND SURVEYOR
No. 189369
DALE J.
ROBINSON
STATE OF UTAH

Attachment C

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

As of the effective date of this permit modification there are no wells requiring corrective action.

Attachment D

Construction and Cavern Development Plan

Cavern Construction and Development Plan

Underground Injection Control Permit UTU 27-AP-9232389

MAGNUM

NGLs

CAVERN CONSTRUCTION
AND DEVELOPMENT PLAN
UNDERGROUND INJECTION CONTROLPERMIT UTU 27-AP-9232389

MAGNUM NGLs, LLC
DELTA, UTAH

December 2014

Table of Contents

Tables

Figures

Section 1

Introduction

1.1 Purpose of the Plan

This Plan has been developed to outline clear processes and procedures for storage cavern construction (drilling and cavern well installation) and development (solution mining) at the Magnum NGLs storage facility. The construction (drilling) of storage caverns at the facility is under the jurisdiction of both the Utah Department of Environmental Quality (DEQ), the Division of Water Quality (DWQ), and the Utah Department of Natural Resources (DNR), the Division of Oil, Gas and Mining (DOGM). The development of storage caverns is under the sole jurisdiction of the DWQ. In addition to the UIC Permit, Magnum has also obtained the appropriate permits and authorizations from the necessary federal, state and local agencies.

Magnum has created this Plan, to meet the requirements for the solution mining of salt caverns under DWQ Underground Injection Control (UIC) Permit UTU-27-AP-9232389. This Plan has been reviewed and approved by the DWQ. Any future modifications to this plan requested by Magnum are subject to approval by DWQ. DWQ may also modify the Plan after it receives new, previously unavailable information or after a review of the Plan. A copy of the Plan will be kept at the facility.

1.2 Facility Location

The Magnum NGLs storage facility is located approximately eight miles north of Delta in Millard County and on lands leased from the Utah School and Institutional Trust Lands Administration (SITLA). The facility address is 9650 North 540 East Delta, Utah 84624. As shown on Figure 1, the facility is situated west of Highway 6 near the intersection of Jones Road and Brush Wellman Road/SR-174.

1.3 Facility Description

The Magnum NGLs storage facility is located on a salt dome that is approximately one mile thick, two miles in diameter and 3,000 feet below the ground surface. Magnum will be solution mining storage caverns within the salt dome for the purpose of storing NGLs such as butane and propane. Figure 2 is a map depicting the storage facility layout as currently constructed and proposed. As shown, the facility consists of three main components that are connected by utilities contained within a central utility corridor. The main components are a Storage Cavern Field, a 152-acre brine evaporation pond, and a truck and rail loading and transfer facility. The utilities between the main components include brine, water, power, and product transfer lines. As currently designed, the facility will be capable of storing 16 million barrels (MMbbls) of NGLs in eight caverns with an individual capacity of 2 MMbbls each. The timing of cavern construction is dependent upon market demand.

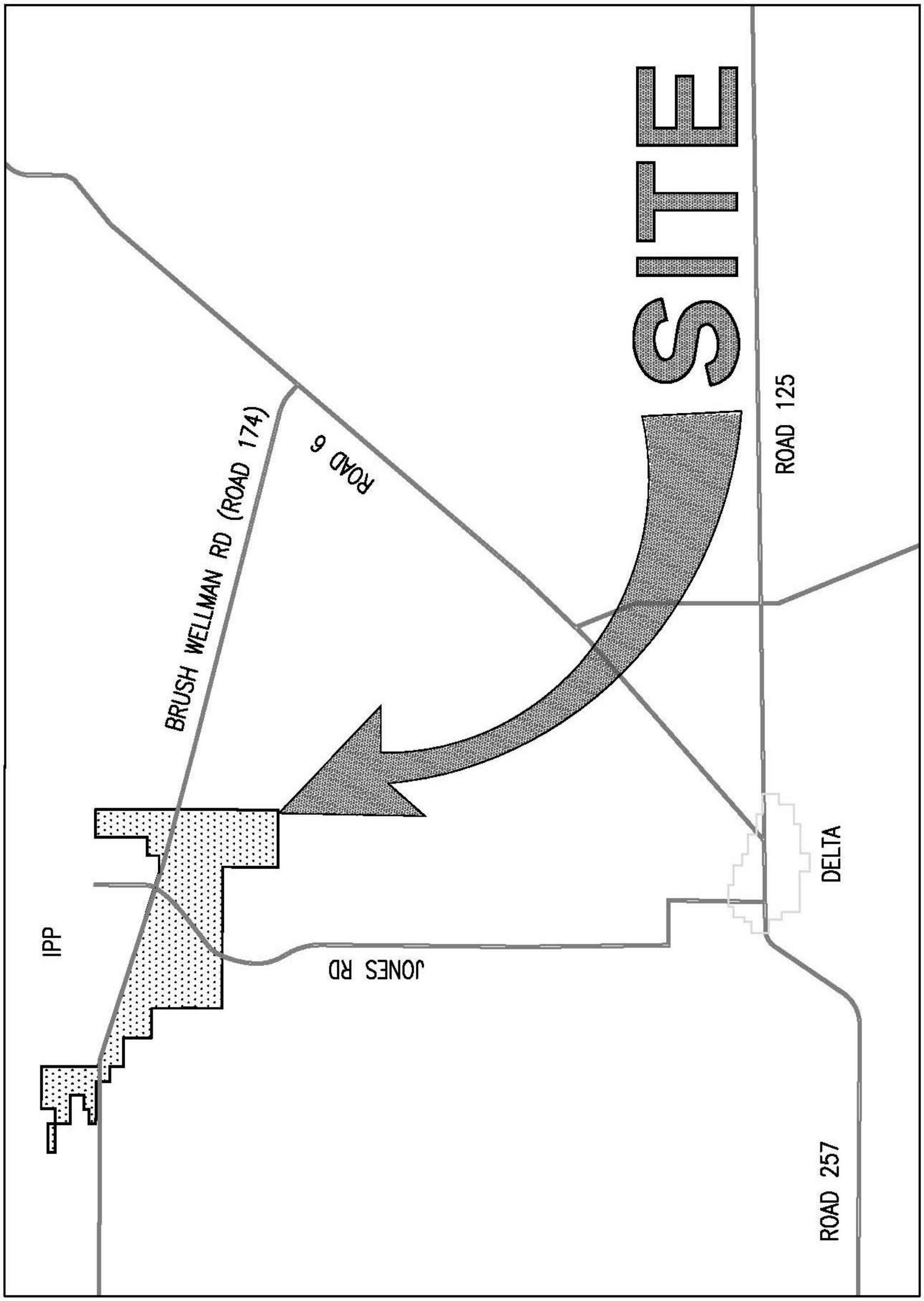


Figure 1: Vicinity Map

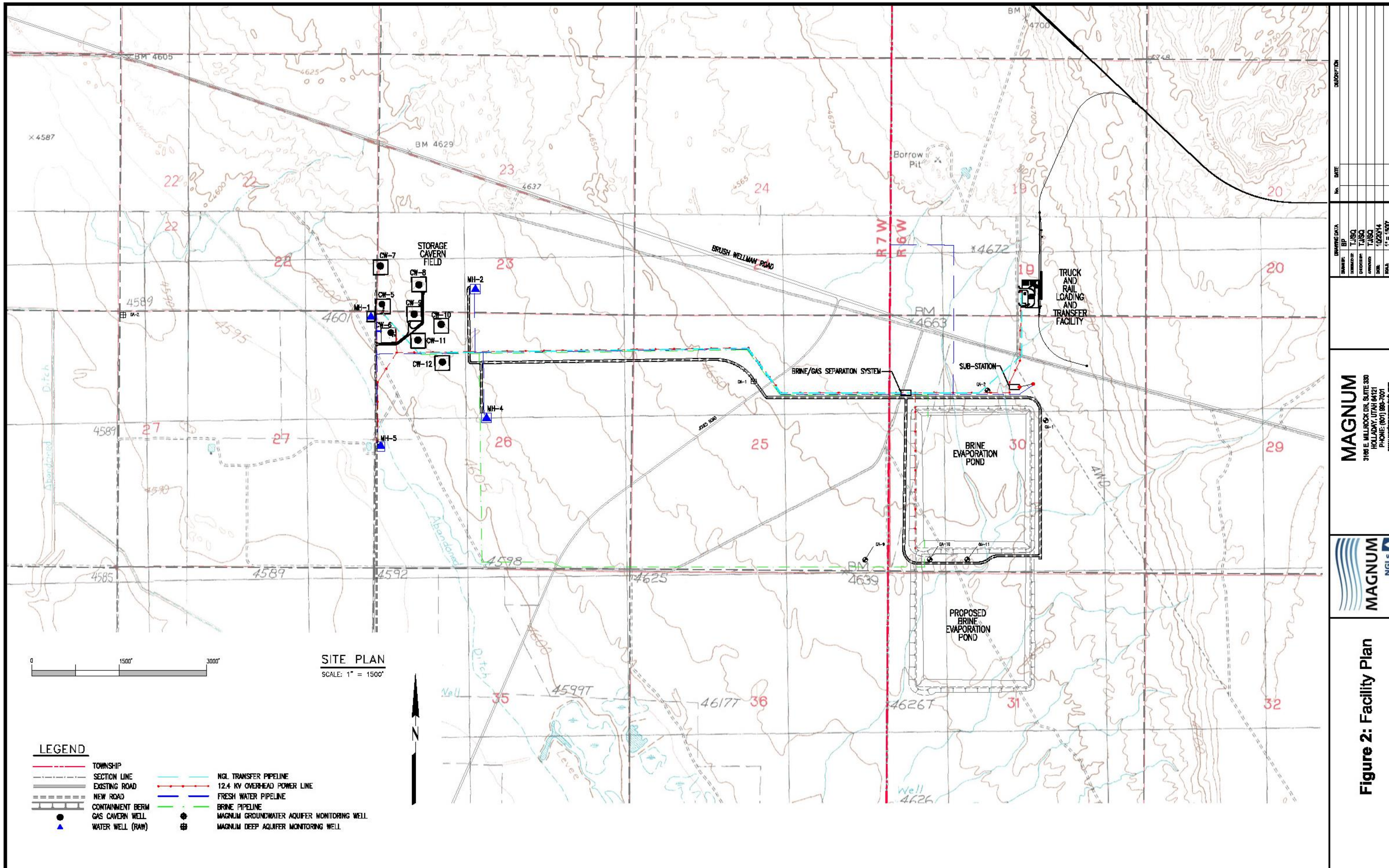


Figure 2: Facility Plan

1.4 Storage Cavern Field Description

This Plan specifically addresses the construction and development of cavern well and storage caverns within the Storage Cavern Field. Figure 2 depicts the location of the Storage Cavern Field within the broader facility, the specific locations and numbers of the first eight storage caverns and cavern wells, and the location of the gas detection system near the northwest corner of the brine evaporation pond. The Storage Cavern Field currently includes plans for eight storage cavern and cavern well locations: Cavern Well 5 (CW-5), Cavern Well 6 (CW-6), Cavern Well 7 (CW-7), Cavern Well 8 (CW-8), Cavern Well 9 (CW-9), Cavern Well 10 (CW-10) Cavern Well 11 (CW-11), and Cavern Well 12 (CW-12). The storage caverns within the Field are being constructed using conventional solution mining technology. Depending upon the cavern size, solution mining will take between six and 12 months to complete. Both DWQ and DOGM have approved the engineering design and plans for cavern well spacing, wellhead design, casing design, drilling plan, cementing plan, solution mining plan, and cavern operations.

The UIC Permit has cavern spacing and depth requirements in order to maintain both cavern wall and roof integrity of the individual caverns and of the overall salt web. The requirement for the solid salt pillars between any 2 caverns and offset from the edge of the salt dome is two times the individual storage cavern diameter. This translates to a 600 foot surface spacing of the cavern wells to accommodate storage caverns that are 2 MMbbls in size (approximately 200 feet in diameter and approximately 1,250 feet in height). Given the nature of NGLs storage, however, Magnum has spaced caverns within the Storage Cavern Field between 600 and 700 feet apart to ensure that each cavern maintains the required pillar spacing through time. While cavern depths within the salt dome are dependent upon the individual cavern locations relative to the below ground elevation of the top of salt, the tops of caverns will likely range in depth between 3,500 and 4,100 feet bgs and the base of caverns will range in depth between 4,500 to 5,500 feet bgs. With that said, the final cemented casing will be set a depth of no less than 200 feet below the top of the salt structure, and the roof of the cavern will be established at a depth no less than 100 feet below the setting depth of the last cemented casing.

Section 2
General Well Construction/Drilling Plan

2.1 Cavern Well Design Methodology

Prior to the construction of individual caverns in the Storage Cavern Field the specific cavern well design and cavern well construction plan is reviewed and approved by DOGM as part of the Permit to Drill process. The general cavern well design outlined in this section is a typical cavern well design developed specifically for the Magnum NGLs storage caverns and meets the state rules for drilling (R649-3-6) and casing testing (R649-3-13 and R649-3-7.4). The design has been previously reviewed and approved by both the DWQ and DOGM.

The typical Magnum NGLs cavern well design includes a well head, five cemented casings, and two hanging casing strings (Figure 3). The cavern well is designed to provide a strong foundation for mechanical integrity of the cavern well and storage cavern as well as protect against the potential for groundwater contamination. The cavern well casing design includes: one surface casing; two water protection casing strings, one cemented in the freshwater zone and the other to the top of the salt; two casing strings cemented into the upper section salt; and, two hanging strings.

The two guiding principles of the cavern well design are: the need to support injection and production from the completed storage cavern at 1,500 gpm with a velocity about 16 feet per second; and, sizing the casing to allow for the use of hanging casing strings for solution mining at rates of about 2,500 gpm. Consequently, the goal of the Magnum NGLs cavern well design is to specify casing sizes and grades that allow a safety factor of about 1.05 for collapse, 1.2 for burst and 1.6 for tensile forces based on published strength data. The various casing strings included in the typical design are therefore sized to withstand foreseeable collapse, burst and tensile forces that might act upon the casing.

In normal operations collapse forces generally are greatest during cementing of the casing string when the inside of the casing is filled with drilling mud and the annulus is filled with heavier cement slurry. In normal operations the collapse forces resulting from the weight difference between cement and drilling mud are low. At 4,000 feet this can amount to about 1,000 psi. However, in keeping with generally accepted practices (such as ERCB Directive 10) the collapse pressures are calculated with the assumption that the annulus is filled with cement and the inside of the casing is air-filled.

In the case of the outer hanging casing string, the collapse pressures also result from the use of nitrogen as a blanket material. The nitrogen blanket pressure will be greatest at the start of mining when the nitrogen blanket is at its deepest location. At the worst case (for collapse calculations) the largest pressures occur during reverse mining when the cavern is shut-in. In this instance, water is in the outer tubing string, and the brine in the cavern is unsaturated and continues to dissolve salt. The continued dissolution increases space in the cavern so that the wellhead fluid pressures fall to a vacuum. If at the same time the borehole has closed around the hanging tubing, the nitrogen pressure will be locked in at its normal operating pressure. The full nitrogen pressure of about 2,000 psi will be acting against the 13-3/8-inch tubing with a vacuum on the inside. The tubing has been sized to withstand this event, however it is unlikely.

Burst forces again are generally greatest during cementing operations but are normally very low during normal operations. The worst case occurs if the casing has been run in the well, the float shoe/collar gets stuck shut and a gas blowout occurs at the bottom of the hole. In this event the full hydrostatic pressure of the drilling mud in the casing would be acting against a low-pressure gas-filled annulus. The pressure of the annulus was conservatively assumed to be “0” psi.

In the case of the final cemented casing, significant burst forces occur during mining operations due to the use of nitrogen as the blanket material. After mining is completed, lesser pressures will act inside the final cemented casing as a result of normal liquid storage operations.

The purpose of the heavier wall casing at the bottom of the 8-5/8” string is to have a compatible set of hanging casing strings (13-3/8” and 8-5/8”) that sonar caliper tools may be able to survey through. An intermediate sonar survey will be completed to determine if the hanging casing strings area compatible. In the event that the hanging casings strings are incompatible, then a workover to pull the strings will be required in order to obtain a cavern survey that meets the requirements of the UIC Permit.

Table 1: Summary of Casings for Magnum Gas Storage Well				
Casing String	**Size – inches**	**Weight – pounds/foot**	**Grade**	**Depth – feet**
Conductor	36	282.35	X-52	0 – 150
Surface	30"	234.29	X-56	0 - 750
Intermediate	24"	156.17	X-52	0 – 950
Intermediate	24"	245.64	X-52	950 – 3,100
Intermediate **Final cemented depth 3,300 feet**	24"	303.7	X-52	3,100 – 3,300
First Salt	20"	129.33	X-52	0 – 1,500
First Salt **Final cemented depth 3,500 feet**	20"	202.92	X-52	1,500 – 3,500
Production (2nd Salt)	16"	97	N-80	0 – 2,400
Production (2nd Salt) **Final cemented depth 3,600 feet**	16"	109	P-110	2,400 – 3,600
Outer Mining String	13-3/8"	72	N-80	0 – 4,300
Inner Mining String	8-5/8"	32	K-55	0 – 3,950
Inner Mining String	8-5/8"	44	N-80	3,950 – 4,950

The typical casing design for the Magnum NGLs cavern wells is summarized in Table 1 and shown in Figure 3. In the event that these casing and pipe sizes are not available, the next higher grade or increased wall thickness should be chosen. The safety factors for the various loading scenarios are summarized in Table 2.

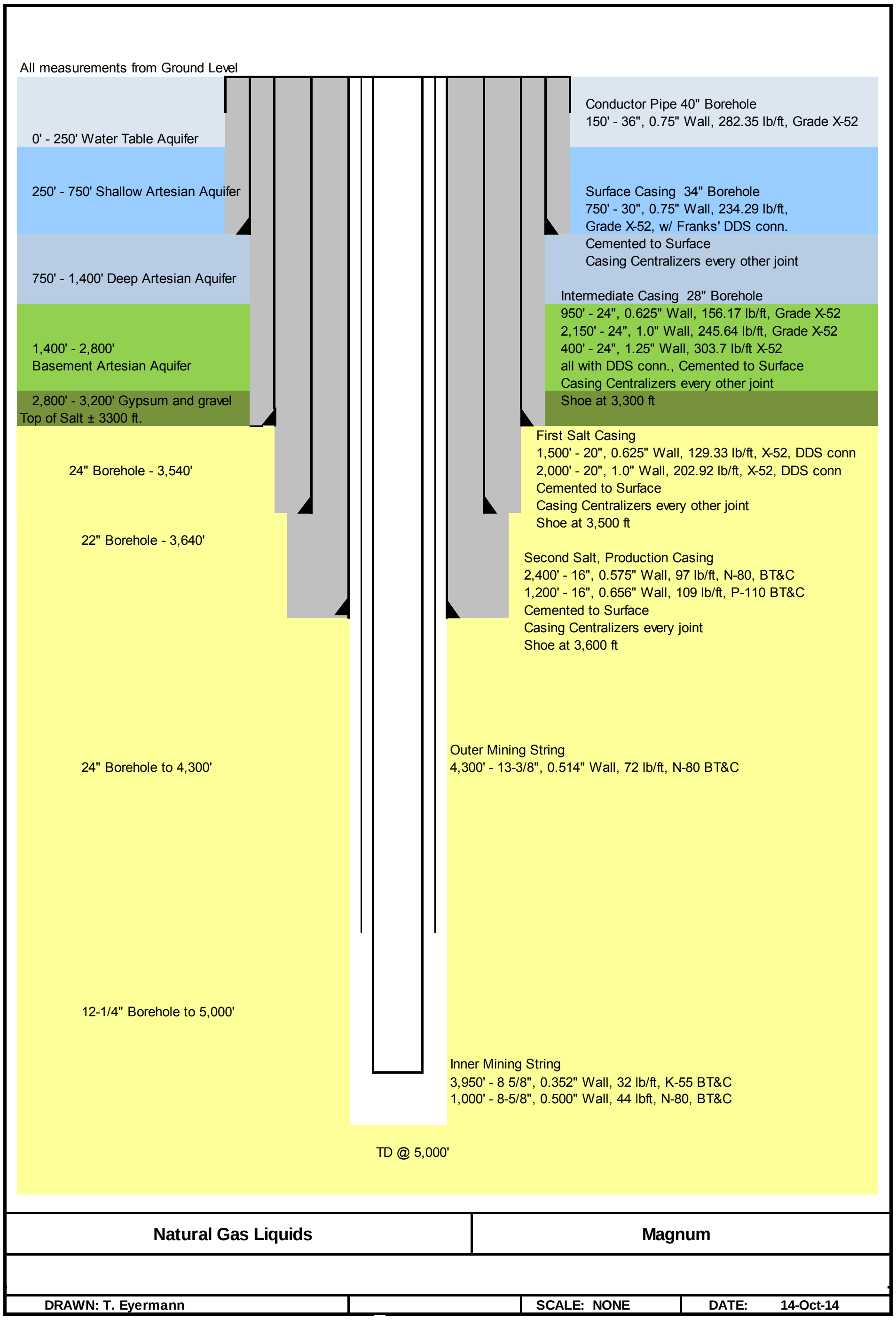


Figure 3: General Cavern Well Schematic

Table 2: Summary of Calculated Factors of Safety			
Casing String	Safety Factor		
	Collapse – 1.1	Burst – 1.2	Tensile – 1.6
36-inch Conductor	N/A	N/A	N/A
30-inch Surface	5.03	3.91	18.20
24-inch Intermediate	1.13	5.06	2.52
24-inch Intermediate	1.10	2.31	6.38
24-inch Intermediate	1.20	1.82	N/A
20-inch First Salt String	1.14	4.91	3.30
20-inch First Salt String	1.53	1.98	N/A
16-inch Production (2nd Salt String)	1.12	3.88	4.02
16-inch Production (2nd Salt String)	1.14	4.04	N/A
13-3/8-inch Outer Mining String	1.19	1.84	5.46
8-5/8-inch Inner Mining String	1.23	1.91	4.05
8-5/8-inch Inner Mining String	3.24	3.14	N/A

2.2 Casing Design Calculations

2.2.1 Conductor Pipe

36-inch, wall thickness 1-inch, grade X-52, plain end, welded pipe from 0 feet to approximately 150 feet. Pipe is to be cemented in an open hole.

2.2.2 Surface Casing

30-Inch, 234.29 lb/ft, wall thickness 0.75-inch, grade X-56 pipe, with Frank's DDS connections from 0 feet to 750 feet.

2.2.2.1 *Collapse Calculations*

Assume that the bottom hole depth of the 30-inch surface casing is at ±750 feet from surface, with a welded float shoe located at the bottom of the casing string. The worst-case scenario for collapse pressure would be a full column of cement in the casing/hole annulus, and a column of gas inside the 30-inch surface casing.

1. (750 feet) (0.052 psi/ft) (15.6 lb/gal cement) = 608 psi hydrostatic pressure exerted on the exterior of the 30-inch casing, at 750 feet.
2. 0 psi hydrostatic pressure is exerted on the interior of the 30-inch casing, at 750 feet.
3. Differential pressure, (collapse pressure) annulus pressure verses pressure inside the 30-inch casing equals: 608 psi – 0 psi = 608 psi.

The 30-inch surface casing has a collapse rating of 898 psi. According to the above differential calculations, the proposed 30-inch surface casing to be used has a collapse rating of 1,631 psi, greater than any outside pressure that will be exerted against the exterior of the casing.

2.2.2.2 *Burst Calculations*

Assume that the bottom hole depth of the 30-inch surface casing is at ±750 feet from surface, with a welded float shoe located at the bottom of the casing string. The 30-inch surface casing will be loaded with 9.5 lb per gallon drilling mud. The worst case for burst is if the float shoe becomes stuck closed and a gas blowout occurs at the shoe. In this case there would be a column of gas outside of the casing and a full column of drilling mud inside the casing.

1. (750 feet) (0.052 psi/ft/lb/gal) (9.5 lb/gal drilling mud) = 371 psi hydrostatic pressure exerted on the interior of the 30-inch casing, at 750 feet.
2. Differential pressure, (burst pressure) inside pressure verses annulus pressure on the outside of the 30-inch casing equals: 371 psi – 0 psi = 371 psi.

According to API Bulletin 5L the 30-inch surface casing has a minimum test pressure of 2,100 psi. According to the above differential calculations, the proposed 30-inch surface casing to be used has a minimum test pressure greater than any inside pressure that will be exerted against the interior of the casing.

2.2.2.3 *Tensile Calculations*

The proposed 30-inch surface casing weighs 234.29 lb/ft and will be set at approximately 750 feet, for a total string weight of 175,717.5 lbs.

The 30-inch, welded surface casing proposed has a tensile rating of 3,584,000 lbs, which is greater than tensile weight exerted by the weight of the casing.

2.2.3 Intermediate String Casing

24-inch, 156.17 lb/ft, Wall Thickness 0.625-inch, X-52 Grade, Plain end fitted with threaded connections from 0 feet to 950 feet

24-inch, 245.64 lb/ft, Wall Thickness 1.0-inch, X-52 Grade, Plain end fitted with threaded connections from 950 feet to 3,100 feet

24-inch, 303.70 lb/ft, Wall Thickness 1.25-inch, X-52 Grade, Plain end fitted with threaded connections from 3,100 feet to 3,300 feet

2.2.3.1 *Collapse Calculations*

Assume that the bottom hole depth of the 24-inch 303.7lb/ft casing (pipe) at ±3,300 feet from surface, with a welded float shoe located at the bottom of the casing string. The worst-case scenario for collapse pressure would be a full column of cement in the casing/hole annulus, and an empty column inside the 24-inch surface casing.

1. (950 feet) (0.052 psi/ft/lb/gal) (15.6 lb/gal cement) = 771 psi hydrostatic pressure exerted on the exterior of the 24-inch casing, at 950 feet.

1a. (3,100 feet) (0.052 psi/ft/lb/gal) (15.6 lb/gal cement) = 2,515 psi hydrostatic pressure exerted on the exterior of the 24-inch casing, at 3,100 feet.

1b (3,300 feet) (0.052 psi/ft/lb/gal) (15.6 lb/gal cement) = 2,677 psi hydrostatic pressure exerted on the exterior of the 24-inch casing, at 3,300 feet.

2. Differential pressure, (collapse pressure) annulus pressure verses pressure inside the 24-inch casing at 1,600 feet equals: 771 psi – 0 psi = 771 psi.

2a. Differential pressure, (collapse pressure) annulus pressure verses pressure inside the 24-inch casing at 3,100 feet equals: 2,515 psi – 0 psi = 2,515 psi.

2b. Differential pressure, (collapse pressure) annulus pressure verses pressure inside the 24-inch casing at 3,300 feet equals: 2,677 psi – 0 psi = 2,677 psi.

According to Frank's 2008, the 24-inch outer string casing at 950 feet has a collapse rating of 874 psi, at 3,100 feet the collapse rating is 2,761 psi and at 3,300 feet a collapse rating of 3,213 psi. According to the above differential Calculations, the proposed 24-inch outer string casing to be used has a collapse rating greater than any outside pressure that will be exerted against the exterior of the casing.

2.2.3.2 *Burst Calculations*

Assume that the bottom hole depth of the 24-inch surface casing is at ±3,300 feet from surface, with a welded float shoe located at the bottom of the casing string. The 24-inch surface casing will be loaded with 10.2 lb per gallon drilling mud. The actual cement process will be down drill pipe, which will be stung into the float shoe at 3,300 feet so that the casing is not filled with cement. The worst case for burst is if the float shoe becomes stuck closed and a gas blowout occurs at the shoe. In this case there would be a column of gas outside the outside of the casing and a full column of drilling mud inside the casing.

1. (950 feet) (0.052 psi/ft/lb/gal) (10.2 lb/gal drilling mud) = 504 psi hydrostatic pressure exerted on the interior of the 24-inch casing, at 950 feet.

1a. (3,100 feet) (0.052 psi/ft/lb/gal) (10.2 lb/gal drilling mud) = 1,644 psi hydrostatic pressure exerted on the interior of the 24-inch casing, at 3,100 feet.

1b (3,300 feet) (0.052 psi/ft/lb/gal) (10.2 lb/gal drilling mud) = 1,750 psi hydrostatic pressure exerted on the interior of the 24-inch casing, at 3,300 feet.

2. Differential pressure, (burst pressure) inside pressure verses annulus pressure on the outside of the 24-inch casing at 950 feet equals: 504 psi – 0 psi = 504 psi

2a. Differential pressure, (burst pressure) inside pressure verses annulus pressure on the outside of the 24-inch casing at 3,100 feet equals: 1,644 psi – 0 psi = 1,644 psi

2b. Differential pressure, (burst pressure) inside pressure verses annulus pressure on the outside of the 24-inch casing at 3,300 feet equals: 1,750 psi – 0 psi = 1,750 psi

According to Frank's, the 24-inch outer sting casing has a minimum burst pressure of 3,281 psi above 950 feet, 4,375 psi between 950 feet and 3,100 feet and 3,190 psi for the deeper segment of the string. According to the above differential calculations, the proposed 24-inch surface casing to be used has a minimum test pressure greater than any inside pressure that will be exerted against the interior of the casing.

2.2.3.3 *Tensile Calculations*

The proposed 24-inch outer string casing weighs 156.17 lb/ft, 245.64 lb/ft and 303.70 lb/ft and will be set at approximately 3,300 feet, for a total string weight of 737,228 lbs.

The proposed 24-inch, welded intermediate casing has a tensile rating of 1,856,000 lbs, which is greater than tensile weight exerted by the casing.

2.2.4 First Salt String Casing

20-Inch, 129.33 lb/ft, wall thickness 0.625-inch, grade X-52pipe, DDS connection, Casing from 0 to 1,500 feet.

20-Inch, 202.92 lb/ft, wall thickness 1.0-inch, grade X-56 pipe, DDS connection from 1,500 to 3,500 feet.

2.2.4.1 *Collapse Calculations*

Assume that the bottom hole depth of the 20-inch first salt string of casing is at ±3500 feet from surface, with a float shoe located at the bottom of the casing string. The casing string will be made up of two weights of casing.

Above 1,500 feet the casing will be 129.33 lb/ft X-52 casing. From 1,500 feet to 3,500 feet the casing will be 202.92 lb/ft X-52 casing. This string will have proprietary connections on the entire string. The worst-case scenario for collapse pressure would be a full column of cement in the casing/hole annulus, and an empty inside the 20-inch surface casing.

1. (1,500 feet) (0.052 psi/ft/lb/gal) (16.3 lb/gal cement) = 1,271 psi hydrostatic pressure exerted on the exterior of the 20-inch casing, at 1,500 feet.

1a. (3,500 feet) (0.052 psi/ft/lb/gal) (16.3 lb/gal cement) = 2,967 psi hydrostatic pressure exerted on the exterior of the 20-inch casing, at 3,500 feet.

2. At 1,500 feet, the differential pressure equals: 1,271 psi – 0 psi = 1,271 psi. According to API, the 20-inch 129.33-lb/ft casing has a collapse rating of 1,445 psi. According to the above differential calculations, the proposed 20-inch first salt string casing to be used has a collapse rating greater than any outside pressure that will be exerted against the exterior of the casing.

2a. At 3,500 feet, the differential pressure equals: 2,967 psi – 0 psi = 2,967 psi. The 20-inch 202.92 lb/ft pipe has a collapse rating of 4,550 psi according to Frank's. According to the above differential calculations, the proposed 20-inch first salt string casing to be used has a collapse rating greater than any outside pressure that will be exerted against the exterior of the casing.

2.2.4.2 *Burst Calculations*

Assume that the bottom hole depth of the 20-inch surface casing is at ±3,500 feet from surface, with a welded float shoe located at the bottom of the casing string. The 20-inch surface casing will be loaded with 10.2 lb per gallon drilling mud. The actual cement process will be down drill pipe, which will be stung into the float shoe at 3,500 feet so the casing will not be filled with cement. The worst case for burst considerations would be if there was a gas blowout in the salt after the casing was set but before it was cemented. This could potentially leave a column of gas along the outside of the casing and a full column of drilling mud inside the casing.

1. (1,500 feet) (0.052 psi/ft/lb/gal) (10.2 lb/gal drilling mud) = 796 psi hydrostatic pressure exerted on the interior of the 20-inch casing, at 1,500 feet.

1a. (3,500 feet) (0.052 psi/ft/lb/gal) (10.2 lb/gal drilling mud) = 1,856 psi hydrostatic pressure exerted on the interior of the 20-inch casing, at 3,500 feet.

2. Differential pressure (burst pressure), inside pressure verses annulus pressure on the outside of the 20-inch casing equals: 796 psi – 0 psi = 796 psi.
2. Differential pressure (burst pressure), inside pressure verses annulus pressure on the outside of the 20-inch casing equals: 1,856 psi – 0 psi = 1,856 psi.

The 20-inch pipe has a minimum burst pressure of 3,904 psi above 1,500 feet and 3,675 psi for the deeper segment of the string. According to the above differential calculations, the proposed 20-inch surface casing to be used has a minimum test pressure greater than any inside pressure that will be exerted against the interior of the casing.

2.2.4.3 *Tensile Calculations*

The 20-inch surface casing proposed weighs 129.33 lb/ft set at 1,500 feet and 202.92 lb/ft set at approximately 3,500 feet, for a total string weight of 599,835 lbs.

Franks provides a tensile strength for the DSS connection on the casing at the top of the string of 1,978,000 pounds; which exceeds the above-calculated weight of the 20-inch casing.

2.2.5 Production String Casing

16-inch, 97 lb/ft, grade N-80 pipe, wall thickness 0.575-inch, buttress connection, casing from 0 to 2,400 feet.

16-inch, 109 lb/ft, grade P-110 pipe, wall thickness 0.656-inch, buttress connection, casing from 2,400 to 3,600 feet.

2.2.5.1 *Collapse Calculations*

Assume that the bottom hole depth of the 16-inch production string of casing is at ±3,600 feet from surface, with a welded float shoe located at the bottom of the casing string. This string will have buttress connections. The worst-case scenario for collapse pressure would be a full column of cement in the casing/hole annulus, and gas (from a blowout) inside the 16-inch surface casing.

1. (2,400 feet) (0.052 psi/ft/lb/gal) (16.3 lb/gal cement) = 2,034 psi hydrostatic pressure exerted on the exterior of the 16-inch casing, at 2,400 feet.

1a. (3,600 feet) (0.052 psi/ft/lb/gal) (16.3 lb/gal cement) = 3,051 psi hydrostatic pressure exerted on the exterior of the 16-inch casing, at 3,600 feet.

2. Differential pressure, collapse pressure, annulus pressure verses pressure inside the 16-inch casing equals: 2,034 psi – 0 psi = 2,034 psi.

2a. Differential pressure, collapse pressure, annulus pressure verses pressure inside the 16-inch casing equals: 3,051 psi – 0 psi = 3,051 psi.

According to API, the 16-inch N-80 97 lb/ft casing has a collapse rating of 2,270 psi and the 16-inch P-110, 109-lb/ft casing has a collapse rating of 3,470 psi. According to the above differential calculations, the proposed 16-inch casing to be used has a collapse rating greater than any outside pressure that will be exerted against the exterior of the casing.

2.2.5.2 *Burst Calculations*

Assume that the bottom hole depth of the 16-inch surface casing is at ±3,600 feet from surface, with a welded float shoe located at the bottom of the casing string. The 16-inch surface casing will be loaded with 10.2 lb per gallon drilling mud. The actual cement process will be down drill pipe, which will be stung into the float shoe at 3,600 feet so the inside of the casing will not be filled with cement. The worst case for burst considerations would be if there was a gas blowout in the salt after the casing was set but before it was cemented. This could potentially leave a column of gas along the outside of the casing.

1. (2,400 feet) (0.052 psi/ft/lb/gal) (10.4 lb/gal drilling mud) = 1,298 psi hydrostatic pressure exerted on the interior of the 16-inch casing, at 2,400 feet.

1a. (3,600 feet) (0.052 psi/ft/lb/gal) (10.4 lb/gal drilling mud) = 1,947 psi hydrostatic pressure exerted on the interior of the 16-inch casing, at 3,600 feet.

2. Differential pressure (burst pressure), inside pressure verses annulus pressure on the outside of the 16-inch casing equals: 1,298 psi – 0 psi = 1,298 psi. The 16-inch casing above 2,400 feet has a minimum test pressure of 5,030 psi. According to the above differential calculations, the proposed 16-inch surface casing to be used has a minimum test pressure greater than any inside pressure that will be exerted against the interior of the casing.

2a. Differential pressure (burst pressure), inside pressure verses annulus pressure on the outside of the 16-inch casing equals: 1,947 psi – 0 psi = 1,947 psi. According to API, the 16-inch casing has a minimum test pressure of 7,870 psi. According to the above differential calculations, the proposed 16-inch surface casing to be used has a minimum test pressure greater than any inside pressure that will be exerted against the interior of the casing.

3. During mining operations, the 16” casing annulus will be filled with nitrogen used as a blanket during mining operations. At the surface, the maximum gas pressure will be about 1,872 psi / (e ^ (0.00003347 * 0.58 * depth) = 1,770 psi. The wellhead gas pressure is below the rated burst pressure of 5,030 psi of the 16” casing at the surface.

2.2.5.3 *Tensile Calculations*

The 16-inch surface casing proposed weighs 97 lb/ft at 2,400 ft. and 109 lb/ft at approximately 3,600 feet, for a total string weight of 472,600 lbs.

The tensile strength for buttress end casing is about 2,229,000 pounds; which exceeds the above-calculated weight of the 16-inch casing.

2.2.6 Outer Mining String

13-3/8-inch, 72 lb/ft, wall thickness 0.514-inch, grade N-80 pipe, buttress connection, casing from 0 to 4,300 feet.

2.2.6.1 *Collapse Calculations*

Assume that the nitrogen roof blanket will be at a depth of ±3,600 feet from surface, the maximum differential pressure exerted against the 13-3/8-inch casing will be at the surface.

The worst-case scenario for collapse pressure would be a column of fluid in the casing (during the first steps of mining) that goes on a vacuum when the well is shut-in and the brine in the cavern continues to dissolve salt; and nitrogen is in the annulus.

1. (3,600 feet) (0.052 psi/ft/lb/gal) (10.0 lb/gal brine) = 1,872 psi hydrostatic pressure exerted on the exterior of the 13-3/8-inch casing, at 3,600 feet. The nitrogen pressure on the outside of the string and the brine pressure in the cavern are balanced at this point.

1a. Pressure outside the 13-3/8-inch at the surface is (nitrogen blanket pressure) / (1.000316 ^ blanket level depth) = 1,872 / (1.0000316 ^ 3600) = 1,770 psi

2. (3,600 feet) (0.052 psi/ft/lb/gal) (10.0 lb/gal brine) = 1,872 psi hydrostatic pressure exerted on the interior of the 13-3/8-inch casing, at 3,600 feet.

2a. Differential pressure, collapse pressure, annulus pressure verses pressure inside the 13-3/8- casing at the surface equals: 1,770 psi – (-100 psi) (vacuum) = 1,870 psi. According to API Bulletin 5C2, the 13-3/8-inch string casing has a collapse rating of 2,670 psi. According to the above differential calculations, the proposed 13-3/8-inch casing to be used has a collapse rating greater than the pressure that will be exerted against the exterior of the casing.

2.2.6.2 *Burst Calculations*

Assume that the bottom hole depth of the 13-3/8-inch surface casing is at ±4,300 feet from surface, with an open end of the hanging casing string. The 13-3/8-inch surface casing will be loaded with water during reverse mining steps. The worst case for burst considerations would be if the nitrogen blanket bled off and the bottom of the 13-3/8-inch tubing was salted into the 16-inch production casing during normal operations with a salt plug at or near the bottom of the 13-3/8” x 8-5/8” annulus. This could potentially leave a column of gas along the outside of the tubing and high-pressure fluid on the inside of the tubing string.

1. 0 psi hydrostatic pressure is exerted on the exterior of the 13-3/8-inch casing, at the 16-inch casing shoe.
2. Pump pressure (Value unknown but assumed) 780 psi exerted on the 13-3/8-inch casing.
3. Fluid pressure at 3,600 feet of (3,600 feet) (0.052 psi/ft/lb/gal) (8.34 lb/gal water) = 1,561 psi exerted on the interior of the 13-3/8-inch casing at 3,600 feet.
4. Differential pressure (burst pressure), inside pressure verses annulus pressure on the outside of the 13-3/8-inch casing equals: 1,561 psi + 780 psi (assumed pump pressure) – 0 psi = 2,341 psi.

According to API Bulletin 5C2, the 13-3/8-inch casing has a minimum test pressure of 5,380 psi. According to the above differential Calculations, the proposed 13-3/8-inch surface casing to be used has a minimum test pressure greater than any inside pressure that will be exerted against the interior of the casing.

2.2.6.3 *Tensile Strength*

The outer hanging casing string 72 lb/ft casing set at 4,300 feet. Based on these depths, the maximum hanging casing string weight will be 309,600 lbs. This is well below the maximum tensile strength at the surface of 1,693,000 lbs.

2.2.7 Inner Mining String

8-5/8-inch, 32 lb/ft, Wall Thickness 0.352-inch, K-55 Grade, Buttress Connection, Casing from 0 to 3,950 feet

8-5/8-inch, 44 lb/ft, Wall Thickness 0.55-inch, N-80 Grade, Buttress Connection, Casing from 3,950 to 4,950 feet.

2.2.7.1 *Burst and Collapse Calculations*

The 8-5/8-inch inner wash hanging casing string has the similar circumstance as the 13-3/8-inch outer hanging casing string, in that the tubing will basically have equal weight of fluids (brine water) on the outside as well as the inside, internal and external pressures will be equal. Therefore, since there will not be any differential pressures exerted externally or internally, burst and collapse calculations are not necessary. The 8-5/8-inch hanging casing string will not have nitrogen acting against it.

2.2.7.2 *Tensile Strength*

The deepest depth for the inner hanging casing string is estimated at approximately 4,950 feet. Based on this depth, the maximum sting weight will be 170,400 lbs. This is well below the maximum tensile 690,000 lbs.

2.2.8 Sources Used for Cavern Well Design

- American Petroleum Institute, Specification for Line Pipe, API Specification 5L.
- American Petroleum Institute, Bulletin on Performance Properties of Casing, Tubing and Drill Pipe, API Specification 5C2.
- American Petroleum Institute, Technical Report on Equations and Calculations for Casing, Tubing and Line Pipe Used as Casing or Tubing; and Performance Properties Tables for Casing and Tubing, API Technical Report 5C3.
- Energy Resource Conservation Board, 2008. Minimum Casing Design Requirements, Directive 010.
- Frank's Casing, 2008, DDS Double Drive Shoulder Connector.

2.3 General Well Construction/Drilling Plan

Cavern wells are drilled from the surface to about eighteen hundred feet into the salt, generally between 3,500 and 4,100 feet bgs. The depths lists are approximate from ground level. Casing lengths, grades and wall thicknesses may change as determined by availability and drilling conditions. The cavern well design, to include the casing specifications and setting depths, conforms to the requirements set forth in the UIC Permit. The typical cavern well design depicted in Figure 3 corresponds to the general well construction /drilling plan presented in this section. The well construction process for the individual cavern wells will be completed per the steps outlined below:

1. Rig up drilling rig.
2. Drill 40” hole for or drive 36” 0.75” wall thickness, 282.35 lb/ft, Grade X-52 conductor pipe to approximately 150 feet.
3. During all drilling of pilot holes, the deviation should be measured at least every 200 feet. The deviation is not to exceed 1.5 °. If the deviation exceeds the tolerance, steps will be taken to correct it. Chip samples will be collected every five feet of drilling. The on-site geologist will log these chip samples but the samples will not be saved.
4. Drill a 17-1/2" hole to ±770 feet and log.
5. Open 17-1/2" hole up to 34" with hole openers as appropriate.
6. Run and cement 750 feet of 30" O.D., 0.75” wall thickness, API 5L Grade X-56 pipe. Centralizers to be placed every other casing section.
7. Allow the cement to set a minimum of 18 hours. Pressure test the casing in accordance with State rules.
8. After the cement sets, cut off the 30" casing and attach appropriate mud piping.
9. Drill a 17-1/2" hole to about 3,300 feet, slightly above top of salt structure estimated to be ± 3,250 feet. Lost circulation may occur over this interval; control as necessary by the use of lost circulation material, cement plugs or drill without returns.
10. Run gamma ray, neutron, density, SP induction and resistivity logs as specified.
11. Open the 17-1/2" hole to 28" with hole openers of increasing size.
12. Run X-Y caliper log.
13. Run and cement ±200 feet of 24: O.D. 1.25” wall thickness, API 5L X-52, 2,150 feet of 24" O.D., 1” wall thickness, API 5L X-52 and 950 feet of 24” O.D. 0.625” wall thickness API 5L X-52 or equivalent threaded and coupled pipe to top of salt structure. *Casing string weight is approximately 737,228 pounds in air.* Use the stab-in cementing method. Centralizers to be placed every other casing section.
14. After the cement sets for 48 hours, pressure test the casing in accordance with State rules.
15. Cut off the 24" casing and connect appropriate mud flow equipment.
16. Drill out cement and shoe with 22” bit.
17. Switch to salt saturated mud after drilling out cement.
18. Drill a 12-1/4” hole to ± 3,650 feet.
19. Run gamma ray, SP induction, neutron and bulk density logs as specified. An experienced salt geologist will review the logs to determine the top of salt.
20. Open the 12-1/4" hole to 24" to about 3,520 feet with hole openers and underreamers of increasing size.
21. Run X-Y caliper log.
22. Run and cement 2,000 feet of 20”, 1.0” wall thickness, X-52, threaded and coupled pipe and 1,500 feet of 20", 0.625" wall thickness, X-52 threaded and coupled pipe. *Casing string weight is approximately 600,000 pounds in air.* Use the stab-in cementing method. Centralizers to be placed on each of the first 10 joints and then every other casing section.
23. Allow the cement to set a minimum of 72 hours.
24. Cut off the 20" casing and weld on a 21-1/4" flange. Nipple up an annular BOP or blind flange for testing. Pressure test the casing in accordance with State rules.

25. Drill out cement, shoe and about 5 feet of formation. Pressure test casing seat in accordance with state regulations.
26. Open the 12-1/4" hole up to 22" to about 3,620 feet using hole openers and underreamers.
27. Run X-Y caliper log.
28. Run and cement 1,200 feet of 16” 0.656" wall thickness, P-110 BT&C API pipe and 2,400 feet of 16" 0.575” wall thickness N-80 casing. Use the stab-in cementing method. Centralizers to be placed every casing joint.
29. Allow the cement to set a minimum of 96 hours. Pressure test the casing in accordance with State rules (R649-3-13 and R649-3-7.4).
30. Install blowout preventer on 16” or 20” casing.
31. Drill out plug and ten feet of salt formation.
32. Pressure test casing shoe in accordance with the State rules and regulations.
33. Drill a 12-1/4” hole to ±5,000 feet.
34. Log cuttings and check for loss of drilling fluid indicating a porous formation is encountered. If so, perform a tightness test over this interval.
35. Run gamma ray, neutron and bulk density logs as specified.
36. If logs indicate a porous zone in the salt section, perform tightness test over the zone.
37. If no gas has been encountered, nipple down BOP.
38. Under ream the 12-1/4” hole to 24” down to a depth of about 4,350 feet.
39. Flush hole with clean brine, approximately 1,100 barrels.
40. Run X-Y caliper log.
41. Run casing inspection, cement evaluation logs in 16” casing from shoe to surface and inclinometer log from total depth to surface..
42. Run in approx. 4,300 feet of 13-3/8” 0.514” wall thickness, 72 lb/ft N-80, BT&C pipe.
43. Install and test the upper wellhead assembly.
44. Run in approx. 3,950 feet of 8-5/8” 0.352” wall thickness, 32 lb/ft, K-55, BT&C pipe and 1,000 feet of 8-5/8”, 0.55” wall thickness, 44 lb/ft, N-80, BT&C casing.
45. Install remainder of wellhead.
46. Rig down and move out rig from location.
47. Clean up location.

2.4 Welding Protocol

1. Lift ring welding and inspection to be performed in accordance with AWS (American Welding Society) D1.1 Structural Welding Code. Perform nondestructive testing (NDT) on the welds using ultrasonic shear wave equipment as specified in AWS D1.1 and interpreted by a NDT Level II or III Certified Technician who is qualified under ASNT CP-189, Standard for Qualification and Certification for Nondestructive Testing Personnel, 2006 Edition and CP-105, ASNT Standard Topical Outlines for Qualification of Nondestructive Testing Personnel, 2006 Edition..

2. Casing double joint welding shall be performed in accordance with API Standard 1104 Welding of Pipelines and Related Facilities. Pipe base material’s carbon equivalency will

be computed from the material composition as written in the Material Test Report (MTR) that is provided when the pipe is purchased. The welding contractor will provide a Welding Procedure Specification (WPS) that matches the base material and Procedure Qualification Report (PQR) and welders who are qualified to the WPS with Welders Qualification Report (WQR). The welding contractor will provide the WQR for each potential welder prior to beginning production welding. The field supervisor will verify that the WQR and welder's photo identification match. Perform nondestructive testing (NDT) on the butt welds using radiography as specified in API Standard 1104 and interpreted by a NDT Level II or III Certified Technician who is qualified under ASNT CP-189, Standard for Qualification and Certification for Nondestructive Testing Personnel, 2006 Edition and CP-105, ASNT Standard Topical Outlines for Qualification of Nondestructive Testing Personnel, 2006 Edition. Each completed girth, butt weld shall be radiograph tested to API Standard 1104 qualifications. The radiograph methods and qualifications shall comply with API Standard 1104 –"Certification of Nondestructive Testing Personnel" and "Acceptance Methods for Nondestructive Testing Personnel".

3. Casing rig welding shall be performed in accordance with API Standard 1104 Welding of Pipelines and Related Facilities. Pipe base material's carbon equivalency will be computed from the material composition as written in the Material Test Report (MTR) that is provided when the pipe is purchased. The welding contractor will provide a Welding Procedure Specification (WPS) that matches the base material and Procedure Qualification Report (PQR) and welders who are qualified to the WPS with Welders Qualification Report (WQR). The welding contractor will provide the WQR for each potential welder prior to beginning production welding. The field supervisor will verify that the WQR and welder's photo identification match. Perform nondestructive testing (NDT) on the butt welds using radiography as specified in API Standard 1104 and interpreted by a NDT Level II or III Certified Technician who is qualified under ASNT CP-189, Standard for Qualification and Certification for Nondestructive Testing Personnel, 2006 Edition and CP-105, ASNT Standard Topical Outlines for Qualification of Nondestructive Testing Personnel, 2006 Edition. Each completed girth, butt weld shall be nondestructively tested to API Standard 1104 qualifications. The test methods and qualifications shall comply with API Standard 1104 "Certification of Nondestructive Testing Personnel" and "Acceptance Methods for Nondestructive Testing Personnel".

2.5 Well Conditioning

Before commencing drilling operations (spudding the well), Magnum will condition the well hole prior to cementing casing. The procedures for drilling mud conditioning will ensure that the drilling mud in the well has been displaced at least one time (circulated bottoms up) after completion of drilling to displace drill cuttings before tripping out the drill string. After running in the casing string to the desired depth, the mud volume will again be circulated bottoms up. This "pre-flush" procedure will ensure that the wellbore is properly conditioned for cementing operations in accordance with recommendations from the cementing contractor. The process will entail the circulation of drilling fluids to sweep cuttings out of the hole and obtain consistent fluid properties as well as adjust the fluid viscosity and density in an attempt to prevent cement channeling through the fluid.

2.6 Cementing Services and Materials Specifications

Magnum will cement the individual casings during the cavern well installation of the Magnum NGLs storage caverns per the UIC Permit requirements. The specification presented in this section covers the requirements to supply cement, equipment and services. A detailed overview of the typical cementing program for the installation of a Magnum NGLs cavern well is provided below. A land rig will be used to complete the process described.

Typical wellbore configuration (Depths RKB):

36" Conductor Pipe: 0 - Approx. 150 feet (Driven or set in 40" hole)
30" Surface Casing: 0 - Approx. 750 feet (Approx. 34" Open Hole)
24" Intermediate Casing: 0 – 3,300 feet (Approx. 28" Open Hole)
20" Next to Last Casing: 0 – 3,500 feet (Approx. 24" Open Hole)
16" Last Cemented Casing: 0 – 3,600 feet (Approx. 22" Open Hole)
Top of Salt: Approx. 3,400 feet

1. Cement specifications for the 30" Surface casing. Cement job will be pumped through a stabbed-in 5-1/2" DP.
   Cement to surface: Class A (Standard) + Defoamer (if deemed necessary)
   Water Ratio 5.2 gals/sack
   Slurry Weight 15.6 lbs/gal.
   Slurry Volume 1.18 cu. ft./sack
   Excess 50% Open Hole Volume (Caliper Available)

2. Cement specifications for the 24" Intermediate. Cement job will be pumped through a stabbed-in 5-1/2" DP.
   Cement to surface: Class A (Standard) + Defoamer (if deemed necessary).
   Water Ratio 5.2 gals/sk
   Slurry Weight 15.6 lbs/gal.
   Slurry Volume 1.18 cu. ft./sack
   Excess 50% Open Hole Volume (Caliper Available)

3. Cement specifications for the 20" Next to Last Casing. Cement job will be pumped through a stabbed-in 5-1/2" DP.
   Cement to surface: Class G (Premium) + 37.2% Salt + Defoamer (as necessary).
   Water Ratio 5.0 gals/sk
   Slurry Weight 16.3 lbs/gal.
   Slurry Volume 1.24 cu. ft./sack
   Excess 30% Open Hole Volume (Caliper Available)

4. Cement specifications for the 16" Last Casing. Cement job will be pumped through a stabbed-in 5-1/2" DP.

Cement to surface: Class G (Premium) + 37.2% Salt + Defoamer (as necessary).
Water Ratio 5.0 gals/sk
Slurry Weight 16.3 lbs/gal.
Slurry Volume 1.24 cu. ft./sack
Excess 30% Open Hole Volume (Caliper Available)

A summary of the typical cementing program for Magnum NGLs well is included in Table 3 below.

Table 3: Typical Cementing Program

Hole Size	**Driven**	**34-inch**	**28-inch**	**24-inch**	**22-inch**
Casing Size	**36-inch**	**30-inch**	**24-inch**	**20-inch**	**16-inch**
Mud Weight Type	N/A	9.5 ppg Fresh Water	10.2 ppg Fresh Water	10.2 ppg Saturated Brine	10.2 ppg Saturated Brine
Slurry Weight	N/A	15.6 ppg Fresh Water	15.6 ppg Fresh Water	16.3 ppg Saturated Brine	16.3 ppg Saturated Brine
Cement Type	N/A	Class A Standard	Class A Standard	Class G Premium	Class G Premium
Cement Yield	N/A	1.18cu ft/sk	1.18 cu ft/sk	1.24 cu ft/sk	1.24 cu ft/sk

Cementing operations will be visually verified at the time of the cementing via the observance of cement rising within the outer well annulus to the surface. The casing cement jobs will also be documented by an affidavit from the cementing company showing the amount and type of cementing materials and the method of placement. Three samples of the cement slurry for each of the salt casings shall be collected in suitable sized and shaped containers so that the hardened cement can be tested for compressive strength. As noted in Section 2.1 above a cement evaluation log will also be completed for each cemented casing after a 72 hour curing period and attaining a compressive strength of 500 psi. The results of these tests will be included in the Well Completion Report.

Section 3

Cavern Development /Solution Mining Plan

3.1 Cavern Development Plan Methodology

The individual solution mining plans for the Magnum NGLs storage caverns are developed using a cavern simulation modeling program, SaltCav3D that simulates mining asymmetrically around the well. The program is based on SalGas, an industry-accepted cavern simulation program developed for the Solution Mining Research Institute. SalGas and SaltCav3D are well suited for modeling development of caverns in massive salt deposits, such as salt domes. The general assumptions used in the Magnum NGLs model are detailed below.

The desired final cavern capacity is 2,000,000 barrels. The final cemented 16" casing is set at about 3400 feet. The hanging strings for mining are 13-3/8" and 8-5/8". The tubular sizes are not important to the mining plan after the first few days of mining. The blanket is initially set at about 3650 feet and is moved upward as mining progresses. The final roof level was placed at 3575 feet depth or about 175 feet below the final cemented casing.

An average insoluble content of 8% with a bulking factor of 1.3 was used in the modeling. The gamma log shows the salt to be somewhat dirty, and chemical analysis performed by Sandia National Laboratories on samples from the MH-1 well core confirmed that the insolubles content is variable, averaging about 9%. Mining of CW-5 indicted that the insoluble content was about 8%. This assumption is not significant as long as the overall insoluble content is less than 12%.

The basic input for the model consists of average radii of the well, the depth of the water injection and brine production strings, the depth of the product level, water injection rates, and duration of mining. If a cavern exhibits a region of abnormal or non-symmetric growth, SaltCav3D cannot fully predict continued growth in such a region until after an initial sonar survey in the anomalous region has been conducted. However, the simulated growth can closely approximate future growth in regions of concern once shape data from a sonar survey of the cavern has been obtained.

As with all numerical models, SaltCav3D does not fully represent the actual salt caverns. This is due to limitations in the equations for flow within the cavern. The limitations in the hydraulic equations result in over-estimation of development near the bottom of the injection tubing in both reverse and direct mining and a corresponding underestimation of mining in the upper portions of the cavern. This limitation becomes more evident at high water injection rates, which were utilized in this study.

For this model, the cavern interval from the chimney to 5,000 feet depth was divided into a series of twenty foot tall cells. The final cemented casing was 16 inches. The inner string was to be 8-

5/8" tubing and the outer string to be 13-3/8" tubing. The casing sizes do not impact the final solution mining plan, although they have some influence on the very early days of mining.

The production flow rate was modeled at 2,500 gpm. A normal dissolution factor of "1" was used for the salt with an assumed cavern brine temperature of 80° F.

3.2 Cavern Development Plan

3.2.1 Solution Mining Schedule

Development of a storage cavern with a 2,000,000-barrel capacity will require approximately 318 days to complete. The "total time" required to develop a cavern includes time for mining, workovers, unknown shutdown times, logging episodes, and mechanical integrity testing at the end. A summary of the total time to develop a Magnum NGLs storage cavern is detailed in Table 4.

Table 4: Summary of Estimated Time to Develop a Typical Magnum NGLs Cavern

Mining Plan	Solution Mining Time (days)	Workover Time (days)	15% Contingency (days)	Sonar, Logging and Blanket Movement Time (days)	Mechanical Integrity Test & Completion Workover Time (days)	Total Time (days)
2,000,000 bbl. Cavern	230	15	35	8	30	318

As described in Table 4, the actual "solution mining time" is only 230 days of the 318 total days required to complete a cavern. Solution mining time represents days when water is injected at 2,500 gpm without interruption for 24 hours. The additional activities included in Table 4 are activities that may or may not be required, such as a workover. A workover is not required at a specific time during the solution mining of a cavern, but it be necessary sometime during mining to repair damaged tubing or to allow a sonar survey to be conducted. In order to create a conservative schedule, time for a workover has been included as well as a number of days for contingency, blanket movements, sonar surveys, and mechanical integrity testing.

Figure 4 shows both the rate of cavern development and the change in brine specific gravity through the development process, to include the change in the flow regime from direct to reverse circulation.

It is anticipated that approximately 19,000,000 barrels of brine will be produced during the development of the 2,000,000 barrel cavern. During mining operations the brine will have a specific gravity of less than 1.18, or about 90% saturation. During filling operations, the displaced brine will be saturated.

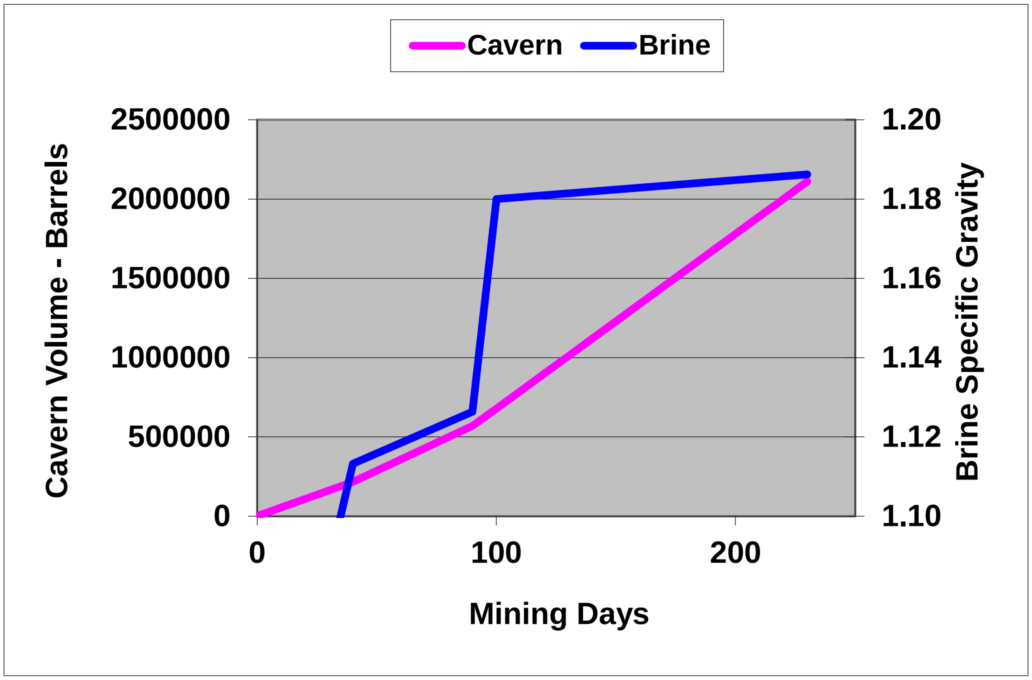


Figure 4: Rate of Cavern Development and Increase in Brine Specific Gravity for 2,000,000 Barrel Cavern

3.2.2 Typical Solution Mining Plan

Mining begins with the inner tubing string set close the bottom of the borehole. The outer string is set at 4,300 feet, about 700 feet above the inner string. The nitrogen blanket is set at about 3,650 feet or about 250 feet below the last cemented casing string. The setting depths for the tubing strings and blanket for a typical Magnum NGLs cavern are shown in Table 5 for all steps of the mining plan.

Mining commences with water injected in the deeper inner string and brine produced from the outer string – direct mining. Mining in this combined sump and chimney stage develops a large sump near the bottom of the cavern for accumulation of the insolubles that will be released from the salt during mining of the salt. This mining also begins development of the chimney where the main cavern will be located. This stage lasts about 50 days as shown in Table 6.

During the sump/chimney stage, the inner tubing may need to be cut one or more times to keep it above the accumulating insoluble pile. Direct mining can generally continue even with the inner string buried in the insoluble pile as long as water injection is maintained. In order to maintain the maximum height of the cavern, the inner tubing should be kept as near to the floor during this stage as is practical.

During the sump/chimney stage, the roof blanket should be monitored about every two weeks to ensure that it remains at the desired depth. Small quantities of nitrogen should be added on a weekly basis until a clear roof at a stable depth has been developed.

Table 5: Setting Depths for Development of Well CW-7 Developed to 2 mmbbls Capacity				
Mining Step	**Injection Setting – Feet**	**Production Setting - Feet**	**Blanket Setting - Feet**	**Insoluble Depth at End of Step– Feet**
Sump/Chimney	5,000	4,300	3,650	4,809
Reverse flow, cut inner tubing, raise blanket, run sonar survey, add nitrogen				
Reverse 1	4,300	4,700	3,625	4,757
Cut inner tubing, raise blanket, possibly run sonar survey, add nitrogen				
Reverse 2	4,300	4,650	3,600	4,701
Cut inner tubing, raise blanket, add nitrogen				
Reverse 3	4,300	4,600	3,575	4,649

At the completion of the sump/chimney stage, a workover is not required to reposition the tubing strings, but the inner string will need to be cut above the insolubles as shown in Table 5. Cavern volume, not elapsed time, is the key indicator for changes in flow and blanket depth to form the cavern roof. Mining is then changed to reverse flow – water injected in the outer, shallower string and brine produced from the deeper, inner string. At the start of reverse mining, the roof blanket should be moved uphole about 100 feet to about 3,500 feet.

Table 6: Duration and Volumes for Development of Magnum NGLs Caverns					
Mining Step	**Step Time – Days**	**Total Mining Time – Days**	**Gross Volume Mined in Step - Barrels**	**Open Cavern Volume – Barrels**	**Cumulative Brine Produced – MMbbls**
Sump/Chimney	90	90	639,000	568,000	7,560,000
Reverse 1	45	135	535,000	1,042,000	11,340,000
Reverse 2	45	180	560,000	1,537,000	15,120,000
Reverse 3	50	230	650,000	2,112,000	19,320,000

Reverse mining continues until completion of the initial mining. The blanket will need to be moved uphole twice during the reverse mining as shown in Table 5. The inner tubing string will probably have to be cut one or two times during mining depending upon the rate of insoluble build-up on the floor of the cavern.

At completion of mining, a workover will be required to remove the mining string and run a sonar survey of the entire cavern including the roof. Sonar surveys of the cavern will include imaging of the cavern floor and cavern roof after each solution mining phase and before commencement and / or recommencement of product storage in accordance with Part III(D)(12) of the UIC Permit. A mechanical integrity test will also need to be conducted before injecting natural gas liquids for storage.

The various steps vary in cavern height and maximum cavern diameter. The cavern height is a function of the amount of mining completed in the sump/chimney stage as compared to the overall volume of the completed cavern and the amount of insolubles in the salt. The maximum diameter and open height of the cavern is listed in Table 7.

Table 7: Parameters for Magnum NGLs Storage Caverns at Completion			
Cavern Storage Capacity – Barrels	**Maximum Diameter – Feet**	**Open Height of Cavern – Feet**	**Open Cavern Volume – Barrels**
2,000,000	198	1,034	2,112,000

As shown in Table 7, not all of the open space in a salt cavern is useable for storage. Some portion at the bottom of the cavern will remain filled with brine because the dewatering string will be set above the floor. This is done to prevent material on the floor from being carried into the dewatering string where it might form a plug, stopping brine flow. Additional space is loss due to the need to keep the brine/product interface above the shoe of the dewatering string to prevent overfilling and resulting hazardous conditions at the surface. A permanent brine pool of about 135,000 barrels remains in the cavern during storage operations.

3.2.3 Allowable Operating Pressure Gradients

Minimum and maximum operating pressures for the cavern well and storage cavern will be maintained at all times during cavern well development. While the typical operating pressure is anticipated to be 0.55 pounds per square inch per foot of depth to the last cemented casing shoe, a minimum allowable operating pressure gradient (MinAOPG) and maximum allowable operating pressure gradient (MaxAOPG) have been established in the UIC Permit. These pressure gradients are based on geomechanical analyses provided to DWQ by Magnum. The pressure gradients that will be maintained at the last cemented casing seat are:

- A MinAOPG of 0.25 pounds per square inch per foot of depth;
- A MaxAOPG of 0.75 pounds per square inch per foot of depth; and,
- A maximum allowable test pressure of 0.85 pounds per square inch per foot of depth.

Based on the geomechanical analysis of the salt formation in which the Magnum NGLs caverns are designed and built, the upper limit of operating pressures is 0.92 pounds per square inch per foot of depth to the last cemented casing shoe. This is well above the MaxAOPG of 0.75 pounds per square inch per foot of depth to the last cemented casing shoe. While the individual maximum operating pressures will differ for each cavern well/storage cavern system due to the individual cavern designs, at no time will the cavern wells or storage caverns be subjected to pressures in excess of the MaxAOPG, including pressure pulsations and abnormal operating conditions.

3.2.4 Cavern Testing

Upon completion of drilling, the well will be tested by a nitrogen/brine interface test. The test pressures will utilize the maximum allowable test pressure of 0.85. The well will be tested again in a similar manner after completion of solution mining (or the initial stage of mining) and before storage of hydrocarbons begins. The detailed procedures for the testing will be provided to DWQ for review and approval before the testing starts.

Section 4

Cavern Capacity Expansion Plan

4.1 Cavern Capacity Expansion Schedule

The schedule for new cavern construction and the initial cavern size of new caverns is heavily dependent upon the demand for storage in the NGLs market. Consequently, caverns may be developed and placed into service with a capacity that is less than the total 2,000,000 barrel permitted capacity. As market demand increases for storage, Magnum plans to complete additional solution mining to increase the capacity of individual storage caverns to the maximum permitted size. After a cavern has been placed into operation, cavern expansion can only be completed during periods of product storage when the caverns are mostly empty. Some product will be left in the cavern to protect the cavern roof.

This section provides an overview of the two methods that are utilized in the salt cavern storage industry to enlarge the caverns. The overview does not provide detailed procedures, just the basic principles. In the event that Magnum would like to expand the capacity of a cavern, a cavern specific Cavern Expansion Plan will be developed that takes into account the size and shape of the cavern when the enlargement is planned to start. Magnum will submit this plan to DWQ for approval and inclusion in the well specific files prior to the initiation of any cavern expansion.

4.2 Cavern Capacity Expansion Options

There are two basic options for expanding capacity or enlarging the storage caverns:

- Using freshwater to displace the product, and
- Conducting “normal” solution mining.

The preferred method for any particular cavern will depend upon the:

- Shape of the existing cavern,
- Configuration of the well (hanging strings, roof, depth),
- Amount of stored product in the well during the enlargement operation, and
- Time frame in which the capacity expansion is to be completed.

<u>4.2.1 Freshwater Displacement</u>

Conceptually the simplest method to expand the capacity of existing storage caverns is through freshwater displacement. Freshwater, instead of brine, is used to displace product when it is removed from the cavern. The freshwater then dissolves more salt. There is no need to change the completion plans for the wells or perform any workover to ready the cavern for mining or to return it to storage configuration. However, the success of this method is dependent upon the:

- Shape of the cavern;

- Spacing to adjacent caverns;
- Time available to complete the enlargement; and,
- Operational mode of product movement.

The shape and size of the cavern to be enlarged and adjacent caverns must be such that a sufficiently strong web will remain between them after enlarging a cavern. The shape and spacing of the cavern must be consistent with the shape that will be developed using freshwater for product displacement.

The time available to enlarge the cavern may impact the feasibility of freshwater displacement for enlargement. The freshwater that can be used to enlarge the cavern is limited in volume to the volume of product displaced. Assuming that the freshwater dissolves sufficient salt to become saturated brine (an assumption that is dependent upon the time between emptying the cavern and then refilling it), the cavern will grow by about 15% of volume of water injected during each cycle.

The operational mode of product movements in the cavern is the principle unknown in developing a safe freshwater enlargement plan. In order to avoid preferential mining of portions of the cavern during the enlargement program, several operational limits need to be adhered to:

- A sufficient pool of brine must exist above the shoe of the hanging string when injecting water,
- An adequate amount of product must be left in the cavern to protect the roof until the cavern brine has become nearly saturated, and
- The product withdrawal time should not be interrupted by numerous or large episodes of product injection.

The brine pool between the end of the hanging string and the product/brine interface should be of a volume and height that allows the injected water to dilute within it and spread the new dissolution over the cavern wall to minimize growth of a wide disk at the injection level. If product has been stored within this safety zone, it should be moved by the injection of brine until the safety pool has been cleared of product.

The roof salt needs to be protected from being dissolved by undersaturated brine. During enlargement by freshwater displacement, freshwater injection needs to be stopped before the roof is exposed, leaving a minimum of 1,500 barrels of product in the well until the cavern p\brine is essentially saturated.

Once enlargement of the cavern has begun, the brine-filled portion of the cavern will be undersaturated. If the enlargement program is interrupted by product injections there is an increased risk of developing overly enlarged diameters as the brine is pushed downward and continues to mine portions of the cavern that have already been enlarged.

4.2.2 Conventional Solution Mining

Enlargement of a well by conventional mining techniques would require that a second hanging string be in the well. If two hanging strings are not in the well, a workover would need to be performed while the well is in storage mode to pull the existing brine string and to reinstall both the outer string and the brine string. A workover would require that all product be removed from the well prior to the workover.

Enlargement would then be accomplished by injecting freshwater in one string and producing brine from the second string. The direction of flow will be determined by the size and shape of the cavern being enlarged and the depth to the product/brine interface.

Attachment E

Monitoring, Recording, and Reporting Plan

Cavern Monitoring, Recording and Reporting Plan

Underground Injection Control Permit
UTU 27-AP-9232389

MAGNUM
NGLs

CAVERN MONITORING, RECORDING
AND REPORTING PLAN
UNDERGROUND INJECTION CONTROL
PERMIT UTU 27-AP-9232389

MAGNUM NGLs, LLC
DELTA, UTAH

December 2014

Table of Contents

Section 1
Introduction

1.1 Purpose of the Plan

This Plan has been developed to outline clear processes and procedures for the monitoring, reporting, and recording activities associated with the development (solution mining) of storage caverns at Magnum NGLs storage facility. The Plan is intended to accompany the Cavern Construction and Development Plan.

The construction (drilling) of storage caverns at the facility is under the jurisdiction of both the Utah Department of Environmental Quality (DEQ), the Division of Water Quality (DWQ), and the Utah Department of Natural Resources (DNR), the Division of Oil, Gas and Mining (DOGM). The development of storage caverns is under the sole jurisdiction of the DWQ. In addition to the UIC Permit, Magnum has also obtained the appropriate permits and authorizations from the necessary federal, state and local agencies.

Magnum has created this Plan, to meet the requirements for the solution mining of salt caverns under DWQ Underground Injection Control (UIC) Permit UTU-27-AP-9232389. This Plan has been reviewed and approved by the DWQ. Any future modifications to this Plan requested by Magnum are subject to approval by DWQ. DWQ may also modify the Plan after it receives new, previously unavailable information or after a review of the Plan. A copy of the Plan will be kept at the facility.

1.2 Facility Location

The Magnum NGLs storage facility is located approximately eight miles north of Delta in Millard County and on lands leased from the Utah School and Institutional Trust Lands Administration (SITLA). The facility address is 9650 North 540 East Delta, Utah 84624. As shown on Figure 1, the facility is situated west of Highway 6 near the intersection of Jones Road and Brush Wellman Road/SR-174.

1.3 Facility Description

The Magnum NGLs storage facility is located on School and Institutional Trust Lands Administration (SITLA) lands over a salt dome that is approximately one mile thick, two miles in diameter and 3,000 feet below the ground surface. Magnum will be solution mining storage caverns within the salt dome for the purpose of storing NGLs such as butane and propane. Figure 1 is a map depicting the storage facility layout as currently constructed and proposed. As shown, the facility consists of three main components that are connected by utilities contained within a central utility corridor. The main components are a Storage Cavern Field, a 152-acre brine evaporation pond, and a truck and rail loading and transfer facility. The utilities between the main components include brine, water, power, and product transfer lines. As currently designed, the facility will be capable of storing 16 million barrels (MMbbls) of NGLs in eight storage caverns with an individual capacity of 2 MMbbls each. The timing of cavern construction is dependent upon market demand.

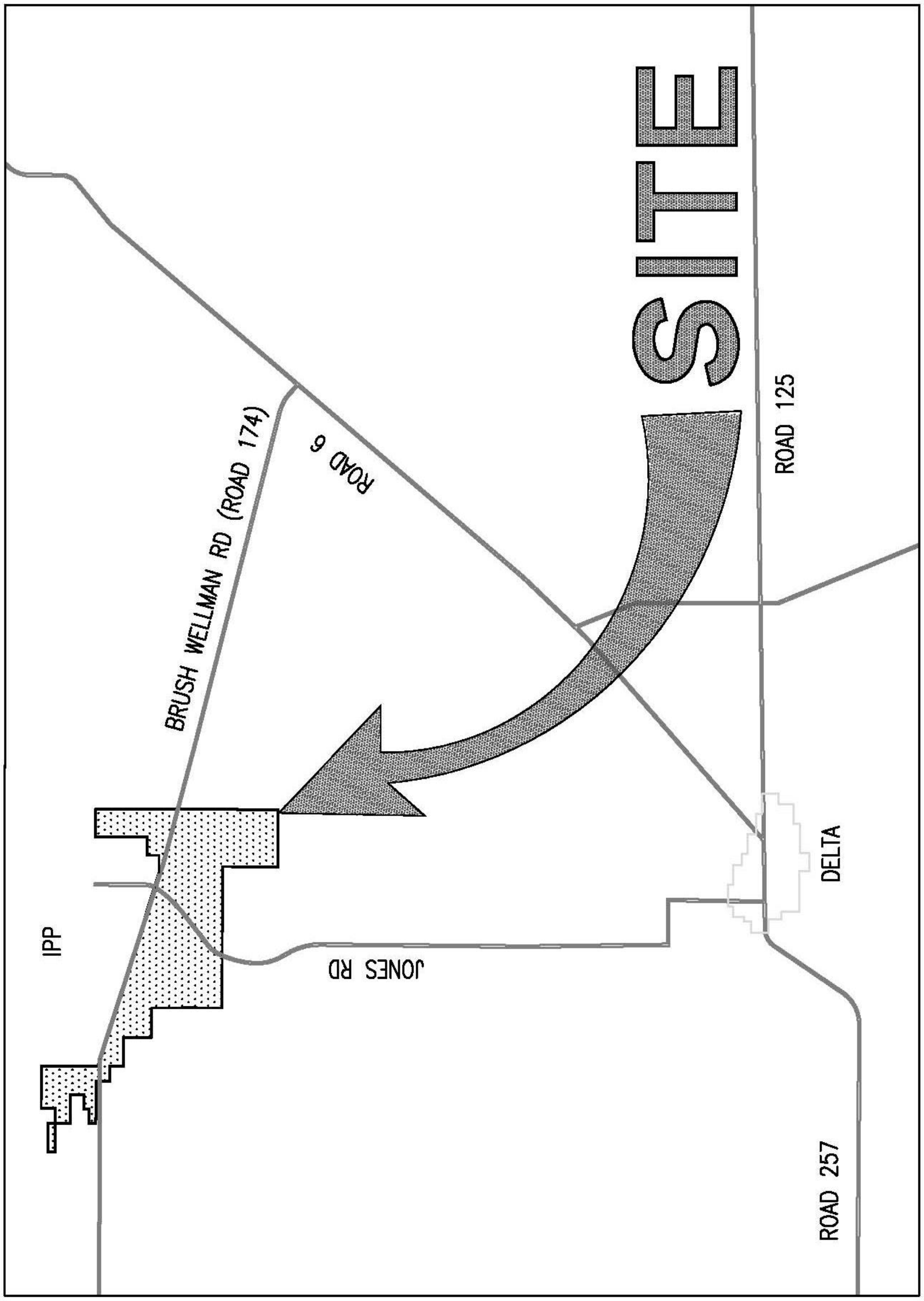


Figure 1: Vicinity Map

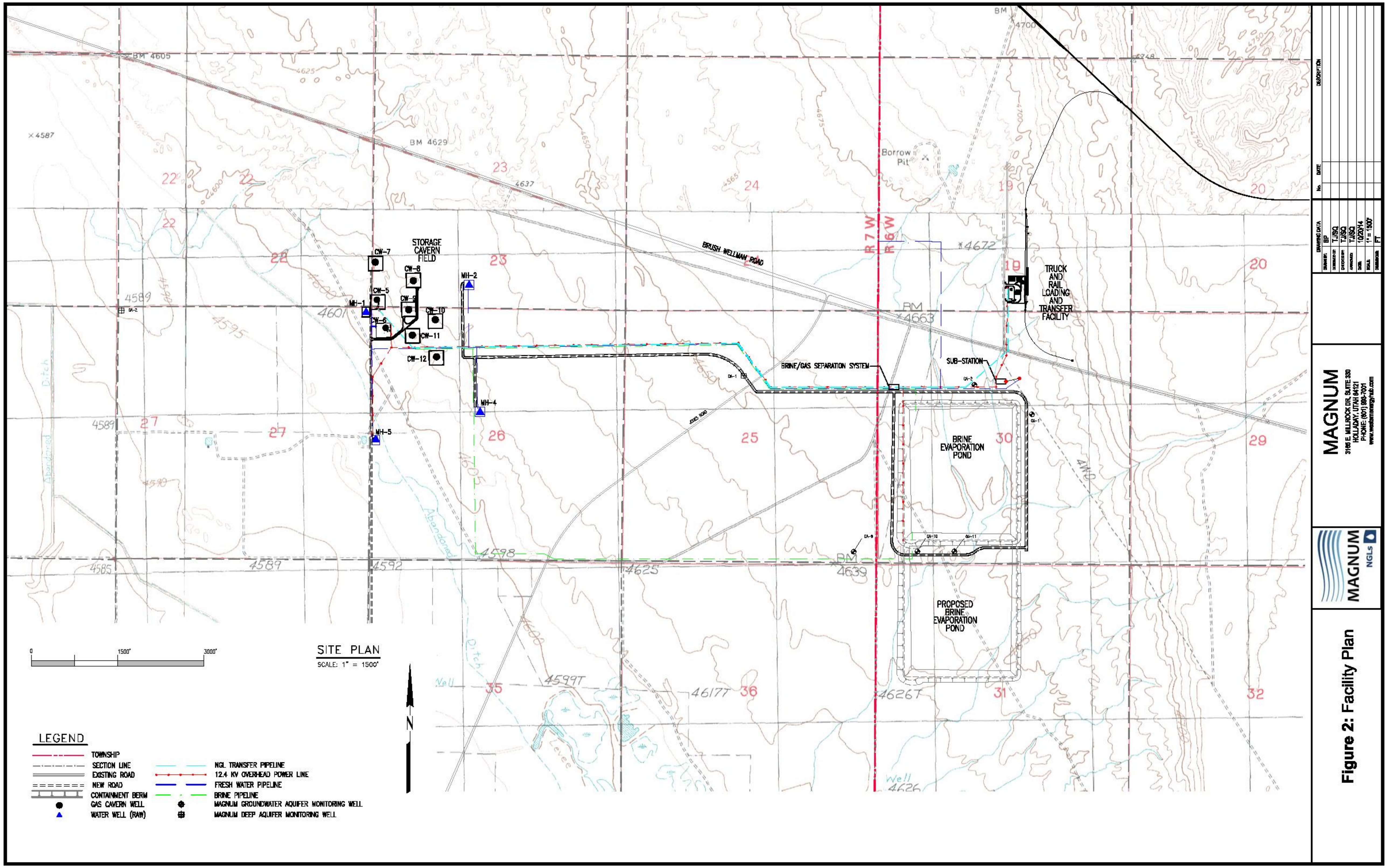


Figure 2: Facility Plan

Section 2

Monitoring and Recording Procedures

2.1 Monitoring Methods and Equipment

2.1.1 Cavern Volume

The cavern volume will be monitored during development so that it does not exceed the permitted capacity of 2 mmbbls. Cavern volume will be monitored on a daily basis and periodically using two methods as a means of independent verification. The daily monitoring method will be completed by recording and calculating the amount of salt mined using the flowmeter data and taking daily measurements of the produced brine specific gravity. The measured data will be used to determine the gross amount of salt mined, the net open cavern space and the ratio of injected water to produced brine. The salinity and temperature of the injected fluid will be monitored on a daily basis as stipulated in the UIC Permit. This monitoring will be completed as follows:

- Specific gravity and temperature will be measured using calibrated hydrometers and thermometers.
- Hydrometers will be calibrated and maintained in accordance with American Society for Testing and Materials (ASTM) standard A126-05a.
- Thermometers will be calibrated and maintained in accordance with ASTM E77-07.

The periodic method for monitoring will be to conduct a sonar survey. This method verifies both the cavern volume and the accuracy of the instrumentation used in the daily monitoring method. The sonar surveys may be made through the mining strings if a signal is obtainable. If needed, a workover will be performed to remove the inner string to allow a sonar survey to be conducted. At the end of solution mining, a workover will be performed to remove both hanging strings, thus allowing a complete survey of the cavern, cavern floor, and cavern roof to be conducted. Sonar surveys of the cavern, cavern floor and cavern roof shall also be conducted after each solution mining phase and before commencement and / or recommencement of product storage in accordance with Part III(D)(12) of the UIC Permit.

2.1.2 Nitrogen Blanket Control

The nitrogen blanket will also be monitored by conducting periodic interface surveys and a daily review of the recorded surface nitrogen pressure. Pressure monitoring of the nitrogen blanket is important. Possible changes in nitrogen pressure due to nitrogen dissolution are small on a daily basis. If relatively large changes in the nitrogen pressure are observed these will generally be related to a major change in the mining activities (rate of mining, direction of mining, depth to the blanket) unless there is a catastrophic loss of blanket. The nitrogen pressure should trend to increasing pressures as the gravity of the produced brine increases.

There are reasons for slight variations in the nitrogen pressure due to changes in the:

- Specific gravity of the brine,

- Chemistry and temperature of the mining water,
- Depth of the nitrogen blanket as it is adjusted for roof development, and
- Rate of mining.

To ensure that nitrogen remains at the desired level, sufficient nitrogen shall be added to the blanket to replace expected losses due to dissolution into the brine and to replenish the thickness of the blanket as it thins due to covering the expanding roof. The required quantity of nitrogen is estimated to be about 500 SCF per week for the initial six weeks of mining.

Once a roof has developed at the desired depth, after about four weeks of mining, and is verified with a log, a large quantity of nitrogen should be injected into the well to establish a reservoir to account for dissolution and thinning. The needed quantity of nitrogen is on the order of 50,000 SCF. Additional injection of nitrogen may be made after about one month or 150,000 barrels of development, depending upon the specific roof development program for the cavern.

Interface logs should be run in the cavern after each 100,000 barrels of mining, until a distinct cavern roof has been developed at the desired depth. After a clear roof has been developed, interface logging should be done after each 250,000 barrels or two months (whichever is more frequent) of development

2.1.3 Cavern Operating Pressures

Cavern operating pressures will be monitored with pressure gauges and sensors installed on both the product and brine sides of the cavern well wellhead:

- Sensors will be linked to the system programmable logic controller (PLC), which provides the capability of continuous pressure recording.
- Each of the pressure sensors will record the maximum and minimum operating pressures during a 24-hour period.
- Each pressure sensor will record operating pressures at an interval of one (1) hour.

Table 1 provides the typical wellhead pressures during cavern development.

Table 1 - Typical Wellhead Pressures During Cavern Development

Mining Direction	Nitrogen Pressure (psig)	Water Pressure (psig)	Brine Pressure (psig)
Direct – Mining	1800	750	50
Direct – Static	1700	280	30
Reverse – Mining	1850	750	50
Reverse – Static	1700	405	30

Magnum will also monitor the wellheads for leakage with a handheld gas detection meter at least once every eight (8) hours.

2.1.4 Solution Mining Injectate

Monitoring of the injected fluid will be completed on a periodic basis to determine if the composition of the fluid is consistent with the initial characterization analysis. The mining fluid will be analyzed on a monthly basis. The analysis will include, as a minimum, sodium, calcium, potassium, magnesium, chlorides and sulfates.

2.1.5 Produced Brine

Monitoring of the produced brine composition will be completed on a weekly basis to identify zones of highly soluble salts.   The monitoring will include an analysis of the brine for high levels of magnesium and potassium content that may indicate an adjustment in the development process is necessary. The produced brine will be analyzed on a monthly basis. The analysis will include, as a minimum, sodium, calcium, potassium, magnesium, chlorides and sulfates.

Section 3

Mechanical Integrity Testing

As required by the UIC Permit, mechanical integrity tests (MIT) will be completed on all storage caverns in the Storage Cavern Field during cavern well drilling, after the cavern well installation is complete (prior to the start of cavern development), and when cavern development is complete (prior to product storage). MITs will be completed at the maximum allowable testing pressure and all test procedures will use certified gauges and pressure transducers that have been calibrated annually. No storage cavern will be used for product storage if the MIT is determined unsuccessful. Several testing methods will be employed to demonstrate mechanical integrity of both the cavern well and storage cavern. These methods vary depending upon the stage of development of the well or cavern as described below.

3.1 MIT During Cavern Well Drilling/Construction

During construction, the mechanical integrity of each casing string will be demonstrated by a hydraulic pressure test which will be completed after the installation and cementing of each casing string. The pressure tests of the casing strings including the final cemented 16" casing will be completed in accordance with state rules R649-3-13 and R649-3-7.4 to ensure that the casing have no leaks. The tests will be conducted after cementing the strings and before drilling out the cement shoe. Magnum will perform the hydrostatic pressure tests before drilling out any casing string 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.

After drilling out the cement plug and drilling about 20 feet of salt below the casing shoe, a hydraulic pressure test of casing seat and cement in 16-inch production casing will be run. The surface test pressure will be 70% of the lithostatic pressure as calculated at the casing seat minus the hydrostatic pressure of the test fluid, or about 1,000 psi. The tests will last at least 30 minutes. The tests will be considered good if the pressure loss is less than 5%.

3.2 MIT of Completed Cavern Well and Storage Cavern

Prior to initiating solution mining and again at the completion of any cavern development and / or solution mining before the commencement and / or recommencement of product storage, the cavern will be tested using the nitrogen/brine interface mechanical integrity technique in accordance with Part III(H) and (D)(12) of the UIC Permit. Magnum can also request approval from the DWQ to use an alternate method for demonstrating mechanical integrity. The test pressure at the shoe of the 16-inch cemented casing will be about 0.75 psi per foot of depth, or about 0.23

psi per foot greater that the normal operating pressure (0.52 psi per foot of depth) to ensure that the casing and cement are not leaking.

The nitrogen/brine interface mechanical integrity test technique essentially involves pressuring the well, and cavern after mining, to the desired test pressure, and injecting nitrogen in the outer annulus of the well (the space between the cemented 16-inch casing and the hanging 13-3/8-inch tubing) to a depth of about 50 to 100 feet below the casing shoe.

The well will then be shut-in for 24 to 48 hours to allow the nitrogen temperature to equalize with the in-situ temperature. The initial depth of the nitrogen/brine interface below the casing shoe and the temperature of the wellbore will then be measured with a wireline tool. After a period of time, not less than 24 hours, determined by the size of the borehole below the casing shoe, a second interface and temperature survey will be run. The pressure at the wellhead will be monitored and recorded continuously during testing.

The change in the calculated volume of the nitrogen between the two interface measurements will be determined from the surface nitrogen pressure, the well temperature logs and the change in the level of the nitrogen/brine interface. The change in the nitrogen volume will then be converted to an equivalent fluid loss.

The temperature stabilization period, the duration of the test and the desired depth of the initial nitrogen/brine interface level will be determined from logs run during and after well construction. The selection of these features will be made so as to ensure that the test has a minimum detectable leak rate (test sensitivity) of no more than 1,000 barrels per year of nitrogen. An acceptable test will be a demonstration that the calculated leak rate is less than the minimum detectable leak rate.

The calculated leak rate and minimum detectable leak rate will be determined by the method specified by DWQ Guidance UIC-3-14 or an equivalent industry utilized method that sums and integrates temperature and pressure changes that impact nitrogen volumes over short vertical intervals to determine total quantity of nitrogen in the well at the beginning and end of each test. The nitrogen volume is determined by:

$$V_{N_2} = N_{scf} \times \sum_{i}^{N} \frac{\left[\left(P_{WB}\right)_i \times 144 \times \left(V_{WB}\right)_i \right]}{\left[\left(Z_{AVE}\right)_i \times R \times \left(T_{AVE}\right)_i \right]} \qquad (0\text{-}1)$$

where:

V_{N_2} = volume of nitrogen measured in the wellbore over a specific depth interval "i" (scf)

$\left(P_{WB}\right)_i$ = average calculated wellbore pressure over a specific depth interval "i" (psia)

$(V_{WB})_i$ = volume of wellbore of a specific depth interval "i" (ft^3)[1]

$(Z_{AVE})_i$ = gas compressibility factor at a specific depth interval[2] "i" (dimensionless)

R = specific gas constant $\left[55.16\left((\text{ft} \times \text{lb}_f)/(\text{lb mol} \times {}^\circ\text{R})\right)\right]$

$(T_{AVE})_i$ = average wellbore temperature over a specific depth interval "i" (°R)

N_{scf} = gas conversion for mass to volume at standard pressure and temperature conditions (13.8 scf_{N2} = 1 lb_{N2})

$i = 1, 2, \ldots N$, N = total number of depth intervals.

The calculated leak rate is the slope of the nitrogen volume versus time data.

The Minimum Detectable Leak Rate is estimated as:

$$\text{MDLR} = 3 \times \left[\frac{V_{N_2}\left(P + \sigma_P, T - \sigma_T, D + \Delta D\right) - V_{N_2}\left(P - \sigma_P, T + \sigma_T, D - \Delta D\right)}{\Delta t} \right] \tag{0-2}$$

where:

σ_P = standard deviation in pressure measurement bias

σ_T = standard deviation in temperature measurement bias

ΔD = accuracy of interface measurement

Δt = test duration.

All pressure monitoring instruments will be calibrated in accordance with manufacturer's recommendations. Testing will be performed under the supervision of a degreed engineer experienced in salt cavern testing.

3.3 Storage Operations

Following the post-completion mechanical integrity test, the individual storage caverns will be tested periodically using methods and procedures in accordance with requirements set forth by the Division of Oil, Gas and Mining.

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1 NOTE: Determined by wellbore geometry.

2 Compressibility Factor (Z) research developed in NOWSCO Technical Manual, NOWSCO Services, 1980.

Section 4

Agency Reporting

4.1 Reporting Requirement

All reports required by the UIC Permit for compliance or noncompliance with, or any progress reports on, interim and final requirements must be submitted no later than 30 days following each schedule date. The following section details the required reporting.

4.2 Well Completion Report

After completion of construction of a storage well, Magnum will prepare a report describing the well construction and testing prior to initiating solution mining activities. The report will describe the casing and cementing program for the well, including:

- Size and grade of all casing strings,
- Results of internal pressure tests of the cemented casing strings,
- Casing seat test of the final cemented casing in the salt,
- Reports from the cementing contractor showing the type and quantity of cement used for each string of casing.

The report will include copies of the geophysical logs run during drilling of the well with a description of the results. These logs will include a cement evaluation log (where available tools allow) and casing inspection log for the final cemented casing. The results of the initial nitrogen-brine interface test on the completed well will be included in this report.

4.3 Quarterly Monitoring Reporting

Quarterly monitoring reports will be submitted during the solution mining of a storage cavern. The schedule for submittals will be:

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

The reports will include the following data per the UIC Permit:

- Periodic Injectate Characterization
- Daily cavern development monitoring data

- Weekly Brine Analysis
- Wireline logs for all blanket/brine interface confirmations
- Sonar surveys for all cavern shape and configuration verification
- 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.
- Other Required Monitoring

4.4 Mechanical Integrity Reporting

Tests determining the mechanical integrity of the well will be conducted during drilling, after completion of drilling, after completion of solution mining, and as required by DOGM during storage operations. In the event solution mining is suspended or prolonged, a mechanical integrity test will be conducted five years after completion of drilling.

These tests will be described in a report detailing the well fluids, pressures, temperatures (where appropriate) and the results of the testing.

4.5 Planned Changes

Magnum will give written notice to the DWQ Director of any planned physical alterations or additions to the UIC-permitted facility. This includes significant changes in the depths of casing strings while drilling, changes in the solution mining plan, or changes in the injectate while mining the cavern.

4.6 Anticipated Noncompliance

Magnum will give advance notice to the DWQ Director of any planned physical changes in the permitted facility or activity that may result in noncompliance with permit requirements. With the notification of anticipated noncompliance, Magnum understands that all permit conditions remain applicable.

4.7 Endangering/Noncompliance Reporting

Magnum will report to the DWQ 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 Magnum becomes aware of the circumstances. Such reports shall include, but not be limited to, the following information:

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

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

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

4.8 Closure and Abandonment Reporting

Should a well need to be closed and abandoned, the procedures used are described in Section 6, Plugging and Abandonment Plan. The results of the closure activities will be described in a report that details condition of the well and cavern at the time of closure and the location and composition of each plug

4.9 Permit Transfers

This permit is not transferable to a new owner or operator except in accordance with Part II (D)(6)(d) of the UIC Permit No. UTU-27-AP-9232389. Magnum shall notify the DWQ 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 the UIC permit.

4.10 Financial Assurance

Magnum has posted the required reclamation bonds with SITLA and DOGM for the drilling, operation, and abandonment of storage caverns at the Magnum NGLs storage facility. These bonds are on file with the respective agencies.

Appendix A

Typical Mechanical Integrity Test Procedure

Appendix A

Typical Mechanical Integrity Test Procedure

1. INTRODUCTION

The purpose of the Mechanical Integrity Test (MIT) procedure is to test the mechanical integrity of the production casing and cement and to ensure that the wellbore below the casing shoe has integrity before beginning mining. In summary, the test procedure consists of the following basic steps.

1.1 Bleeding brine from the well to maintain the pressure at approximately 750 psi.
1.2 Monitoring and recording the cavern pressure for a period of time, minimum 24 hours, until the pressure is decreasing less than 10 psi per day.
1.3 Inject nitrogen to place the interface at about 3460 feet depth.
1.4 Measuring the position of the nitrogen/brine interface and temperature of the nitrogen column at the beginning and end of the test period,
1.5 Recording the brine and nitrogen wellhead pressures throughout the test period, a minimum of 24 hours,
1.6 Determining the calculated leak rate and the minimum detectable leak rate.

2. PREPARATION

2.1 Provide blind flanges and/or double valves to isolate the well during the test. Test flanges with connections that are required for wellhead valves.
2.2 Install pressure-monitoring equipment on both tubing strings and the cemented annulus connections to allow continuous monitoring of wellhead pressures.
  2.2.1 NOTE: Digital pressure recorders and temperature recorders (including logging tools) utilized for the mechanical integrity test shall be calibrated in accordance with manufacturer specifications.
  2.2.2 Calibration papers are to be on location, available for DWQ review.
2.3 Provide a connection to permit injecting brine into or withdrawing brine from the well.

3. BRINE INJECTION AND MONITORING (Only applicable for pre-storage MIT)

3.1 Pressurize the cavern by injecting saturated (or as strong as possible) brine into the hanging string of the subject well. See the MIT Well Data Sheet for the approximate brine wellhead pressure and estimated volume of brine required. *Use of unsaturated brine will result in: 1) increase in time required to stabilize cavern pressures as the unsaturated brine dissolves salt and 2) the need to repressure the cavern multiple times.*

3.2 Measure and record, at approximately fifteen-minute intervals, the volume of fluid injected and the wellhead brine pressure. The rate of pressurization should not exceed 1.5 psi per minute.

3.3 Monitor the final brine wellhead pressures for a minimum of 24 hours or longer until the pressures stabilize at an acceptable level and rate of change. Pressure decline rates shall be less than 10 psi/day before starting the test.

3.4 If the pressure falls below 1000 psi during the period of monitoring, inject additional brine and monitor as in steps 3.1 through 3.3.

4. NITROGEN INJECTION

4.1 Rig up wireline logging unit and install a lubricator on wellhead. Run base interface log (Gamma-Gamma Ray or other suitable log for detecting nitrogen/brine interface) and temperature log. Temperature log should be completed from surface to approximately the end of the 13-3/8" tubing. The base interface log should be completed from the end of the 13-3/8" tubing to 300 feet above the cemented casing shoe.

4.2 Rig up nitrogen pumping unit to inject into the product annulus. Start injecting nitrogen at a slow rate. Control the nitrogen injection temperature as close as possible to the average wellbore temperature measured by the base temperature log.

4.3 Monitor and record nitrogen and brine pressures and flow conditions during injection. The MIT Well Data Sheet lists the appropriate wellhead test pressures. Monitor the differential nitrogen-brine pressure to insure the brine string is not subjected to collapse pressure condition.

4.4 While injecting nitrogen, it may be necessary to bleed off brine to avoid overpressuring the well. After the interface reaches 2,500 feet, regulate the brine flow to maintain the brine pressure specified in Step 2.0 of the Well Data Sheet.

4.5 Find the nitrogen/brine interface with the density tool and track the interface movement down the well by moving the tool down in 100 to 150 feet increments after the nitrogen is at 3,000 feet. Continue tracking the interface until it reaches the desired depth. Record the nitrogen quantity injected for each interval.

4.6 When the interface is at about 3,400 feet, stop nitrogen injection to run a casing test.

4.6.1 An initial log is recorded of the interface in the cemented casing. Nitrogen and brine pressures are recorded. The wellhead and associated piping and connections are checked for leaks and any leaks are repaired.

4.6.2 After a time interval determined by the test conditions, but not less than sixty minutes, a second interface log is recorded of the interface in the cemented casing. Nitrogen and brine pressure are recorded.

4.6.3 If the nitrogen pressure has remained constant and the interface in the cemented casing has not moved, the cemented casing string is considered tight and nitrogen injection resumed.

4.6.4 If the interface in the cemented casing moves up hole and the nitrogen pressure decreases the well head is again checked for leaks and the casing test is extended. This procedure is repeated until the casing is considered tight or a leak is identified.

4.7 Resume nitrogen injection and record the nitrogen volume, pressure and interface depth at each station. Continue tracking the interface until it reaches approximately the planned interface depth about 50 feet below the 16" casing.

4.8 Run a density log to verify the position of the nitrogen/brine interface relative to the 16” casing shoe. Determine total volume of nitrogen injected from original interface location to interface location for the MIT. See MIT Well Data Sheet for planned interface depth and estimated volumes.

4.9 Remove the logging tool from the well and close the logging valve.

4.10 Shut-in well for nitrogen temperature stabilization of at least 18 hours. During the temperature stabilization period, record nitrogen and brine wellhead pressures. Check all wellhead fittings and flanges with liquid soap or equivalent to insure there are no nitrogen leaks.

4.11 Determine the duration of the test using the appropriate test data and following calculation:

$$T = \frac{V \times R \times 365\, days/year \times 24\, hours/day}{100\, bbls/year}$$

Where:

T = Duration of test, 13 hours, with a minimum of 24 hours

V = Unit annular volume of casing, bbls/ft - 0.2964 bbls per linear foot estimated. Actual volume will be determined during nitrogen injection below the casing by injecting known quantity of nitrogen over a measured length of the borehole.

R = Resolution of the interface tool, ft, 0.5 feet

There is an over-riding minimum test period of 24 hours.

5. TEST INITIALIZATION

5.1. After a minimum wait of at least 18 hours rig up wireline logging unit and install lubricator on wellhead. Run initial density and temperature logs. Temperature log should be completed from surface to approximately 100 feet below interface depth. The density log should be completed from 100 feet below to 200 feet above the interface location below the 16” casing.

5.2. Record nitrogen and brine wellhead pressures at least every five minutes during the test.

6. TEST FINALIZATION

6.1. After the planned test duration, a minimum of 24 hours, run the final density and temperature logs. Temperature log should be completed from surface to approximately 100 feet below proposed interface depth. The base density log should be completed from 100 feet below to 200 feet above the proposed interface location below the 16” casing.

6.2. Record nitrogen and brine wellhead pressures.

6.3. If results indicate the test period must be extended, repeat steps 6.1 and 6.2 as required.

6.4. If results indicate the MIT is successful, end test

6.5. If the test indicates the well is leaking, shut-in the well and continue to monitor nitrogen pressures and interface levels to more closely isolate leak location.

7. REPORT ON TEST RESULTS

7.1. Prepare a written report presenting test procedures, results and conclusions, along with a chronology of test activity, wellhead pressure records, and supporting calculations.

7.2. The Minimum Detectable Leak Rate (MDLR) will be calculated with the following formula also described in Section 3.2:

$$\text{MDLR} = 3 \times \left[\frac{V_{N_2}\left(P+\sigma_P, T-\sigma_T, D+\Delta D\right) - V_{N_2}\left(P-\sigma_P, T+\sigma_T, D-\Delta D\right)}{\Delta t} \right]$$

where:

σ_P = standard deviation in pressure measurement bias

σ_T = standard deviation in temperature measurement bias

ΔD = accuracy of interface measurement

Δt = test duration.

7.3 The Calculated Nitrogen Leak Rate will be determined using the following methodology, also described in Section 3.2. In addition to measured quantities, knowledge of the well casing and tubular sizes and previous knowledge of the diameter of the wellbore from the casing shoe to the interface allows the nitrogen volume in the annulus to be calculated. The following *P-V-T* gas equation (which is an approximation to an integral over the axis of the annulus) is used to calculate the volume of nitrogen (at Standard temperature and pressure conditions) in the wellbore at any time during the test:

$$V_{N_2} = N_{scf} \times \sum_{i}^{N} \frac{\left[\left(P_{WB}\right)_i \times 144 \times \left(V_{WB}\right)_i\right]}{\left[\left(Z_{AVE}\right)_i \times R \times \left(T_{AVE}\right)_i\right]}$$

where:

V_{N_2} = volume of nitrogen measured in the wellbore over a specific depth interval "*i*" (scf)

$\left(P_{WB}\right)_i$ = average calculated wellbore pressure over a specific depth interval "*i*" (psia)

$(V_{WB})_i$ = volume of wellbore of a specific depth interval "*i*" (ft^3)[3]

$(Z_{AVE})_i$ = gas compressibility factor at a specific depth interval "*i*" (dimensionless)

R = specific gas constant $\left[55.16\left((\mathrm{ft}\times\mathrm{lb_f})/(\mathrm{lb\ mol}\times{}^\circ\mathrm{R})\right)\right]$

$(T_{AVE})_i$ = average wellbore temperature over a specific depth interval "*i*" (°R)

N_{scf} = gas conversion for mass to volume at standard pressure and temperature conditions (13.8 scf_{N2} = 1 lb_{N2})

$i = 1, 2, \ldots N$, N = total number of depth intervals.

The calculated leak rate is the slope of the nitrogen volume versus time data between the start and end of the nitrogen/brine interface test.

[3] NOTE: Determined by wellbore geometry.

M.I.T. TEST WELL DATA SHEET (TYPICAL)

WELL DESCRIPTION

Name: Magnum Typical

Operator: Magnum NGL Solution Mining

Location Field: Delta

Cemented Casing Size O.D.: 16 inches

Size I.D.: 14.868 inches

Depth: 2,396 feet, measured depth

Weight: 97 lbs/ft

Size I.D.: 14.688 inches

Depth: 2,396 – 3,410 feet, measured depth

Weight: 109 lbs/ft

Hanging String: Size 13-3/8 inches

Depth: 4,100 feet

Total Depth: 4,950 feet (estimated)

TEST PRESSURES

Brine Specific Gravity in 8-5/8”: 1.2 (estimated)

Desired Interface level at Start: 3,460 feet

Test Gradient: 0.75 psi/ft

Casing Shoe Pressure: 2,558 psig

Surface Brine Pressure: 784 psig

ANNULUS VOLUME ESTIMATE

Total Volume to Casing Shoe: 150 bbls (2,396 feet*0.404 bbls/ft + 1,014 feet*0.0375 bbls/ft)

Volume from Casing Shoe to Interface Depth: 15 bbls (50 feet*0.2964 bbls/ft)

NITROGEN VOLUME

Nitrogen Volume to Casing Shoe: 92,000 SCF

Nitrogen Volume Below Casing Shoe: 36,000 SCF

Total Nitrogen Volume Required: 128,000 SCF

CAVERN COMPRESSIBILITY RESPONSE

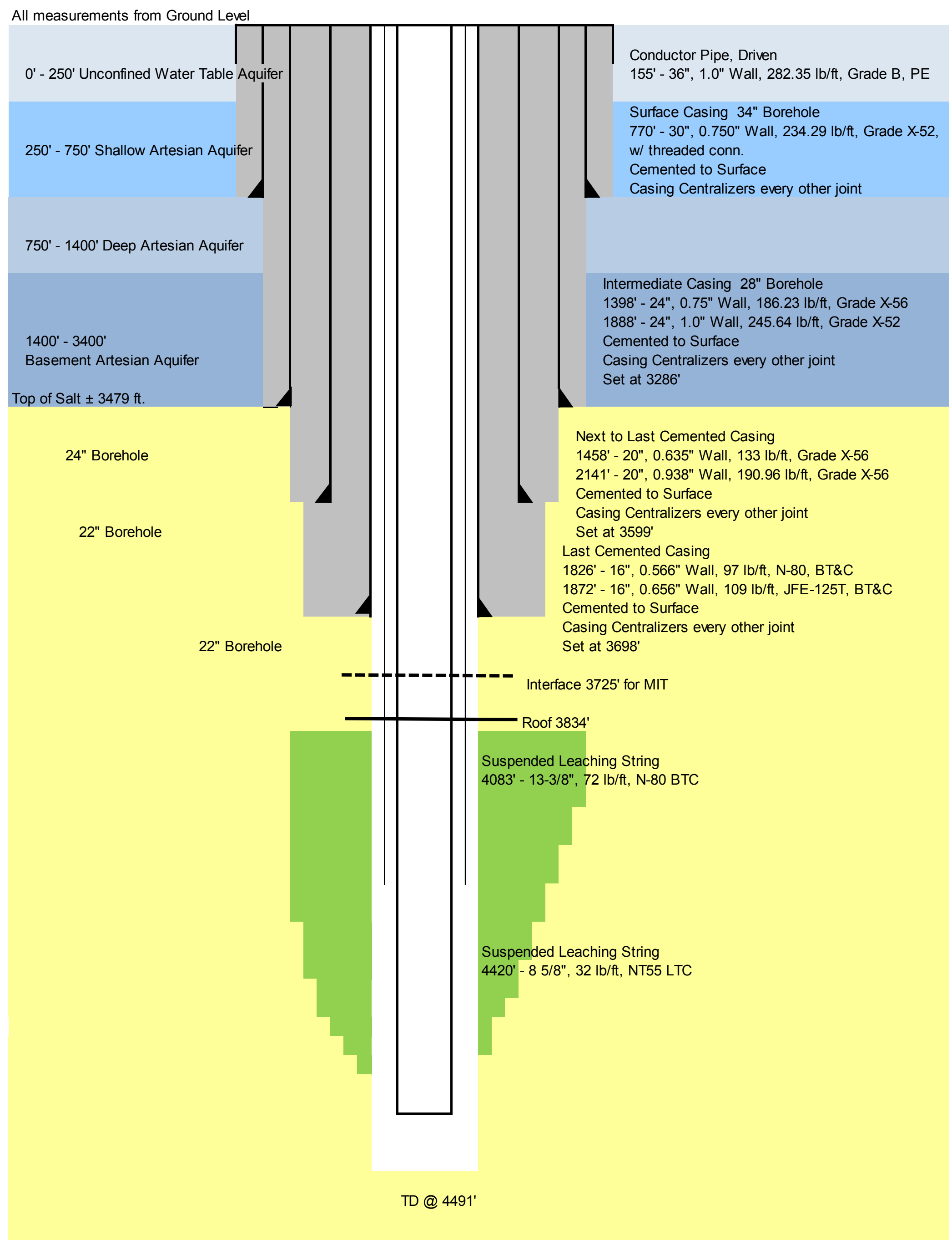
Well Volume: 744 bbls (estimated)

Well Compressibility, estimated: 0.000801 bbls/psi

Wellhead Pressure with Brine, before test: 0 psi

Pressure Increase due to nitrogen injection: over 260000 psi

Brine requirement: -210 bbls (260,000 psi*0 000801 bbls/psi)



Natural Gas Liquids	Magnum

Typical Well Configuration for MIT

DRAWN: T. Eyermann	DATE: 11/5/14	SCALE: NONE	

Appendix B
Reporting

Nitrogen / Brine Interface Mechanical Integrity Test (MIT)
Part I: Casing (Internal) MIT
Part II: Cavern (External) MIT

Guideline #:

UIC-3-14

(February 2014)

Introduction

Operators of all Class III injection wells are required to demonstrate periodically both internal and external mechanical integrity (MI) of the wells. The nitrogen / brine interface test is the industry standard for making this demonstration for solution mined caverns and associated wells for underground hydrocarbon storage. This nitrogen / brine interface test procedure is taken, with permission, from the Kansas Underground Hydrocarbon Storage Unit.

Narrative

The nitrogen/brine interface test is designed to evaluate the internal (well) mechanical integrity and/or the external (cavern) mechanical integrity. The MIT procedure consists of filling the cavern with brine and then injecting nitrogen into the well and establishing an interface at a depth appropriate for either a well or cavern test. The nitrogen test pressure should be equal to the maximum allowable operating pressure (MAOP) gradient based on the casing seat. The interface, temperature and pressure data are used to calculate the pre-test and post-test nitrogen volumes. Comparison of the pre-test and post-test nitrogen volumes and movement of the nitrogen/brine interface are used to evaluate the well/cavern integrity.

Test Procedure Summary

All nitrogen/brine mechanical integrity tests must be conducted by a party that has experience in conducting this type of test due to the complexity of the test and associated safety requirements. The test contractor must have knowledge of: 1) the pressure rating of the well and wellhead components; 2) the use of dead-weight tests or calibrated data loggers to verify brine and nitrogen pressure; 3) methods to track the volume of nitrogen injected before and during the test; 4) differential pressure monitoring to prevent collapse of the tubing; and 5) a working knowledge of other procedural tasks that ensure a viable and safe test.

The permittee is responsible for verifying that the party/company contracted to conduct the mechanical integrity test has experience and is qualified to conduct the test in a safe manner. Failure to follow test procedure and failure to submit supporting data may result in the test being considered invalid by the Utah Division of Water Quality (DWQ). An invalid test will not meet the regulatory requirement.

Submit a test plan as specified in form UIC-3-15 to DWQ for review and approval at least 30 days prior to test commencement. Do not commence test operations until approval for the plan is received from the DWQ.

Test Preparation

- Certify that pressure ratings of the wellhead and the tubulars are adequate for the test pressures.
- Visually inspect the wellhead.
- Ensure fittings are adequate to facilitate wireline equipment, nitrogen injection, and pressure instrumentation. Install an accurate electronic pressure recording system on the well's annulus and brine tubing.
- Remove all product (to the extent feasible) from the cavern prior to conducting the test.
- Note the presence of any product in the annulus.

- Coordinate the test time with DWQ so that DWQ may have the opportunity to witness the test.

Pre-Pressurization (typically for cavern test)

Pre-pressure the cavern with brine prior to nitrogen injection, if necessary. The compressibility of the cavern and the volume of nitrogen to be injected must be considered (estimated) in calculating the pressure required prior to nitrogen injection.

1. Record the volume of fluid injected and the rate of pressurization. The fluid used for pre-pressuring should be saturated brine. The rate of pressurization typically should not exceed 2.5 psi/min. The casing seat pressure is not to exceed the permitted MAOP. The well should be tested at the MAOP.
2. Record the tubing and annulus pressures.
3. Monitor the cavern pressure until the rate of pressure change is 10 psi/day or less. Stabilization period must be a minimum of 24 hours.

Pre-Nitrogen Injection

4. Check with nitrogen supplier for the nitrogen volume required for equipment "cool down".
5. Nitrogen must be measured with a meter. Connect pressure and flow recording equipment to the wellhead so that accurate nitrogen pressure and volume data can be obtained for the test analysis.
6. Prior to nitrogen injection, conduct a temperature survey (base log) from the surface to 50 ft below the expected nitrogen interface for the casing or cavern MIT.
7. Conduct a density survey from 50 feet below the lowest expected nitrogen interface to 50 feet above the uppermost expected nitrogen interface. Note the location of any product present in the annulus. Optimal logging speed for the density log is approximately 15 – 20 ft/min. Subsequent logging runs with the density tool should be at approximately the same speed as the initial logging run for accuracy and correlation purposes.

PART I: CASING (INTERNAL) MECHANICAL INTEGRITY TEST

Nitrogen Injection

8. Inject nitrogen into the annulus between the cemented casing and the hanging string at a constant rate and at (approximately) the same temperature indicated by the temperature log. Measure nitrogen with a nitrogen meter.
9. Position the logging tools at regular depth intervals and record the annulus, brine pressure, nitrogen temperature and time as the nitrogen interface passes.
10. Terminate nitrogen injection when the interface depth is just above the casing seat (if this is the only interval being tested). If multiple intervals are to be tested, test shallow intervals before testing the deep intervals.
11. If a single test interval is used to test the casing, use the following formula to calculate the time required to achieve a minimum detectable leak rate (MDLR), or test sensitivity, of less than 100 barrels of nitrogen per year.

$$T = \frac{V \times R \times 365\ days/year \times 24\ hours/day}{100\ bbls/year}$$

where

T = Duration of test, hours

V = Unit annular volume of casing, bbls/ft

R = Resolution of the interface tool, ft

Note: reference programs or tables and show calculations for converting weight or volume (standard cubic feet - scf) of nitrogen to barrels (bbls) of nitrogen.

The test duration may be shortened if a leak is identified.

A one-hour casing test may be conducted if it is followed by a cavern nitrogen/brine interface test. The minimum test duration for the cavern test is 24 hours.

12. Record the time, nitrogen pressure, tubing pressure and the interface depth. Initialize the test for the calculated test duration.
13. At the end of the test, log the interface depth with the density tool and record the surface pressures. Down-hole movement of the interface may indicate that the test length should be extended.
14. If the nitrogen interface test is being run on the casing only, run a final temperature log.
15. Any up-hole movement of the interface accompanied by a loss in nitrogen pressure indicates nitrogen is being lost from that portion of the casing in contact with the nitrogen. Any interface movement greater than the resolution of the tool should be explained. If a leak is located in the casing above the interface depth, the interface may move up hole to the location of the leak. If multiple leaks are present in the casing, the interface may rise to the location of the greatest leak, however, conclusive determination of the leak location may not be possible.

If the casing test is not followed by a cavern test, calculate the MDLR and the CNLR.

16. Calculate the minimum detectable leak rate (MDLR):

$$MDLR\ (bbls/yr) = \frac{V \times R \times 365\ days/year}{T}$$

where

V = Unit volume of borehole, bbls/ft

R = Resolution of the interface tool, ft

T = Duration of test, days

17. Calculate the nitrogen leak rate (CNLR). Submit supporting data for determination of nitrogen volume (charts, conversion tables, weight measurements, mass-balance calculations accounting for temperature and pressure, source for values used in equation, data from software packages, etc.)

$$CNLR\ (bbls/day) = \frac{1}{T}\left[(VS) - \frac{(PF) \times (VF)}{(PS)}\right]$$

where

$CNLR$ = Calculated nitrogen leak rate, bbls/day

T = Duration of test, days

$VS =$ nitrogen volume at test start (bbls)

$VF =$ nitrogen volume at test finish (bbls)

$PS =$ nitrogen pressure at the test start (psia)

$PF =$ nitrogen pressure at the test finish (psia)

$CNLR\ (bbls/yr) =$ CNLR (bbls/day) X 365 days/year

Pass/fail criteria: The MDLR must be less than 100 barrels of nitrogen per year. The CNLR must be less than the MDLR to demonstrate integrity.

Part II: Cavern (External) Mechanical Integrity Test

1. Resume the nitrogen injection and monitor the interface location with the logging tools. Record the time and surface pressures as the interface crosses the casing seat.

2. Spot the nitrogen below the casing seat and terminate the nitrogen injection.

3. Calculate the initial nitrogen volume at the start of the test. Submit formulas (PVT) and calculations used to determine nitrogen volume. The unit volume of the borehole can be determined from casing and tubing sizes. The open-hole volume below the casing seat may be determined with a sonar survey. Another method for determining the annular or borehole unit volume is as follows:

   Pump a finite volume of nitrogen into the annulus and log the interface.

   Calculate unit volume:

   $$\left[\frac{nitrogen\ (bbls)}{depth(ft)}\right]$$ Nitrogen pumped / change in interface depth

4. Run the post-nitrogen injection density survey to log the nitrogen interface.

5. Record the nitrogen and brine wellhead pressures.

6. Conduct a temperature survey over the test interval.

7. The test length is typically not less than 24 hours. Monitor the brine and nitrogen wellhead pressures during the test period. The test duration should ensure that the leak rate can be resolved with the accuracy of the instrumentation used.

8. At the end of the test, record the final brine and nitrogen wellhead pressures.

9. Run a density survey to determine if the nitrogen interface has moved. Down-hole movement of the interface may indicate that the test length should be extended.

10. Run a final temperature log over the test interval.

11. Calculate the final nitrogen volume. Submit formulas (PVT) and calculations used to determine nitrogen volume. Accurate nitrogen volume is necessary to determine if pressure changes were affected by temperature, salt leaching, salt creep or from volume loss in the cavern system.

12. Calculate the minimum detectable leak rate (MDLR).

$$MDLR\ (bbls/yr) = \frac{V \times R \times 365\ days/year}{T}$$

where

V = Unit volume of borehole, bbls/ft

R = Resolution of the interface tool, ft

T = Duration of test, days

Pass/fail criteria: The MDLR must be less than 1000 barrels of nitrogen per year. The CNLR must be less than the MDLR to demonstrate integrity.

13. Calculate the nitrogen leak rate (CNLR):

$$CNLR\ (bbls/day) = \frac{1}{T}\left[(VS) - \frac{(PF) \times (VF)}{(PS)}\right]$$

where

$CNLR$ = Calculated nitrogen leak rate, bbls/day

T = Duration of test, days

$VS =$ nitrogen volume at test start (bbls)

$VF =$ nitrogen volume at test finish (bbls)

$PS =$ nitrogen pressure at the test start (psia)

$PF =$ nitrogen pressure at the test finish (psia)

$CNLR\ (bbls/yr) =$ CNLR (bbls/day) X 365 days/year

References

Kansas Department of Health and Environment, Bureau of Water, Geology Section, Underground Hydrocarbon Storage Unit http://www.kdheks.gov/uhs/

Mechanical Integrity Test-Nitrogen Interface Method; SMRI Short Course; Spring 1998 Meeting

Goin, Kennith L., 1983, A Plan For Certification and Related Activities For The Department of Energy Strategic Petroleum Reserve Oil Storage Caverns: SPR Geotechnical Division 6257, Sandia National Laboratories, Albuquerque, New Mexico

McDonald, Larry K., Nitrogen Leak-Rate Testing; Subsurface Technology, Inc.: 2003 KDHE/KCC Underground Liquid Hydrocarbon and Natural Gas Cavern Well Technology Fair

Joe Ratigan, PB Energy Storage Services, Inc., Rapid City, South Dakota

Bérest P, Brouard B, Durup G. 2001. Tightness tests in salt-cavern wells. Oil & Gas Science and Technology. 56:451-469.

	Nitrogen / Brine Interface Mechanical Integrity Test (MIT) Plan	Guideline #: UIC-3-15 (February 2014)

Introduction

Operators of all Class III injection wells are required to demonstrate periodically both internal and external mechanical integrity (MI) of the wells. The nitrogen / brine interface test is the industry standard for making this demonstration for solution mined caverns and associated wells for underground hydrocarbon storage. This nitrogen / brine interface test plan template is taken, with permission, from the Kansas Underground Hydrocarbon Storage Unit.

Plan

The nitrogen/brine interface test is designed to evaluate the internal (well) mechanical integrity and/or the external (cavern) mechanical integrity. Submit a test plan to the Utah Division of Water Quality (DWQ) for review and approval at least 30 days prior to test commencement. Use the following format.

Submit a casing schematic. Attachment #:	Depth to salt:
Single casing ☐ Double casing ☐	Depth to casing shoe:
	Depth to cavern:
	Total depth:
Describe roof configuration:	Date of last sonar survey:
Salt roof thickness:	Date of last gamma-density log:
Additional logs or test to be run:	1.
	2.
	3.
Maximum operating pressure (MAOP) and test pressures:	Formulas and calculations:
Proposed changes to field procedure described in form UIC-3-16:	

TEST DESIGN: Estimate nitrogen for cool down: Estimate compressibility: Estimate nitrogen volume for test:	MIT Type: Casing Cavern Casing and Cavern (circle)	
	Interval Depth:	Test Duration:
	1.	
	2.	
	3	
	4.	
Additional Comments:		

Submit final test report in the format specified in form UIC-3-17 to DWQ within 60 days after completion of the test.

References

Kansas Department of Health and Environment, Bureau of Water, Geology Section, Underground Hydrocarbon Storage Unit http://www.kdheks.gov/uhs/

Bérest P, Brouard B, Durup G. 2001. Tightness tests in salt-cavern wells. Oil & Gas Science and Technology. 56:451-469.

	Nitrogen / Brine Interface Test Field Procedure Report	Guideline #: UIC-3-16 (February 2014)

Narrative

The following field procedure report for the nitrogen / brine interface test must be completed and submitted with the final test report (UIC-3-17). This field procedure report template is taken, with permission, from the Kansas Underground Hydrocarbon Storage Unit.

Type of MIT:	Well Casing	Cavern	Well Casing and Cavern	(circle)
Facility:		Well:		

TEST PREPARATION	Date / Time:
Wellhead inspection results: Describe external corrosion, faulty valves, gasket leaks, verification of adequate fittings for wireline equipment and nitrogen injection, installation of accurate electronic pressure instrumentation on tubing and annulus, etc.	
Removal of product	Date / Time:

PRE-PRESSURIZATION	Date / Time:		
Annulus pressure:		Tubing pressure:	
Cavern compressibility:			
Cavern Pressure (P) Stabilization:	P change < 10 psi/day? Yes / No Record P change / day:	Duration of Stabilization Period:	

PRE-NITROGEN INJECTION		
Nitrogen ‘cool down’ volume		
Baseline temperature log (from surface to 50 ft below expected interface)	Date / Time:	Temperature (F):

Baseline Temperature Log logging speed:		
Baseline Density Log (a minimum of 50 ft below the expected interface level or an acceptable depth above the casing seat)	Date / Time:	Interface depth:
		Anomalies (washouts, etc.)
Baseline Density Log logging speed:		

PART I: CASING TEST

Interval Depth	**Nitrogen Pressure**	**Brine Pressure**	**Nitrogen Temperature**	**Time nitrogen interface passed**

Measure nitrogen with a meter. Terminate nitrogen injection when the interface depth is just above the casing seat. If multiple intervals are to be tested, test intervals from shallow to deep.

CASING TEST		
Interval 1		
TEST START	***Time:***	
	Interface depth:	
	Nitrogen pressure:	
	Brine pressure:	

TEST END	***Time:***		
	Length of test:		
Density Log	***Interface depth:***	***Brine pressure:***	***Nitrogen pressure:***
Temperature Log **Interval logged:**	***Time:***		
	Maximum temperature:		
	Average temperature:		
	Surface temperature:		
Comments: Note any interface movement or loss of nitrogen pressure			

CASING TEST			
Interval 2			
TEST START	***Time:***		
	Interface depth:		
	Nitrogen pressure:		
	Brine pressure:		
TEST END	***Time:***		
	Length of test:		
Density Log	***Interface depth:***	***Brine pressure:***	***Nitrogen pressure:***

Temperature Log Interval logged:	***Time:***	
	Maximum temperature:	
	Average temperature:	
	Surface temperature:	
Comments: Note any interface movement or loss of nitrogen pressure		

CASING TEST			
Interval 3			
TEST START	***Time:***		
	Interface depth:		
	Nitrogen pressure:		
	Brine pressure:		
TEST END	***Time:***		
	Length of test:		
Density Log	***Interface depth:***	***Brine pressure:***	***Nitrogen pressure:***
Temperature Log Interval logged:	***Time:***		
	Maximum temperature:		
	Average temperature:		
	Surface temperature:		

Comments: Note any interface movement or loss of nitrogen pressure

PART II: CAVERN TEST

Cavern Test		
Resume nitrogen injection	**Record surface pressures and time the interface crosses the casing seat**	
	Brine pressure:	
	Nitrogen pressure:	
	Time:	
Set interface below the casing and terminate nitrogen injection		
Log interface with density log	**Interface depth:**	
Brine pressure:	**Nitrogen pressure:**	
Temperature log over test interval	**Comments:**	
START TEST		
Calculate initial nitrogen volume at start of test:		
Test period	**Length:**	
Monitor brine and nitrogen pressures during test		
Time:	**Brine:**	**Nitrogen:**
Time:	**Brine:**	**Nitrogen:**
Time:	**Brine:**	**Nitrogen:**
Time:	**Brine:**	**Nitrogen:**
Time – Final:	**Brine:**	**Nitrogen:**
Final Density log:	**Depth:**	
Final Temperature log:	**Comments:**	
Final nitrogen volume:		

Comments:	
Supervised by: (Print name)	
Company/Title:	
Signature:	**Date:**

References

Kansas Department of Health and Environment, Bureau of Water, Geology Section, Underground Hydrocarbon Storage Unit http://www.kdheks.gov/uhs/

Bérest P, Brouard B, Durup G. 2001. Tightness tests in salt-cavern wells. Oil & Gas Science and Technology. 56:451-469.

	Nitrogen / Brine Interface Test Final Report	Guideline #: UIC-3-17 (February 2014)

Narrative

Submit to the Utah Division of Water Quality the final report of the nitrogen / brine interface test following the format below. This final report template is taken, with permission, from the Kansas Underground Hydrocarbon Storage Unit.

Test Results	
Show formula and calculation for MDLR:	Compare MDLR and NLR:
Show formula and calculation for nitrogen leak rate (NLR):	
Explain any interface movement during the test:	
Discuss the relationship of pressure trends to cavern integrity:	
Discuss temperature stability and any accompanying effect on the MIT:	
Discuss pressure changes in adjacent caverns. Attach a chart or a graph.	

Summarize test results:
Submit field procedure report (UIC-3- 16)
Submit all logs.
Submit supporting data, including graphs for stabilization, temperatures, pressures, injection, etc. Submit appropriate charts.
Submit calibration charts for gauges and meters.

References

Kansas Department of Health and Environment, Bureau of Water, Geology Section, Underground Hydrocarbon Storage Unit http://www.kdheks.gov/uhs/

Bérest P, Brouard B, Durup G. 2001. Tightness tests in salt-cavern wells. Oil & Gas Science and Technology. 56:451-469.

Attachment F

Well and Cavern Closure and Abandonment Plan

Plugging and Abandonment Plan

16-Inch Injection Well Plugging and Abandonment Plan

In the event plugging and abandonment of a cavern well is required prior to the completion of a cavern well, the following procedures are provided as a general guideline. Actual plugging measures will be submitted in advance to DWQ for approval.

1. All stored product will be removed and the cavern will be filled with saturated brine water.
2. All free hanging tubing will be pulled from the well.
3. The exact depth to the bottom of the cemented production casing will be determined.
4. A drillable plug capable of supporting a cement plug will be installed in the cemented casing with the bottom of the plug within 10 feet of the end of the casing.
5. The following plugs will be placed. All cement plugs will be Class G cement with no additives and the slurry weight will be 14.5 pounds per gallon or more.
    a. Bottom plug: A 300-foot plug from the plug at the bottom of the production casing upward.
    b. Surface casing plug: A 150-foot plug from 75 feet below the bottom of the surface casing upward.
    c. Top plug: A 75-foot plug from 75 feet below surface grade upward to surface.
6. The casing between each of the plugs shall be filled with a non-corrosive mud slurry of at least 10 pounds per gallon weight.
7. An alternative technique that could be used involves filling the entire wellbore with cement.

Upon completion of the plugging operation, all reports will be filed in accordance with DWQ rules as applicable.

Attachment G

Financial Responsibility