PUBLIC NOTICE DRAFT

UTAH WATER QUALITY BOARD

Major Modification of

CLASS III AREA PERMIT

UNDERGROUND INJECTION CONTROL (UIC) PROGRAM

UIC Permit Number: UTU-27-AP-9232389

Millard County, Utah

Permit Issued to:

Magnum Solution Mining, LLC
(fka Magnum Solutions, LLC)
3165 East Millrock Drive, Suite 330
Salt Lake City, Utah   84121

TABLE OF CONTENTS

Contents .... Page

Contents .... Page

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,

Magnum Solution Mining, LLC (fka Magnum Solutions, LLC)
3165 East Millrock Drive, Suite 330
Salt Lake City, Utah 84121

is hereby authorized to construct and operate six (6) new Class III solution mining injection wells in a Project Area centered approximately at 39 ° 29' 39" latitude 112 ° 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 four (4) natural gas and two (2) natural gas liquid storage caverns in a bedded salt deposit that has been tectonically thickened. According to the Solution Mining Plan (Mining Plan) included as Attachment G-1 of the Technical Report of the permit application, each natural gas storage cavern will have an open volume of approximately 10.5 million barrels corresponding to a gas storage space of 9.8 million barrels and each natural gas liquid storage cavern will have a maximum open volume of approximately 2.1 million barrels corresponding to a natural gas liquid storage space of 2 million barrels . According to the Mining Plan for the natural gas storage caverns, the final cemented casing will be set at a depth of approximately 3,950 feet, within the salt structure, and the roof of the cavern will be established 200 feet below that depth at approximately 4,150 feet. The maximum diameter of each cavern is intended to be 300 feet and the open height approximately 1,000 feet. It is estimated that each cavern will require approximately 2 years for completion. According to the Mining Plan for the natural gas liquid storage caverns, the final cemented casing will be set at least 200 feet into the salt. The roof of the cavern will be established 200 feet below the final cemented casing. The maximum diameter of each cavern is intended to be approximately 200 feet and the open height approximately 575 feet. It is estimated that each cavern will require approximately 1 year for completion.

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:

Beginning at a point N 03° 52' 52" W, 1088.69 feet from the N.W. Corner of Section 26, T. 15 S., R. 7 W. SLB&M; thence S 00° 34' 02" W, 89.86 feet; thence S 22° 12' 15" E, 431.59 feet; thence S 01° 28' 13" W, 815.25 feet to the beginning of a curve to the left having a radius of 4235.14 feet, thence along said curve a distance of 1714.42 feet, through a central angle of 23.19° with a chord bearing and distance of S 23° 22' 25" E, 1702.74 feet; to the beginning of a curve to the left having a radius of 14369.02 feet, thence along said curve a distance of 3938.26 feet, through a central angle of 15.70° with a chord bearing and distance of N 64° 15' 59" E, 3925.94 feet; thence N 67° 27' 17" W, 2974.65 feet; thence N 89° 12' 14" W, 1606.22 feet more or less to Point of Beginning. Said described parcel contains 7,369,561.83 square feet (169.18 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 that this permit becomes effective. The following attachments are incorporated into this permit:

Attachment A ....General Location Map of the Magnum Gas Storage Project, Millard County.

Attachment B ....Map of the Facility Property, Project Area, Area of Review, and Class III Solution Mining Injection Wells

Attachment C ....Technical Report

Attachment D ....Plan for Plugging and Abandonment of Class III Solution Mining Wells and Caverns

Attachment E ....Financial Assurance for Plugging and Abandoning

Attachment F.....Well Construction Plans

Attachment G....Monitoring and Mechanical Integrity Testing (MIT) Protocols

Attachment H....Reporting Tables

This original permit consists of a total of **22** pages plus the above 8 attachments and includes all items listed in the Table of Contents. Further, it is based upon representations made by the permittee and other information contained in the administrative record. **It is the responsibility of the permittee to read and understand all provisions of this permit.**

This permit shall become effective **January ??, 2011**.

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

____
Walter L. Baker, P.E.
Executive Secretary
Utah Water Quality Board

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. 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. 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 by 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.

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 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))

The Executive Secretary may, for cause or upon request from the permittee, modify, revoke and re-issue, or terminate this permit in accordance with UAC R317-7-5.4, R317-7-9.6 (40 CFR 144.39 and 144.40), and R317-7-5.8. Also, the permit is subject to minor modifications for cause as specified in UAC R317-7-9.6 (40 CFR 144.41). The filing of a request for a permit modification, revocation and re-issuance, or termination, or the notification of planned changes, or anticipated noncompliance on the part of the permittee, does not stay the applicability or enforceability of any permit condition.

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 Executive Secretary within a time specified, any information which the Executive Secretary 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 Executive Secretary upon request, copies of records required to be kept by this permit.

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

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

a) Enter upon the permittee's premises where a regulated facility or activity is located or conducted, or where records must be kept under the conditions of this permit;

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

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

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

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

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

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

(1) Calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation and copies of all reports required by this permit, for a period of at least 3 years from the date of the sample, measurement, or report. This period may be extended by request of the Executive Secretary at any time; and
2) Records of all data required to complete the permit application form and technical report for this permit and any supplemental information submitted under UAC R317-7-9.2 for a

period of at least three years from the date the application was signed. This period may be extended by request of the Executive Secretary at any time.

3) The nature and composition of all injected fluids until three years after the completion of any plugging and abandonment procedures specified in Part III of this permit. The Executive Secretary may require the owner or operator to deliver the records to the Executive Secretary 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) A precise description of sampling methodology, sample handling or custody, and all quality assurance methods used;
(4) The date(s) analyses were performed;
(5) The names of individual(s) who performed the analyses;
(6) The analytical techniques or methods used; and
(7) The results of such analyses.

11. <u>Signatory Requirements (40CFR144.51(k))</u>

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

12. <u>Reporting Requirements (40CFR144.51(l))</u>

a) Planned Changes

The permittee shall give written notice to the Executive Secretary, as soon as possible, of any planned physical alterations or additions to the UIC-permitted facility. The UIC-permitted facility includes:

(1) The final pumps that boost fluids into the injection wells, and remove fluids from the extraction well(s).

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

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

(4) Instrumentation and equipment used to measure and control volume, flow rate, and pressure of fluids injected into and extracted from the solution well / cavern system.

b) Anticipated Noncompliance

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

c) Permit Transfers

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

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

Quarter		Report Due On:
lst Quarter	(Jan 1 – March 31)	April 15
2nd Quarter	(April 1 – June 30)	July 15
3rd Quarter	(July 1 – September 30)	October 15
4th Quarter	(October 1 – December 31)	January 15

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 Reporting

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

(1) Twenty-four Hour Reporting

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

(i) Any monitoring or other information that indicates any contaminant may cause an endangerment to 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 Executive Secretary, the permittee shall submit such facts or information within 10 days after becoming aware of the failure to submit relevant facts.

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

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

a) The permittee has submitted notice of completion of construction to the Executive Secretary; and

b) Either of the following:

(1) The Executive Secretary has inspected or otherwise reviewed the new injection well and finds it is in compliance with the conditions of the permit; or

(2) The permittee has not received notice from the Executive Secretary of his or her intent to inspect or otherwise review the new injection well within 13 days of the date the notice in paragraph 13a)(1) of this section, in which case prior inspection or review is waived and the permittee may commence injection. The Executive Secretary shall include in his notice a reasonable time period in which he shall inspect the well.

For new injection wells authorized by an area permit under UAC R317-7-7(C) (40 CFR 144.33(c)), 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 Executive Secretary 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 I and III permit shall include and a Class V permit may 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 Executive Secretary 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 Executive Secretary 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 F of this permit.

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

Requirements for the submittal of a plugging and abandonment report shall be specified in Part III of this permit.

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

a) The owner or operator of a Class I or III well permitted under UAC R317-7 shall establish prior to commencing injection or on a schedule determined by the Executive Secretary, and thereafter maintain mechanical integrity as defined in 40CFR146.8.

b) When the Executive Secretary determines that a Class I or III well lacks mechanical integrity pursuant to 40CFR146.8, he shall give written notice of his determination to the owner or operator. Unless the Executive Secretary requires immediate cessation, the owner or operator shall cease injection into the well within 48 hours of receipt of the Executive Secretary's determination. The Executive Secretary 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 Executive Secretary that the owner or operator has demonstrated mechanical integrity pursuant to 40CFR146.8.

c) The Executive Secretary may allow the owner/operator of a well which lacks 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.

18. Report on Permit Review

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

19. Electronic Reporting

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

20. Penalties for Violations of Permit Conditions (UCA 19-5-115)

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

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 the four natural gas storage caverns and the two natural gas liquid storage caverns, to demonstrate mechanical integrity of the injection well / storage cavern system, and to effect the transfer of control from the Utah Division of Water Quality to the Utah Division of Oil, Gas and Mining for regulatory oversight of the operation and maintenance of the natural gas and natural gas liquid storage facility.

The Executive Secretary shall review this permit once every five (5) years to determine whether it should be modified, revoked and re-issued, terminated, or undergo minor modification according to the requirements of 40CFR144.36, 40CFR144.39, 40CFR144.40, and 40CFR144.41.

B. SCHEDULE OF COMPLIANCE (40CFR144.53)

Magnum 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 as allowed by 40CFR144.40.

1. Financial Responsibility

Magnum shall submit evidence of adequate resources acceptable to the Executive Secretary of the UWQB and the Director of the Division of Oil, Gas and Mining to implement the approved plugging and abandonment plan required by Part II D 15 and Part III F of this permit according to Part III G of this permit.

Magnum shall submit the document referenced in this section before drilling of the wells commences.

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

1. Class III and Natural Gas Storage Construction Standards

Each well and cavern shall be constructed according to the requirements of Class III wells as set forth in R317-7-10.1(B) and 40CFR146.32 and according to those generally held to be construction standards by the underground natural gas storage industry (*Natural Gas Storage in Salt Caverns: A Guide for State Regulators*, IOGCC, 1998 and *Recommended Practice for the Design of Solution-Mined Underground Storage Facilities – API Recommended Practice 1114*, API, July 2007). Additionally, the construction requirements in the approved Application for a Permit to Drill (APD) issued by the Utah Division of Oil, Gas and Mining must be met. The approved well construction plan is included in Attachment F.

2. Casing and Cement

The casing and cement used in the construction of each new well shall prevent the migration of fluids into or between USDWs and shall be designed for the life expectancy of the well.

a) Only new casing shall be installed.

b) 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.

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

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

e) Salt saturated cement shall be used across salt formations.

f) Centralizers shall be used on all cemented casing strings.

g) Boreholes shall be conditioned prior to running cement.

3. Cavern Capacity and Configuration

This permit authorizes the creation of four caverns with a final open volume of 10,500,000 barrels and a gas storage capacity of 9,800,000 barrels. The maximum diameter of each cavern is limited to 300 feet. The top of each cavern will be no less than 200 feet below the casing shoe of the last cemented casing. Communication between caverns shall not be permitted. Changes of cavern capacity greater than 20% will require a major permit modification. Cavern development shall proceed in such a manner as to maintain the mechanical integrity of the pillar between caverns during cavern development and during gas storage.

The original permit is herein modified to authorize the creation of two additional caverns with a final maximum open volume of 2,110,000 barrels and a product storage capacity of 2,000,000 barrels. The maximum diameter of each cavern is limited to 200 feet. The top of each cavern will be no less than 200 feet below the casing shoe of the last cemented casing. Communication between caverns shall not be permitted. Changes of cavern capacity greater than 20% will require a major permit modification. Cavern development shall proceed in such a manner as to maintain the mechanical integrity of the pillar between caverns during cavern development and during gas storage.

4. Solution Mining Blanket

Nitrogen shall be the blanket material used to control development of each cavern. Solution mining under gas (SMUG) is not authorized by this permit.

5. Logging and Testing

The following geophysical logs and tests must be performed during construction and after completion of the Class III injection well / cavern system:

a) Cement Bond Log on surface, all intermediate and production casings after WOC of 72 hours unless an appropriate CBL tool is not available for the larger diameter casings in which case an alternative logging program shall be proposed by the permittee.

b) Casing Inspection Log on innermost cemented casing.

c) Mechanical integrity tests according to Part III H of this permit.

d) Inclination and Directional Surveys starting at 500' taken 500' thereafter.

e) Field checking of welded joints according to the standards prescribed in API Standard 1104, ASME Boiler and Pressure Vessel Code, or other applicable standard.

f) Conduct periodic sonar surveys to monitor the growth of the cavern and upon completion of each well / cavern system.

g) Conduct hydrostatic pressure tests of zones over five (5) feet thick showing a porosity of over 30% on geophysical logs of the salt interval conducted during the drilling of the pilot hole.

D. OPERATION REQUIREMENTS (40CFR146.33 and R317-7-10.2(A))

1. <u>Class III and Natural Gas Storage Operation Standards for Construction Phase</u>

Operation requirements for the drilling and solution mining of each well and cavern shall be those for Class III wells as set forth in R317-7-10.2(A) and 40CFR146.33(a) and those generally held to be standards by the underground natural gas storage industry (*Natural Gas Storage in Salt Caverns: A Guide for State Regulators*, IOGCC, 1998 and *Recommended Practice for the Design of Solution-Mined Underground Storage Facilities – API Recommended Practice 1114,* API, July 2007). Additionally, the operational requirements for the drilling and solution mining of each well and cavern in the approved Application for a Permit to Drill (APD) issued by the Utah Division of Oil, Gas and Mining must be met. Operation and maintenance requirements for gas storage shall be set by the Utah Division of Oil, Gas and Mining once the well / cavern system has been released from the Class III UIC permit.

2. <u>Maximum Allowable Surface Operating Pressure (MASOP)</u>

The injection pressure at the wellhead shall not exceed a maximum value which shall be calculated to assure that the 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 movement of injection or formation fluids into an USDW.

Based on the analysis of the formation tests conducted on the MH-1 exploratory well submitted in the permit application, it was determined that lithostatic pressure is a conservative estimate for the minimum principal stress or the fracture closure pressure. Magnum will provide an additional safeguard against fracture opening or initiation by operating below 90% of the lithostatic pressure at any given depth during cavern creation. Additionally, no allowances will be given for pipe friction. The maximum allowable surface operating pressures for the nitrogen blanket, the brine string and the fresh water string are given in the following table:

Maximum Allowable Surface Operating Pressures (MASOP)	
Casing Seat of Last Cemented Casing (20") – Depth in Ft below ground surface	D
Maximum Allowable Casing Seat Pressure – psi 90% of lithostatic pressure at 1 psi/ft of depth	$0.9 \times \rho_{Lithostatic} \times D$
Maximum Allowable Surface Nitrogen Pressure - psi	3000
Maximum Allowable Surface Fresh Water Pressure - psi	$(0.9 \times \rho_{Lithostatic} \times D) - (\rho_{FreshWater} \times D)$
Maximum Allowable Surface Brine Pressure - psi	$(0.9 \times \rho_{Lithostatic} \times D) - (\rho_{Brine} \times D)$

$\rho_{Lithostatic}$ = psi per foot of depth of overburden = 1.0

$\rho_{FreshWater}$ = psi per foot of depth of fresh water = 0.433

ρ_{Brine} = psi per foot of depth of saturated brine = 0.5195

The MASOPs in the table are based on the assumption that fresh water, with a hydrostatic pressure of 0.433 psi per foot of depth, will be the solution mining medium and the brine produced will be saturated salt (NaCl) brine. If the specific gravity of the solution medium varies significantly from 1.0, the maximum allowable surface operating pressure will be changed also.

3. <u>Maximum Allowable Injection Rate</u>

Under no circumstances shall the injection rate cause the injection pressure to rise above the maximum allowable surface operating pressure.

4. <u>Borehole – Casing Annulus Injection Prohibited</u>

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

5. Minimum Surface Operating Pressure

The permittee shall maintain a minimum operating pressure during the creation of each cavern that is protective of each cavern's integrity.

E. MONITORING, RECORDING, AND REPORTING REQUIREMENTS (40CFR144.54, 40CFR146.33, R317-7-10.3(B), and R317-7-10.4(B))

1. Class III and Natural Gas Storage Monitoring, Recording, and Reporting Standards for Construction Phase

Monitoring, recording, and reporting requirements for the drilling and solution mining of each well and cavern shall be those for Class III wells as set forth in R317-7-10.3(B), R317-7-10.4(B) and 40CFR146.33(b and c) and those generally held to be standards by the underground natural gas storage industry (*Natural Gas Storage in Salt Caverns: A Guide for State Regulators*, IOGCC, 1998 and *Recommended Practice for the Design of Solution-Mined Underground Storage Facilities – API Recommended Practice 1114*, API, July 2007). Additionally, the monitoring, recording, and reporting requirements for the drilling and solution mining of each well and cavern in the approved Application for a Permit to Drill (APD) issued by the Utah Division of Oil, Gas and Mining must be met.

2. Injectate Characterization

The permittee shall submit a full chemical analysis of the injectate plus temperature and specific gravity at commencement of cavern formation. Thereafter, specific gravity and temperature shall be reported on the monthly wash reports submitted in the quarterly reports. Subsequent full chemical analysis will only be required if the specific gravity indicates a markedly different chemistry.

3. Monthly Wash Reports

Monthly solution mining (wash) reports shall be submitted with each quarterly report. They shall include: Specific Gravity, Volume Injected/Extracted, Pressure (mean, maximum, and minimum on injection and extraction lines), Temperature, Average Flow Rate (bbls/day), Cumulative Total (bbls) for both injectate and brine extracted for each day of cavern mining and the Pressure on the Nitrogen Blanket.

4. Mechanical Integrity Testing

Mechanical integrity testing shall be conducted according to Part III H of this permit. Due to the complexities of creating storage caverns in salt, the mechanical integrity tests shall be designed and analyzed by personnel knowledgeable with these tests as applied to natural gas storage facilities.

5. Sonar Surveys

Sonar surveys shall be conducted at least annually to monitor the cavern development and upon completion of each well / cavern system.

6. Monitoring of Nitrogen-Brine Interface

Periodically, during cavern creation the position of the nitrogen – brine interface should be verified with an interface log or similar method. Due to the complexities of creating storage caverns in salt, this periodic monitoring shall be designed and analyzed by personnel knowledgeable with these tests as applied to natural gas and natural gas liquid storage facilities.

7. Tightness Tests

Hydrostatic pressure tests shall be conducted on zones over five (5) feet thick showing a porosity of over 30% on the geophysical logs of the salt interval conducted during the drilling of the pilot hole. Due to the complexities of creating storage caverns in salt, the tightness tests shall be designed and analyzed by personnel knowledgeable with these tests as applied to natural gas and natural gas liquid storage facilities.

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

1. Requirement for Plugging and Abandonment Plan

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

2. Notice of Plugging and Abandonment

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

a) Well Condition Report

The permittee shall provide a report on the current condition of the well in order to update, supplement or complete any information found in the Plan. This report shall discuss in detail and evaluate:

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

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

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

(4) The adequacy of casing cement bonding across the salt formation, as determined from

cement bond logs run at the time of well construction or just prior to well abandonment.

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

b) Individual Plugging and Abandonment Plan

The permittee shall also submit an individual plugging and abandonment plan for each well to be plugged and abandoned. In coordination with the Well Condition Report, this plan shall modify and supersede the Plan, as necessary, to ensure adequate plugging and abandonment of the well.

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

3. <u>Emergency Well Conversion or Plugging and Abandonment</u>

Emergency conversion or abandonment of wells is allowed by this permit, conditional upon the following requirements:

a) The permittee will seek oral approval from the Executive Secretary for emergency well conversion or abandonment no less than 24 hours prior to the emergency action.

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

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

d) Oral or written approval from the Executive Secretary for emergency well conversion or abandonment will not waive or absolve the permittee from its responsibility to comply with the conditions of this permit, including requirements of the Plan.

4. <u>Plugging and Abandonment</u>

The permittee shall plug and abandon the well(s) consistent with 40 CFR 146.10, as provided for in the Plan, and any conditions issued by the Executive Secretary in approval of the individual plugging and abandonment plans required by Part III F(2) of this permit.

5. <u>Plugging and Abandonment ("As-Plugged") Report</u>

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

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

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

6. <u>Inactive or Temporarily Plugged Wells</u>

a) Inactive Wells

After cessation of operation of a well(s) for two years the permittee shall plug and abandon the well(s), unless the permittee requests and receives a variance from this requirement from the Executive Secretary prior to the end of the two year cessation period, based on:

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

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

b) Temporary Plugging of a Well

Temporary plugging of a well shall consist of:

(1) Submittal of a notice of well conversion.

(2) Submittal of a well condition report and an individual plugging plan, for Executive Secretary approval.

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

4) Emplacement of at least 10 feet of salt saturated Class B cement immediately above the bridge plug. This cement and its emplacement shall meet requirements of the Plan and 40 CFR 146.10.

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

c) Temporarily plugged or inactive wells may be reactivated at the discretion of the permittee <u>after</u>:

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

(2) Demonstration of mechanical integrity to the Executive Secretary, as required in Part III H of this permit, and

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

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

1. Demonstration of Financial Responsibility

The permittee is required to maintain financial responsibility and resources to close, plug, and abandon all wells / caverns. Satisfaction of this requirement is demonstrated by submission of Certificates of Deposit or other evidence of financial responsibility acceptable to the Executive Secretary of the UWQB and the Director of the Division of Oil, Gas and Mining to implement the approved plugging and abandonment plan (Attachment D) required by Part II D 15 and Part III F of this permit. Evidence of adequate financial assurance is included in Attachment E of this permit.

2. Renewal of Financial Responsibility

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

3. Alternate Financial Responsibility

The permittee must submit an alternate demonstration of financial responsibility acceptable to the Executive Secretary 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.

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

1. <u>Class III and Natural Gas Storage Mechanical Integrity Standards for Construction Phase</u>

Mechanical integrity testing requirements for each well and cavern prior to gas storage shall be those for Class III wells as set forth in R317-7-10.3(B) and 40CFR146.8 and those generally held to be standards by the underground natural gas storage industry (*Natural Gas Storage in Salt Caverns: A Guide for State Regulators,* IOGCC, 1998 and *Recommended Practice for the Design of Solution-Mined Underground Storage Facilities – API Recommended Practice 1114*, API, July 2007). Additionally, the mechanical integrity requirements for each well and cavern prior to gas storage in the approved Application for a Permit to Drill (APD) issued by the Utah Division of Oil, Gas and Mining 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, <u>and</u>

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

2. <u>Mechanical Integrity Testing (MIT) Methods</u>

The following testing methods shall be employed to demonstrate MI of the well / cavern system:

a) Hydraulic pressure test of the 20" production casing before drilling out the plug (shoe) and after WOC of 72 hours. The test pressure shall be 125% of the anticipated working pressure during gas storage. The test shall last 30 minutes.

b) Hydraulic test of casing seat and cement of 20" production casing after 10 feet of salt is drilled out below casing shoe. The surface test pressure shall be 90% of the lithostatic pressure as calculated at the casing seat minus the hydrostatic pressure of the test fluid. The test shall last 60 minutes.

c) Nitrogen-Brine interface test of the 20" casing and the cavern.

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

The permittee shall prepare a detailed plan to demonstrate MI. Once the plan is approved by the Executive Secretary, it will become a permit condition of this permit and be incorporated as Attachment G. In preparing a plan, which includes MI tests or demonstration methods allowed by the Executive Secretary, the permittee shall apply methods and standards generally accepted in the industry for conducting and evaluating the tests (40CFR146.8(e)).

4. <u>Mechanical Integrity Demonstration Frequency</u>

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

a) Before the solution mining of each cavern;

b) Once every 5 years after the initial demonstration, unless the well / cavern system has been placed into service, within 5 years, as a natural gas storage facility and regulatory oversight authority has been transferred to the Utah Division of Oil, Gas and Mining.

c) After the solution mining of the cavern has been completed and before the well / cavern system has been released from regulatory oversight authority under this permit and transferred to the Utah Division of Oil, Gas and Mining.

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

5. Prohibition Without Demonstration

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

a) Prior demonstration of MI, and

b) Receipt of Executive Secretary written approval of the MI demonstration.

6. Loss of Mechanical Integrity

If the permittee or the Executive Secretary 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) In the event of a mechanical integrity failure which may potentially endanger an USDW, report to the Executive Secretary verbally within 24 hours followed by submission of a written report within 5 days.

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

e) Within 90 days after loss of MI, restore MI or plug and abandon the well in accordance with a plugging and abandonment plan approved by the Executive Secretary.

The permittee may resume operation of the well after demonstration of MI and receiving written approval from the Executive Secretary.

7. Mechanical Integrity Demonstration Requests

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

8. Mechanical Integrity Demonstration Inspections

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

9. Mechanical Integrity Demonstration Reporting

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.

I. ADDITIONAL CONDITIONS (40CFR144.52)

There are no additional conditions placed on this permit.

Attachment A

Magnum Solutions, LLC

Millard County, Utah

Magnum Gas Storage Project

General Location Map

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)

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GENERAL LOCATION MAP

FIGURE 1

03/04

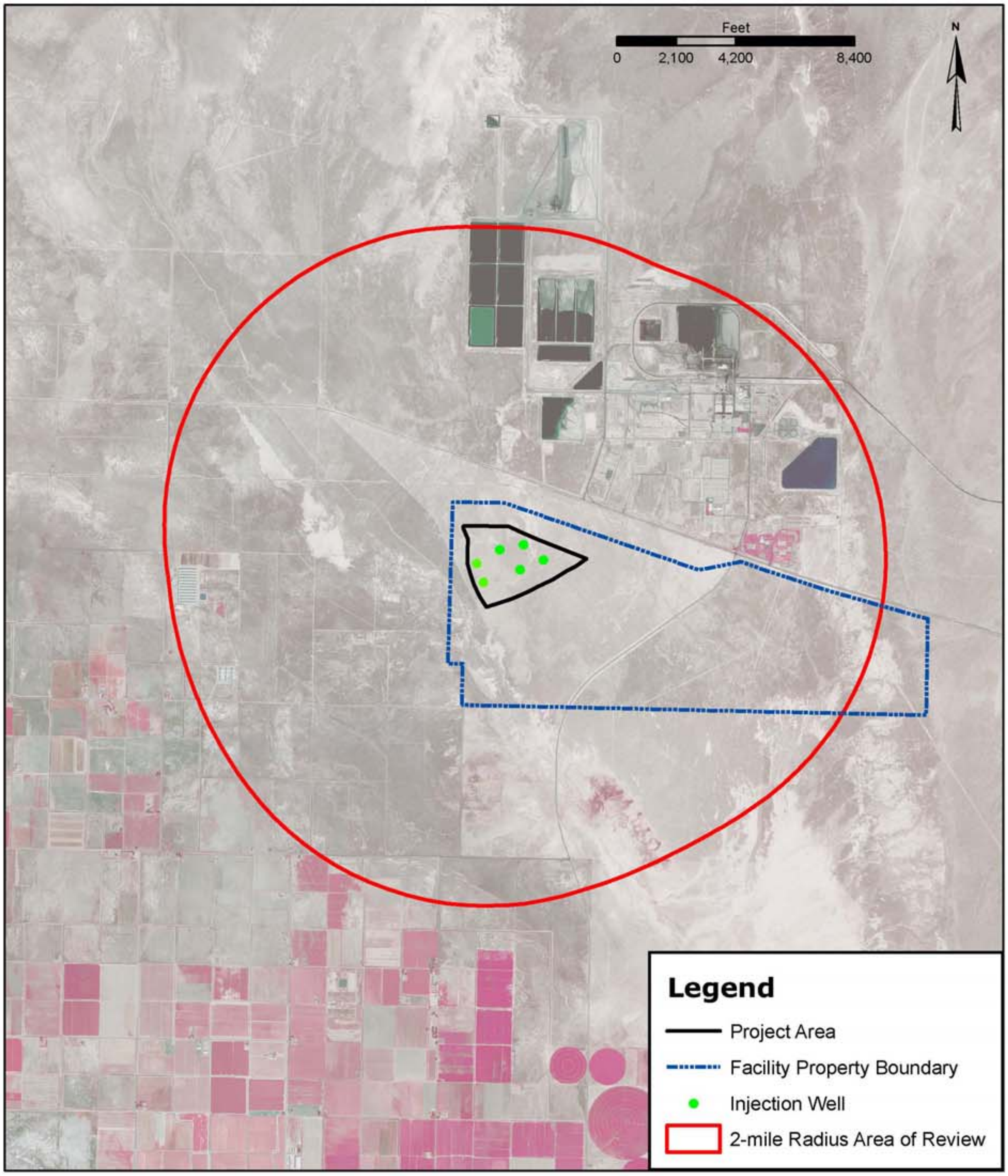
Attachment B

Magnum Solutions, LLC

Millard County, Utah

Magnum Gas Storage Project

**Map of UIC Wells,
UIC Project Area,
UIC Area of Review,
and Property Boundary**



MAGNUM
Enabling Renewables

Project Area, Facility Property Boundary & Area of Review

MAP A-1.1

Attachment C

Magnum Solutions, LLC

Millard County, Utah

Magnum Gas Storage Project

Technical Report

Technical details for the 16" wells for the natural gas liquid storage caverns are presented in the major permit modification application beginning on page 140 of this attachment.

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TECHNICAL REPORT
CLASS III INJECTION WELLS
FOR
MAGNUM SOLUTIONS PROJECT
DELTA, UTAH
May 21, 2010

Updated on October 26, 2010

TABLE OF CONTENTS

TABLES

FIGURES

MAPS

1	General Location Map
A-1.1	Project Area, Facility Property Boundary & Area of Review
B-1.1	Map of Facility and Project Area
B-2.1	Area of Review Map - Domestic Water Rights
B-2.2	Area of Review Map - Irrigation Water Rights
B-2.3	Area of Review Map - Stock Water Rights
B-2.4	Area of Review Map - Other Water Rights
B-2.5	Area of Review Map - Power Water Rights
B-2.6	Area of Review Map - Undefined Water Rights
B-2.7	Area of Review Map - Surface Features

DRAWINGS

B-4.1	Local Geology / Structure – Sub-Surface Projection – 3,000 Feet
B-4.2	Geologic Cross-Section A-A'
B-4.3	Geologic Cross-Section B-B'

ATTACHMENTS

4.1	Stratigraphy and Groundwater of the Lake Bonneville Sediments near the Magnum Holdings #1 Well
C-1.1	Argonaut Well
	Well Schematic
	Monthly Reports
	Sundry Notices and Reports on Wells
C-1.2	Magnum Holdings LLC Exploratory Well MH-1 Data
	Water Right Drilling Approval
	DOGM Permits
	Core Log
	Cuttings Log
	Drillers Report
	Casing Schematic
	Geophysical Logs
	Water Quality
C-1.3	Initial Water Quality and Testing of Well MH-1
	Well MH-1 Start-up, Test Pumping and Evaluation
D-1	Well MH-1 Grouting Isolation
E-1	Part E – Formation Testing
	Hydrofracture Testing at Well MH-1 – Golder Associates, Inc., May 22, 2009
G-1	Proposed Solution Mining Plan for Development of Magnum Gas Storage Caverns at Delta, Utah
G-2	Well Drilling Details
	Underground Front End Engineering Design (FEED) Casing Design
	Well Construction Plan
	Proposed Casing and Cementing Program
	Specifications for Cementing Services and Materials
	Plugging and Abandonment Program
	Drilling Program
	Cavern Well P & ID

ATTACHMENTS – Continued

INTRODUCTION

The Magnum Solutions (Magnum) facility site is located along the south side of Brush-Wellman Road and west of Jones Road approximately 9 miles north of Delta, Utah. Map 1 has been inserted to show the general project location within the State of Utah. As a general note, all attachments to this document are also being provided electronically. The electronic files include Arcview shape files used in the preparation of water right mapping and pdf files of submitted data and reports.

Part A – Determination of Area of Review (AOR)

Per Utah regulation, a fixed radius Area of Review (AOR) of 2 miles around the proposed injection well field area (Project Area) has been used for this application. As noted on Map A-1.1 there are four injection/cavern wells proposed within this application. However, as can be seen from the map, the Project Area encompasses an area larger than that identified by the four individual wells. The Project Area has been defined herein as that area wherein it is projected that injection/cavern wells could be constructed within the salt structure. The area as defined is bounded on the west 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, on the south and east by the downward dip of the salt structure at 3,000 feet, and on the north by buffer zones between existing and potential future power lines and the Project Area (see Map A-1.1).

Based on seismic logging, conditions west and east of the main north-south trending fault vary. West of the fault, sedimentary layers appear to be more broken up and less uniform whereas zones east of the fault show significant uniformity throughout the investigated areas.

The south boundary was identified as the reasonable overlying depth to which storage caverns could be created. Although the salt structure extends farther to the south, this 3,000 foot depth boundary was chosen for this permit to limit the depth to storage caverns.

The northern boundary was fixed based on a desired offset from existing and future high voltage power lines paralleling Brush-Wellman Road.

The proposed Project Area and surrounding 2 mile AOR are shown on Map A-1.1. Note on mapping included herein that two basic project or facility areas may be shown on attached maps. The first area referred to as the "Project Area" includes the injection or cavern creation area, and is the area specific to this permit application. The second area referred to as the "Facility Area" (defined by the facility property boundary) is that area wherein surface support facilities required for the gas storage project will be located. Related surface facilities may include office buildings, maintenance and storage facilities, pumping stations, pipelines, evaporation ponds, power generation facilities, electrical substations and other related facilities.

Descriptions of the Project Area and Facility Property Boundary are as follows. The two mile radius surrounding the Project area was determined using the ArcView computer graphics program.

Project Area: Beginning at a point N 03° 52' 52" W, 1088.69 feet from the N.W. Corner of Section 26, T. 15 S., R. 7 W. SLB&M; thence S 00° 34' 02" W, 89.86

feet; thence S 22° 12' 15" E, 431.59 feet; thence S 01° 28' 13" W, 815.25 feet to the beginning of a curve to the left having a radius of 4235.14 feet, thence along said curve a distance of 1714.42 feet, through a central angle of 23.19° with a chord bearing and distance of S 23° 22' 25" E, 1702.74 feet; to the beginning of a curve to the left having a radius of 14369.02 feet, thence along said curve a distance of 3938.26 feet, through a central angle of 15.70° with a chord bearing and distance of N 64° 15' 59" E, 3925.94 feet; thence N 67° 27' 17" W, 2974.65 feet; thence N 89° 12' 14" W, 1606.22 feet more or less to Point of Beginning. Said described parcel contains 7,369,561.83 square feet (169.18 acres), more or less.

Facility Property Boundary: Beginning at a point N 12° 58' 15" W, 1971.44 feet from the N.W. Corner of Section 26, T. 15 S., R. 7 W. SLB&M; thence S 1° 43' 16" W, 5702.42 feet; thence S 88° 37' 49" E, 523.27 feet; thence S 01° 22' 11" W, 1451.15 feet; thence S 88° 43' 26" E, 16399.18 feet; thence N 00° 54' 18" E, 3403.50 feet; thence N 74° 05' 21" W, 3673.29 feet; thence N 72° 00' 07" W, 2341.60 feet; thence N 72° 00' 06" W, 98.76 feet; thence N 70° 25' 40" W, 779.24 feet; thence S 79° 09' 01" W, 1529.60 feet; thence N 70° 55' 01" W, 7233.33 feet; thence N 89° 10' 00" W, 1840.10 feet more or less to Point of Beginning. Said described parcel contains 90,562,610.70 square feet (2,079.02 acres), more or less.

Part B - Permit Application Maps

1. Map of Facility and Project Area

Map B-1.1 shows USGS 7 ½ minute topography extending a minimum of one mile beyond the Project Area. Per State requirements we have determined that:

1) No existing injection wells or Project Areas are known within 1 mile of the proposed Project Area.
2) No existing facilities, intake structures, or discharge structures are known to exist within 1 mile of the proposed Project Area.
3) No hazardous waste treatment, storage, or disposal facilities are known to exist within 1 mile of the proposed Project Area.
4) No wells where fluids are injected underground are known to exist within 1 mile of the proposed Project Area.
5) A review and summary of Irrigation, industrial or drinking water wells, springs, and other surface water bodies within 1 mile of the Project Area has been completed and added to Map B-1.1. A breakdown of water sources referenced on the map based on the State of Utah Division of Water Rights database is provided in Table B-2.1.
6) No springs have been identified within 1 mile of the proposed Project Area.

2. Map of Area of Review (AOR)

A review and summary of Irrigation, industrial or drinking water wells, springs, and other surface water bodies within 2 miles of the Project Area (Area of Review) has been completed. A breakdown of water sources based on water right use type (as provided by the State of Utah Division of Water Rights database) is provided in Table B-2.1. Each of the water sources are also shown graphically on Maps B-2.1 thru B-2.6 as follows:

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Map B-2.1	Area of Review Map - Domestic Rights
Map B-2.2	Area of Review Map - Irrigation Rights
Map B-2.3	Area of Review Map - Stock Rights
Map B-2.4	Area of Review Map - Other Rights
Map B-2.5	Area of Review Map - Power Rights
Map B-2.6	Area of Review Map - Undefined Rights

Water well information is also shown in part in Table B-3.1, "Information from Selected Wells" and on Figure B-5.1, "Regional Geology Map".

Maps B-2.1 thru B-2.6 and Table B-2.1 show related information as required for wells (including depth, diameter and perforation zones when available) and surface water sources for the project and applicable area:

(i) A search using the State of Utah water rights database was made for abandoned wells located within a 13,200 foot radius (2 ½ miles) around the approximate center of the project site, defined as North 0 feet, East 1320 feet, from the NW cor, Sec 26, T15S, R7W, SLB&M. There are no known existing dry or abandoned wells identified within the defined AOR per the database.

A check of abandoned wells was also completed through the Utah Division of Oil, Gas & Mining website. The only well identified on the database within the AOR is a well referred to as the Argonaut exploratory oil and gas well shown on Figures B-3.1 and B-5.1. As discussed in coordination meetings with the Division of Environmental Quality, although the data has been reviewed, an additional evaluation of data from the Argonaut well has not been completed by Magnum and therefore an full disclosure of available materials for the well is not included within this document. A well schematic and limited construction reports are provided in Part C of this technical report. A complete copy of available information can be obtained directly through the Utah Division of Oil, Gas & Mining database, or will be provided by Magnum on request.

(ii) Producing wells within the AOR are shown on Maps B-2.1 thru B-2.6. In general, the shallow unconfined water table aquifer (discussed more in Part B.3) is found at depths between 0 and 200 feet and is used little due to generally poor water quality conditions. Wells drilled at depths between 200-800 feet are generally used for private, culinary, and irrigation purposes; while wells drilled between 800-1,400 feet are generally used for industrial and or municipal purposes.

(iii) No existing injection wells have been located or are known to exist within the AOR.

(iv) IPP has a non-transient non-community system that includes four well sources associated that is located within the 2-mile area of review as shown on Map B-1.1. Although technically not located within the AOR, the Delta Egg Farm also has a non-transient non-community well just outside the AOR as also shown. The drinking water source protection zones for each of these sources are also identified. The DWSP zones for four IPP wells are located within the eastern portions of the AOR. The DWSP zone for the Delta Egg Farm is projected to extend into the AOR west of the facility.

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(v) No springs, mines (surface or subsurface), quarries or other pertinent surface features, including residences are known to exist within the AOR. During review however DEQ identified three springs for which information was requested based on the high-resolution National Hydrogpaphy Dataset (NHD). As it turns out, two of the three springs identified are actually old stock and/or irrigation wells that appear to have gone un-used for several years. Each is discussed below.

Un-used Well 1. This well is located approximately 1 mile south of the Project Area is associated with irrigation water right 68-317 as shown on Map B-2.7. A visit to the site in the fall of 2009 verified that the well is equipped with a motor and drive shaft that appears to have been used to fill the adjacent pond. There was no evidence that the well had been used in some time and is not currently used. While on site the owner of the well drove up and verified the visual observations made. Many of the local wells penetrate the shallow or deep artesian aquifers, which if not tightly sealed, may result in the uncontrolled discharge of water which in turn may be interpreted as a spring. This condition was personal observed in another local well in the winter of 2009.

Un-used Well 2. This un-used well is located just outside the AOR to the south and west of the Project Area, and is associated with irrigation and stock watering right 68-2838 as shown on Map B-2.7. A review of the state water right database shows that the source is associated with a well and used for irrigation and stock watering. Areal photography shows that the well is likely used in conjunction with the adjacent pond, and has gone unused for some time based on the lack of water or adjacent irrigated acreage present. Many of the local wells penetrate the shallow or deep artesian aquifers, which if not tightly sealed, may result in the uncontrolled discharge of water which in turn may be interpreted as a spring. This condition was personal observed in another local well in the winter of 2009.

Spring 1. Spring 1 shown on Map B-2.7 is located to the southeast of the project site and is outside the AOR east of Jones Road. The spring however is a small spring associated with water right 68-71 that is used for stockwatering. The water right shows a flow of 0.006 cfs (2.7 gpm). This information is consistent with grazing use observed during 2009 in the vicinity of the spring, and as verified by the individual mentioned in the discussion related to Abandoned Well 1. Although flow data is not available, areal photography would tend to show that the spring is relatively small since the discharge terminates a relatively short distance of approximately 300 – 400 feet downstream.

(vi) Only limited surface water bodies as shown on Map B-2.7 are known to exist within the AOR. From areal photography there appears to be one small surface impoundment containing water approximately 1.8 miles west of the project site. The pond is believed to be used in conjunction with the Delta Egg Farm operation. Other surface impoundments are located sparsely within the area, but they are either very small or don't appear to be currently used. One pond / wetland area also shows up east of Jones Road approximately 1¼ to 1¾ miles southeast of the project site. In addition, several surface impoundments have been constructed as part of the Intermountain Power Project's electric generation facilities north of Brush-Wellman Road north and north-east of the project site. These features including residences and roads are shown on the areal photograph incorporated into Map B-2.7.

(vii) Surface and subsurface faults known or suspected to exist are shown hereafter on Figure B-3.1. Faults identified at depth during the drilling of Magnum Exploratory Hole #1 (MH-1) and or from seismic surveys are also shown on Drawing B-4.1 which shows the Local Geology / Structure at a projected depth of 3,000 feet as prepared by Rodger C. Fry.

3. Maps and Cross Sections of USDWs

Terminology related to ground water aquifers are defined based on historic reporting as well as added information gleaned by Magnum during this project. Basic aquifer terms referenced within this report are defined as follows.

Depth	Definition	Comment
0 to 150	Unconfined Water Table Aquifer	The water table aquifer is unconfined and generally not used within the area due to high TDS poor quality conditions.
150 to 700	Shallow Artesian Aquifer	Confining zones vary in thickness and location and can comprise several hundred feet of the identified depths.
700 to 1,400	Deep Artesian Aquifer	Confining zones vary in thickness and location and can comprise several hundred feet of the identified depths.
> 1,400 to 3,000	Basement Aquifer	This aquifer extends to bedrock or the salt structure and is comprised of several small inter-bedded sand and gravel units within significant silt and clay zones.
>3,000	Salt Structure (also referred to previously as the Salt Diapir or Salt Formation)	The salt structure and overlying transition zone located beneath the project site was found to begin at about 3,000 feet. The top depth to the Salt structure generally deepens to the south, east and west.

This section contains regional information as provided by Mr. Bill Loughlin, a geologic sub-consultant to Magnum, which was evaluated prior to the drilling of Exploratory Well MH-1. Mr. Loughlins evaluation which has been incorporated directly into this technical report provides regional information including 1) the cross section and vertical limits of underground sources of drinking water (USDWs) within the AOR, 2) the location of USDW's relative to the salt formation in which the proposed injection wells will be located, 3) the direction of water movement within aquifers which have historically been defined as the shallow unconfined water table, the shallow artesian and the deep artesian aquifer.

Information related to specific geology at the project site based on seismic and other information gleaned from the drilling of Exploratory Well MH-1 as documented by Magnum and Mr. Rodger Fry are provided within Section 4. The information provided within Section 4 followed the effort completed by Mr. Loughlin and focuses on the specific Project Area following a review of on-site seismic and exploratory well data.

3.1 General Description of Area

The Magnum facility is located in Millard County, in west central Utah, about 9 miles north of the town of Delta, Utah. A topographic map of the area is presented in Section B-1. The area drains generally toward the west and southwest to the Sevier River, which lies to south of the Magnum Permit Area. Irrigated agricultural lands lie to the southwest of the Project Area while lands to the northeast are generally barren flats and sand dunes. The Intermountain Power Project (IPP) plant site is located northeast of the Permit Area.

3.2 USDW Map and Cross Sections

Figure B-3.1 presents a surface geologic map of the region. The geologic descriptions are shown in Part B-3.4 below. The entire Area of Review (AOR) is underlain by basin-fill sediments wherein Underground Sources of Drinking Water (USDW) are commonly found. B-3.1 also shows potentiometric contours and direction of groundwater flow in the shallow artesian aquifer and the deep artesian aquifer. Groundwater flow direction is perpendicular to the potentiometric contours and is shown on the figure for the shallow artesian aquifer and the deep artesian aquifer. The flow direction in shallow unconfined water table aquifer is similar to the topographic slope direction and has been estimated on Figure B-3.1.

It should be noted at this time that historic well development within general area has been limited to depths above 1,400 feet. Historic reports have therefore relied upon data available from existing wells from which extrapolations have been made regarding potential conditions at depth. The shallow and deep artesian aquifers referenced therefore within this section of the technical report have been considered to be generally representative of these historically developed aquifer zones above 1,400 feet.

A deeper artesian zone located at depths between 1,400 and 2,700 feet has recently been identified based on data retrieved from seismic investigations and drilling of Exploratory Well MH-1 and is hereafter referred to as the "basement aquifer". This basement aquifer is separated from the aquifers above 1,400 feet by extensive layers of silt and clay, the first of which was found in Exploratory Well MH-1 to exist between 1,405 and 1,650 feet in depth. For reference in an effort to maintain consistency with historic reporting, any reference to the "deep" artesian aquifer within this Section B-3 will therefore assume to terminate at a maximum depth of 1,400 feet. The "Basement Aquifer" identified below 1,400 feet is discussed later in Part B-4. Regional groundwater occurrence and flow within the historic aquifers above 1,400 feet are described further in this section.

Figure B-3.2 presents geologic cross sections showing an alluvial valley fill zone consisting of Pliocene-Miocene basin deposits of sand, silt, clay, and gravel. It is within these zones wherein USDW's would be located. Although data is not yet available, groundwater below depths of about 3,000 feet within the AOR are believed to have total dissolved solids concentrations greater than 10,000 milligrams per liter (mg/L) due to the presence of the salt structure and the presence of anhydrite and gypsum in deep basin-fill sediments. Information related to specific geology at Exploratory Well MH-1 (located in the NE4 of the NE4 of Section 27, Township S, Range W, SLBM) upon which this conclusion is based is provided within Section B-4.

3.3 Publications

A number of publications (referenced at the end of this technical report) describe the geology and groundwater hydrology of the Sevier Desert area, although most of the groundwater publications are more than 20 years old. The report by Holmes (1984) summarizes previous studies, basic data, aquifer characteristics and modeling of the regional groundwater system. Groundwater conditions are summarized in the annual report series *Ground-Water Conditions in Utah*. Information learned and gleaned from these and other reports referenced at the end of this technical report have been incorporated into the technical conclusions reported herein.

3.4 Regional Geology

The mountains that surround the basin of the Sevier Desert are composed of a variety of consolidated sedimentary, metamorphic and igneous rock. The basin is underlain by deposits primarily of semi-consolidated and unconsolidated sediments of Tertiary and Quaternary age. The basin-fill includes sand, silt, clay and gravel deposited as alluvial fans, stream alluvium, mudflows, lacustrine (lake) sediments and deltas. The basin fill also contains scattered basalt flows and tuffs of late Tertiary and Quaternary age. Tertiary and Quaternary basin-fill deposits are over 7,000 feet thick. Oligocene and Miocene basin-fill sediments contained evaporite deposits. Through time, evaporites in the Permit Area vicinity flowed to form a salt dome or diapir (hereafter described as salt structure). Evaporite deposits were reported in the Argonaut Energy No. 1 Well (Well ID "N" on Table B-3.1 and Figure B-3.1) from a depth of 2,550 to 7,734 feet. Evaporite deposits were encountered in the Magnum MH-1 Well below a depth of about 3,140 feet.

Figure B-3.1 presents a surface geologic map of the region. Figure B-3.2 presents east-west and north-south geologic cross sections referenced in Figure B-3.1. Symbols and geologic descriptions of geologic units shown on the map and cross sections are summarized below:

Symbol	Description
Q	Quaternary surficial deposit (undivided); on cross sections only
Qal_2	Alluvium, middle and lower Holocene -- Tan and gray silt and sandy silt in large low-gradient alluvial fans.
Qes	Eolian sand – Wind-blown sand; mostly silty fine-grained quartz sand.
Qed	Eolian dunes – Chiefly barchan, parabolic, dome and transverse sand dunes that are active and not stabilized by vegetation; mostly tan, well-sorted, fine-grained quartz sand.
Qpm	Playa mud – Laminated, silty fine sand, silt, and clayey silt infused with various salts, gypsum, and calcium carbonate.
Qdf	Underflow fan deposit – Thin-bedded to laminated, calcareous silt with minor interbedded very fine sand in thin beds that were deposited into the Lake Bonneville deltas of the Sevier River.
Qlf	Fine-grained lake deposits – Grayish-tan, tan and light gray, calcareous silts that are deep-water sediments of Lake Bonneville.
QTlf	Fine-grained lacustrine deposits of Sevier Desert – Brown and light olive gray, calcareous, lacustrine silt and silty clay with minor sand; off shore to deep-water sediments. Pliocene to middle Pleistocene in age.
Tvs	Tertiary volcanic and sedimentary units, undivided – on cross section only.
Tbf	Tertiary basin-fill, undivided – Alluvium, mudflow and lacustrine deposits of sand, silt, clay and gravel – on cross section only.
Ts	"Salt" structure, Miocene and upper Oligocene – Halite, anhydrite, gypsum and minor detrital sand and clay – on cross-section only.

3.5 Groundwater Occurrence

The principal regional groundwater system is the unconsolidated basin-fill deposits that formed from erosion of the surrounding mountains and laid down by streams, lakes, and mudflows. These regional deposits consist of interbedded and lenticular deposits of clay, silt, sand, gravel and boulders. The regional depositional processes created alternating and interfingering layers and lenses with regional horizontal and vertical heterogeneity. The degree of sorting and grain size, major factors in influencing permeability and storage, vary with the process of deposition and general location in the valleys. Sediments are generally coarser near the mountain front and grade finer towards the valley centers. Stream channel deposits are coarser and better sorted than alluvial fan and mudflow deposits that generally occur at the base of steep drainages. Vast lakes that occupied the valleys many thousands of years ago deposited interbedded clay and fine-grained sands. Rivers flowing into these lakes formed coarse-grained delta deposits near the ancient lake shore, such as near the mouth of Leamington Canyon.

Mower and Feltis (1968) and Holmes (1984) divided the groundwater reservoir into a water table aquifer, a shallow artesian aquifer and a deep artesian aquifer, with low permeability layers (confining beds) between the aquifers. In reality, there are no historically reported simple, clear-cut boundaries identified between the aquifers or confining beds within the developed ground water aquifers located at depths above 1,400 feet. More recent seismic testing by Magnum however has shown that there is some consistency and apparent uniformity within the area local to the proposed project as evidenced by recently completed seismic and well data specific to the Magnum project. More about this is presented in Section B-4.

Table B-3.1 summarizes information for wells deeper than 500 feet, and a few other wells, that are located in the AOR and vicinity. The maximum water well depth (other than MH-1) is 1,334 feet. Well locations are shown on Figure B-3.1. Figure B-3.3 (Water Well Log Diagram) illustrates reported lithologies, static water levels and perforation zones in the water wells. The figure also shows Mr. Loughlin's interpretation of the extent of the shallow and deep artesian aquifers. It is Important to note in Figure B-3.3 that as historically defined, the unconfined water table aquifer is located above the shallow artesian aquifer and is generally confined to the upper 50 to 150 feet, the shallow artesian aquifer to depths of about 150 to 700, and the deep artesian aquifer between about 700 to 1,400 (the bottom of historically drilled wells). Part B-4 will discuss and present data showing what is believed to be a previously undefined deeper confined aquifer (defined herein as the basement aquifer) located at depths greater than 1,400 feet.

A shallow unconfined water table aquifer within about 50 feet of the land surface occurs in the central part of the valley. The water table is feed by slow upward movement of water from the shallow artesian aquifer, and infiltration of irrigation and surface water; discharge occurs by evapotranspiration. The shallow unconfined water table aquifer is little utilized because of high salinity and poor quality.

3.6 Recharge, Discharge and Groundwater Flow Direction

Recharge to the principal groundwater aquifer system (basin-fill deposits) in the Sevier Desert occurs by stream infiltration along mountain fronts, subsurface inflow from consolidated rocks of mountain areas, subsurface inflow from adjoining basins, precipitation on basalt outcrops, and seepage from rivers, canals, reservoirs and unconsumed irrigation.

Most of the recharge is to the unconfined water table aquifer near the mountain front, from which it flows into the artesian aquifers.

Groundwater generally flows from recharge areas near the mountains on the northeast and east of the Sevier Desert toward discharge areas in the central and western parts of the area. Groundwater flow direction is perpendicular to the potentiometric contours and is shown on Figure B-3.1 for the shallow artesian aquifer and the deep artesian aquifer. As indicated earlier, no data is available to verify flow direction in the shallow unconfined water table aquifer. As a general rule however, unconfined flows typically move in a direction perpendicular to the topographic contour, or in the same direction as the ground surface slope.

Groundwater discharge occurs by evapotranspiration, subsurface outflow to adjoining basins, discharge to springs (largely to Clear Lake Springs, located about 20 miles south of Delta City), and to wells. Snyder (1998) identifies a large groundwater discharge area due to evapotranspiration generally to the west and south of the Permit Area.

3.7 Regional Water Quality

Total dissolved solids (TDS) concentrations in the deep artesian aquifer from two of the wells listed in Table B-3.1 were low, reported to be 281 and 300 milligrams per liter (mg/L) (Well ID "D" and "P", respectively, in Table B-3.1). TDS concentrations are generally higher in the shallow artesian aquifer, and can be very high in the water table aquifer near the ground surface where salts are concentrated by evapotranspiration.

Water quality information related to Magnum well MH-1 is included within Attachment C-1.2.

4. Maps and Cross Sections of Local Geologic Structure and Lithology

Maps and cross sections detailing the geologic structure and lithology of the regional area are provided in Part B-3. This section provides more detailed and localized information and interpretation of the geology at the Project Area based on Magnum site investigations, data retrieved from Exploratory Well MH-1, and interpretations by the geologist involved with the drilling operation, Mr. Rodger Fry.

4.1 Stratigraphy and Groundwater of the Lake Bonneville Sediments near the Magnum Holdings #1 Well

Millard County, Utah is located in the Basin and Range geographical Provence. This province is marked by north-south trending fault block mountain ranges that have been uplifted and bounded by valleys that have dropped relative to the mountains. The valleys contain very thick accumulations of sediments that were deposited in Lake Bonneville during the last ice age.

During the time Lake Bonneville was present (30,000 to 10,000 years before present) the valleys were slowly sinking, allowing very thick deposits of lake sediments to accumulate. In the Millard County area, the Lake Bonneville sediments in the valleys are up to 10,000 feet thick. During earlier periods of lower precipitation layers of evaporate sediments (salts) were deposited that were subsequently covered by the thousands of feet of alternating clays, sands and occasional gravels now found on the valley floors throughout Millard County. Under these conditions, the weight of the overlying sediments caused the salt to flow and become mobile. This occurred in the area near Sugarville, Utah (9 miles north of Delta, Utah) resulting in a 5,000 foot thick salt structure that was initially discovered in the Argonaut #1 well drilled in 1978 just southwest of the Intermountain Power Project (IPP) plant.

Additional information related specifically to Magnum efforts is provided in Attachment 4.1.

5. Maps and Cross Sections of Regional Geologic and Hydrologic Setting

Figure B-5.1 presents a surface geologic map of the region. Regional geologic cross sections at the locations shown on Figure B-5.1 are provided on Figure B-3.2. The regional hydro-geology conditions of the regional and local areas are discussed in Sections B-3 and B-4 respectively.

Part C – Tabulation of Artificial Penetration Data

Only two wells have been identified within the AOR that penetrate the proposed injection zone. The first is referred to as the Argonaut well (API # 43-027-30012), an exploratory oil and gas well, which was drilled in 1978 to a depth of 11,266 feet. The open hole was drilled using a 7 7/8" bit to a depth of 4,237 feet and a 6 1/8" bit to a depth of 11,266 feet as reported by the logger. The well location is shown on Figures B-3.1, B-3.2, and B-5.1. Data including miscellaneous filings, operation reports, well completion reports, correspondence, and Seismic, Resistivity, and Density logs and abandonment information are available for this well through the Utah Division of Oil, Gas & Mining. Copies however of the US Geological Survey "Monthly Reports" and "Sundry Notices and Reports on Wells" are included within Attachment C-1.1. Attachment C-1.1 includes information related to the well casing construction and abandonment including casing and cementing details. Also included within the attachment is an "as-built" well schematic of the Argonaut well as interpreted from the data contained in the attachment. Since no specific geologic description, interpretation or write-up has been located or identified for the Argonaut well, and following a discussion with Utah DEQ, data including geophysical logs and miscellaneous ancillary letters and documents pertaining to the well are not included herein. Magnum will however provide the geophysical data available through DOGM should it be desired at a later date.

The second well penetrating the proposed injection zone was recently drilled by Magnum and is referred to herein as Well MH-1. This well was drilled during the winter of 2008-2009 to a total depth of 6,238 feet. Permits were obtained from both the Utah Division of Water rights to drill the exploratory well as well as from DOGM. Data available for this well includes copies of the State permits, the Drillers Report, Core Log, Lithologic Log, geophysical logs, and water quality, is included within Attachment C-1.2. Note that the water quality samples taken were representative of up hole conditions within the 1,650-1,680, 1,840-2,020, 1,950-2,020, and 2,180-2,240 foot zones, well above the salt structure located below 3,300 feet. No water quality data is available for zones below 2,240 feet since the drilling operation utilized a fully saturated brine solution during coring operations below 3,000 feet to maintain the integrity of the salt cores.

Part D – Corrective Action Plan

No underground sources of drinking water have been identified (including exploratory well MH-1 or future source water wells) within the Project Area or AOR that penetrate the injection zone. In fact, the injection zone is projected to be vertically separated from existing wells by more than 2,000 feet. The separation between any future source water wells drilled by Magnum and the top of the injection zone is anticipated to be at least 1,000 feet. A minimum 500 foot separation is also planned (designed) between the top of the injection zone (top of salt cavern) and any potential USDW. To eliminate the potential for vertical movement of water along the injection well strings, the following will also be provided as part of the development plan.

The injection and salt extraction wells will be drilled and completed utilizing fully grouted steel casings that penetrate into the target salt structure as outlined within Part G of this technical report. The presence of the full grout seals and protective steel casings will prevent the vertical movement of water development water and stored gases, thus protecting all known and potential USDW zones above the target cavern zones.

An evaluation of the Argonaut and MH-1 wells has also been made to determine the potential for the vertical movement of water that could potentially contaminate USDW's as follows.

<u>Argonaut Well (Abandoned)</u> – A review of reports for the Argonaut well was discussed within Part C of this technical report. A well schematic (see Attachment C-1.1) was also prepared based on these reports to graphically show as-built conditions of the well, well casings, and grout seals based on an interpretation of information reviewed. Based on this information, it is believed that the abandonment of the Argonaut well was properly completed to prevent movement of water into potential USDW's resulting from Magnum operations. Type Class G cement plugs were placed within the well between 4,170-4,300, 7,397-7,700, and 9,930-10,050 feet, all of which are below potential USDW's located above 3,000 feet at MH-1. In addition, grout seals were also placed at the surface and at depths of 649-663' and at 2,340-2,406 which will limit vertical movement of water within the Argonaut well within known USDW's above the local salt structure.

An evaluation of theoretical and actual grout volumes was made based on available data. This evaluation assuming 1.15 ft^3 per sack of concrete is summarized as follows. Note in the summary that in general, and at the locations of the grout seals, the well is believed to have experienced some washouts. This conclusion is based on the fact that the volume of grout placed is higher than the calculated volume which the well should have taken had the bore hole diameter been maintained (based on measured top and bottom grout limits). This is especially true within the upper 649-663 foot zone. This is in contrast to the likelihood of bore sloughing which is concluded for the 7,397-7,700 foot zone wherein the volume of grout placed was only 45% of the calculated volume based on grout limits. The origin of the sloughing is not known. Based on the nature of materials within this zone, it is highly likely that some sloughing of upper zones occurred, which dropped down the well and filled the lower zones. The sloughing however is believed to be of little consequence since it occurred in zones projected at this time to be approximately 1,000 feet below the bottom of the solution caverns proposed herein, and since there is an estimated total depth of about 135 feet of concrete that exists in that part of the bore hole.

<table>
<tr><th colspan="2">Diameter (in)</th><th>Annulus</th><th colspan="2">Sacks</th><th colspan="2">Grouted Zone</th><th>Calc'd</th><th rowspan="2">Diff (%)</th><th rowspan="2">Comment</th></tr>
<tr><th>Casing</th><th>Bore</th><th>Volume (ft^3/ft)</th><th>#</th><th>Vol (ft^3)</th><th>Top</th><th>Bottom</th><th>Volume (ft^3)*</th></tr>
<tr><td>13 3/8</td><td>17 1/2</td><td>0.69</td><td>167</td><td>192</td><td>663</td><td>649</td><td>10</td><td>1975</td><td>Bore washout</td></tr>
<tr><td>7</td><td>12 ¼</td><td>0.55</td><td>82</td><td>94.3</td><td>2,405</td><td>2,340</td><td>35.8</td><td>263</td><td>Bore washout</td></tr>
<tr><td>7</td><td>12 ¼</td><td>0.55</td><td rowspan="3">50</td><td rowspan="3">57.5</td><td>4,300</td><td>4,248</td><td rowspan="3">48</td><td rowspan="3">120</td><td rowspan="3">Some bore washout</td></tr>
<tr><td>7</td><td>8 ¾</td><td>0.15</td><td>4,248</td><td>4,198</td></tr>
<tr><td>0</td><td>8 ¾</td><td>0.42</td><td>4,198</td><td>4,170</td></tr>
<tr><td>0</td><td>8 ¾</td><td>0.42</td><td>50</td><td>57.5</td><td>7,700</td><td>7,397</td><td>126.5</td><td>45</td><td>Bore sloughing</td></tr>
<tr><td>0</td><td>8 ¾</td><td>0.42</td><td>50</td><td>57.5</td><td>10,050</td><td>9,930</td><td>50</td><td>114</td><td>Some bore washout</td></tr>
</table>

* - Calculated volume is the theoretical volume that would have occurred in the well without washouts or wall sloughing based on the measured grouted zone.

Information related to the grouting and isolation of aquifer zones within well MH-1 is provided in Attachment D-1.

Part E – Formation Testing Program

Information related to the Formation Testing Program is included within Attachment E-1.

Part F – Well Stimulation Program

No well stimulation is planned for the proposed wells. The injection wells will create solution caverns through the natural dissolution of salts by injecting fresh water at pressures sufficient to "lift" the resultant partially saturated brines back to the surface for management in solar evaporation ponds. Developmental facilities will be designed to prevent lift pressures from exceeding maximum operating pressures.

Part G - Injection Well Construction Plan

Cementing and Casing Program

A report outlining the basic well casing program, entitled "Proposed Solution Mining Plan for Development of Magnum Gas Storage Caverns at Delta, Utah", prepared by Thomas Eyermann, is included within Attachment G-1. Figure G-1.1 has been inserted to provide a well schematic showing the anticipated casing construction plan outlined in the Attachment, including casing depths, diameters, weight and grade of steel. Information related to the cementing program is also provided in Attachment G-2 within the documents entitled "Well Construction Plan" and "Specifications for Cementing Services and Materials".

Drilling Program

The drilling program presented herein is based on lithologic information available from the Argonaut and Magnum MH-1 wells as provided herein. Site specific lithology of the injection and confining zones will be re-evaluated on a site by site basis for each well drilled.

Geophysical logging will be completed by a reputable logging company such as Schlumberger which will collect log data immediately following completion of the bore hole, and prior to the installation of steel casing. It is anticipated that two or more runs will be made during drilling for the purposes of identifying geologic conditions down the hole including (but not limited to) the top of salt and salt conditions at depth. Logs anticipated to be run include caliper, Gamma, Resistivity, Neutron, Density, Temperature, Delta Temperature, and Spontaneous Potential.

Deviation checks will potentially be conducted at two stages. If during drilling is appears that vertical deviation is a concern, the driller can conduct a survey using a single shot camera. The camera is lowered inside the drill stem and data is collected that is compared to up-hole data to determine inclination or deviation within the well bore. At termination of drilling when the well reaches total depth, or at times wherein geophysical logging is required, an electronic deviation survey will be collected during electric logging to evaluate the straightness of the well hole.

Water used during the drilling process will be from the ground water aquifer generally located between 1,650 and 2,250 feet as accessed by well MH-1. Water quality data for the source is documented within Attachment C-1.2 appears to be of drinking water quality and is non-corrosive. The salt formation in which mining is planned is naturally devoid of water and will only be exposed to injected water.

Additional information related to the drilling program is provided in Attachment G-2.

Part H - Injection Well Construction Details

A schematic showing basic injection well casing details was discussed within Part G and shown in Figure G-1.1. During the initial stage of mining which will be done in direct mode, the average injection pressure will be about 1,480 psi. The average injection pressure during the long second phase of solution mining which will be reverse mode will be about 950 psi.

A one line P & ID diagram, a Typical Cavern Well Piping Plan, and a Gas Storage Wellhead schematic have been added to the permit application and are included at the end of Attachment G-2.

Part I - Injection Well Operation Plan and Procedures

The injection well operating plan and procedures is outlined within the report entitled "Proposed Solution Mining Plan for Development of Magnum Gas Storage Caverns at Delta, Utah" presented within Part G, and included within Attachment G-1. A Cavern Well Schematic is also shown in Figure G-1.1. The report generally defines the following operating criteria:

Average Daily Rate: 3,300 gpm
Maximum Daily Rate: 3,300 gpm

Volume of Fluid to be Injected: 75.8 million barrels (3,1834 million gallons)

Average Injection Pressure: 1,000 psi
Maximum Injection Pressure: 1,000 psi

The report included within Attachment G-1 also includes information related to the mining methods and stages, tubing placements, testing, and information related to potential problems that could be associated with cavern creation.

Injected water will comprise local ground water sources which will target confined aquifers located generally at depths greater than 1,450 feet. Representative water quality data collected from exploratory well MH-1 within potential source zones was previously discussed in Part C of this application with water quality data being provided within Attachment C-1.2. Because the source of water is a new source no range data is available for the source, however, little variation is expected due to the limiting nature of the confined aquifer.

Part J - Monitoring, Recording, and Reporting Plan

The monitoring, recording and reporting plan is presented in the "UIC Monitoring, Recording, and Reporting Plan" included within Attachment J-1.

Part K - Contingency Plan

Drinking quality waters in the vicinity of the project are found to be developed in local artesian aquifers to depths of up to approximately 1,350 feet. At exploratory well MH-1 a 250 foot thick clay layer was found to isolate the existing artesian aquifer systems above and below 1,400 feet. In addition, significant clay zones were found at depths up to about 3,000 feet that significantly isolate the small sand and gravel aquifers located between 1,650 and 2,700 feet. These clay zones provide natural isolation of upper and lower zones and limit vertical communication. Additional information regarding these issues is included within Part C and Attachment C-1.2.

As discussed within Part G and shown in Attachment G-1, the well will be cased and grouted in place to the top of the cavern which is anticipated to be located at depths of approximately 4,000 feet. Pressure grouting, grouting from the bottom up will be in place between each casing string and the outer bore annulus and or outer casing. All in all, there will be grout placed outside the surface conductor casing, surface casing, contingency casing (if needed), intermediate casing, and inner mining casing (see schematic in Attachment G-1). These combined casings and grout seals penetrating to depths of up to 3,950 feet will prevent the upward or downward movement of water along the well casings.

The following corrective action plan will be implemented should at any time it be found that the grout or natural confining aquifer seals have failed creating a concern for the vertical movement of injected brine waters from the salt structure.

Monitoring And Actions During Well Construction

During drilling, the wells will be monitored continuously by observing fluid levels in the mud system. A loss of fluid level will indicate drilling mud is leaving the borehole. In this event the appropriate measures will be taken to stop the lost circulation. These measures will include adding various substances to the drilling mud as it is pumped down the hole. These substances are generally inert material such as cotton seed hulls, cellophane chips or bentonite gel that are designed to plug pores in the rock. If the fluid loss cannot be contained by conventional mud additives, it may be necessary to set and cement a string of casing through the loss zone.

Methods Used To Monitor Well Data

Magnum Wells will be monitored during development by solution mining on a continuous basis. The well/cavern pressures will be collected continuously at the wellhead(s) and transmitted to a central control facility. Cavern flow rates and temperatures will be monitored by individual flow meters on the water and brine flow lines of each cavern. The pressure, temperature and flow data will be recorded on a regular timed basis and stored.

Monitoring Of Injection Pressure And Flow

Well\Cavern water pressures (static or flowing), water flow rates, water temperature, brine pressure, brine flow rate, and brine temperature will be continuously monitored. Pressures will be measured using electronic pressure indicators. Flow rates will be measured with meters (ultrasonic or orifice type) capable of measurement in injection or withdrawal operations. All pressure monitoring, temperature monitoring, and flow rate monitoring instrumentation will be calibrated in accordance with manufacturer recommendations.

Action(s) Taken In The Of Loss Of Cavern\Well Integrity

If a loss of pressure integrity is indicated in a Cavern\Well the system will be de-pressured to a point that will minimize the loss of nitrogen and preclude the flow of brine out of the Cavern\Well system and into the overlaying fresh water formations based on the indicated or suspected leak point. This may necessitate reversing the direction of flow in the well to ensure that water fills the 20" x 16" annulus that is normally filled with nitrogen. Further testing and evaluation will then be undertaken to assess further actions with the approval of the Executive Secretary.

In the event of a major loss of integrity in the Cavern\Well mining will be stopped and the cavern de-pressured to a zero pressure at the wellhead. Further testing and evaluation will then be conducted with the approval of the Executive Secretary.

Should for any unforeseen reason the well be found to be failing, or to have failed, the plugging and abandonment plan provided in Part L will be implemented.

Part L - Plugging and Abandonment Plan

An updated plugging and abandonment plan has been included within Attachment G-2. A duplicate plugging and abandonment insert included within prior draft submittals has been deleted from Attachment D-1. Modifications to these methods as outlined due to unanticipated down hole conditions will be discussed and coordinated with the regulatory agency prior to abandonment.

Part M - Financial Responsibility

The permittee is required to maintain financial responsibility and resources to close, plug and abandon all wells constructed by Magnum located within the Project Area. To meet this obligation the applicant will post CD's sufficient to cover the costs of well abandonment and plugging for wells drilled as required under the current regulations. Prior to drilling, the appropriate CD's will be posted in the name of the Utah Department of Environmental Quality, Division of Water Quality (DEQ). Following construction these CD's will remain in force and be transferred to the Utah Division of Oil, Gas & Mining (DOGM) as a transfer in responsibility occurs from DEQ for well construction oversight to DOGM for operational oversight. It is most likely that any required plugging and abandonment will occur during the operational phase of the development.

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

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

a) The CD is determined to be insufficient to cover well closure, plugging and abandonment.
b) The CD is suspended or revoked.

Part N - Request for Aquifer Exemption

A request for Aquifer Exemption is not being considered nor requested at this time.

Part O - Expected Changes Due to Injection

As stated earlier the injection zone involves the dissolution of salts within an unsaturated salt structure located at depths of over 3,000 feet. As a result there will be no native fluid displacement nor resulting movement of the injected fluid outside the dissolution chamber making up the salt cavern. Operational flow rates and pressure were discussed in prior Parts of this permit.

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TABLES

TABLE B-2.1 – WATER RIGHT / SOURCE SUMMARY WITHIN 2 MILES OF PROJECT AREA

WRNUM	PRIORITY	LOCATION	OWNER	CFS	ACFT	Depth (ft)	Dia (in)	Perf Intervals	SOURCE
USE: DOMESTIC									
68-1017	19251000	S89 E2740 NW 34 15S 7W SL	FRANK A-. FOOTE	0.156	0.000	n/a	n/a	n/a	Underground Water
68-120	19420317	S100 E300 NW 03 16S 7W SL	RICHARD G-. CLARK	0.015	0.000	n/a	340	n/a	Underground Water
68-1200	19160701	N160 E113 SW 34 15S 7W SL	LINDA M-. CHERNISKE	0.004	0.000	n/a	n/a	n/a	Underground Water
68-1212	19200000	S134 E867 N4 33 15S 7W SL	LORIS LAMBERT	0.022	0.000	n/a	n/a	n/a	Underground Water
68-1529	1910	N737 E405 SW 28 15S 7W SL	DELTA EGG FARM LLC	0.000	4.756	300	6	223-245	Underground Water
68-1723	19250000	S1600 W75 NE 29 15S 7W SL	DELTA EGG FARM L.L.C.	0.022	0.000	n/a	n/a	n/a	Underground Water
68-1767	19570204	S9 W203 E4 27 15S 7W SL	MAGNUM HOLDINGS, LLC	0.100	0.000	n/a	n/a	n/a	Underground Water
68-2139	19790710	N1023 W1651 S4 10 15S 7W SL	ELLEN AND FRANK BATTY	0.015	0.000	n/a	n/a	n/a	Underground Water
68-229	19490706	N285 W445 SE 33 15S 7W SL	MICHAEL AND DAVID JENSEN	0.015	0.000	n/a	n/a	n/a	Underground Water
68-245	19510519	S200 E50 NW 03 16S 7W SL	HAROLD DONE	0.015	0.000	n/a	n/a	n/a	Underground Water
68-2558	19350000	N190 E110 S4 28 15S 7W SL	ERNEST SAXTON	0.015	0.000	180	6	160-180	Underground Water
68-997	19160000	N2027 W146 E4 03 16S 7W SL	LLOYD M-. HEINLEIN	0.007	0.000	n/a	n/a	na/	Underground Water
USE: IRRIGATION									
68-1017	19251000	S89 E2740 NW 34 15S 7W SL	FRANK A-. FOOTE	0.156	0.000	n/a	n/a	n/a	Underground Water
68-1723	19250000	S1600 W75 NE 29 15S 7W SL	DELTA EGG FARM L.L.C.	0.022	0.000	n/a	n/a	n/a	Underground Water
68-2139	19790710	N1023 W1651 S4 10 15S 7W SL	ELLEN AND FRANK BATTY	0.015	0.000	n/a	n/a	n/a	Underground Water
68-2558	19350000	N190 E110 S4 28 15S 7W SL	ERNEST SAXTON	0.015	0.000	180	6	160-180	Underground Water
68-2717	19541014	S1320 E2651 NW 28 15S 7W SL	DELTA EGG FARM LLC.	0.650	86.680	n/a	n/a	n/a	Underground Water
68-2829	19541014	S1320 E2651 NW 28 15S 7W SL	WAYNE & ZOE PHELPS UNITRUST	0.000	10.000	n/a	n/a	n/a	Underground Water
68-2838	19601230	N78 E1314 W4 33 15S 7W SL	DELTA EGG FARM	5.451	795.880	n/a	n/a	n/a	Underground Water
68-2875	19560823	S294 E1854 W4 27 15S 7W SL	LEONARD B-. MILLER	0.056	10.000	n/a	n/a	n/a	Underground Water
68-3060	19601230	N78 E1314 W4 33 15S 7W SL	JOSEPH L-. YOUNG	0.000	2.000	n/a	n/a	n/a	Underground Water
68-317	19510327	N43 E1269 W4 35 15S 7W SL	IPA	3.000	0.000	n/a	n/a	n/a	Underground Water
68-334	19510828	N1330 W1777 SE 35 15S 7W SL	CHESLEY AND BLACK, LC	39.320	0.000	n/a	n/a	n/a	Unnnamed Channel
68-428	19541014	S1320 E2651 NW 28 15S 7W SL	IPA	2.775	0.000	n/a	n/a	n/a	Underground Water
68-50	19360723	N2202 E264 SW 36 15S 7W SL	CHESLEY AND BLACK, LC	3.000	0.000	420	6	n/a	Underground Water
68-50	19360723	N2423 E390 SW 36 15S 7W SL	CHESLEY AND BLACK, LC	3.000	0.000	n/a	n/a	n/a	Underground Water
68-50	19360723	N2014 E732 SW 36 15S 7W SL	CHESLEY AND BLACK, LC	3.000	0.000	n/a	n/a	n/a	Underground Water
68-50	19360723	N2015 E732 SW 36 15S 7W SL	CHESLEY AND BLACK, LC	3.000	0.000	n/a	n/a	n/a	Underground Water
68-50	19360723	N1672 E1062 SW 36 15S 7W SL	CHESLEY AND BLACK, LC	3.000	0.000	n/a	n/a	n/a	Underground Water
68-50	19360723	N1669 E1070 SW 36 15S 7W SL	CHESLEY AND BLACK, LC	3.000	0.000	n/a	n/a	n/a	Underground Water

TABLE B-2.1 – WATER RIGHT / SOURCE SUMMARY WITHIN 2 MILES OF PROJECT AREA

WRNUM	PRIORITY	LOCATION	OWNER	CFS	ACFT	Depth (ft)	Dia (in)	Perf Intervals	SOURCE
68-50	19360723	N1065 E1371 SW 36 15S 7W SL	CHESLEY AND BLACK, LC	3.000	0.000	n/a	n/a	n/a	Underground Water
68-50	19360723	S1206 E2098 NW 01 16S 7W SL	CHESLEY AND BLACK, LC	3.000	0.000	n/a	n/a	n/a	Underground Water
68-50	19360723	N608 E1767 SW 36 15S 7W SL	CHESLEY AND BLACK, LC	3.000	0.000	n/a	n/a	n/a	Underground Water
68-50	19360723	N62 E1957 SW 36 15S 7W SL	CHESLEY AND BLACK, LC	3.000	0.000	n/a	n/a	n/a	Underground Water
68-552	19601230	N78 E1314 W4 33 15S 7W SL	KEITH ALAN WILLIAMS	0.882	150.080	n/a	n/a	n/a	Underground Water
68-647	19640420	S294 E1854 W4 27 15S 7W SL	LEONARD B-. MILLER	0.100	0.000	n/a	n/a	n/a	Underground Water
68-71	19400213	S120 E1395 N4 01 16S 7W SL	LONE TREE RANCH L.L-. C.	0.006	0.000	n/a	n/a	n/a	Underground Water
68-780	19331100	N2216 W2398 S4 36 15S 7W SL	JOHN A-. ELDER	0.089	0.000	n/a	n/a	n/a	Underground Water
68-781	19341000	N118 E1960 SW 36 15S 7W SL	JOHN A-. ELDER	0.067	0.000	n/a	n/a	n/a	Underground Water
68-997	19160000	N2027 W146 E4 03 16S 7W SL	LLOYD M-. HEINLEIN	0.007	0.000	n/a	n/a	n/a	Underground Water
68-428	19850627	N700 E150 SW 19 15S 6W SL	IPA	2.775	0.000	n/a	n/a	n/a	Underground Water
68-428	19850627	N1470 E150 SW 19 15S 6W SL	IPA	2.775	0.000	n/a	n/a	n/a	Underground Water
68-428	19850627	N500 E100 SE 13 15S 7W SL	IPA	2.775	0.000	n/a	n/a	n/a	Underground Water
68-428	19850627	S1170 E150 NW 19 15S 6W SL	IPA	2.775	0.000	n/a	n/a	n/a	Underground Water
68-428	19850627	N1470 E150 SW 18 15S 6W SL	IPA	2.775	0.000	n/a	n/a	n/a	Underground Water
68-428	19850627	S2485 E217 NW 19 15S 6W SL	IPA	2.775	0.000	n/a	n/a	n/a	Underground Water
68-428	19850627	S2390 E150 NW 18 15S 6W SL	IPA	2.775	0.000	n/a	n/a	n/a	Underground Water
68-428	19850627	S1470 E150 NW 18 15S 6W SL	IPA	2.775	0.000	n/a	n/a	na/	Underground Water
USE: STOCK									
68-1017	19251000	S89 E2740 NW 34 15S 7W SL	FRANK A-. FOOTE	0.156	0.000	n/a	n/a	n/a	Underground Water
68-120	19420317	S100 E300 NW 03 16S 7W SL	RICHARD G-. CLARK	0.015	0.000	n/a	340	n/a	Underground Water
68-1200	19160701	N160 E113 SW 34 15S 7W SL	LINDA M-. CHERNISKE	0.004	0.000	n/a	n/a	n/a	Underground Water
68-1212	19200000	S134 E867 N4 33 15S 7W SL	LORIS LAMBERT	0.022	0.000	n/a	n/a	n/a	Underground Water
68-1723	19250000	S1600 W75 NE 29 15S 7W SL	DELTA EGG FARM L.L.C.	0.022	0.000	n/a	n/a	n/a	Underground Water
68-1767	19570204	S9 W203 E4 27 15S 7W SL	MAGNUM HOLDINGS, LLC	0.100	0.000	n/a	n/a	n/a	Underground Water
68-2139	19790710	N1023 W1651 S4 10 15S 7W SL	ELLEN AND FRANK BATTY	0.015	0.000	n/a	n/a	n/a	Underground Water
68-2508	19831209	S85 E462 N4 35 15S 7W SL	NEIL R-. DUTSON	0.007	0.000	n/a	n/a	n/a	Underground Water
68-2558	19350000	N190 E110 S4 28 15S 7W SL	ERNEST SAXTON	0.015	0.000	180	6	160-180	Underground Water
68-2838	19601230	N78 E1314 W4 33 15S 7W SL	DELTA EGG FARM	5.451	795.880	n/a	n/a	n/a	Underground Water
68-391	19530202	S713 W812 N4 33 15S 7W SL	DELTA EGG FARM L.L.C.	0.015	0.000	n/a	n/a	n/a	Underground Water
68-455	19560316	S900 E250 NW 19 15S 6W SL	EDWIN A-. LYMAN	0.015	0.000	n/a	n/a	n/a	Underground Water
68-647	19640420	S294 E1854 W4 27 15S 7W SL	LEONARD B-. MILLER	0.100	0.000	n/a	n/a	n/a	Underground Water

TABLE B-2.1 – WATER RIGHT / SOURCE SUMMARY WITHIN 2 MILES OF PROJECT AREA

WRNUM	PRIORITY	LOCATION	OWNER	CFS	ACFT	Depth (ft)	Dia (in)	Perf Intervals	SOURCE
68-71	19400213	S120 E1395 N4 01 16S 7W SL	LONE TREE RANCH L.L-. C.	0.006	0.000	n/a	n/a	n/a	Underground Water
68-780	19331100	N2216 W2398 S4 36 15S 7W SL	JOHN A-. ELDER	0.089	0.000	n/a	n/a	n/a	Underground Water
68-781	19341000	N118 E1960 SW 36 15S 7W SL	JOHN A-. ELDER	0.067	0.000	n/a	n/a	n/a	Underground Water
68-997	19160000	N2027 W146 E4 03 16S 7W SL	LLOYD M-. HEINLEIN	0.007	0.000	n/a	n/a	na/	Underground Water
USE: OTHER									
68-1529	1910	N737 E405 SW 28 15S 7W SL	DELTA EGG FARM LLC	0.000	4.756	300	6	223-245	Underground Water
68-2161	19790921	N500 W500 SE 13 15S 7W SL	IPA	0.000	44.000	n/a	n/a	n/a	Underground Waters
68-2161	19790921	N600 E150 SW 19 15S 6W SL	IPA	0.000	44.000	n/a	n/a	n/a	Underground Waters
68-2161	19790921	N1470 E150 SW 19 15S 6W SL	IPA	0.000	44.000	n/a	n/a	n/a	Underground Waters
68-2161	19790921	S2490 E150 NW 19 15S 6W SL	IPA	0.000	44.000	n/a	n/a	n/a	Underground Waters
68-2161	19790921	S1170 E150 NW 19 15S 6W SL	IPA	0.000	44.000	n/a	n/a	n/a	Underground Waters
68-2161	19790921	N1470 E150 SW 18 15S 6W SL	IPA	0.000	44.000	n/a	n/a	n/a	Underground Waters
68-2161	19790921	S2490 E150 NW 18 15S 6W SL	IPA	0.000	44.000	n/a	n/a	n/a	Underground Waters
68-2161	19790921	S1470 E150 NW 18 15S 6W SL	IPA	0.000	44.000	n/a	n/a	n/a	Underground Waters
68-2168	19791003	N500 W500 SE 13 15S 7W SL	IPA	0.000	435.000	n/a	n/a	n/a	Underground Water
68-2168	19791003	N1470 E150 SW 19 15S 6W SL	IPA	0.000	435.000	n/a	n/a	n/a	Underground Water
68-2168	19791003	S1170 E150 NW 19 15S 6W SL	IPA	0.000	435.000	n/a	n/a	n/a	Underground Water
68-2168	19791003	N1470 E150 SW 18 15S 6W SL	IPA	0.000	435.000	n/a	n/a	n/a	Underground Water
68-2173	19791004	N500 W500 SE 13 15S 7W SL	IPA	0.000	205.600	n/a	n/a	n/a	Underground Water
68-2173	19791004	N600 E150 SW 19 15S 6W SL	IPA	0.000	205.600	n/a	n/a	n/a	Underground Water
68-2173	19791004	N1470 E150 SW 19 15S 6W SL	IPA	0.000	205.600	n/a	n/a	n/a	Underground Water
68-2173	19791004	S2490 E150 NW 19 15S 6W SL	IPA	0.000	205.600	n/a	n/a	n/a	Underground Water
68-2173	19791004	S1170 E150 NW 19 15S 6W SL	IPA	0.000	205.600	n/a	n/a	n/a	Underground Water
68-2173	19791004	N1470 E150 SW 18 15S 6W SL	IPA	0.000	205.600	n/a	n/a	n/a	Underground Water
68-2173	19791004	S2490 E150 NW 18 15S 6W SL	IPA	0.000	205.600	n/a	n/a	n/a	Underground Water
68-2173	19791004	S1470 E150 NW 18 15S 6W SL	IPA	0.000	205.600	n/a	n/a	n/a	Underground Water
68-2182	19791019	N600 E150 SW 19 15S 6W SL	IPA	0.000	44.400	n/a	n/a	n/a	Underground Water
68-2182	19791019	N1470 E150 SW 19 15S 6W SL	IPA	0.000	44.400	n/a	n/a	n/a	Underground Water
68-2182	19791019	S2490 E150 NW 19 15S 6W SL	IPA	0.000	44.400	n/a	n/a	n/a	Underground Water
68-2182	19791019	S1170 E150 NW 19 15S 6W SL	IPA	0.000	44.400	n/a	n/a	n/a	Underground Water
68-2182	19791019	N1470 E150 SW 18 15S 6W SL	IPA	0.000	44.400	n/a	n/a	n/a	Underground Water
68-2182	19791019	S2490 E150 NW 18 15S 6W SL	IPA	0.000	44.400	n/a	n/a	n/a	Underground Water

TABLE B-2.1 – WATER RIGHT / SOURCE SUMMARY WITHIN 2 MILES OF PROJECT AREA

WRNUM	PRIORITY	LOCATION	OWNER	CFS	ACFT	Depth (ft)	Dia (in)	Perf Intervals	SOURCE
68-2182	19791019	S1470 E150 NW 18 15S 6W SL	IPA	0.000	44.400	n/a	n/a	n/a	Underground Water
68-2430	19821018	N500 E100 SW 18 15S 6W SL	IPA	3.540	0.000	n/a	n/a	n/a	Five Underground Waters
68-2432	19600107	N700 E150 SW 19 15S 6W SL	IPA	1.722	400.000	n/a	n/a	n/a	Underground Water
68-2432	19600107	S2485 E217 NW 19 15S 6W SL	IPA	1.722	400.000	n/a	n/a	n/a	Underground Water
68-2432	19600107	S2390 E150 NW 18 15S 6W SL	IPA	1.722	400.000	n/a	n/a	n/a	Underground Water
68-2432	19600107	S1470 E150 NW 18 15S 6W SL	IPA	1.722	400.000	n/a	n/a	n/a	Underground Water
68-264	19800326	N500 W500 SE 13 15S 7W SL	IPA	0.000	289.640	n/a	n/a	n/a	Underground Water
68-264	19800326	N600 E150 SW 19 15S 6W SL	IPA	0.000	289.640	n/a	n/a	n/a	Underground Water
68-264	19800326	S2490 E150 NW 19 15S 6W SL	IPA	0.000	289.640	n/a	n/a	n/a	Underground Water
68-264	19800326	S2490 E150 NW 18 15S 6W SL	IPA	0.000	289.640	n/a	n/a	n/a	Underground Water
68-264	19800326	S1470 E150 NW 18 15S 6W SL	IPA	0.000	289.640	n/a	n/a	n/a	Underground Water
68-410	19821018	N1470 E150 SW 19 15S 6W SL	IPA	3.000	0.000	n/a	n/a	n/a	Five Underground Waters
68-410	19821018	N500 E100 SE 13 15S 7W SL	IPA	3.000	0.000	n/a	n/a	n/a	Five Underground Waters
68-410	19821018	S1170 E150 NW 19 15S 6W SL	IPA	3.000	0.000	n/a	n/a	n/a	Five Underground Waters
68-410	19821018	N1470 E150 SW 18 15S 6W SL	IPA	3.000	0.000	n/a	n/a	n/a	Five Underground Waters
68-2430	19821018	N1470 E150 SW 19 15S 6W SL	IPA	3.540	0.000	n/a	n/a	n/a	Five Underground Waters
68-2430	19821018	S1170 E150 NW 19 15S 6W SL	IPA	3.540	0.000	n/a	n/a	n/a	Five Underground Waters
68-2430	19821018	N1470 E150 SW 18 15S 6W SL	IPA	3.540	0.000	n/a	n/a	n/a	Five Underground Waters
68-2430	19821018	S2390 E150 NW 18 15S 6W SL	IPA	3.540	0.000	n/a	n/a	n/a	Five Underground Waters
68-317	19510327	N500 E100 SE 13 15S 7W SL	IPA	3.000	0.000	n/a	n/a	n/a	5 Underground Waters
68-2432	19821018	N700 E150 SW 19 15S 6W SL	IPA	2.100	0.000	n/a	n/a	n/a	Underground Waters (5)
68-2432	19821018	N500 E100 SE 13 15S 7W SL	IPA	2.100	0.000	n/a	n/a	n/a	Underground Waters (5)
68-2432	19821018	S2485 E217 NW 19 15S 6W SL	IPA	2.100	0.000	n/a	n/a	n/a	Underground Waters (5)
68-2432	19821018	S2390 E150 NW 18 15S 6W SL	IPA	2.100	0.000	n/a	n/a	n/a	Underground Waters (5)
68-2432	19821018	S1470 E150 NW 18 15S 6W SL	IPA	2.100	0.000	n/a	n/a	n/a	Underground Waters (5)
68-428	19850627	N700 E150 SW 19 15S 6W SL	IPA	2.775	0.000	n/a	n/a	n/a	Underground Water
68-428	19850627	N1470 E150 SW 19 15S 6W SL	IPA	2.775	0.000	n/a	n/a	n/a	Underground Water
68-428	19850627	N500 E100 SE 13 15S 7W SL	IPA	2.775	0.000	n/a	n/a	n/a	Underground Water
68-428	19850627	S1170 E150 NW 19 15S 6W SL	IPA	2.775	0.000	n/a	n/a	n/a	Underground Water
68-428	19850627	N1470 E150 SW 18 15S 6W SL	IPA	2.775	0.000	n/a	n/a	n/a	Underground Water
68-428	19850627	S2485 E217 NW 19 15S 6W SL	IPA	2.775	0.000	n/a	n/a	n/a	Underground Water
68-428	19850627	S2390 E150 NW 18 15S 6W SL	IPA	2.775	0.000	n/a	n/a	n/a	Underground Water

TABLE B-2.1 – WATER RIGHT / SOURCE SUMMARY WITHIN 2 MILES OF PROJECT AREA

WRNUM	PRIORITY	LOCATION	OWNER	CFS	ACFT	Depth (ft)	Dia (in)	Perf Intervals	SOURCE
68-428	19850627	S1470 E150 NW 18 15S 6W SL	IPA	2.775	0.000	n/a	n/a	n/a	Underground Water
68-356	19850627	N700 E150 SW 19 15S 6W SL	IPA	3.500	0.000	n/a	n/a	n/a	Underground Water
68-356	19850627	N1470 E150 SW 19 15S 6W SL	IPA	3.500	0.000	n/a	n/a	n/a	Underground Water
68-356	19850627	N500 E100 SE 13 15S 7W SL	IPA	3.500	0.000	n/a	n/a	n/a	Underground Water
68-356	19850627	S1170 E150 NW 19 15S 6W SL	IPA	3.500	0.000	n/a	n/a	n/a	Underground Water
68-356	19850627	N1470 E150 SW 18 15S 6W SL	IPA	3.500	0.000	n/a	n/a	n/a	Underground Water
68-356	19850627	S2485 E217 NW 19 15S 6W SL	IPA	3.500	0.000	n/a	n/a	n/a	Underground Water
68-356	19850627	S2390 E150 NW 18 15S 6W SL	IPA	3.500	0.000	n/a	n/a	n/a	Underground Water
68-356	19850627	S1470 E150 NW 18 15S 6W SL	IPA	3.500	0.000	n/a	n/a	na/	Underground Water
USE: POWER									
68-2161	19790921	N500 W500 SE 13 15S 7W SL	IPA	0.000	44.000	n/a	n/a	n/a	Underground Waters
68-2161	19790921	N600 E150 SW 19 15S 6W SL	IPA	0.000	44.000	n/a	n/a	n/a	Underground Waters
68-2161	19790921	N1470 E150 SW 19 15S 6W SL	IPA	0.000	44.000	n/a	n/a	n/a	Underground Waters
68-2161	19790921	S2490 E150 NW 19 15S 6W SL	IPA	0.000	44.000	n/a	n/a	n/a	Underground Waters
68-2161	19790921	S1170 E150 NW 19 15S 6W SL	IPA	0.000	44.000	n/a	n/a	n/a	Underground Waters
68-2161	19790921	N1470 E150 SW 18 15S 6W SL	IPA	0.000	44.000	n/a	n/a	n/a	Underground Waters
68-2161	19790921	S2490 E150 NW 18 15S 6W SL	IPA	0.000	44.000	n/a	n/a	n/a	Underground Waters
68-2161	19790921	S1470 E150 NW 18 15S 6W SL	IPA	0.000	44.000	n/a	n/a	n/a	Underground Waters
68-2168	19791003	N500 W500 SE 13 15S 7W SL	IPA	0.000	435.000	n/a	n/a	n/a	Underground Water
68-2168	19791003	N1470 E150 SW 19 15S 6W SL	IPA	0.000	435.000	n/a	n/a	n/a	Underground Water
68-2168	19791003	S1170 E150 NW 19 15S 6W SL	IPA	0.000	435.000	n/a	n/a	n/a	Underground Water
68-2168	19791003	N1470 E150 SW 18 15S 6W SL	IPA	0.000	435.000	n/a	n/a	n/a	Underground Water
68-2173	19791004	N500 W500 SE 13 15S 7W SL	IPA	0.000	205.600	n/a	n/a	n/a	Underground Water
68-2173	19791004	N600 E150 SW 19 15S 6W SL	IPA	0.000	205.600	n/a	n/a	n/a	Underground Water
68-2173	19791004	N1470 E150 SW 19 15S 6W SL	IPA	0.000	205.600	n/a	n/a	n/a	Underground Water
68-2173	19791004	S2490 E150 NW 19 15S 6W SL	IPA	0.000	205.600	n/a	n/a	n/a	Underground Water
68-2173	19791004	S1170 E150 NW 19 15S 6W SL	IPA	0.000	205.600	n/a	n/a	n/a	Underground Water
68-2173	19791004	N1470 E150 SW 18 15S 6W SL	IPA	0.000	205.600	n/a	n/a	n/a	Underground Water
68-2173	19791004	S2490 E150 NW 18 15S 6W SL	IPA	0.000	205.600	n/a	n/a	n/a	Underground Water
68-2173	19791004	S1470 E150 NW 18 15S 6W SL	IPA	0.000	205.600	n/a	n/a	n/a	Underground Water
68-2182	19791019	N600 E150 SW 19 15S 6W SL	IPA	0.000	44.400	n/a	n/a	n/a	Underground Water
68-2182	19791019	N1470 E150 SW 19 15S 6W SL	IPA	0.000	44.400	n/a	n/a	n/a	Underground Water

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TABLE B-2.1 – WATER RIGHT / SOURCE SUMMARY WITHIN 2 MILES OF PROJECT AREA

WRNUM	PRIORITY	LOCATION	OWNER	CFS	ACFT	Depth (ft)	Dia (in)	Perf Intervals	SOURCE
68-2182	19791019	S2490 E150 NW 19 15S 6W SL	IPA	0.000	44.400	n/a	n/a	n/a	Underground Water
68-2182	19791019	S1170 E150 NW 19 15S 6W SL	IPA	0.000	44.400	n/a	n/a	n/a	Underground Water
68-2182	19791019	N1470 E150 SW 18 15S 6W SL	IPA	0.000	44.400	n/a	n/a	n/a	Underground Water
68-2182	19791019	S2490 E150 NW 18 15S 6W SL	IPA	0.000	44.400	n/a	n/a	n/a	Underground Water
68-2182	19791019	S1470 E150 NW 18 15S 6W SL	IPA	0.000	44.400	n/a	n/a	n/a	Underground Water
68-2166	19790921	N500 W500 SE 13 15S 7W SL	IPA	0.000	362.500	n/a	n/a	n/a	Underground Waters (5)
68-2166	19790921	N600 E150 SW 19 15S 6W SL	IPA	0.000	362.500	n/a	n/a	n/a	Underground Waters (5)
68-2166	19790921	S2490 E150 NW 19 15S 6W SL	IPA	0.000	362.500	n/a	n/a	n/a	Underground Waters (5)
68-2166	19790921	S2490 E150 NW 18 15S 6W SL	IPA	0.000	362.500	n/a	n/a	n/a	Underground Waters (5)
68-2166	19790921	S1470 E150 NW 18 15S 6W SL	IPA	0.000	362.500	n/a	n/a	n/a	Underground Waters (5)
68-2161	19790921	N500 W500 SE 13 15S 7W SL	IPA	0.000	44.000	n/a	n/a	n/a	Underground Water
68-2161	19790921	N600 E150 SW 19 15S 6W SL	IPA	0.000	44.000	n/a	n/a	n/a	Underground Water
68-2161	19790921	S2490 E150 NW 19 15S 6W SL	IPA	0.000	44.000	n/a	n/a	n/a	Underground Water
68-2161	19790921	S2490 E150 NW 18 15S 6W SL	IPA	0.000	44.000	n/a	n/a	n/a	Underground Water
68-2161	19790921	S1470 E150 NW 18 15S 6W SL	IPA	0.000	44.000	n/a	n/a	n/a	Underground Water
68-2169	19791003	N500 W500 SE 13 15S 7W SL	IPA	0.000	322.510	n/a	n/a	n/a	Underground Waters (5)
68-2169	19791003	N600 E150 SW 19 15S 6W SL	IPA	0.000	322.510	n/a	n/a	n/a	Underground Waters (5)
68-2169	19791003	S2490 E150 NW 19 15S 6W SL	IPA	0.000	322.510	n/a	n/a	n/a	Underground Waters (5)
68-2169	19791003	S2490 E150 NW 18 15S 6W SL	IPA	0.000	322.510	n/a	n/a	n/a	Underground Waters (5)
68-2169	19791003	S1470 E150 NW 18 15S 6W SL	IPA	0.000	322.510	n/a	n/a	n/a	Underground Waters (5)
68-2170	19791003	N500 W500 SE 13 15S 7W SL	IPA	0.000	307.590	n/a	n/a	n/a	Underground Waters (5)
68-2170	19791003	N600 E150 SW 19 15S 6W SL	IPA	0.000	307.590	n/a	n/a	n/a	Underground Waters (5)
68-2170	19791003	S2490 E150 NW 19 15S 6W SL	IPA	0.000	307.590	n/a	n/a	n/a	Underground Waters (5)
68-2170	19791003	S2490 E150 NW 18 15S 6W SL	IPA	0.000	307.590	n/a	n/a	n/a	Underground Waters (5)
68-2170	19791003	S1470 E150 NW 18 15S 6W SL	IPA	0.000	307.590	n/a	n/a	n/a	Underground Waters (5)
68-2168	19791003	N500 W500 SE 13 15S 7W SL	IPA	0.000	435.000	n/a	n/a	n/a	Underground Waters (5)
68-2168	19791003	N600 E150 SW 19 15S 6W SL	IPA	0.000	435.000	n/a	n/a	n/a	Underground Waters (5)
68-2168	19791003	S2490 E150 NW 19 15S 6W SL	IPA	0.000	435.000	n/a	n/a	n/a	Underground Waters (5)
68-2168	19791003	S2490 E150 NW 18 15S 6W SL	IPA	0.000	435.000	n/a	n/a	n/a	Underground Waters (5)
68-2168	19791003	S1470 E150 NW 18 15S 6W SL	IPA	0.000	435.000	n/a	n/a	n/a	Underground Waters (5)
68-2171	19791003	N500 W500 SE 13 15S 7W SL	IPA	0.000	435.000	n/a	n/a	n/a	Underground Waters (5)
68-2180	19791003	N600 E150 SW 19 15S 6W SL	IPA	0.000	388.000	n/a	n/a	n/a	Underground Waters (5)

TABLE B-2.1 – WATER RIGHT / SOURCE SUMMARY WITHIN 2 MILES OF PROJECT AREA

WRNUM	PRIORITY	LOCATION	OWNER	CFS	ACFT	Depth (ft)	Dia (in)	Perf Intervals	SOURCE
68-2180	19791003	S2490 E150 NW 19 15S 6W SL	IPA	0.000	388.000	n/a	n/a	n/a	Underground Waters (5)
68-2180	19791003	S1470 E150 NW 18 15S 6W SL	IPA	0.000	388.000	n/a	n/a	n/a	Underground Waters (5)
68-2181	19791003	N600 E150 SW 19 15S 6W SL	IPA	0.000	579.840	n/a	n/a	n/a	Underground Waters (5)
68-2181	19791003	S2490 E150 NW 19 15S 6W SL	IPA	0.000	579.840	n/a	n/a	n/a	Underground Waters (5)
68-2181	19791003	S2490 E150 NW 18 15S 6W SL	IPA	0.000	579.840	n/a	n/a	n/a	Underground Waters (5)
68-2181	19791003	S1470 E150 NW 18 15S 6W SL	IPA	0.000	579.840	n/a	n/a	n/a	Underground Waters (5)
68-2173	19791004	N600 E150 SW 19 15S 6W SL	IPA	0.000	250.000	n/a	n/a	n/a	Underground Water (5)
68-2173	19791004	S2490 E150 NW 19 15S 6W SL	IPA	0.000	250.000	n/a	n/a	n/a	Underground Water (5)
68-2173	19791004	S2490 E150 NW 18 15S 6W SL	IPA	0.000	250.000	n/a	n/a	n/a	Underground Water (5)
68-2173	19791004	S1470 E150 NW 18 15S 6W SL	IPA	0.000	250.000	n/a	n/a	n/a	Underground Water (5)
68-2182	19791019	N500 W500 SE 13 15S 7W SL	IPA	0.000	250.000	n/a	n/a	n/a	Underground Water (5)
68-2182	19791019	N600 E150 SW 19 15S 6W SL	IPA	0.000	250.000	n/a	n/a	n/a	Underground Water (5)
68-2182	19791019	S2490 E150 NW 19 15S 6W SL	IPA	0.000	250.000	n/a	n/a	n/a	Underground Water (5)
68-2182	19791019	S2490 E150 NW 18 15S 6W SL	IPA	0.000	250.000	n/a	n/a	n/a	Underground Water (5)
68-2182	19791019	S1470 E150 NW 18 15S 6W SL	IPA	0.000	250.000	n/a	n/a	n/a	Underground Water (5)
68-2227	19800227	N600 E150 SW 19 15S 6W SL	IPA	0.000	605.420	n/a	n/a	n/a	Underground Waters (5)
68-2227	19800227	S2490 E150 NW 19 15S 6W SL	IPA	0.000	605.420	n/a	n/a	n/a	Underground Waters (5)
68-2227	19800227	S2490 E150 NW 18 15S 6W SL	IPA	0.000	605.420	n/a	n/a	n/a	Underground Waters (5)
68-2227	19800227	S1470 E150 NW 18 15S 6W SL	IPA	0.000	605.420	n/a	n/a	n/a	Underground Waters (5)
68-264	19800326	N500 W500 SE 13 15S 7W SL	IPA	0.000	289.640	n/a	n/a	n/a	Underground Water
68-264	19800326	N600 E150 SW 19 15S 6W SL	IPA	0.000	289.640	n/a	n/a	n/a	Underground Water
68-264	19800326	S2490 E150 NW 19 15S 6W SL	IPA	0.000	289.640	n/a	n/a	n/a	Underground Water
68-264	19800326	S2490 E150 NW 18 15S 6W SL	IPA	0.000	289.640	n/a	n/a	n/a	Underground Water
68-264	19800326	S1470 E150 NW 18 15S 6W SL	IPA	0.000	289.640	n/a	n/a	na/	Underground Water
USE: UNDEFINED									
0768001M00	20070716	S505 W1812 NE 24 15S 7W SL	Intmtn Power Service Corp	0.000	0.000	170	1	n/a	Non-Production Well: Cathodic Prot
0768001M00	20070716	S633 W1663 NE 24 15S 7W SL	Intmtn Power Service Corp	0.000	0.000	170	1	n/a	Non-Production Well: Cathodic Prot
0768001M00	20070716	S501 W1462 NE 24 15S 7W SL	Intmtn Power Service Corp	0.000	0.000	170	1	n/a	Non-Production Well: Cathodic Prot
0768001M00	20070716	S654 W1325 NE 24 15S 7W SL	Intmtn Power Service Corp	0.000	0.000	170	1	n/a	Non-Production Well: Cathodic Prot
0768001M00	20070716	S564 W1174 NE 24 15S 7W SL	Intmtn Power Service Corp	0.000	0.000	170	1	n/a	Non-Production Well: Cathodic Prot
0768001M00	20070716	S565 W863 NE 24 15S 7W SL	Intmtn Power Service Corp	0.000	0.000	170	1	n/a	Non-Production Well: Cathodic Prot
0768001M00	20070716	S570 W427 NE 24 15S 7W SL	Intmtn Power Service Corp	0.000	0.000	0	0	n/a	Non-Production Well: Cathodic Prot

TABLE B-2.1 – WATER RIGHT / SOURCE SUMMARY WITHIN 2 MILES OF PROJECT AREA

WRNUM	PRIORITY	LOCATION	OWNER	CFS	ACFT	Depth (ft)	Dia (in)	Perf Intervals	SOURCE
0768001M00	20070716	S632 W426 NE 24 15S 7W SL	Intmtn Power Service Corp	0.000	0.000	170	1	n/a	Non-Production Well: Cathodic Prot
0768001M00	20070716	S566 W423 NE 24 15S 7W SL	Intmtn Power Service Corp	0.000	0.000	170	1	n/a	Non-Production Well: Cathodic Prot
0768001M00	20070716	S650 W37 NW 19 15S 6W SL	Intmtn Power Service Corp	0.000	0.000	170	1	n/a	Non-Production Well: Cathodic Prot
0768001M00	20070716	S572 W3 NE 24 15S 7W SL	Intmtn Power Service Corp	0.000	0.000	170	1	n/a	Non-Production Well: Cathodic Prot
0768001M00	20070716	S601 E27 NW 19 15S 6W SL	Intmtn Power Service Corp	0.000	0.000	170	1	n/a	Non-Production Well: Cathodic Prot
0768001M00	20070716	S575 E27 NW 19 15S 6W SL	Intmtn Power Service Corp	0.000	0.000	170	1	n/a	Non-Production Well: Cathodic Prot
0768001M00	20070716	S461 E120 NW 19 15S 6W SL	Intmtn Power Service Corp	0.000	0.000	170	1	n/a	Non-Production Well: Cathodic Prot
0768001M00	20070716	S242 E243 NW 19 15S 6W SL	Intmtn Power Service Corp	0.000	0.000	170	1	n/a	Non-Production Well: Cathodic Prot
0768001M00	20070716	S495 E383 NW 19 15S 6W SL	Intmtn Power Service Corp	0.000	0.000	170	1	n/a	Non-Production Well: Cathodic Prot
0768001M00	20070716	S181 E408 NW 19 15S 6W SL	Intmtn Power Service Corp	0.000	0.000	170	1	n/a	Non-Production Well: Cathodic Prot
0768001M00	20070716	S796 E412 NW 19 15S 6W SL	Intmtn Power Service Corp	0.000	0.000	170	1	n/a	Non-Production Well: Cathodic Prot
0768001M00	20070716	S140 E685 NW 19 15S 6W SL	Intmtn Power Service Corp	0.000	0.000	170	1	n/a	Non-Production Well: Cathodic Prot
0768001M00	20070716	S837 E693 NW 19 15S 6W SL	Intmtn Power Service Corp	0.000	0.000	170	1	n/a	Non-Production Well: Cathodic Prot
0768001M00	20070716	S490 E841 NW 19 15S 6W SL	Intmtn Power Service Corp	0.000	0.000	170	1	n/a	Non-Production Well: Cathodic Prot
0768001M00	20070716	S833 E1010 NW 19 15S 6W SL	Intmtn Power Service Corp	0.000	0.000	170	1	n/a	Non-Production Well: Cathodic Prot
0768001M00	20070716	S198 E1013 NW 19 15S 6W SL	Intmtn Power Service Corp	0.000	0.000	170	1	n/a	Non-Production Well: Cathodic Prot
0768001M00	20070716	S420 E1254 NW 19 15S 6W SL	Intmtn Power Service Corp	0.000	0.000	170	1	n/a	Non-Production Well: Cathodic Prot
0768001M00	20070716	S754 E1257 NW 19 15S 6W SL	Intmtn Power Service Corp	0.000	0.000	170	1	n/a	Non-Production Well: Cathodic Prot
0768001M00	20070716	S624 E1307 NW 19 15S 6W SL	Intmtn Power Service Corp	0.000	0.000	170	1	n/a	Non-Production Well: Cathodic Prot
0768003M00	20071029	S80 W50 N4 22 15S 7W SL	Intmtn Power Service Corp	0.000	0.000	56	4	n/a	Non-Production Well: Monitor
0768003M00	20071029	S1180 W1550 NE 22 15S 7W SL	Intmtn Power Service Corp	0.000	0.000	66	4	n/a	Non-Production Well: Monitor
0768003M00	20071029	N1500 W150 SE 15 15S 7W SL	Intmtn Power Service Corp	0.000	0.000	50	4	n/a	Non-Production Well: Monitor
0768003M00	20071029	S80 W60 NE 22 15S 7W SL	Intmtn Power Service Corp	0.000	0.000	76	6	n/a	Non-Production Well: Monitor
0768003M00	20071029	S1200 E1300 NW 23 15S 7W SL	Intmtn Power Service Corp	0.000	0.000	46	4	n/a	Non-Production Well: Monitor
0768003M00	20071029	N1520 E1835 SW 14 15S 7W SL	Intmtn Power Service Corp	0.000	0.000	62	2	n/a	Non-Production Well: Monitor
0768003M00	20071029	N1500 E1850 SW 14 15S 7W SL	Intmtn Power Service Corp	0.000	0.000	66	6	n/a	Non-Production Well: Monitor
0768003M00	20071029	N300 E1900 SW 14 15S 7W SL	Intmtn Power Service Corp	0.000	0.000	36	4	n/a	Non-Production Well: Monitor
0868002M00	20080911	N1300 E0 S4 15 15S 7W SL	Intmtn Power Service Corp	0.000	0.000	n/a	n/a	n/a	Non-Production Well: Monitor
0868002M00	20080911	S2300 E2150 NW 14 15S 7W SL	Intmtn Power Service Corp	0.000	0.000	n/a	n/a	n/a	Non-Production Well: Monitor
0868002M00	20080911	S1750 E2150 NW 14 15S 7W SL	Intmtn Power Service Corp	0.000	0.000	n/a	n/a	n/a	Non-Production Well: Monitor
0868002M00	20080911	S1200 E2150 NW 14 15S 7W SL	Intmtn Power Service Corp	0.000	0.000	n/a	n/a	n/a	Non-Production Well: Monitor
0868002M00	20080911	S500 E2700 NW 14 15S 7W SL	Intmtn Power Service Corp	0.000	0.000	n/a	n/a	n/a	Non-Production Well: Monitor

TABLE B-2.1 – WATER RIGHT / SOURCE SUMMARY WITHIN 2 MILES OF PROJECT AREA

WRNUM	PRIORITY	LOCATION	OWNER	CFS	ACFT	Depth (ft)	Dia (in)	Perf Intervals	SOURCE
0868002M00	20080911	S500 E3000 NW 14 15S 7W SL	Intmtn Power Service Corp	0.000	0.000	n/a	n/a	n/a	Non-Production Well: Monitor
0868004M00	20081015	S50 W50 NE 27 15S 7W SL	MANGUM HOLDINGS, LLC	0.000	0.000	3250	7-14	1650-1680 1840-1870 1950-2020 2180-2240	Non-Production Well: Test
0868004M00	20081015	N0 E1600 SW 23 15S 7W SL	MANGUM HOLDINGS, LLC	0.000	0.000	n/a	n/a	n/a	Non-Production Well: Test
0968001M00	20090305	N2060 E0 SW 14 15S 7W SL	Intmtn Power Service Corp	0.000	0.000	57	4	n/a	Non-Production Well: Monitor
0968001M00	20090305	S1300 E2080 NW 14 15S 7W SL	Intmtn Power Service Corp	0.000	0.000	55	6	n/a	Non-Production Well: Monitor
9868002P00		S4510 E420 NW 28 15S 7W SL	CRS CONSULTING ENGS	0.000	0.000	300	6	n/a	Non-Production Well:
68-2717	19850627	N700 E150 SW 19 15S 6W SL	C+ LAND & CATTLE Co.	0.725	0.000	n/a	n/a	n/a	Underground Water
68-2717	19850627	N1470 E150 SW 19 15S 6W SL	C+ LAND & CATTLE Co.	0.725	0.000	n/a	n/a	n/a	Underground Water
68-2717	19850627	N500 E100 SE 13 15S 7W SL	C+ LAND & CATTLE Co.	0.725	0.000	n/a	n/a	n/a	Underground Water
68-2717	19850627	S1170 E150 NW 19 15S 6W SL	C+ LAND & CATTLE Co.	0.725	0.000	n/a	n/a	n/a	Underground Water
68-2717	19850627	N1470 E150 SW 18 15S 6W SL	C+ LAND & CATTLE Co.	0.725	0.000	n/a	n/a	n/a	Underground Water
68-2717	19850627	S2485 E217 NW 19 15S 6W SL	C+ LAND & CATTLE Co.	0.725	0.000	n/a	n/a	n/a	Underground Water
68-2717	19850627	S2390 E150 NW 18 15S 6W SL	C+ LAND & CATTLE Co.	0.725	0.000	n/a	n/a	n/a	Underground Water
68-2717	19850627	S1470 E150 NW 18 15S 6W SL	C+ LAND & CATTLE Co.	0.725	0.000	n/a	n/a	na/	Underground Water

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Table B-3.1
Information for Selected Deep Water Wells

Well ID*	Well Number**	Name	Year Drilled	Drilled Depth (ft)	Casing Diameter (inch)	Finish Type and Interval ****	Pump Test Information			Ground Elev. (ft)	Aquifer***	Static Water Level			Other data****	Comments
							Yield (gpm)	Drawdown (ft)	Hours			Depth (ft) ****	Date	Elevation (ft)		
A	(C-15-6)18bcc-1	IPP	1981	819	3	S 619 - 819				4695	Deep	42.9	4/5/1981	4652		
B	(C-15-6)18bcc-2	IPP	1982	1,333	20,16,14	S 890 - 980	3,503	83.1	4	4695	Deep	49	5/10/1982	4646	L	*Location in R7W?
						S 1000 - 1080										
						S 1120 1200										
						S 1210 1230										
						S 1250 1260										
						S 1280 1300										
C	(C-15-6)18ccc-1	IPP	1982	1,334	20,16,14	S 902 - 944	3,608	107.8	1	4690	Deep	42	4/2/1982	4648	L	Pump test data
						S 1034 - 1164										
						S 1184 1224										
						S 1244 1264										
						S 1294 1314										
D	(C-15-6)19bcc-1	IPP	1981	1,222	20,16,10	S 664 - 1,180				4680	Deep	25.6	11/2/1988	4654	LC	Renovated information on screen placement is different TDS = 281 mg/L (4-12-1981)
D	(C-15-6)19bcc-1	IPP	1988 renovated	1,177	16,12,10	S 569 - 814	244	47.66	1		Deep				L	
							480	97.90	1							
							732	172.39	24							
D	(C-15-6)19bcc-1	IPP	Clean 2004		zone cleaned	568 - 806									L	Installed 75 HP 750 gpm pump at 225 ft
E	(C-15-6)19ccc-1	IPP	1981	1,110	3	S 1,000 - 1,110					Deep			4645		Water level from TP79 Plate 1
F	(C-15-7)13ddd-1	IPP	1981	500	2.5	S 300 - 500					Shallow					
G	(C-15-7)13ddd-2	IPP	1981	770	2.5	S 570 - 770										
H	(C-15-7)13ddd-3	IPP	1981	1,105	3	S ?				4687		18	1/19/1981	4669	L	
J	(C-15-7)13ddd-4	IPP	1982	1,328	20,16,14	S 830 - 910	3,600	75	5.5	4687	Deep	27	2/28/1982	4660	L	
						S 930 - 1070										
K	(C-15-7)18caa-1	Davis	1952	795	12,8	P 300 - 780	690			4577	Shallow & Deep				L	Same as Petty well?
M	(C-15-7)23bac-1	Argonaut	1978	182	6.6	P 160 - 182				4630	Shallow				W	Observation well in shallow artesian aquifer
N	(C-15-7)23bac-2	Argonaut	1978	11,266												Argonaut Energy Exploration Well
O	(C-15-7)27daa-1	George	1952	650	12,8	P 175 - 634				4597				4597	LW	
P	(C-15-7)33bcd-1	Davis	1962	900	24	P 500 - 900	1,000			4583	Deep	2+	4/10/1962	4585	LCP	TDS = 300 mg/L (6-22-1962) 600 gpm artesian flow
Q	(C-15-7)35bcd-1	Andersen	1951	594		P 279 - 537	550	artesian flow		4597	Shallow	18+	11/3/1951	4615	L	
R	(C-15-7)27cab-1	Miller		668												
S	(C-16-7)3acc-1	Done	1966	875	16,12,13	P 550 - 835						20	6/20/1966		L	
T	(C-16-7)10bad-1	Done	1961	919	16,12	P 500 - 915						+	9/3/1961		L	
U	(C-16-7)11ccd-1	Jensen	1966	729	16,14	P 612 - 724	500		0.5			4+	1/6/1966		L	Artesian flow of 200 gpm
V	(C-15-7)28abc-1	Delta Egg		800	16											Water right proof says 3.7 cfs observed from 10" discharge pipe from well
W	(C-15-7)33bcd-1	Delta Egg		900	14											
X	(C-15-7)30caa-1	Tyree		500								147?	12/15/1963			

Data are from Mower and Feltis (1964), Enright and Holmes (1982), and files of Utah Division of Water Rights; blank field means no data.

* See Figure B-3.1 for well location.

** Well numbering system used by US Geological Survey.

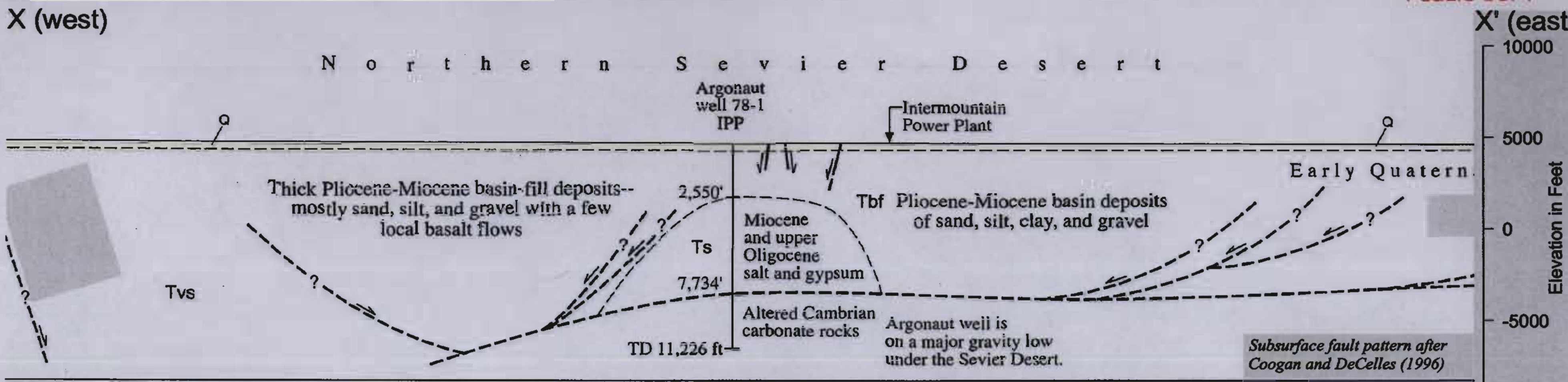
*** Shallow means shallow artesian aquifer; Deep means deep artesian aquifer.

**** S means scrren; P means perforations; + means level above ground; L means drillers log available; C means chemical analysis available; W means water level data available.

PUBLIC COPY

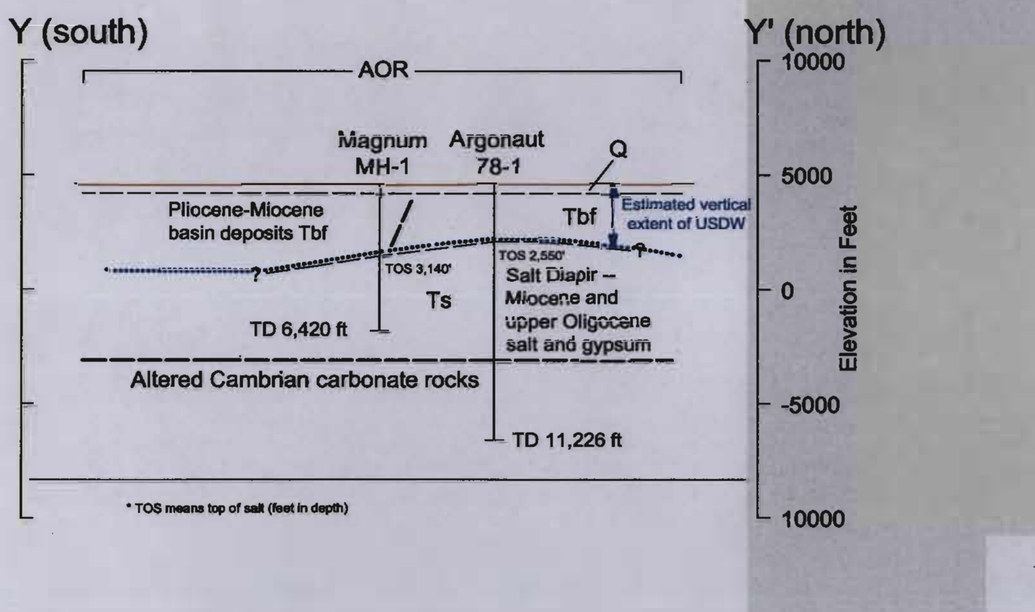
FIGURES

THE FOLLOWING FIGURES ARE CONFIDENTIAL



Cross section X-X' modified from: "Geologic Map of the Delta 30' x 60' Quadrangle ..." (Hintze and Davis, 2002, cross section A-A')

0 1
Scale in Miles
No vertical exaggeration



* TOS means top of salt (feet in depth)

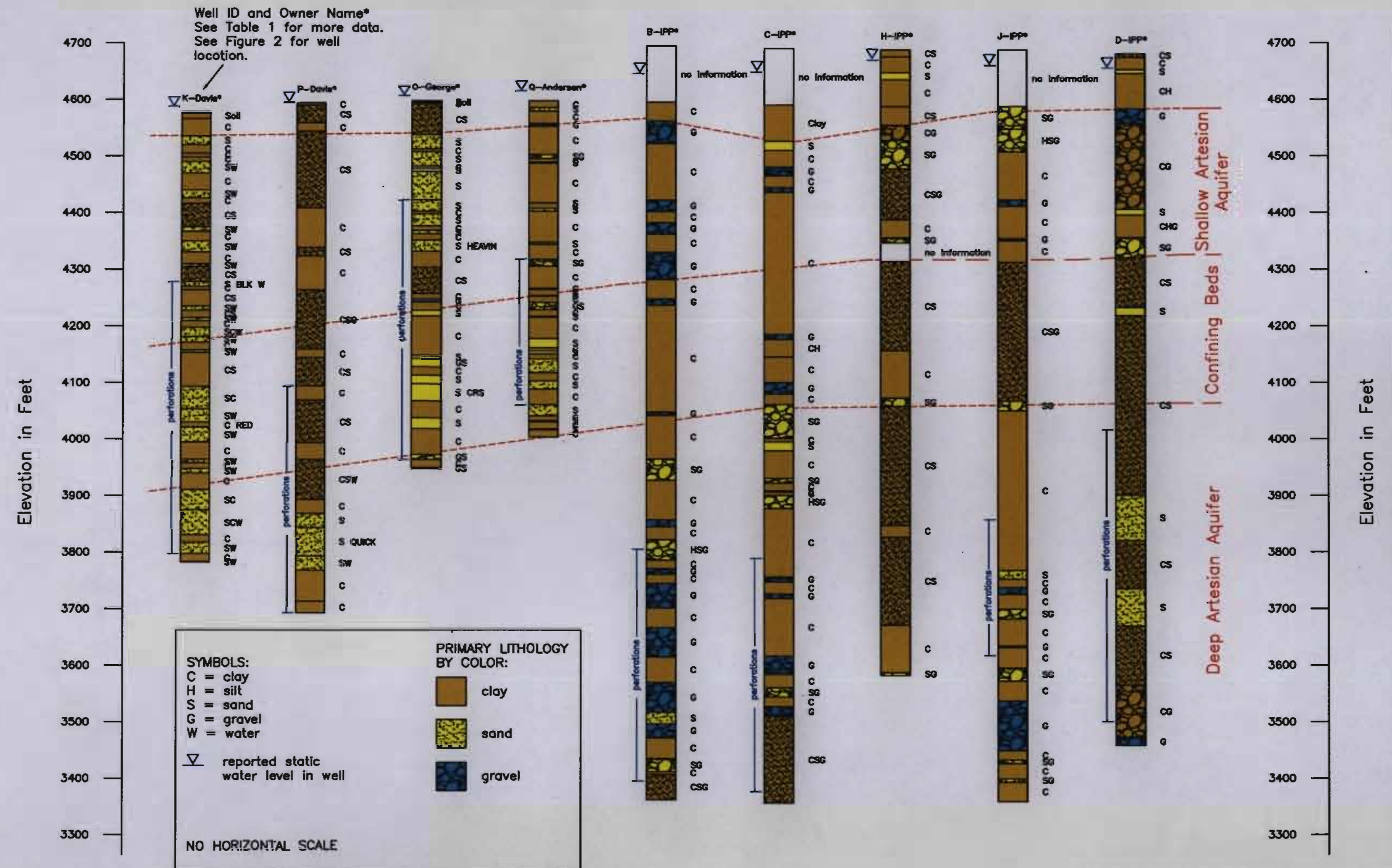
Magnum Energy LLC

USDW Cross Sections

Figure B-3.2

File: Fig3–WellDiag.dwg   Date: April 2008   By: GWC   Checked by: ___

PUBLIC COPY



Note: This is not a scaled cross section but rather shows logs of distant wells placed side-by-side. Locations of the wells (designated by letter at the top of each log) on this diagram are shown on Figure B-3.1.

LOUGHLIN WATER ASSOCIATES LLC

Magnum Energy LLC

Well Log Diagram

Figure B-3.3

PUBLIC COPY

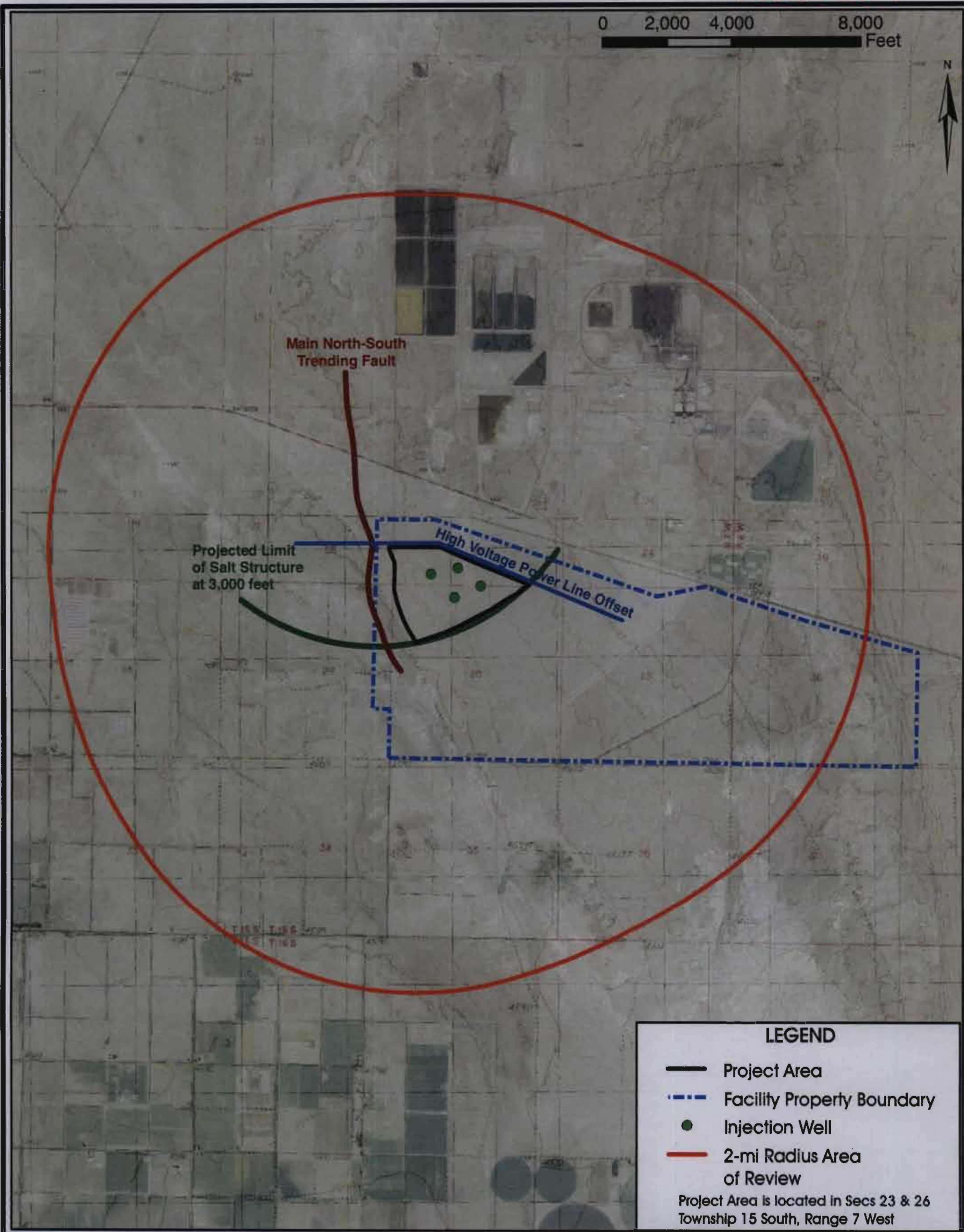
MAPS

FILE DATE: 10.2.2009 12:32:02 (CAH)

GENERAL LOCATION MAP

FIGURE 1

PUBLIC COPY



HANSEN ALLEN & LUCE INC ENGINEERS

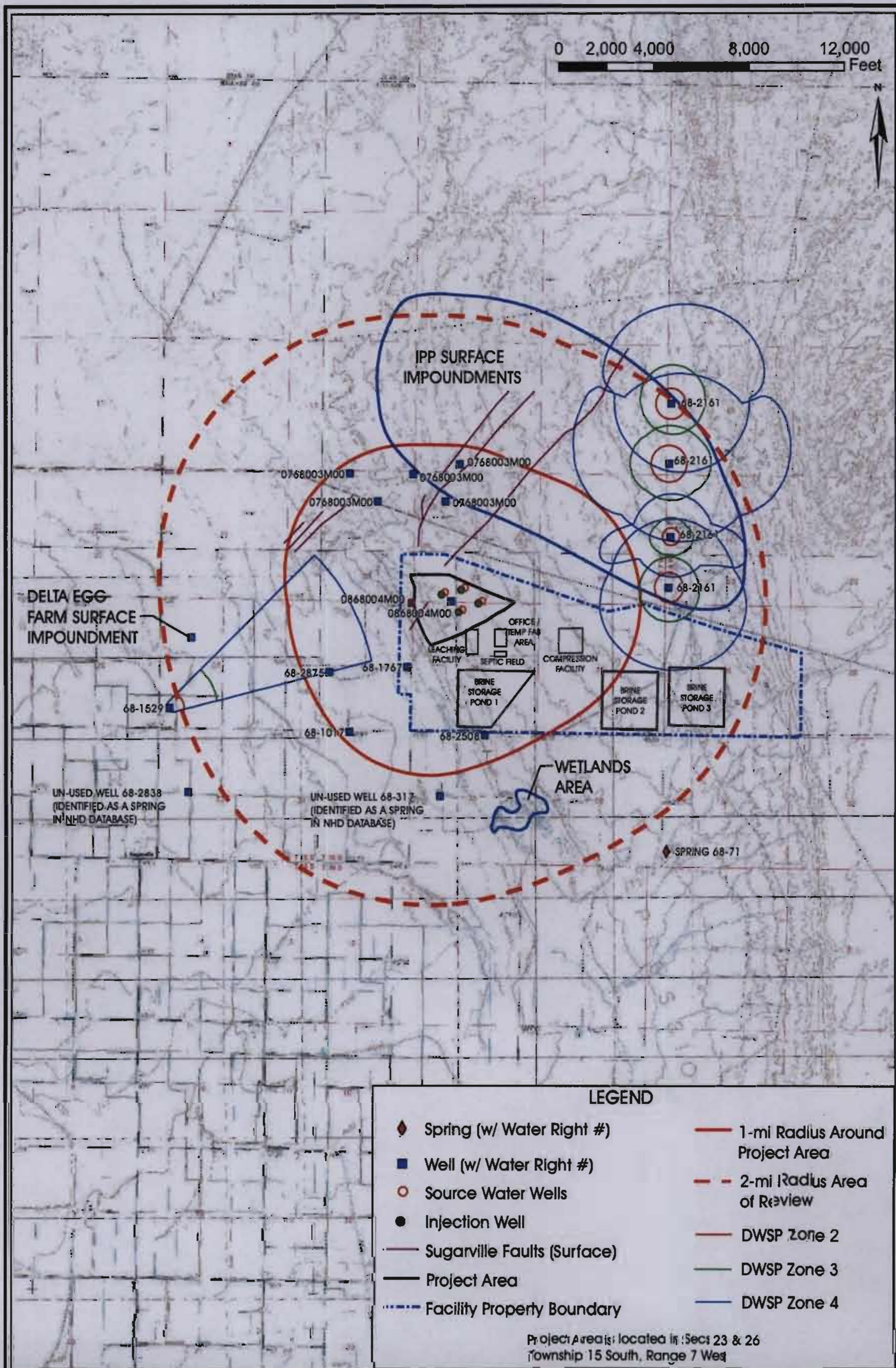
MAGNUM ENERGY, LLC
Western Energy Hub

MAGNUM GAS STORAGE PROJECT

PROJECT AREA, FACILITY PROPERTY BOUNDARY & AREA OF REVIEW

MAP A-1.1

PUBLIC COPY



HANSEN ALLEN & LUCE INC. ENGINEERS

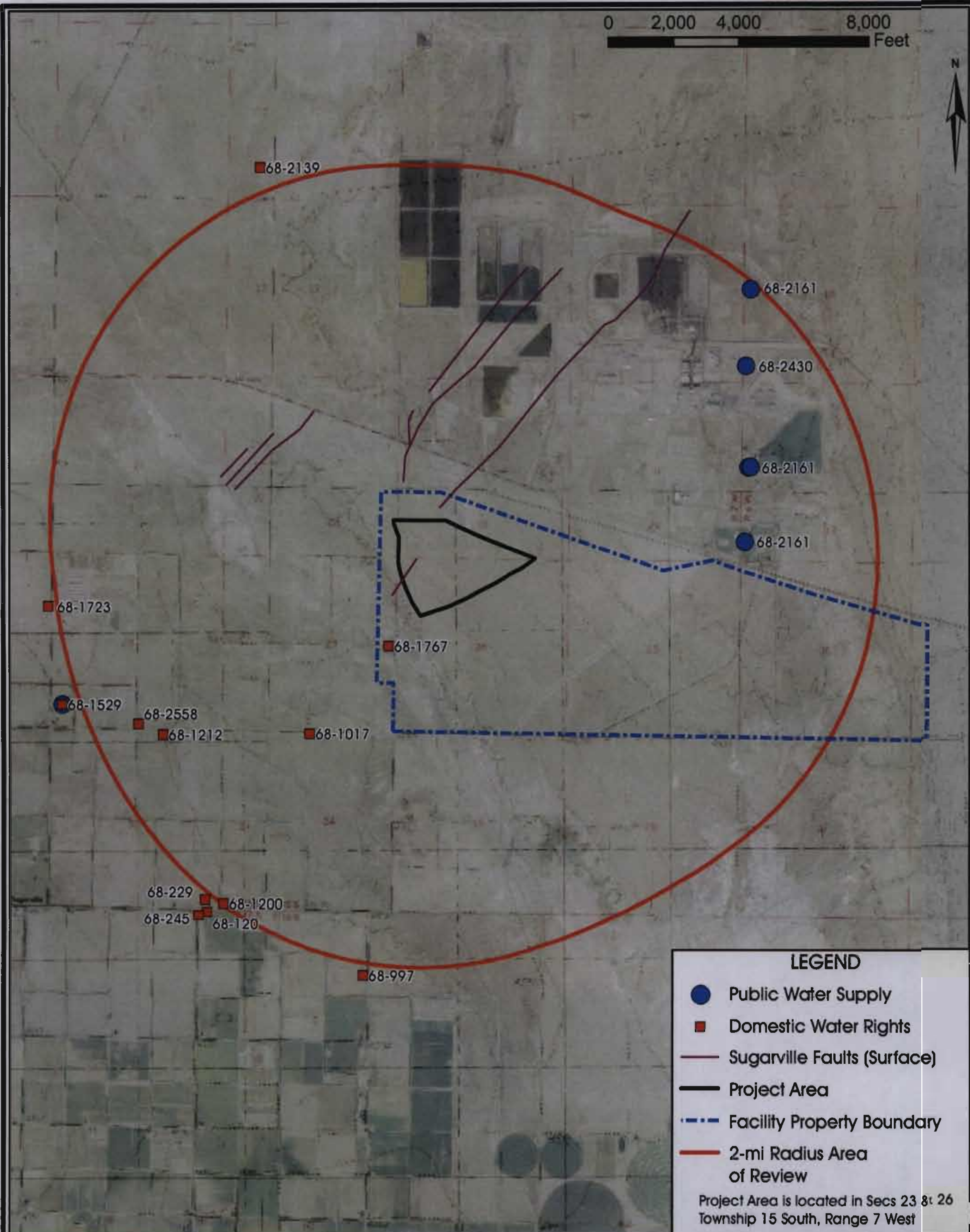
MAGNUM ENERGY, LLC Western Energy Hub

MAGNUM GAS STORAGE PROJECT

MAP OF FACILITY AND PROJECT AREA

MAP B-1.1

PUBLIC COPY



HANSEN ALLEN & LUCE INC ENGINEERS

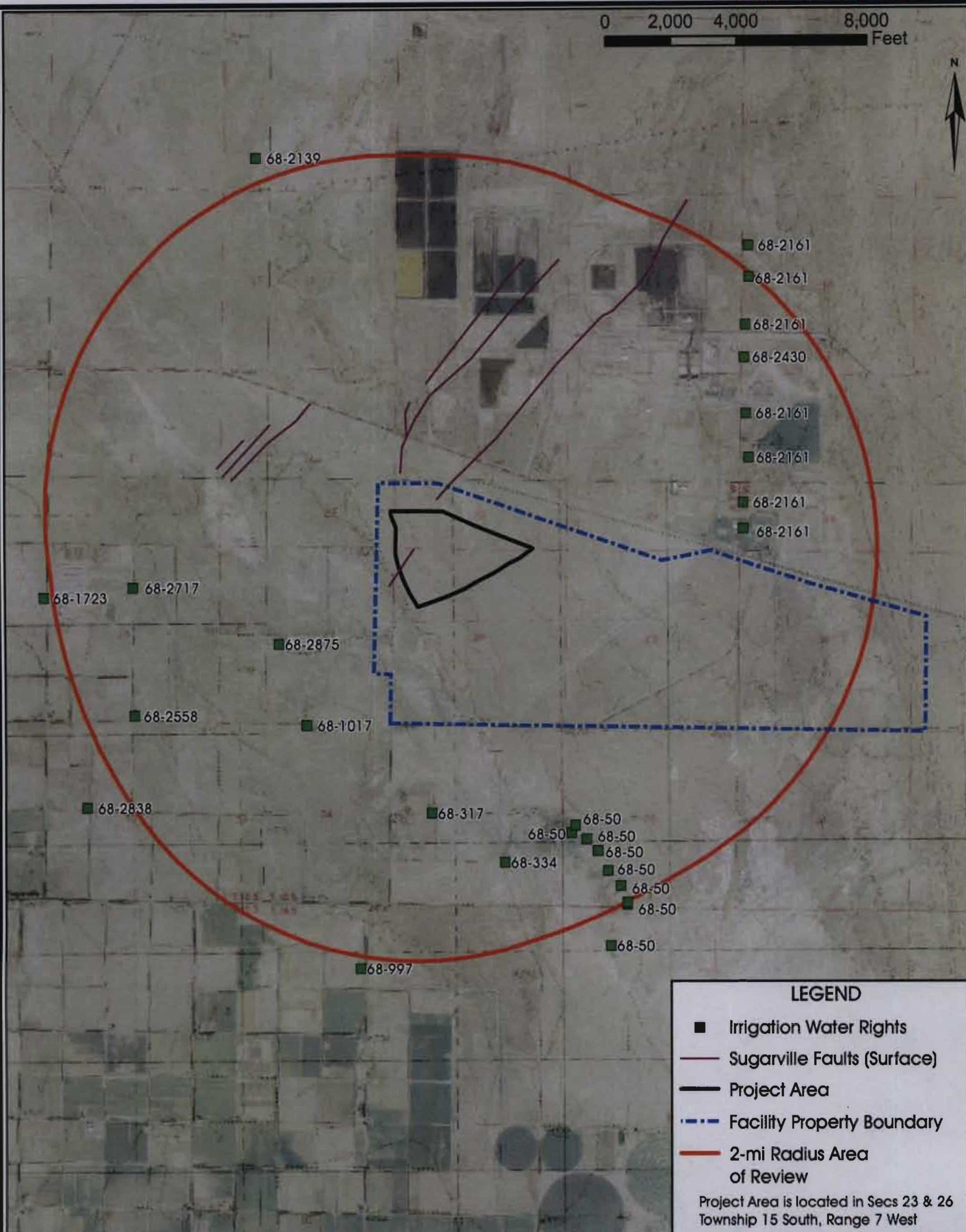
MAGNUM ENERGY, LLC
Western Energy Hub

MAGNUM GAS STORAGE PROJECT

AREA OF REVIEW MAP
DOMESTIC WATER RIGHTS

MAP
B-2.1

PUBLIC COPY



HANSEN ALLEN & LUCE INC ENGINEERS

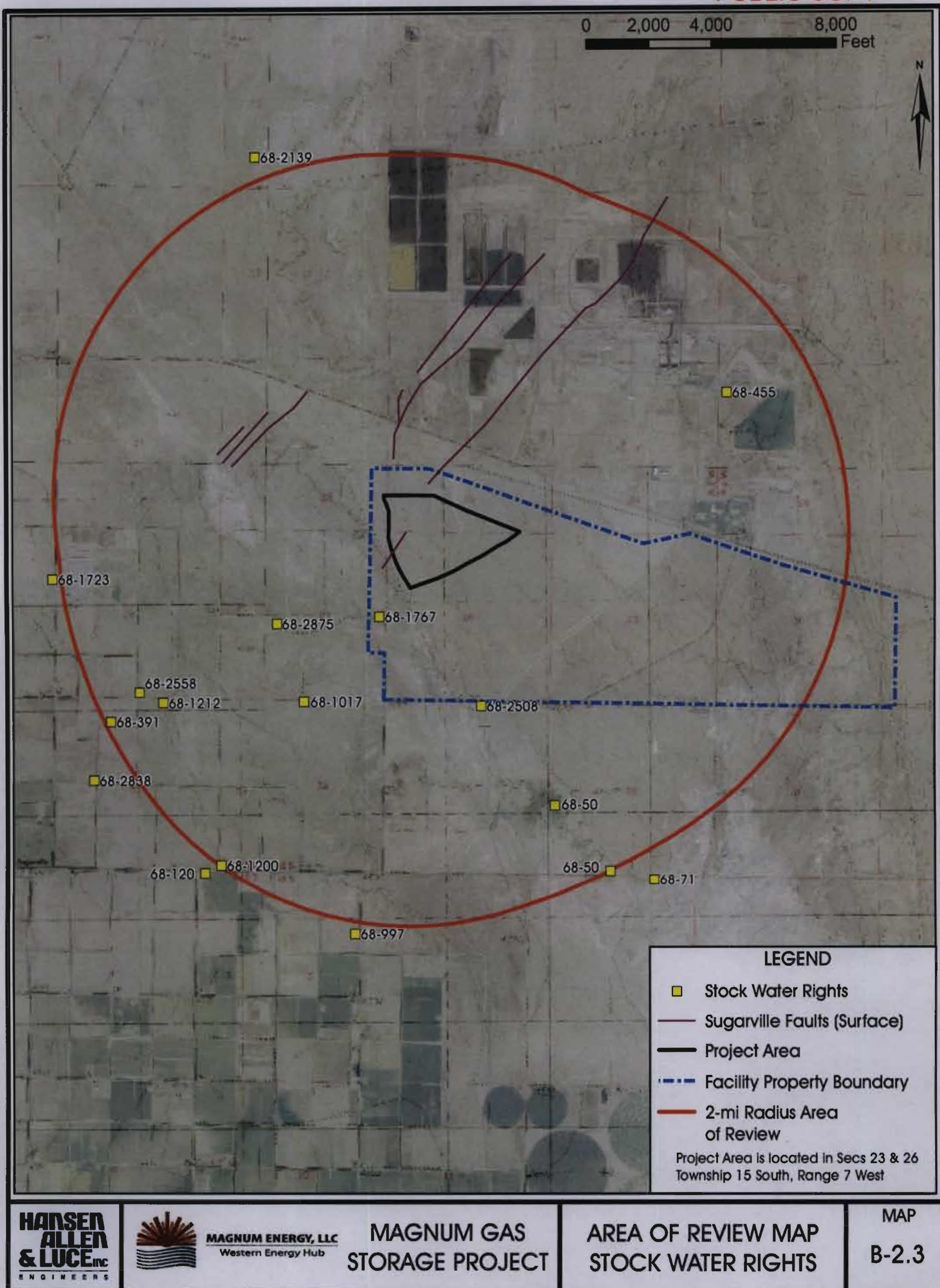
MAGNUM ENERGY, LLC
Western Energy Hub

MAGNUM GAS STORAGE PROJECT

AREA OF REVIEW MAP
IRRIGATION WATER RIGHTS

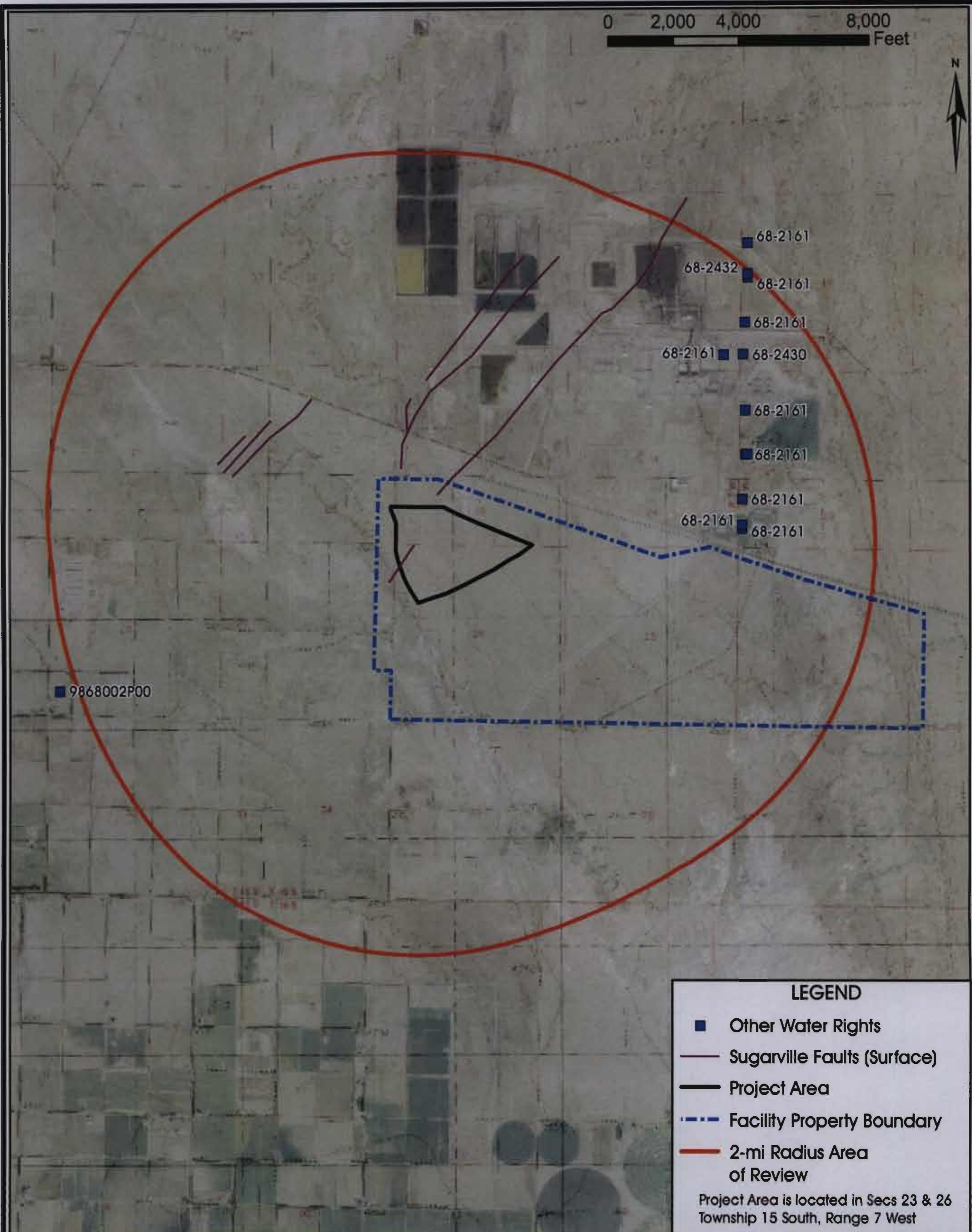
MAP
B-2.2

PUBLIC COPY



0 2,000 4,000 8,000
Feet
N
68-2139
68-455
68-1723
68-2875
68-1767
68-2558
68-1212
68-1017
68-2508
68-391
68-2838
68-50
68-120
68-1200
68-50
68-71
68-997
LEGEND
Stock Water Rights
Sugarville Faults (Surface)
Project Area
Facility Property Boundary
2-mi Radius Area of Review
Project Area is located in Secs 23 & 26
Township 15 South, Range 7 West
HANSEN ALLEN & LUCE INC ENGINEERS
MAGNUM ENERGY, LLC
Western Energy Hub
MAGNUM GAS STORAGE PROJECT
AREA OF REVIEW MAP
STOCK WATER RIGHTS
MAP
B-2.3

PUBLIC COPY



HANSEN ALLEN & LUCE INC ENGINEERS

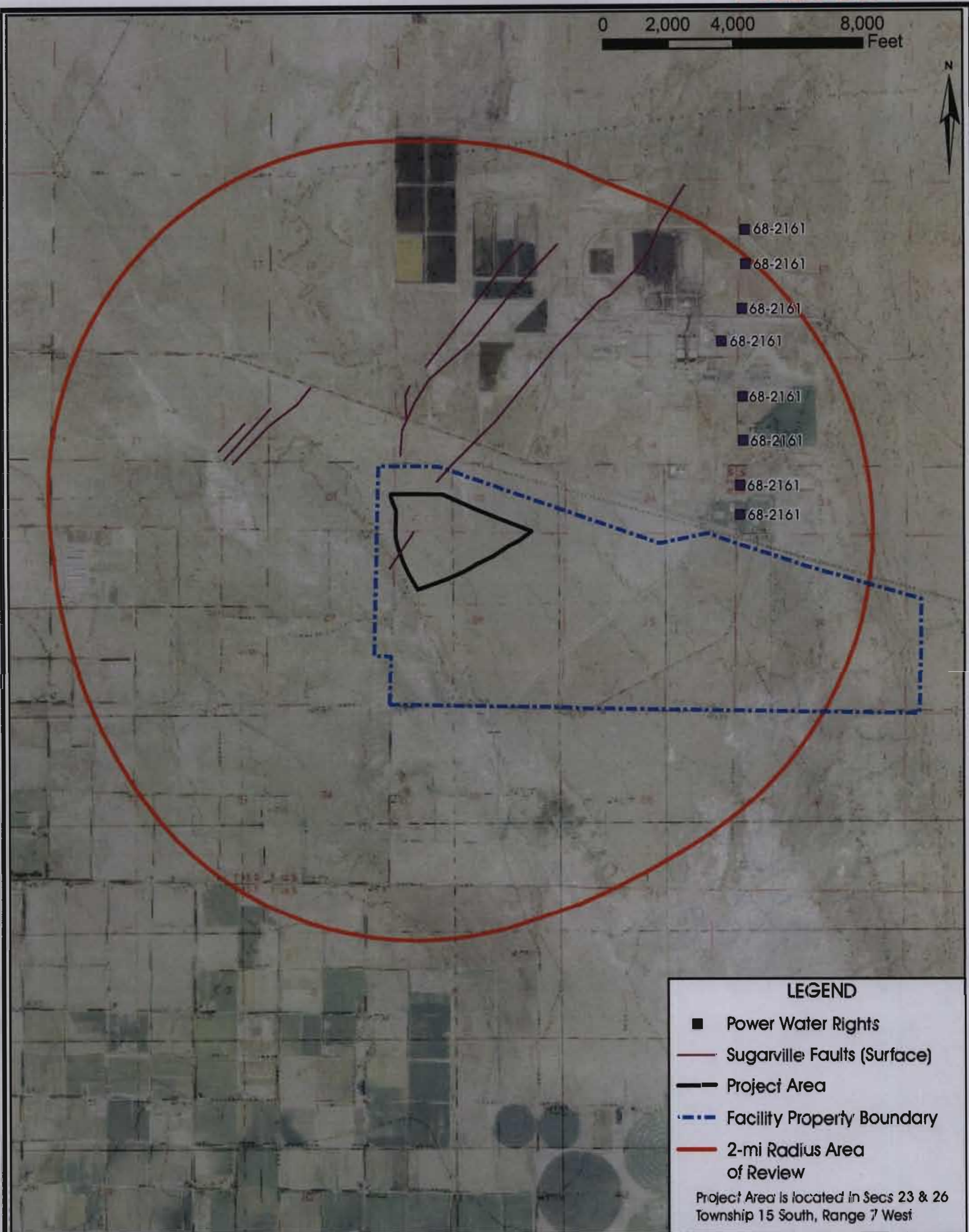
MAGNUM ENERGY, LLC Western Energy Hub

MAGNUM GAS STORAGE PROJECT

AREA OF REVIEW MAP OTHER WATER RIGHTS

MAP B-2.4

PUBLIC COPY



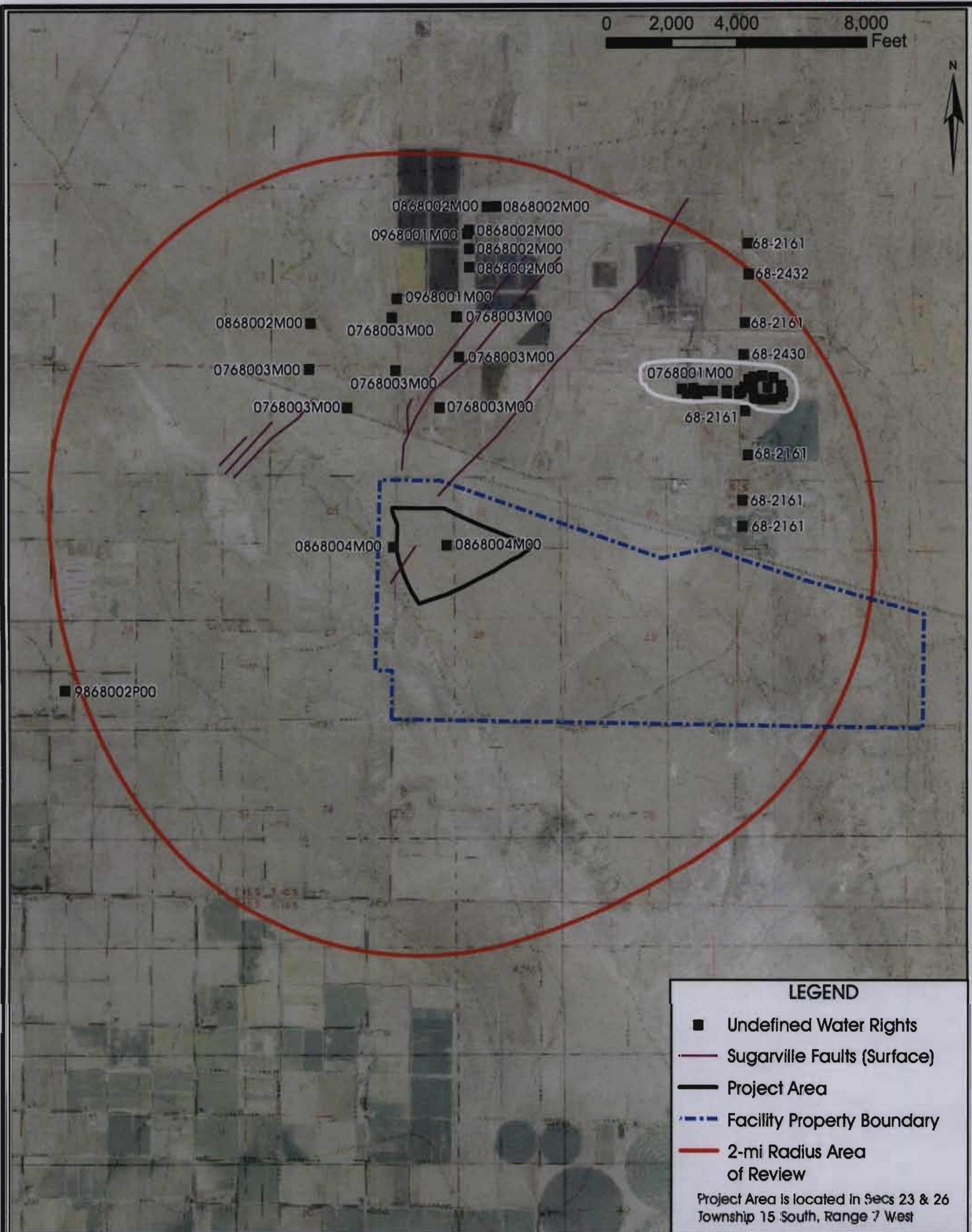
HANSEN ALLEN & LUCE inc ENGINEERS

MAGNUM ENERGY, LLC
Western Energy Hub

MAGNUM GAS STORAGE PROJECT

AREA OF REVIEW MAP POWER WATER RIGHTS

MAP B-2.5



HANSEN ALLEN & LUCE INC ENGINEERS

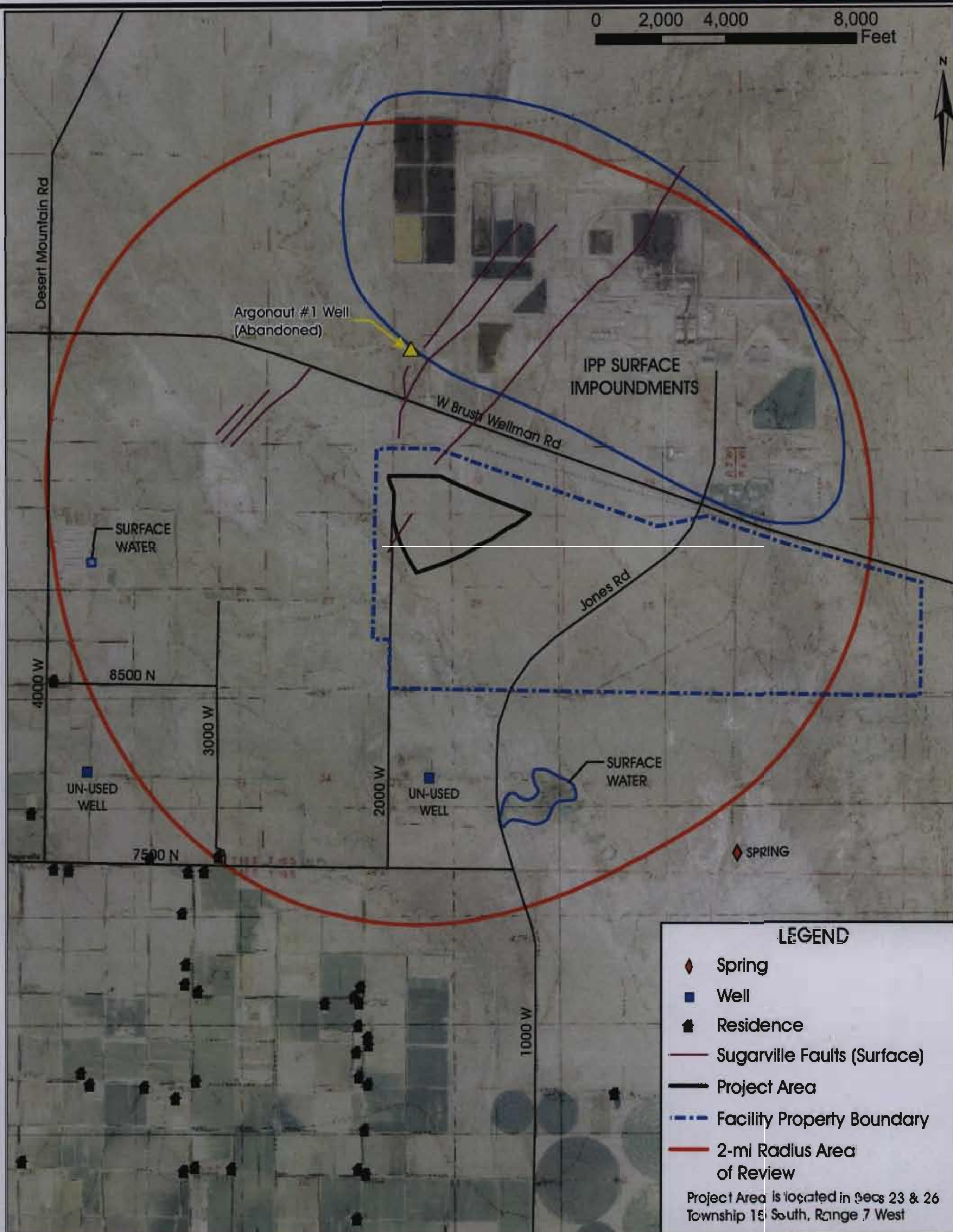
MAGNUM ENERGY, LLC Western Energy Hub

MAGNUM GAS STORAGE PROJECT

AREA OF REVIEW MAP UNDEFINED WATER RIGHTS

MAP B-2.6

PUBLIC COPY



HANSEN ALLEN & LUCE INC ENGINEERS

MAGNUM ENERGY, LLC
Western Energy Hub

MAGNUM GAS STORAGE PROJECT

AREA OF REVIEW MAP SURFACE FEATURES

MAP B-2.7

PUBLIC COPY

DRAWINGS

THE FOLLOWING DRAWINGS ARE CONFIDENTIAL

Drawing B-4.1	Local Geology / Structure – Sub-Surface Projection – 3,000 Feet
Drawing B-4.2	Geologic Cross-Section A-A’
Drawing B-4.3	Geologic Cross-Section B-B’

PUBLIC COPY

ATTACHMENT 4.1

Stratigraphy and Groundwater of the Lake Bonneville Sediments near the Magnum Holdings #1 Well

In the fall of 2008, Magnum conducted 3-D sonic surveys within the area that covered the salt structure and surrounding area. These surveys provided detailed images of the geometry of the salt structure and its position within the Lake Bonneville sediments. Figure B-4.1 shows a color plan view of the project site that generally focuses on the location of the salt structure. [redacted] The locations of planned gas storage caverns are within the northern half of Section 26 and southern half of Section 23. [redacted]

Figure B-4.2 shows an east-west cross section (through well MH-1) through the salt structure. Note from the figure [redacted]

The numerous sediment horizons present in the Lake Bonneville sediments act as sonic reflectors and aid in the mapping of the geologic structure within the area. [redacted]

Based on the data provided by the sonic survey, Magnum drilled a well that penetrated the Lake Bonneville strata and the salt structure, to evaluate the suitability of the salt to be used to store natural gas. This well, Magnum-Holdings # 1 (MH-1) was started on December 8, 2008 and completed on March 15, 2009 at a depth o[redacted] feet. The well penetrated [redacted] feet of Lake Bonneville sediments before being drilled the rest of the way in [redacted] The sediments penetrated between [redacted] feet and [redacted] feet were alternating layers of detrital sediment, mainly sand and clayey sand and evaporites, primarily anhydrite and halite. Below a depth of [redacted] feet to the bottom of the hole was drilled using both core and rotary methods. The cores recovered showed tha[redacted]

[redacted]

The sediments above the salt structure are for the most part very fine-grained and clay-rich. This is because the majority of the water and sediment entering into Lake Bonneville occurred from the major rivers draining the Wasatch Mountain Range located to the east. Minor water and sediment was provided from drainage off the numerous islands within the lake. The area where the MH-1 well was drilled is not near the sources of sediment and as a result, most of the sediment drilled is fine-grained and very clay-rich. Numerous zones of [redacted] Geologic cross-sections, one oriented in a northeast direction (section A-A') and one oriented in a northwest direction (section B-B') are provided to show the relationship of the developed aquifer, undeveloped aquifer and the saline aquifer in relationship to the salt structure (see Drawings B-4.2 & B-4.3 respectively). The geologic cross-sections are based on the sediments penetrated in drill hole MH-1 and the sonic survey.

The data collected by Magnum though the sonic survey and the drilling of well MH-1 indicate the local existence of three separate groundwater systems. An upper, previously known and developed aquifer above 1,400 feet (containing the shallow unconfined water table, shallow artesian, and deep artesian aquifers discussed earlier in Part B), a previously undocumented and currently undeveloped aquifer system between 1,400 feet and [redacted] feet, and [redacted] As indicated above, pump testing [redacted] was shown to have no impact on the upper developed aquifer, and the quality of water pumped showed no indication of communication with the saline aquifer below.

coarser-grained sediments were intersected in the MH-1 well. These zones were either sandy-gravels or sand and are aquifers within the area. The sedimentary beds penetrated in the upper [redacted] feet of the MH-1 well were primarily light-tan to buff in color. When drilling penetrated below [redacted] feet, the color of the sediment was gray to dark-gray/black. [redacted]

While drilling the MH-1 well, an SDI data logger was placed in the drilling mud flow to identify changes in water quality as drilling progressed. This data logger recorded measurements of dissolved oxygen, pH, salinity, conductivity, total dissolved solids and temperature on 15 minute intervals. The data was influenced by changes in the drilling mud but broad changes in water quality as the hole progressed downward could be identified. Figure B-4.3 illustrates the changes in salinity as the hole progressed to the top of salt influence at [redacted] feet.

In addition to the water quality data logged on 15 minute intervals, water samples were decanted from the drilling mud at intervals as close as 20 feet in depth and tested for their chloride content. As the drilling penetrated strata approaching the top of the salt at [redacted] feet, [redacted] Figure B-4.4 illustrates the results of the chloride testing approaching the top of salt. The amount of groundwater flowing into the well and diluting the drilling mud was small, so a slight increase in measured chloride content equates to a substantial increase in the groundwater's chloride content. It is expeced that the chloride content of the water below [redacted] All drilling completed below [redacted] feet was converted to 100% saturated calcium chloride brine solution rather than drilling mud, therefore, additional chemical testing during drilling would not be relevant.

After the drilling of MH-1 Well was completed, several isolated aquifer zones were tested. This testing was completed through the perforation of casing that had been placed in the well, followed by the installation of packers above and below the zone to be tested. Pump tests were then conducted on the individual aquifers as discussed in Part C of this technical report. From these tests, it was concluded that the clay-rich sediments between the sand/gravel zones act as effective aquicludes, thus compartmentalizing the strata into several isolated aquifer systems. In summary, pumping of the aquifer located between [redacted] feet had no impact on the next higher aquifer in the MH-1 Well located between [redacted] feet. Recently completed seismic logging (see Figure B-4.2) shows that although there is some vertical variation, the sediments which have been deposited within the local lacustrine environment within the Project Areas have formed a fairly uniform blanket deposit east of the main bounding fault located near well MH-1. T he clay-rich zones therefore locally act as boundaries that separate the aquifers within the section. [redacted]

Although data does not yet exist to confirm this fact, the quality of the water encountered below [redacted] feet is not believed to be suitable for use as either domestic or agricultural use. [redacted]

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ATTACHMENT C-1.1

Argonaut Well

Well Schematic
Monthly Reports
Sundry Notices and Reports on Wells

HANSEN ALLEN & LUCE inc
ENGINEERS

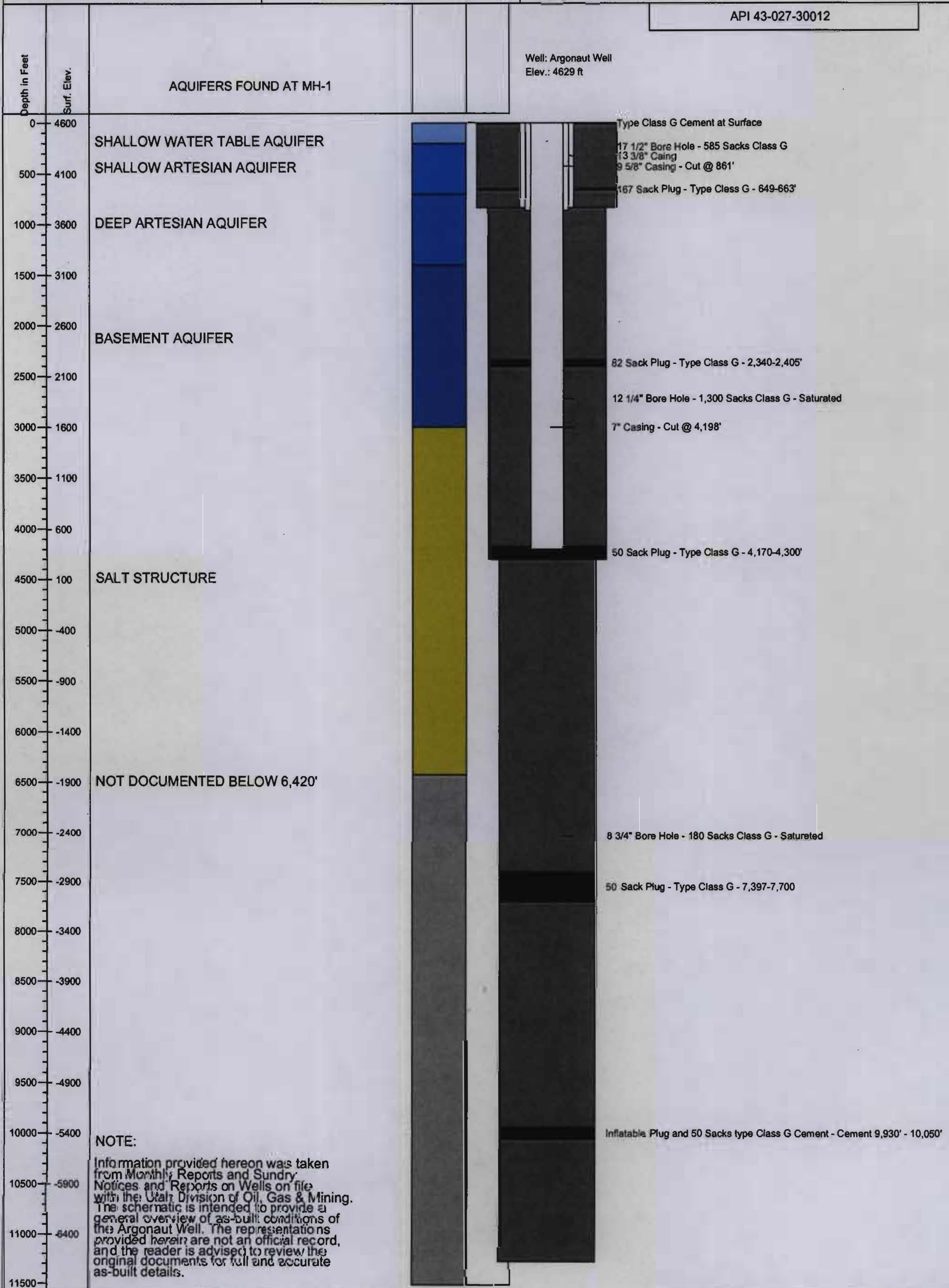
Magnum Holdings
Salt Lake City, Utah

ARGONAUT WELL SCHEMATIC

PUBLIC COPY

Date Started	: MARCH 1978	Company Rep.	:
Date Completed	: JULY 1978	Northing Coord.	: 39.50550000
Hole Diameter	: 8 3/4 - 17 1/2 in.	Easting Coord.	: -112.6076900
Drilling Method	:	Survey By	:
Sampling Method	:	Logged By	:

API 43-027-30012



NOTE:

Information provided hereon was taken from Monthly Reports and Sundry Notices and Reports on Wells on file with the Utah Division of Oil, Gas & Mining. The schematic is intended to provide a general overview of as-built conditions of the Argonaut Well. The representations provided herein are not an official record, and the reader is advised to review the original documents for full and accurate as-built details.

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY
(FORM 9-329)
(2/76)
OMB 42-RO 356

MONTHLY REPORT OF OPERATIONS

Lease No. U19573
Communitization Agreement No. PUBLIC COPY
Field Name WILDCAT
Unit Name Federal No. 1
Participating Area
County Millard State Utah
Operator ARGONAUT ENERGY CORPORATION
☐ Amended Report

The following is a correct report of operations and production (including status of all unplugged wells) for the month of MARCH, 19 78

(See Reverse of Form for Instructions)

This report is required by law (30 U.S.C. 189, 30 U.S.C. 359, 25 U.S.C. 396 d), regulation (30 CFR 221.60), and the terms of the lease. Failure to report can result in the assessment of liquidated damages (30 CFR 221.54 (j)), shutting down operations, or basis for recommendation to cancel the lease and forfeit the bond (30 CFR 221.53).

Well No.	Sec. & ¼ of ¼	TWP	RNG	Well Status	Days Prod.	*Barrels of Oil	*MCF of Gas	*Barrels of Water	Remarks
1	NE-NW	15S	7W	DRG.	0	0	0	0	Spudded @ 8 p.m. 3/26/78 3/31/78 DRG. @ 3,160' Ran 44' of 30" Conductors.

RECEIVED
APR 10 1978
DIVISION OF OIL, GAS, & MINING

*If none, so state.

DISPOSITION OF PRODUCTION (Lease, Participating Area, or Communitized Area basis)

	Oil & Condensate (BBLS)	Gas (MCF)	Water (BBLS)
*On hand, Start of Month		xxxxxxxxxxxxxxxxx	xxxxxxxxxxxxxxxxx
*Produced			
*Sold			xxxxxxxxxxxxxxxxx
*Spilled or Lost		xxxxxxxxxxxxxxxxx	xxxxxxxxxxxxxxxxx
*Flared or Vented	xxxxxxxxxxxxxxxxx		xxxxxxxxxxxxxxxxx
*Used on Lease			xxxxxxxxxxxxxxxxx
*Injected			
*Surface Pits	xxxxxxxxxxxxxxxxx	xxxxxxxxxxxxxxxxx	
*Other (Identify)			
*On hand, End of Month		xxxxxxxxxxxxxxxxx	xxxxxxxxxxxxxxxxx
*API Gravity/BTU Content			xxxxxxxxxxxxxxxxx

Authorized Signature: Robert [signature] Address: P. O. Box 12099, Amarillo, Texas, 7910
Title: Vice President of Production Page 1 of 1

UNITED STATES
DEPARTMENT OF THE INTERI
GEOLOGICAL SURVEY
(FORM 9-329)
(2/76)
OMB 42-RO 356

MONTHLY REPORT OF OPERATIONS

Lease No. U 19575
Communitization Agreei No.
Field Name Wildcat PUBLIC COPY
Unit Name FEDERAL NO. 1
Participating Area
County Millard State UTAH
Operator ARGONAUT ENERGY CORPORATION
☐ Amended Report

The following is a correct report of operations and production (including status of all unplugged wells) for the month of APRIL, 19 78

(See Reverse of Form for Instructions)

This report is required by law (30 U.S.C. 189, 30 U.S.C. 359, 25 U.S.C. 396 d), regulation (30 CFR 221.60), and the terms of the lease. Failure to report can result in the assessment of liquidated damages (30 CFR 221.54 (j)), shutting down operations, or basis for recommendation to cancel the lease and forfeit the bond (30 CFR 221.53).

Well No.	Sec. & ¼ of ¼	TWP	RNG	Well Status	Days Prod.	*Barrels of Oil	*MCF of Gas	*Barrels of Water	Remarks
1	C NW/4	15S	7W	DRG	0	0	0	0	Ran 13 3/8" casin Set @ 834' Drlg. to 4,248' & stuck on 4/3/78 Recovered all fis 4/15/78 Schlumberger ran Compensated Sonic Logs 4/16/78 Ran 9 5/8" casing to 4,248' 4/19/78 Drilling Depth 4/30/78 was 6,850

RECEIVED
MAY 8 1978
DIVISION OF OIL, GAS, & MINING

*If none, so state.

DISPOSITION OF PRODUCTION (Lease, Participating Area, or Communitized Area basis)

	Oil & Condensate (BBLS)	Gas (MCF)	Water (BBLS)
*On hand, Start of Month		XXXXXXXXXXXXXXXX	XXXXXXXXXXXXXXXX
*Produced			
*Sold			XXXXXXXXXXXXXXXX
*Spilled or Lost		XXXXXXXXXXXXXXXX	XXXXXXXXXXXXXXXX
*Flared or Vented	XXXXXXXXXXXXXXXX		XXXXXXXXXXXXXXXX
*Used on Lease			XXXXXXXXXXXXXXXX
*Injected			
*Surface Pits	XXXXXXXXXXXXXXXX	XXXXXXXXXXXXXXXX	
*Other (Identify)			
*On hand, End of Month		XXXXXXXXXXXXXXXX	XXXXXXXXXXXXXXXX
*API Gravity/BTU Content			XXXXXXXXXXXXXXXX

Authorized Signature: Robert Hatten Address: P. O. Box 12099, Amarillo, Texas, 79101
Title: Vice President of Production Page 1 of 1

Filed 5/2/78

Form 9-331
(May 1963)

UN[illegible]D STATES
DEPARTME[illegible] OF THE INTERIOR
GEOLOGICAL SURVEY

SUBMIT IN TRIP[illegible]TE*
(Other instructio[illegible] [illegible] re-
verse side)

PUBLIC COPY

Form approved.
Budget Bureau No. 42-R1424.

5. LEASE DESIGNATION AND SERIAL NO.
U 19573

6. IF INDIAN, ALLOTTEE OR TRIBE NAME

SUNDRY NOTICES AND REPORTS ON WELLS

(Do not use this form for proposals to drill or to deepen or plug back to a different reservoir.
Use "APPLICATION FOR PERMIT—" for such proposals.)

RECEIVED
MAY 8 1978
DIVISION OF OIL,
GAS, & MINING

1. OIL WELL ☐ GAS WELL ☒ OTHER

7. UNIT AGREEMENT NAME

2. NAME OF OPERATOR
ARGONAUT ENERGY CORPORATION

8. FARM OR LEASE NAME
FEDERAL

3. ADDRESS OF OPERATOR
P. O. Box 12099, Amarillo, Texas 79101

9. WELL NO.
1

4. LOCATION OF WELL (Report location clearly and in accordance with any State requirements.*
See also space 17 below.)
At surface
~~1306~~' FNL and ~~2334~~' FWL Of Sec. 23,T15W,R7W

10. FIELD AND POOL, OR WILDCAT
WILDCAT

11. SEC., T., R., M., OR BLK. AND SURVEY OR AREA
Sec. 23-T15S-R7W

14. PERMIT NO.

15. ELEVATIONS (Show whether DF, RT, GR, etc.)
4,629'GR

12. COUNTY OR PARISH
Millard

13. STATE
Utah

16. **Check Appropriate Box To Indicate Nature of Notice, Report, or Other Data**

NOTICE OF INTENTION TO:				SUBSEQUENT REPORT OF:			
TEST WATER SHUT-OFF	☐	PULL OR ALTER CASING	☐	WATER SHUT-OFF	☐	REPAIRING WELL	☐
FRACTURE TREAT	☐	MULTIPLE COMPLETE	☐	FRACTURE TREATMENT	☐	ALTERING CASING	☐
SHOOT OR ACIDIZE	☐	ABANDON*	☐	SHOOTING OR ACIDIZING	☐	ABANDONMENT*	☐
REPAIR WELL	☐	CHANGE PLANS	☒	(Other)			
(Other)							

(NOTE: Report results of multiple completion on Well Completion or Recompletion Report and Log form.)

17. DESCRIBE PROPOSED OR COMPLETED OPERATIONS (Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work. If well is directionally drilled, give subsurface locations and measured and true vertical depths for all markers and zones pertinent to this work.) *

I. Casing program:
   A. Set 7" liner @ 7733'
   B. Casing detail - 3800' 7" 26# N80 LT&C Casing.
   C. Liner Hanger and packer hung @ 3950'.

II. Cementing Program:
   A. 7" liner to be cemented with 120 sacks Class G Salt Saturated cement.

APPROVED BY THE DIVISION OF
OIL, GAS, AND MINING
DATE: May 8 1978
BY: [signature]

Verbal approval received from Mr. Bill Martin 5/3/78

18. I hereby certify that the foregoing is true and correct

SIGNED [signature] TITLE Lois Yates, Prod. Clerk DATE 5/4/78

(This space for Federal or State office use)

APPROVED BY _______ TITLE _______ DATE _______
CONDITIONS OF APPROVAL, IF ANY:

*See Instructions on Reverse Side

Form 9-331
(May 1963)

UNI D STATES
DEPARTMEN OF THE INTERIOR
GEOLOGICAL SURVEY

SUBMIT IN TRIP TE* (Other instruction re-verse side)

PUBLIC COPY

Form approved. Budget Bureau No. 42-R1424.

SUNDRY NOTICES AND REPORTS ON WELLS

(Do not use this form for proposals to drill or to deepen or plug back to a different reservoir. Use "APPLICATION FOR PERMIT—" for such proposals.)

5. LEASE DESIGNATION AND SERIAL NO.: U 19573

6. IF INDIAN, ALLOTTEE OR TRIBE NAME:

1. OIL WELL ☐ GAS WELL ☒ OTHER

7. UNIT AGREEMENT NAME:

2. NAME OF OPERATOR: ARGONAUT ENERGY CORPORATION

8. FARM OR LEASE NAME: FEDERAL

3. ADDRESS OF OPERATOR: P. O. Box 12099, Amarillo, Texas, 79101

9. WELL NO.: 1

4. LOCATION OF WELL (Report location clearly and in accordance with any State requirements.* See also space 17 below.)
At surface

1306' FNL and 1334' FWL of Sec. 23,T15W, R7W

10. FIELD AND POOL, OR WILDCAT: WILDCAT

11. SEC., T., R., M., OR BLK. AND SURVEY OR AREA: Sec. 23-T15S-R7W

14. PERMIT NO.:

15. ELEVATIONS (Show whether DF, RT, GR, etc.): 4,629' GR

12. COUNTY OR PARISH: Millard

13. STATE: Utah

16. Check Appropriate Box To Indicate Nature of Notice, Report, or Other Data

NOTICE OF INTENTION TO:				SUBSEQUENT REPORT OF:			
TEST WATER SHUT-OFF	☐	PULL OR ALTER CASING	☐	WATER SHUT-OFF	☐	REPAIRING WELL	☐
FRACTURE TREAT	☐	MULTIPLE COMPLETE	☐	FRACTURE TREATMENT	☐	ALTERING CASING	☐
SHOOT OR ACIDIZE	☐	ABANDON*	☐	SHOOTING OR ACIDIZING	☐	ABANDONMENT*	☐
REPAIR WELL	☐	CHANGE PLANS	X	(Other)			
(Other)							

(NOTE: Report results of multiple completion on Well Completion or Recompletion Report and Log form.)

17. DESCRIBE PROPOSED OR COMPLETED OPERATIONS (Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work. If well is directionally drilled, give subsurface locations and measured and true vertical depths for all markers and zones pertinent to this work.)*

APPROVED BY THE DIVISION OF
OIL, GAS, AND MINING
DATE: May 17 1978
BY: P L Driscoll

I. Casing program:
   A. Set 7" casing @ 7731'
   B. Casing detail - 7731' 7" 26# N80 LT&C Casing.

II. Cementing Program:
   A. 7" casing to be cemented with 180 sacks Class G. Salt saturated cement.

RECEIVED
MAY 15 1978
DIVISION OF OIL
GAS, & MINING

Verbal approval received prior to commencement of operations.

18. I hereby certify that the foregoing is true and correct

SIGNED Robert J Catt TITLE Vice President of Production DATE 5/5/78

(This space for Federal or State office use)

APPROVED BY ____ TITLE ____ DATE ____
CONDITIONS OF APPROVAL, IF ANY:

*See Instructions on Reverse Side

Form 9-331
(May 1963)

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY

SUBMIT IN TRIPLICATE* (Other instructions on reverse side)

PUBLIC COPY

Form approved. Budget Bureau No. 42-R1424.

SUNDRY NOTICES AND REPORTS ON WELLS

(Do not use this form for proposals to drill or to deepen or plug back to a different reservoir. Use "APPLICATION FOR PERMIT—" for such proposals.)

1. OIL WELL ☐ GAS WELL ☒ OTHER

2. NAME OF OPERATOR
ARGONAUT ENERGY CORPORATION

3. ADDRESS OF OPERATOR
P. O. BOX 12099, Amarillo, Texas, 79101

4. LOCATION OF WELL (Report location clearly and in accordance with any State requirements.* See also space 17 below.)
At surface
1306' FNL and 1384' FWL of Sec. 23, T15S,R7W

5. LEASE DESIGNATION AND SERIAL NO.
U 19573

6. IF INDIAN, ALLOTTEE OR TRIBE NAME

7. UNIT AGREEMENT NAME

8. FARM OR LEASE NAME
FEDERAL

9. WELL NO.
1

10. FIELD AND POOL, OR WILDCAT
WILDCAT

11. SEC., T., R., M., OR BLK. AND SURVEY OR AREA
Sec. 23-T15S-R7W

14. PERMIT NO.

15. ELEVATIONS (Show whether DF, RT, GR, etc.)
4,629' GR

12. COUNTY OR PARISH
Millard

13. STATE
Utah

16. Check Appropriate Box To Indicate Nature of Notice, Report, or Other Data

NOTICE OF INTENTION TO:				SUBSEQUENT REPORT OF:			
TEST WATER SHUT-OFF	☐	PULL OR ALTER CASING	☐	WATER SHUT-OFF	☐	REPAIRING WELL	☐
FRACTURE TREAT	☐	MULTIPLE COMPLETE	☐	FRACTURE TREATMENT	☐	ALTERING CASING	☐
SHOOT OR ACIDIZE	☐	ABANDON*	☐	SHOOTING OR ACIDIZING	☐	ABANDONMENT*	☐
REPAIR WELL	☐	CHANGE PLANS	X	(Other)			
(Other)							

(NOTE: Report results of multiple completion on Well Completion or Recompletion Report and Log form.)

17. DESCRIBE PROPOSED OR COMPLETED OPERATIONS (Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work. If well is directionally drilled, give subsurface locations and measured and true vertical depths for all markers and zones pertinent to this work.)*

DRILL to 12,500' Total Depth.

I. Production Casing Design
1400' 4½" 13.5# N80 ST&C
2400' 4½" 11.6# N80 ST&C
4500' 4½" 11.6# K55 LT&C
2000' 4½" 11.6# N80 LT&C
2200' 4½" 11.6# N80 Buttress

RECEIVED
MAY 30 1978
DIVISION OF OIL, GAS, & MINING

APPROVED BY THE DIVISION OF
OIL, GAS, AND MINING
DATE: June 6, 1978
BY: P h Driscoll

Verbal approval received prior to commencement of operations from Mr. Ed Guynn 5/26/78

18. I hereby certify that the foregoing is true and correct
SIGNED Robert J Patton TITLE Vice President of Production DATE 5/26/78

(This space for Federal or State office use)

APPROVED BY ____ TITLE ____ DATE ____
CONDITIONS OF APPROVAL, IF ANY:

*See Instructions on Reverse Side

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY
(FORM 9-329)
(2/76)
OMB 42-RO 356

MONTHLY REPORT
OF
OPERATIONS

Lease No. U 19573
Communitization Agreement No. PUBLIC COPY
Field Name WILDCAT
Unit Name FEDERAL NO. 1
Participating Area
County Millard State Utah
Operator ARGONAUT ENERGY CORPORATION
☐ Amended Report

The following is a correct report of operations and production (including status of all unplugged wells) for the month of MAY, 19 78

(See Reverse of Form for Instructions)

This report is required by law (30 U.S.C. 189, 30 U.S.C. 359, 25 U.S.C. 396 d), regulation (30 CFR 221.60), and the terms of the lease. Failure to report can result in the assessment of liquidated damages (30 CFR 221.54 (j)), shutting down operations, or basis for recommendation to cancel the lease and forfeit the bond (30 CFR 221.53).

Well No.	Sec. & ¼ of ¼	TWP	RNG	Well Status	Days Prod.	*Barrels of Oil	*MCF of Gas	*Barrels of Water	Remarks
1	C NW/4 Sec. 23	15S	7W	DRG	0	0	0	0	Ran 7" N80 26# Casing. Set at 7731'. Cemented with 180 sacks Class G cement. Drilled to 8891' & Cored from 8891 to 8914'. Drilling Depth 5/31/78 was 10,360

RECEIVED JUN 5 1978 GAS, & MINING

*If none, so state.

DISPOSITION OF PRODUCTION (Lease, Participating Area, or Communitized Area basis)

	Oil & Condensate (BBLS)	Gas (MCF)	Water (BBLS)
*On hand, Start of Month		xxxxxxxxxxxxxxxxx	xxxxxxxxxxxxxxxxx
*Produced			
*Sold			xxxxxxxxxxxxxxxxx
*Spilled or Lost		xxxxxxxxxxxxxxxxx	xxxxxxxxxxxxxxxxx
*Flared or Vented	xxxxxxxxxxxxxxxxx		xxxxxxxxxxxxxxxxx
*Used on Lease			xxxxxxxxxxxxxxxxx
*Injected			
*Surface Pits	xxxxxxxxxxxxxxxxx	xxxxxxxxxxxxxxxxx	
*Other (Identify)			
*On hand, End of Month		xxxxxxxxxxxxxxxxx	xxxxxxxxxxxxxxxxx
*API Gravity/BTU Content			xxxxxxxxxxxxxxxxx

Authorized Signature: Robert F. Patton Address: P. O. Box 12099, Amarillo, Texas, 79101
Title: Vice President of Production Page 1 of 1

Form 9-331
(May 1963)

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY

SUBMIT IN TRIPLICATE* (Other instructions on reverse side)

Form approved. Budget Bureau No. 42-R1424.

PUBLIC COPY

5. LEASE DESIGNATION AND SERIAL NO.
U 19573

6. IF INDIAN, ALLOTTEE OR TRIBE NAME

SUNDRY NOTICES AND REPORTS ON WELLS

(Do not use this form for proposals to drill or to deepen or plug back to a different reservoir. Use "APPLICATION FOR PERMIT—" for such proposals.)

1. OIL WELL ☐ GAS WELL ☒ OTHER DRY HOLE

7. UNIT AGREEMENT NAME

2. NAME OF OPERATOR
ARGONAUT ENERGY CORPORATION

8. FARM OR LEASE NAME
FEDERAL

3. ADDRESS OF OPERATOR
P. O. Box 12099, Amarillo, Texas, 79101

9. WELL NO.
1

4. LOCATION OF WELL (Report location clearly and in accordance with any State requirements.* See also space 17 below.)
At surface
1306' FNL & 1324' FWL of Sec. 23, T15S, R7W

RECEIVED
JUN 23 1978
DIVISION OF OIL, GAS, & MINING

10. FIELD AND POOL, OR WILDCAT
WILDCAT

11. SEC., T., R., M., OR BLK. AND SURVEY OR AREA
Sec. 23 -T15S-R7W

14. PERMIT NO.

15. ELEVATIONS (Show whether DF, RT, GR, etc.)
4,629' GR

12. COUNTY OR PARISH
Millard

13. STATE
Utah

16. Check Appropriate Box To Indicate Nature of Notice, Report, or Other Data

NOTICE OF INTENTION TO:				SUBSEQUENT REPORT OF:			
TEST WATER SHUT-OFF	☐	PULL OR ALTER CASING	☐	WATER SHUT-OFF	☐	REPAIRING WELL	☐
FRACTURE TREAT	☐	MULTIPLE COMPLETE	☐	FRACTURE TREATMENT	☐	ALTERING CASING	☐
SHOOT OR ACIDIZE	☐	ABANDON*	X	SHOOTING OR ACIDIZING	☐	ABANDONMENT*	☐
REPAIR WELL	☐	CHANGE PLANS	☐	(Other)			
(Other)							

(NOTE: Report results of multiple completion on Well Completion or Recompletion Report and Log form.)

17. DESCRIBE PROPOSED OR COMPLETED OPERATIONS (Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work. If well is directionally drilled, give subsurface locations and measured and true vertical depths for all markers and zones pertinent to this work.)*

1. Set 50 sack Class G. cement plug at 10,250' with 3½" drill pipe. Failed.
2. Set another 50 sack Class G. cement plug at 10,250'. Failed. (as per original verbal approval by Mr. Ed Guynn 6/15/78.)
3. Set Lynes inflatable bridge plug at 10,050'. Put 50 sacks Class G cement on top of plug. Tagged top of cement at 9,930'. (Verbal approval of Mr. Ed Guynn 6/17/78).
4. Set Lynes inflatable bridge plug at 7,722'. Pumped 50 sacks on top of plug. Tagged top of cement at 7,392'. (Verbal approval of Mr. Martens 6/18/78).
5. Cut 7" casing at 4,198' (Free point) Spotted 50 sacks Class G salt saturated cement cement through drill pipe at 4,250'. (Verbal approval of Mr. Martens 6/19/78).
6. Set 50 sack Class G salt saturated cement through drill pipe at 2,550'.
7. Cut 9 5/8" at 861' (Free point). Set 50' cement plug below top of cut to 100' above top of cut using Class G cement.
8. Set 10 sacks Class G cement plug in top of 13 3/8" casing with 10' steel 4½" diameter marker cement inplace 4' above ground level.

Well was drilled to a total depth of 11,266'. No formation production of oil or gas was found.

APPROVED BY THE DIVISION OF
OIL, GAS, AND MINING
DATE: Received
BY: For info. only. P.L.D.

18. I hereby certify that the foregoing is true and correct

SIGNED Robert Hatt TITLE Vice President of Production DATE 6/20/78

(This space for Federal or State office use)

APPROVED BY ______ TITLE ______ DATE ______
CONDITIONS OF APPROVAL, IF ANY:

*See Instructions on Reverse Side

Form 9-330
(Rev. 5-63)

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY

SUBMIT IN DUPLICATE (See other instructions on reverse side)

Form approved. Budget Bureau No. 42-R355.5.

PUBLIC COPY

4

WELL COMPLETION OR RECOMPLETION REPORT AND LOG*

1a. TYPE OF WELL: OIL WELL [ ] GAS WELL [ ] DRY [X] Other DRY HOLE

b. TYPE OF COMPLETION: NEW WELL [X] WORK OVER [ ] DEEP-EN [ ] PLUG BACK [ ] DIFF. RESVR. [ ] Other

2. NAME OF OPERATOR
ARGONAUT ENERGY CORPORATION

3. ADDRESS OF OPERATOR
P. O. BOX 12099, Amarillo, Texas, 79101

4. LOCATION OF WELL (Report location clearly and in accordance with any State requirements)*
At surface 1320' FNL 1320' FWL
At top prod. interval reported below
At total depth

5. LEASE DESIGNATION AND SERIAL NO.
U 19573

6. IF INDIAN, ALLOTTEE OR TRIBE NAME

7. UNIT AGREEMENT NAME

8. FARM OR LEASE NAME
FEDERAL

9. WELL NO.
1

10. FIELD AND POOL, OR WILDCAT
Wildcat

11. SEC., T., R., M., OR BLOCK AND SURVEY OR AREA
Sec. 23-T15S-R7W

14. PERMIT NO. 43-027-30012 | DATE ISSUED

12. COUNTY OR PARISH Millard | 13. STATE Utah

15. DATE SPUDDED	16. DATE T.D. REACHED	17. DATE COMPL. (Ready to prod.)	18. ELEVATIONS (DF, RKB, RT, GR, ETC.)*	19. ELEV. CASINGHEAD
3/26/78	6/10/78	6/22/78	4629' GR	

20. TOTAL DEPTH, MD & TVD	21. PLUG, BACK T.D., MD & TVD	22. IF MULTIPLE COMPL., HOW MANY*	23. INTERVALS DRILLED BY	ROTARY TOOLS	CABLE TOOLS
11,266'			→	11,266'	

24. PRODUCING INTERVAL(S), OF THIS COMPLETION—TOP, BOTTOM, NAME (MD AND TVD)*

25. WAS DIRECTIONAL SURVEY MADE
Yes

26. TYPE ELECTRIC AND OTHER LOGS RUN
Laterolog-BHC Sonic-Comp. Neutron Formation Density-GR-Neutron

27. WAS WELL CORED
Yes

28. CASING RECORD (Report all strings set in well)

CASING SIZE	WEIGHT, LB./FT.	DEPTH SET (MD)	HOLE SIZE	CEMENTING RECORD	AMOUNT PULLED
13 3/8"	48#	834'	17½	585 Sacks Class G	
9 5/8"	36#	4,248'	12¼	1300 Sacks Class G *	861'
7 "	26#	7,731'	8 3/4	180 Sacks Class G *	4,198'
				(Salt Saturated)	

29. LINER RECORD

SIZE	TOP (MD)	BOTTOM (MD)	SACKS CEMENT*	SCREEN (MD)

30. TUBING RECORD

SIZE	DEPTH SET (MD)	PACKER SET (MD)

31. PERFORATION RECORD (Interval, size and number)

32. ACID, SHOT, FRACTURE, CEMENT SQUEEZE, ETC.

DEPTH INTERVAL (MD)	AMOUNT AND KIND OF MATERIAL USED

33.* PRODUCTION

DATE FIRST PRODUCTION	PRODUCTION METHOD (Flowing, gas lift, pumping—size and type of pump)	WELL STATUS (Producing or shut-in)
		PA

DATE OF TEST	HOURS TESTED	CHOKE SIZE	PROD'N. FOR TEST PERIOD	OIL—BBL.	GAS—MCF.	WATER—BBL.	GAS-OIL RATIO
			→				

FLOW. TUBING PRESS.	CASING PRESSURE	CALCULATED 24-HOUR RATE	OIL—BBL.	GAS—MCF.	WATER—BBL.	OIL GRAVITY-API (CORR.)
		→				

34. DISPOSITION OF GAS (Sold, used for fuel, vented, etc.)

TEST WITNESSED BY

35. LIST OF ATTACHMENTS

36. I hereby certify that the foregoing and attached information is complete and correct as determined from all available records

SIGNED R O Batt   TITLE Vice President of Production   DATE 6/27/78

*(See Instructions and Spaces for Additional Data on Reverse Side)

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY
(FORM 9-329)
(2/76)
OMB 42-RO 356

MONTHLY REPORT OF OPERATIONS

Lease No. U 19573

Communitization Agreement No. PUBLIC COPY

Field Name WILDCAT

Unit Name FEDERAL No. 1

Participating Area

County Millard State Utah

Operator ARGONAUT ENERGY CORPROATION

☐ Amended Report

The following is a correct report of operations and production (including status of all unplugged wells) for the month of JUNE, 19 78

(See Reverse of Form for Instructions)

This report is required by law (30 U.S.C, 189, 30 U.S.C. 359, 25 U.S.C. 396 d), regulation (30 CFR 221.60), and the terms of the lease. Failure to report can result in the assessment of liquidated damages (30 CFR 221.54 (j)), shutting down operations, or basis for recommendation to cancel the lease and forfeit the bond (30 CFR 221.53).

Well No.	Sec. & ¼ of ¼	TWP	RNG	Well Status	Days Prod.	*Barrels of Oil	*MCF of Gas	*Barrels of Water	Remarks
1	C NW/4 Sec 23	15S	7W	DRG	0	0	0	0	Drilled to depth of 11,266' 6/10/78 Ran DST #1 6/1/78 10,415'= 10,470' DST #2-A 6/13/78 10,285 - 10,340' DST #2-B 6/13/78 10,255' - 10,310' DST #2-C 6/13/78 10,145 - 10,200' Ran logs 6/10/78 * P&A 6/22/78

* Ran Dual Laterolog from 11,240 - 7,731'.
Ran BHC Sonic from 11,251 - 7,723'.
Ran Comp. Neutron Form. Density from 11,265 - 7,732'.

*If none, so state.

DISPOSITION OF PRODUCTION (Lease, Participating Area, or Communitized Area basis)

	Oil & Condensate (BBLS)	Gas (MCF)	Water (BBLS)
*On hand, Start of Month		XXXXXXXXXXXXXXXX	XXXXXXXXXXXXXXXX
*Produced			
*Sold			XXXXXXXXXXXXXXXX
*Spilled or Lost		XXXXXXXXXXXXXXXX	XXXXXXXXXXXXXXXX
*Flared or Vented	XXXXXXXXXXXXXXXX		XXXXXXXXXXXXXXXX
*Used on Lease			XXXXXXXXXXXXXXXX
*Injected			
*Surface Pits	XXXXXXXXXXXXXXXX	XXXXXXXXXXXXXXXX	
*Other (Identify)			
*On hand, End of Month		XXXXXXXXXXXXXXXX	XXXXXXXXXXXXXXXX
*API Gravity/BTU Content			XXXXXXXXXXXXXXXX

Authorized Signature: Robert F. Potter Address: P. O. BOX 12099, Amarillo, Texas, 79101

Title: Vice President of Production Page 1 of 1

Form 9-331
(May 1963)

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY

SUBMIT IN TRIPLICATE (Other instructions on reverse side)

Form approved. Budget Bureau No. 42-R1424.

PUBLIC COPY

SUNDRY NOTICES AND REPORTS ON WELLS

(Do not use this form for proposals to drill or to deepen or plug back to a different reservoir. Use "APPLICATION FOR PERMIT—" for such proposals.)

5. LEASE DESIGNATION AND SERIAL NO.: U 19573

6. IF INDIAN, ALLOTTEE OR TRIBE NAME:

7. UNIT AGREEMENT NAME:

1. OIL WELL ☐ GAS WELL ☒ OTHER DRY HOLE

2. NAME OF OPERATOR: ARGONAUT ENERGY CORPORATION

8. FARM OR LEASE NAME: FEDERAL

3. ADDRESS OF OPERATOR: P. O. BOX 12099, Amarillo, Texas, 79101

9. WELL NO.: 1

4. LOCATION OF WELL (Report location clearly and in accordance with any State requirements.* See also space 17 below.)
At surface
1306' FNL & 1334' FWL of Sec. 23, T15S,R7W

10. FIELD AND POOL, OR WILDCAT: WILDCAT

11. SEC., T., R., M., OR BLK. AND SURVEY OR AREA: Sec. 23-T15S-R7W

14. PERMIT NO.:

15. ELEVATIONS (Show whether DF, RT, GR, etc.): 4629' GR

12. COUNTY OR PARISH: Millard

13. STATE: Utah

16. Check Appropriate Box To Indicate Nature of Notice, Report, or Other Data

NOTICE OF INTENTION TO:				SUBSEQUENT REPORT OF:			
TEST WATER SHUT-OFF	☐	PULL OR ALTER CASING	☐	WATER SHUT-OFF	☐	REPAIRING WELL	☐
FRACTURE TREAT	☐	MULTIPLE COMPLETE	☐	FRACTURE TREATMENT	☐	ALTERING CASING	☐
SHOOT OR ACIDIZE	☐	ABANDON*	☐	SHOOTING OR ACIDIZING	☐	ABANDONMENT*	X
REPAIR WELL	☐	CHANGE PLANS	☐	(Other)			
(Other)							

(NOTE: Report results of multiple completion on Well Completion or Recompletion Report and Log form.)

17. DESCRIBE PROPOSED OR COMPLETED OPERATIONS (Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work. If well is directionally drilled, give subsurface locations and measured and true vertical depths for all markers and zones pertinent to this work.) *

1. Set inflatable plug @ 10,250' with 50 sacks Class G cement. Failed.
2. Set inflatable plug @ 10,250' with 50 sacks Class G cement. Failed.
3. Set inflatable plug @ 10,050' with 50 sacks Class G cement. Top of cement @ 9,930'.
4. Set a 50 sack plug from 7,397' to 7,700' with type Class G cement. Top of cement @ 7,397'.
5. Set a 50 sack plug from 4,170' to 4,300' with type Class G cement.
6. Set a 82 sack plug from 2,340' to 2,550' with type Class G cement. Top of cement @ 2,405'.
7. Set a plug from 649' to 950' with 167 sacks of Class G cement. Top of cement @ 663'.
8. Set 10 sacks Class G cement at surface.
9. Set 10' of 5" pipe with 4' above ground in cement for permanent marker.

Casing Recovery

1. McCullough cut 7" casing at 4,198'. Pulled casing.
2. Mc Cullough cut 9 5/8" casing at 861'. Pulled casing.

RECEIVED JUL 17 1978 DIVISION OF OIL, GAS, & MINING

18. I hereby certify that the foregoing is true and correct

SIGNED Robert Watts TITLE Vice President of Production DATE 7/10/78

(This space for Federal or State office use)

APPROVED BY ____________ TITLE ____________ DATE ____________
CONDITIONS OF APPROVAL, IF ANY:

*See Instructions on Reverse Side

UNITED STATES
DEPARTMENT OF THE INTERI(
GEOLOGICAL SURVEY
(FORM 9-329)
(2/76)
OMB 42-RO 356

MONTHLY REPORT
OF
OPERATIONS

Lease No. U 19573
Communitization Agreer t No. PUBLIC COPY
Field Name WILDCAT
Unit Name FEDERAL NO. 1
Participating Area
County Millard State Utah
Operator ARGONAUT ENERGY CORPORATION
☐ Amended Report

The following is a correct report of operations and production (including status of all unplugged wells) for the montl of July, 1978

(See Reverse of Form for Instructions)

This report is required by law (30 U.S.C. 189, 30 U.S.C. 359, 25 U.S.C. 396 d), regulation (30 CFR 221.60), and the terms of the lease. Failure to report can result in the assessment of liquidated damages (30 CFR 221.54 (j)), shutting down operations, or basis for recommendation to cancel the lease and forfeit the bond (30 CFR 221.53).

Well No.	Sec. & ¼ of ¼	TWP	RNG	Well Status	Days Prod.	*Barrels of Oil	*MCF of Gas	*Barrels of Water	Remarks
1	C NW/4 Sec.23	15S	7W	P&A	0	0	0	0	Allowing pits to dry.

P

*If none, so state.

DISPOSITION OF PRODUCTION (Lease, Participating Area, or Communitized Area basis)

	Oil & Condensate (BBLS)	Gas (MCF)	Water (BBLS)
*On hand, Start of Month		XXXXXXXXXXXXXXXX	XXXXXXXXXXXXXXXX
*Produced			
*Sold			XXXXXXXXXXXXXXXX
*Spilled or Lost		XXXXXXXXXXXXXXXX	XXXXXXXXXXXXXXXX
*Flared or Vented	XXXXXXXXXXXXXXXX		XXXXXXXXXXXXXXXX
*Used on Lease			XXXXXXXXXXXXXXXX
*Injected			
*Surface Pits	XXXXXXXXXXXXXXXX	XXXXXXXXXXXXXXXX	
*Other (Identify)			
*On hand, End of Month		XXXXXXXXXXXXXXXX	XXXXXXXXXXXXXXXX
*API Gravity/BTU Content			XXXXXXXXXXXXXXXX

Authorized Signature: Robert F. Batten Address: P. O. Box 12099, Amarillo, Texas, 79101
Title: Vice President of Production Page ____ of ____

PUBLIC COPY

ATTACHMENT C-1.2

Magnum Holdings LLC
Exploratory Well MH-1 Data

Water Right Drilling Approval
DOGM Permits

THE FOLLOWING FIGURES ARE CONFIDENTIAL

Core Log
Cuttings Log
Drillers Report
Casing Schematic
Geophysical Logs
Water Quality

JON M. HUNTSMAN, JR.
Governor
GARY R. HERBERT
Lieutenant Governor

State of Utah

DEPARTMENT OF NATURAL RESOURCES
Division of Water Rights

PUBLIC COPY

MICHAEL R. STYLER
Executive Director

JERRY D. OLDS
State Engineer/Division Director

MANGUM HOLDINGS, LLC
1250 SOUTH 1300 EAST, SUITE 500
SALT LAKE CITY, UT 84106

October 15, 2008

Dear Applicant:

RE: TEST WELL#: 0868004M00

This letter **IS YOUR AUTHORIZATION** to drill test wells at the following location(s):

(1) S 50 ft W 50 ft from the NE corner, Section 27, Township 15S, Range 7W, SLBM
(2) N 2086 ft E 570 ft from the NE corner, Section 27, Township 15S, Range 7W, SLBM

The purpose of a test well is to determine the quality and availability of an adequate water supply that may be used subsequently to support water use(s) in future applications filed with the Division of Water Rights.

Even though you may proceed with the construction of the well(s), please take note that this letter **DOES NOT GRANT ANY PERMISSION OR APPROVAL TO DIVERT WATER FOR ANY PURPOSE WHATSOEVER, OTHER THAN THE MINIMAL AMOUNT REQUIRED FOR QUALITY/QUANTITY TESTING.**

The well driller must have a current license with the State Engineer (if the well is to be deeper than 30 feet), and the well must be constructed in accordance with the State of Utah Administrative Rules for Water Well Drillers. Following completion and testing, the well casing must either be sealed with a tamper-resistant, water-tight cap or permanently and properly abandoned by a licensed driller (if deeper than 30 feet) before the drill rig is removed from the site.

Enclosed you will find two postage-paid forms. One is the Driller (START) Card form, which you MUST give to the licensed driller with whom you contract to drill the well(s). The other is the Applicant Card form. It is YOUR RESPONSIBILITY to sign and return this form to this office immediately upon well completion. **Your submittal of the APPLICANT Card form will be notice to our office that the work has been completed and will begin the 30-day period in which the driller is to submit a report as required herein.** The driller cannot legally commence drilling the test well(s) until you provide him with the Driller (START) Card form, which will then be submitted to our office for verification. You should review the contents of this approval letter with the driller to be certain that the instructions and conditions are thoroughly understood by all parties.

Please note that your permission to proceed with the drilling under this authorization expires April 15, 2009.

Sincerely,

Kirk Forbush

Kirk Forbush, P.E.
Regional Engineer

PUBLIC COPY

DRILLER (START) CARD for Test WELL#: 0868004M00

|IMPORTANT: THIS CARD MUST BE RECEIVED BY THE DIVISION OF WATER RIGHTS PRIOR TO |
|THE BEGINNING OF WELL CONSTRUCTION -- REQUIRED ONLY FOR WELLS DEEPER THAN 30 FT. |

OWNER/APPLICANT NAME: Mangum Holdings, LLC
MAILING ADDRESS: 1250 South 1300 East, Suite 500, Salt Lake City, UT 84106,
PHONE NUMBER: 801 669-9209
WELL LOCATION: S 50' W 50' from NE Cor, S27, T15S, R7W, SLB&M.
WELL UTM COORDINATES: Northing: 4372658 Easting: 361433
WELL ACTIVITY: NEW (✓) REPAIR ( ) REPLACE ( ) ABANDON ( )
CLEAN ( ) DEEPEN ( )

For surface seals in unconsolidated formations (clay, silt, sand, and gravel), will you be using a temporary conductor casing or other formation stabilizer (e.g., drilling mud) in the surface seal interval to maintain the required annular space?

YES or NO (Circle one).

Answering 'NO' suggests that you will be placing the surface seal in an open and unstabilized annular space, which may require onsite inspection of seal placement by the State Engineer's Office.

PROPOSED START DATE: ______

PROJECTED COMPLETION DATE: ______

LICENSE #: ______ LICENSEE/COMPANY: ______

______ ______

Licensee Signature Date

|NOTICE TO APPLICANT: THIS CARD IS TO BE GIVEN TO A UTAH LICENSED WATER WELL |
|DRILLER FOR SUBMITTAL TO THE DIVISION OF WATER RIGHTS PRIOR TO WELL CONSTRUCTION. |
|STATE OF UTAH DIVISION OF WATER RIGHTS Phone No. 801-538-7416 |
| Fax No. 801-538-7467 |

COMMENTS: ______

PUBLIC COPY

APPLICANT CARD for Test WELL#: 0868004M00

| IMPORTANT: THIS CARD MUST BE COMPLETED, SIGNED AND RETURNED BY THE WELL OWNER/APPLICANT AS SOON AS THE WELL IS DRILLED BY A LICENSED UTAH WATER WELL DRILLER. |

OWNER/APPLICANT NAME: Mangum Holdings, LLC
MAILING ADDRESS: 1250 South 1300 East, Suite 500, Salt Lake City, UT 84106.
PHONE NUMBER: 801 669-9209
WELL LOCATION: S 50' W 50' from NE Cor, S27, T15S, R7W, SLB&M.
WELL UTM COORDINATES: Northing: 4372658 Easting: 361433
WELL ACTIVITY: NEW (✔) REPAIR ( ) REPLACE ( ) ABANDON ( )
CLEAN ( ) DEEPEN ( )

WELL COMPLETION DATE: ______________________

NAME OF DRILLING COMPANY/LICENSEE: ______________________

______________________ ______________

Owner/Applicant Signature Date

| ***COMPLETE, SIGN AND RETURN THIS PORTION UPON FINAL WELL COMPLETION - DO NOT GIVE THIS CARD TO LICENSED WELL DRILLER - YOU MUST RETURN IT. |
| STATE OF UTAH DIVISION OF WATER RIGHTS Phone No. 801-538-7416 |
| Fax No. 801-538-7467 |

COMMENTS: ______________________

START/APPLICANT CARD INSTRUCTIONS: First, for each well, you must give a Driller (Start) Card to the licensed driller with whom you contract to construct the well. Second, it is your responsibility to sign and return this Applicant Card to this office immediately after completion of the well. **CAUTION: There may be local health requirements for the actual siting of your well. Please check with the proper local authority before construction begins. See the enclosed sheet addressing construction information.**

PUBLIC COPY

DRILLER (START) CARD for Test WELL#: 0868004M00

| IMPORTANT: THIS CARD MUST BE RECEIVED BY THE DIVISION OF WATER RIGHTS PRIOR TO |
| THE BEGINNING OF WELL CONSTRUCTION -- REQUIRED ONLY FOR WELLS DEEPER THAN 30 FT. |

OWNER/APPLICANT NAME: Mangum Holdings, LLC

MAILING ADDRESS: 1250 South 1300 East, Suite 500, Salt Lake City, UT 84106.

PHONE NUMBER: 801 669-9209

WELL LOCATION: N 2086' E 570' from NE Cor. S27, T15S, R7W, SLB&M.

WELL UTM COORDINATES: Northing: 4373309 Easting: 361622

WELL ACTIVITY: NEW (✓) REPAIR ( ) REPLACE ( ) ABANDON ( )
CLEAN ( ) DEEPEN ( )

For surface seals in unconsolidated formations (clay, silt, sand, and gravel), will you be using a temporary conductor casing or other formation stabilizer (e.g., drilling mud) in the surface seal interval to maintain the required annular space?

YES or NO (Circle one).

Answering 'NO' suggests that you will be placing the surface seal in an open and unstabilized annular space, which may require onsite inspection of seal placement by the State Engineer's Office.

PROPOSED START DATE:____________________

PROJECTED COMPLETION DATE:____________________

LICENSE #:__________ LICENSEE/COMPANY:________________

Licensee Signature — Date

| NOTICE TO APPLICANT: THIS CARD IS TO BE GIVEN TO A UTAH LICENSED WATER WELL |
| DRILLER FOR SUBMITTAL TO THE DIVISION OF WATER RIGHTS PRIOR TO WELL CONSTRUCTION. |
| STATE OF UTAH DIVISION OF WATER RIGHTS Phone No. 801-538-7416 |
| Fax No. 801-538-7467 |

COMMENTS:____________________

PUBLIC COPY

APPLICANT CARD for Test WELL#: 0868004M00

|IMPORTANT: THIS CARD MUST BE COMPLETED, SIGNED AND RETURNED BY THE WELL |
|OWNER/APPLICANT AS SOON AS THE WELL IS DRILLED BY A LICENSED UTAH WATER |
|WELL DRILLER. |

OWNER/APPLICANT NAME: Mangum Holdings, LLC
MAILING ADDRESS: 1250 South 1300 East, Suite 500, Salt Lake City, UT 84106.
PHONE NUMBER: 801 669-9209
WELL LOCATION: N 2086' E 570' from NE Cor, S27, T15S, R7W, SLB&M.
WELL UTM COORDINATES: Northing: 4373309 Easting: 361622
WELL ACTIVITY: NEW (✔) REPAIR ( ) REPLACE ( ) ABANDON ( )
CLEAN ( ) DEEPEN ( )

WELL COMPLETION DATE: ____________________

NAME OF DRILLING COMPANY/LICENSEE: ____________________

____________________ ____________

Owner/Applicant Signature Date

|***COMPLETE, SIGN AND RETURN THIS PORTION UPON FINAL WELL COMPLETION - |
|DO NOT GIVE THIS CARD TO LICENSED WELL DRILLER - YOU MUST RETURN IT. |
|STATE OF UTAH DIVISION OF WATER RIGHTS Phone No. 801-538-7416 |
| Fax No. 801-538-7467 |

COMMENTS: ____________________

START/APPLICANT CARD INSTRUCTIONS: First, for each well, you must give a Driller (Start) Card to the licensed driller with whom you contract to construct the well. Second, it is your responsibility to sign and return this Applicant Card to this office immediately after completion of the well. **CAUTION: There may be local health requirements for the actual siting of your well. Please check with the proper local authority before construction begins. See the enclosed sheet addressing construction information.**

PUBLIC COPY

JON M. HUNTSMAN, JR.
Governor

GARY R. HERBERT
Lieutenant Governor

State of Utah

DEPARTMENT OF NATURAL RESOURCES

MICHAEL R. STYLER
Executive Director

Division of Oil, Gas and Mining

JOHN R. BAZA
Division Director

November 25, 2008

David K. Detton
Magnum Holdings, LLC
2150 South 1300 East, Suite 500
Salt Lake City, Utah 84106

Subject: Permit to Commence Exploration Activities, Magnum Holdings, LLC., Western Energy Hub, E/027/0075, Millard County, Utah

Dear Mr. Detton:

The Division finds your Notice of Intention (Notice) complete and approves the reclamation surety for the Western Energy Hub exploration project. You are now permitted to conduct exploration activities as outlined in the Notice. Enclosed please find a copy of the reclamation contract and stamped approved Notice.

Please keep in mind the following regulatory requirements.

- This permit is valid until November 30, 2009. It may be extended, however you must receive Division approval for an extension prior to this date. Updating of surety may also required.
- Stockpiling topsoil material prior to beginning activities will help ensure successful revegetation. Even the first few inches of undeveloped material is worth saving to aid in later revegetation efforts, and future regulatory surety release.
- If you encounter any archaeological or historical items, you are asked to notify this office, and State History of your find.
- Permit fees are due July 30
- Annual reports are due by December 31st.

The Division's web page at http://ogm.utah.gov under the Mining Program has a link to the rules you are expected to operate under and other information to assist you in complying with program requirements. Thank you for your cooperation. In reply, please refer to file number E/027 /0075. If you have questions or concerns regarding this letter, please contact me at (801) 538-52618 or Tom Munson at 538-5321. Best wishes exploring!

Sincerely,

Dana Dean, P.E.
Associate Director, Mining

DD:tm:vs Task # 2717
Enclosure: Copy of RC & surety forms
Copy of approved NOI
P:\GROUPS\MINERALS\WP\M027-Millard\E0270075-WesternEnergyHub\final\APVL-11242008.doc

UTAH DNR OIL, GAS & MINING

PUBLIC COPY

JON M. HUNTSMAN, JR.
Governor
GARY R. HERBERT
Lieutenant Governor

State of Utah
DEPARTMENT OF NATURAL RESOURCES
Division of Oil, Gas & Mining

MICHAEL R. STYLER
Executive Director

JOHN R. BAZA
Division Director

November 6, 2008

Wells Fargo National Bank, N.A.
Business Banking Group
299 South Main – 11^{th} Floor
Salt Lake City, UT 84111

Attention: Beth Stauffer, Relationship Manager
(801) 246-1775; beth.stauffer@wellsfargo.com

Subject: Reclamation Surety, Certificate of Deposit for Magnum Holdings, LLC's Western Energy Hub Mine Site (OGM mine file # E0270075), Millard County, Utah
Certificate of Deposit # 8632670918; Principal Amount $27,500.00

This letter describes the mutually agreed upon instructions of the below signed parties to Wells Fargo National Bank, N.A. ("Bank"), regarding the control, redemption, and release of Bank's above-described certificate of deposit ("CD"). This CD is being used as a surety to guarantee the availability of reclamation funds for the Western Energy Hub mine site ("Mine Site"), in Millard County, Utah. It is the intention of the parties that the CD be utilized as surety to guarantee that $27,500.00 in reclamation funds will be available to the State of Utah, Division of Oil, Gas & Mining ("Division") upon demand in the event that the operator(s) of the Mine Site are unable or unwilling to complete reclamation of the mine site in compliance with applicable state law and regulations.

Ownership and Renewal:
Ownership of the CD is retained by Magnum Holdings, LLC, a Utah limited liability company ("Owners"), but it is held by Bank for the benefit of the State of Utah, Division of Oil, Gas & Mining and is subject to the terms and conditions described in this agreement. The CD shall automatically renew indefinitely until either redeemed or released by the Director of the Division.

Redemption:
The CD may only be redeemed (i.e., called on demand), pursuant to the written instruction or demand of the Director of the Utah Division of Oil, Gas & Mining to the Bank. Upon the instruction and demand of the Director, the full initial amount of the CD shall be transferred to the State of Utah, Division of Oil Gas and Mining. Owner agrees and irrevocably instructs Bank that neither the Owner nor any other person claiming an ownership interest in the CD which is derived from the Owner, shall have the authority to prevent the Bank from carrying out the Director's instruction to redeem the CD. Upon redemption, any accrued interest in excess of the initial amount of the CD shall be transferred to Owner's control, or if Owner does not instruct the Bank, the accrued interest shall be reinvested in the CD. If a signature card is prepared, it shall be drafted consistent with the requirement that only the Director of the Division may redeem the CD.

Release:
The Bank shall release the CD only upon the written instruction of the Director of the Division to the Bank. Upon release, the terms and conditions of this agreement are no longer in effect, and the unconditioned control of the CD shall be returned to the Owner, or its legal successor(s)-in-interest.

Accrued Interest:
Prior to release or redemption, all interest which accrues by the CD shall be: 1) dispersed quarterly to the Owner as the Owner may instruct the Bank, or 2) shall be reinvested in the CD until such time the Owner may instruct the Bank where to transfer such interest. In no event shall the Bank transfer any amount from the CD which would cause the redemption amount of the CD to be less than the initial amount, $27,500.00. All tax liabilities for accrued interest shall remain the responsibility of the Owners.

Bank will not be held liable for any dispute between the parties.

Agreed Upon By:

John R. Baza ________________ Date: 11/20/08
John R. Baza, Director
Utah Division of Oil, Gas & Mining

________________ Date: 11/6/08
Robert W. Webster, Manager
Magnum Holdings, LLC (EIN # 26-2543921)

Beth Stauffer ________________ Date: 11-6-08
Beth Stauffer, Relationship Manager
Wells Fargo Bank

PUBLIC COPY

FORM MR-RC (EXP)
Revised August 3, 2006
RECLAMATION CONTRACT

Mine Name: ______

Other Agency File Number: ______

STATE OF UTAH
DEPARTMENT OF NATURAL RESOURCES
DIVISION of OIL, GAS and MINING
1594 West North Temple, Suite 1210
Box 145801
Salt Lake City, Utah 84114-5801
(801) 538-5291
Fax: (801) 359-3940
---ooOoo---

EXPLORATION RECLAMATION CONTRACT

This Reclamation Contract (hereinafter referred to as "Contract") is entered into between Magnum Holdings LLC the "Operator" and the Utah State Division of Oil, Gas and Mining ("Division").

WHEREAS, Operator desires to conduct exploration operations under Notice of Intention (NOI) File No. E0270075 which the Operator has filed with the Division and has been determined by the Division to be complete (Complete NOI) as required by the Utah Mined Land Reclamation Act, Sections 40-8-1 et seq., Utah Code Annotated, (2005, as amended) (hereinafter referred to as "Act") and the regulations adopted pursuant to the Act; and

WHEREAS, Operator is obligated to reclaim the lands affected by the exploration operations in accordance with the Act and the regulations, and is obligated to provide a surety in a form and amount approved by the Division or the Board of Oil, Gas and Mining (Board) to assure reclamation of the lands affected by the exploration operations.

NOW, THEREFORE, the Division and the Operator agree as follows:

1. Operator agrees to promptly reclaim in accordance with the requirements of the Act and applicable regulations, as they may be amended, all of the lands affected by the exploration operations conducted or to be conducted pursuant to a Complete Notice of Intention. If the Notice of Intention to Conduct Exploration Operations affects more than five (5) acres, the Operator further agrees to reclaim in accordance with the mining and reclamation plan (Reclamation Plan) approved by the Division.
2. A Notice of Intention to Conduct Exploration is valid until November 30th of the year following submittal. Reclamation required by this Contract and the Reclamation Plan, must be completed within that time unless an operator prior to expiration notifies the Division in writing specifying the reasons an extension is required. Failure to make a request and pay the fees as required

may result in suspension of the Operator's authorization to conduct exploration operations.

3. The Lands Affected by the exploration operations and subject to the requirements of the Act and this Contract include:

   A. All surface and subsurface areas affected or to be affected by the exploration operations including but not limited to on-site private ways, roads, and railroads; land excavations; drill sites or workings; refuse banks or spoil piles; evaporation or settling ponds; stockpiles; leaching dumps; placer areas; tailings ponds or dumps; work, parking, storage, or waste discharge areas, structures, and facilities; shafts, drill holes, and pits or cuts; and
   B. All exploration disturbances regardless of discrepancies in the map and legal description, unless explicitly and clearly identified as EXCLUDED on maps, and legal descriptions included in the Complete NOI; provided lands may be excluded only if: (1) they were disturbed by exploration or mining operations that ceased prior to July 1, 1977; (2) the lands would be included but have been reclaimed in accordance with a complete notice or reclamation plan; or (3) the lands were disturbed by a prior operation for which there is no surety, no legally responsible entity or person, and which lands are not necessarily or incidentally intended to be affected by the exploration operations as described in the Complete NOI.

4. The Operator shall be responsible for reclamation of all such Lands Affected regardless of errors or discrepancies in the maps or legal descriptions provided with the NOI, which are intended to assist in determining the location of the exploration operations, to describe the areas of disturbance, and to assist estimating the amount of surety required.

5. The Operator prior to commencement of any exploration operations and as a precondition to the rights under the Notice of Intention shall provide a surety in a form permitted by the Act and in an amount sufficient to assure that reclamation of the Lands Affected will be completed as required by the Act. The Surety shall remain in full force and effect according to its terms unless modified by the Division in writing. A copy of the agreement providing for the Surety for the reclamation obligations herein is included as **ATTACHMENT A** to this Contract.

6. If the Surety expressly provides for cancellation or termination for non-renewal:

i. The Operator shall within 60 days following the Division's receipt of notice that the Surety will be terminated or cancelled, provide a replacement Surety sufficient in a form and amount, as required by the Act, to replace the cancelled surety; or

ii. If the Operator fails to provide an acceptable replacement Surety within 60 days of notice of cancellation or termination, the Division may order the Operator to cease further exploration activities, and without further notice proceed to draw upon letters of credit, to withdraw any amounts in certificates of deposit or cash and/or any other forms of surety, and to otherwise take such action as may be necessary to secure the rights of the Division to perfect its claim on the existing surety for the purpose of fully satisfying all of the reclamation obligations incurred by the Operator prior to the date of termination, and the Division may thereafter require the Operator to begin immediate reclamation of the Lands Affected by the exploration operations, and may, if necessary, proceed to take such further actions as may be required for the Division to forfeit the surety for the purpose of reclaiming the Lands Affected.

7. The Operator's liability under this Contract shall continue in full force and effect until the Division finds that the Operator has reclaimed the Lands Affected by exploration operations in accordance with the Act and regulations, as amended. If the Operator desires to extend the exploration operations beyond November 30th of the year following submittal or if the exploration operations are modified or for any other reason vary from those described in the Complete Notice of Intention, the Operator shall immediately advise the Division, and the Notice of Intention shall be revised and the Surety amount shall be adjusted as necessary.

8. If reclamation of discrete sections of the Lands Affected by the exploration operations is completed to the satisfaction of the Division, and the Division finds that such sections are severable from the remainder of the exploration area, Operator may request the Division to find that Operator has reclaimed such area. If the Division makes such finding, Operator may make request to the Division for a reduction in the aggregate face amount of the Surety, and the Division may reduce the surety to an amount necessary to complete reclamation of the remaining exploration operations as anticipated by the Complete Notice of Intention in accordance with the requirements of the Act and regulations, as amended.

9. Operator may, at any time, submit a request to the Division to substitute surety. The Division may approve such substitution if the substitute surety meets the requirements of the Act and the applicable rules.

10. Operator agrees to pay all legally determined public liability and property damage claims resulting from exploration operations, to pay all permit fees, to maintain suitable records, to file all required reports, to permit reasonable inspections, and to fulfill all sundry reporting requirements applicable to the mine as required by the Act and implementing rules.

11. Operator agrees to indemnify and hold harmless the State, Board, and the Division from any claim, demand, liability, cost, charge, suit, or obligation of whatsoever nature arising from the failure of Operator or Operator's agents and employees, or contractors to comply with this Contract.

12. If Operator shall default in the performance of its obligations hereunder, Operator shall be liable for all damages resulting from the breach hereof including all costs, expenses, and reasonable attorney's fees incurred by the Division and/or the Board in the enforcement of this Contract.

13. Any breach of a material provision of this Contract by Operator may, at the discretion of the Division, in addition to other remedies available to it, result in an order by the Division requiring the Operator to cease exploration operations, and may thereafter result in an Order, subject to an opportunity for notice and hearing before the Board, withdrawing and revoking the Notice of Intention, and requiring immediate reclamation by the Operator of the Lands Affected or forfeiture of the Surety.

14. In the event of forfeiture of the Surety, Operator shall be liable for any additional costs in excess of the surety amount that is required to comply with this Contract. Upon completion of the reclamation of all of the Lands Affected, any excess monies resulting from forfeiture of the Surety shall be returned to the rightful claimant.

15. The Operator shall notify the Division immediately of any changes in the Operator's registered agent, the Operator's address, form of business, name of business, significant changes in ownership, and other pertinent changes in the information required as part of the Notice of Intention. Notwithstanding this requirement, any changes to the Notice of Intention, and any errors, omissions, or failures to fully or accurately complete or update the information on the Notice of Intention, or the attached maps, shall not affect the validity of this Contract and the rights of the Division to enforce its terms.

16. If requested by the Division, the Operator shall execute addendums to this Contract to add or substitute parties, or to reflect changes in the Operator, Surety, and otherwise modify the Contract to reflect changes in the exploration operations as requested by the Division. All modifications must be in writing and signed by the parties, and no verbal agreements, or modifications in any of the terms or conditions shall be enforceable.

PUBLIC COPY

17. This Contract shall be governed and construed in accordance with the laws of the State of Utah.

The signatory below represents that the Operator, if not a natural person, is a properly organized entity in good standing under the laws of Utah and the United States, is registered as an entity authorized to do business in the State of Utah, and that he/she is authorized to execute this Contract on behalf of the entity as Operator.

OPERATOR:

Magnum Holdings, LLC
Operator Name

By David K. Detton
Authorized Officer (Typed or Printed)

Manager
Authorized Officer Position

David K. Detton 10/28/08
Officer's Signature Date

STATE OF Utah)
) ss:
COUNTY OF Salt Lake)

On the 28th day of October, 2008, David K. Detton personally appeared before me, who being by me duly sworn did say that he/she is an Manager (owner, officer, director, partner, agent or other (specify)) of the Operator Magnum Holdings, LLC and duly acknowledged that said instrument was signed on behalf of said Operator by authority of its bylaws, a resolution of its board of directors or as may otherwise be required to execute the same with full authority and to be bound hereby.

Penny Berry
Notary Public
Residing at Salt Lake

PENNY BERRY
NOTARY PUBLIC - STATE OF UTAH
1894 W. NORTH TEMPLE, STE 1210
SALT LAKE CITY, UT 84116
My Comm. Exp. 01/11/2011

PUBLIC COPY

1-11-2011
My Commission Expires:

DIVISION OF OIL, GAS AND MINING:

By John R. Baza
John R. Baza, Director

11/20/08
Date

STATE OF Utah)
) ss:
COUNTY OF Salt Lake)

On the 20 day of November, 2008, John R. Baza personally appeared before me, who being duly sworn did say that he, the said John R. Baza is the Director of the Division of Oil, Gas and Mining, Department of Natural Resources, State of Utah, and he duly acknowledged to me that he executed the foregoing document by authority of law on behalf of the State of Utah.

Penny Berry
Notary Public
Residing at: Salt Lake

1/11/2011
My Commission Expires:

PENNY BERRY
NOTARY PUBLIC - STATE OF UTAH
1594 W. NORTH TEMPLE, STE 1210
SALT LAKE CITY, UT 84116
My Comm. Exp. 01/11/2011

PUBLIC COPY

FACT SHEET

Commodity: Salt

Mine Name: Western Energy Hub

Permit Number: E0270075

County: Millard

Disturbed Acres: Less than 1 acre

Operator Name: Magnum Holdings, LLC

Operator address: 2150 South 1300 East, Suite 500, Salt Lake City, UT 84106

Operator telephone: (801) 699-0209

Operator fax: (801) 292-7789

Operator email: dave@westernenergyhub.com

Contact: Dave Detton

Surety Type: CD

Held by (Bank/BLM): Wells Fargo National Bank, N.A.

Surety Amount: $27,500.00

Surety Account Number: CD # 8632670918

Escalation Year: N/A

Tax ID or Social Security (for cash only): N/A

Surface owner: Magnum Holdings, LLC

Mineral owner: Magnum Holdings, LLC

UTU number: N/A

Acres: Less than 1

For Division Use Only
File Number E 0270075
Date NOI Received 10/28/08
Date NOI Approved
Date NOI Expires
DOGM Lead Tom Munson
Permit Fee $ 150.00 Ck# 1146

Task ID# 2717

STATE OF UTAH
DEPARTMENT OF NATURAL RESOURCES
DIVISION OF OIL, GAS AND MINING
1594 West North Temple Suite 1210
Box 145801
Salt Lake City, Utah 84114-5801
Telephone: (801) 538-5291 - Fax: (801) 359-3940

NOTICE OF INTENTION TO CONDUCT EXPLORATION

* * * * * * * * * * * * * * * * * * *

The informational requirements of this form are based on provisions of the Mined Land Reclamation Act, Title 40-8, Utah Code Annotated, 1953, as amended, and the General Rules as promulgated under the Utah Minerals Regulatory Program.

PLEASE NOTE: All information provided in this Notice of Intention shall be protected as confidential information by the Division. If extra space is required to completely answer any section, please attach additional sheets and include cross-referenced page numbers as necessary. The Permittee / Operator may submit this information on an alternate form, but the same or similar format and content must be used.

R647-1-106 - "Exploration" means surface disturbing activities conducted for the purpose of discovering a deposit or mineral deposit, delineating the boundaries of a deposit or mineral deposit, and identifying regions or specific areas in which deposits or mineral deposits are most likely to exist. "Exploration" includes, but is not limited to: sinking shafts; tunneling; drilling holes and digging pits or cuts; building of roads, and other access ways;" (and constructing and operating other facilities related to these activities).

I. GENERAL INFORMATION (Rule R647-2-104)

1. **Name of Mine:** **Western Energy Hub**

2. **Name of Entity Applying for Permit:** **Magnum Holdings, LLC**
Contact (Authorized Officer): **David K. Detton**
Address: **2150 South 1300 East, Suite 500**
City, State, Zip: **Salt Lake City, UT 84106**
Phone: **(801) 699.9209** Fax: **(801) 292-7789**
E-mail Address: **dave@westernenergyhub.com**

APPROVED
NOV 24 2008
DIV. OIL GAS & MINING

Entity is a: Corporation ( ) LLC (**X**) Sole Proprietorship (dba) ( )
Partnership ( ) General or limited
Individual ( ) Other (specify type)

Entity must be registered (and maintain registration) with the State of Utah, Division of Corporations www.commerce.utah.gov.
Are you currently registered to do business in the State of Utah? **X** Yes No
Entity # **7003317-0160**
Local Business License # **(Not yet required.)**
Issued by: County or City

RECEIVED
OCT 28 2008
DIV. OF OIL, GAS & MINING

Registered Utah Agent (as identified with the Utah Department of Commerce):
Name: **Robert W. Webster**
Address: **1248 East Yale Ave.**
City, State, Zip: **Salt Lake City, UT 84105**
Phone: **(801) 557-5444** Fax: **(801) 665-1584**
E-mail Address: **rob@westernenergyhub.com**

3. **Entity's Representative (if different from #2)**
Name: **David K. Detton**
Address: **2018 Maple Grove Way**
City, State, Zip: **Bountiful, UT 84010**
Phone: **(801) 699.9209** Fax: **(801) 292-7789**
E-mail Address: **dave@westernenergyhub.com**

4. **If Partnership or Sole Proprietor:**
Name of 1st partner / Sole Proprietor:
Name
Address:
City, State, Zip:
Phone: Fax:
E-mail Address:

If Partnership:
Name of 2nd Partner:
Address:
City, State, Zip:
Phone: Fax:
E-mail Address:

If Corporation:
Name of Officers: Title:
Title:
Title:
Title:

If Limited Liability Company: Member Managed Manager Managed **X**
Name of 1st Member/Manager: **David K. Detton**
Address: **2018 Maple Grove Way**
City, State, Zip: **Bountiful, UT 84010**
Phone: **(801) 699.9209** Fax: **(801) 292-7789**
E-mail Address: **dave@westernenergyhub.com**

Name of 2nd Member/Manager: **Robert W. Webster**
Address: **1248 East Yale Ave.**
City, State, Zip: **Salt Lake City, UT 84105**
Phone: **(801) 557-5444** Fax: **(801) 665-1584**
E-mail Address: **rob@westernenergyhub.com**

APPROVED
NOV 24 2008
DIV. OIL GAS & MINING

Name of 3rd Member/Manager:
Address:
City, State, Zip:
Phone: Fax:
E-mail Address:

5. **Ownership of Land Surface:**

Private (Fee) **X** Public Domain (BLM) National Forest (USFS)
State Trust Land/School Sections State Sovereign Lands
Other (please describe):

Name	**Magnum Holdings, LLC**	Address	**2150 South 1300 East, Suite 500**
Name		Address	**Salt Lake City, UT 84106**
Name		Address	
Name		Address	

6. **Ownership of Minerals:**

Private (Fee) **X** Public Domain (BLM) National Forest (USFS)
State Trust Land/School Sections State Sovereign Lands
Other (please describe):

Name	**Magnum Holdings, LLC**	Address	**2150 South 1300 East, Suite 500**
Name		Address	**Salt Lake City, UT 84106**
Name		Address	
Name		Address	

BLM Lease or Project File Number(s) and/or USFS assigned Project Number(s):

BLM Claim Numbers

Utah State Lease Number(s):

Name of Lessee(s)

7. **Have the above surface and mineral owners been notified in writing?**
Yes No **X**

If no, why not? **Permittee is the sole owner of 100% of the Surface and Minerals**

Please be advised that if State Trust Lands are involved, notification to the Division of Oil, Gas and Mining alone does not satisfy the notification requirements of Mineral Leases upon State Trust Lands. Exploration or mining activity on State Trust Lands requires a minimum of 60 days notice to the Trust Lands Administration prior to commencing any activities. Please contact the School Institutional Trust Lands Administration (SITLA) at (801) 538-5100 for notification requirements.

8. **Does the Entity have legal right to enter and conduct mining operations on the land covered by this notice?** Yes **X** No

APPROVED

NOV 24 2008

DIV. OIL GAS & MINING

II. PROJECT LOCATION & MAP (Rule R647-3-105)

1. **Project Location** (legal description):

County(ies): **Millard**

NE 1/4, of	**NE** 1/4, of	**NE** 1/4:	Section:	**27**	Township: **15S**	Range: **7W**
1/4, of	1/4, of	1/4:	Section:		Township:	Range:
1/4, of	1/4, of	1/4:	Section:		Township:	Range:

UTM East **361433** (if known) UTM North **4372658** (If known)

Name of Quad Map for Location: **DELTA NE**

2. A general location map (USGS 7.5 Minute Series - scale 1"=2000') that shows project location and proposed access route (include existing and/or proposed roads).

3. An operations map (scale 1"=200', or other scale as approved by the Division) that identifies:
   a. The area to be disturbed,
   b. The location of any existing and proposed operations, including locations of access roads, drill holes, pits, adits, portals, trenches, shafts, cuts, waste dumps, tailing ponds, overburden and soil stockpiles, work areas, etc.,
   c. The location of any adjacent previous disturbances for which the operator is not responsible (provide photo documentation of these areas).

4. The proposed (5 acre or less) disturbed area boundary (including access/haul roads) **should** be marked in the field ON THE GROUND with metal T-Posts (or with some other marker of equal effectiveness). Markers should be appropriately spaced so that the next marker in either direction is clearly visible with the naked eye.

5. **Have the above surface and mineral owners been notified in writing**? Yes No **X**
   If no, why not? **Permittee is the sole owner of 100% of the Surface and Minerals**

Please be advised that if State Trust Lands are involved, notification to the Division of Oil, Gas and Mining alone does not satisfy the notification requirements of Mineral Leases upon State Trust Lands. Exploration or mining activity on State Trust Lands requires a minimum of 60 days notice to the Trust Lands Administration ***prior*** *to commencing any activities. Please contact the School Institutional Trust Lands Administration (SITLA) at (801) 538-5508 for notification requirements.*

6. **Does the Permittee / Operator have legal right to enter and conduct exploration on the land covered by this notice**? Yes **X** No .

III. PROJECT DESCRIPTION (Rule 647-2-106)

1. **Minerals to be explored: Salt (Sodium and Associated Minerals)**
2. **Amount of material to be extracted, moved or proposed to be moved: ~ 17 cu. yds.**
3. **Identify the type or method of exploration proposed** (place an "X"):
   Cuts Pits Trenches Shafts Tunnels
   Air Drilling **X** Fluid Drilling

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Other (describe)

4. **Proposed Disturbances** (Approximate):

Drill Pads: How many? **1** Width **150** (ft) Length **180** (ft)

Drill Holes: How many? **1** Depth ~ **2,600 to 4,600** (ft) Diameter **6 1/2** (in) **(for 4" cores)**
[Depths above projected salt structure (Surface to ~ 2,600 ft) will be tested for water only under a separate permit for a Non-Production Well issued by the Division of Water Rights.]

Shafts, trenches, pits, cuts, or other types of disturbance. **None**

Describe type, how many of each, and general dimensions.

New Road(s): Length (ft) Width (ft)
Improved Road(s) Length (ft) Width (ft)

Total project acreage to be disturbed ~ **0.62** (acres)

5. **Proposed exploration schedule** (dates):
Begin: **November 7, 2008** End: **November 6, 2009**

IV. <u>OPERATION AND RECLAMATION PRACTICES</u> (Rules R647-2-107, 108, and 109)

An exploration site is required to be kept in a clean and safe condition. Upon completion of exploration, the land is to be reclaimed to a useful condition with at least 70 percent of the original vegetative ground cover. To accomplish this, the Permittee / Operator will need to do the following work where applicable:

1. *Keep the exploration site in a safe, clean, and environmentally stable condition.*
2. *Permanently seal all shafts and tunnels to prevent unauthorized or accidental entry.*
3. *Plug drill holes with a five foot cement surface plug. Holes that encounter fluids are to be plugged in the subsurface to prevent aquifer contamination, in accordance with R647-2-108.*
4. *Construct berms, fences, or barriers, when needed, above highwalls and excavations.*
5. *Remove, isolate, or neutralize all toxic materials in a manner compatible with federal and state regulations.*
6. *Remove all waste or debris from stream channels*
7. *Dispose of any trash, scrap metal, wood, machinery, and buildings.*
8. *Conduct exploration activities so as to minimize erosion and control sediment.*

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9. *Reclaim all roads that are not part of a permanent transportation system.*

10. *Stockpile topsoil and suitable overburden prior to making excavations.*

11. *Stabilize highwalls by backfilling or rounding to 45 degrees or less, where feasible; reshape the land to near its original contour, and redistribute the topsoil and suitable overburden.*

12. *Properly prepare seed bed to a depth of six inches by pocking, ripping, discing, or harrowing. Leave the surface rough.*

13. *Reseed disturbed areas with adaptable species. The Division recommends a mixture of species of grass, forb, and browse seed, and will provide a specific species list if requested.*

14. *Plant the seed with a rangeland or farm drill, or broadcast seed. Fall is the preferred time to seed.*

V. VARIANCE REQUEST (Rule R647-2-110) Yes No X

Any variance must be approved by the Division in writing.

Rules R647-2-107, Operation Practices; R647-2-108, Hole Plugging Requirements; and R647-2-109, Reclamation Practices are summarized on the preceding page. Any planned deviations from these rules should be identified below and justification given for the variance request(s).

Item Number Variance Request Justification

VI. SURETY (Act 40-8-7(1)[c])

The surety must be provided to and approved by the Division prior to commencement of operations.

The Utah Mined Land Reclamation Act (40-8-7 (1)[c] and 40-8-14 provides the authority that all mining operations furnish and maintain reasonable surety to guarantee that the land affected is reclaimed according to approved *notices* consistent with on-site conditions. The surety amount is based on the nature, extent and duration of operations.

Acceptable forms of surety may include: certificates of deposit, letters of credit, surety bonds & cash.

VII. PERMIT FEE [Mined Land Reclamation Act 40-8-7(1)(i)]

The Utah Mined Land Reclamation Act of 1975 [40-8-7 (1)(i)] provides the authority for the assessment of permitting fees. Commencing with the 1998 fiscal year (July 1 - June 30), permit fees are assessed to new and existing notices of intention, and annually thereafter, until the project disturbances are successfully reclaimed by the Permittee / Operator and released by the Division.

Exploration Notices require a $150.00 fee which must accompany this application or it cannot be processed by the Division.

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NOTICE: The following person(s) are authorized and designated to receive Notices of Violations, Cessation Orders and all other Notices required by the Division to be given to the Permittee or Operator:

Name:		**David K. Detton**
Address:		**2018 Maple Grove Way**
City, State, Zip:		**Bountiful, UT 84010**
Phone:	**(801) 699.9209**	Fax: **(801) 292-7789**
E-mail Address:	**dave@westernenergyhub.com**	

Name:		**Robert W. Webster**
Address:		**1248 East Yale Ave.**
City, State, Zip:		**Salt Lake City, UT 84105**
Phone:	**(801) 557-5444**	Fax: **(801) 665-1584**
E-mail Address:	**rob@westernenergyhub.com**	

VIII. SIGNATURE REQUIREMENT

I hereby verify that the foregoing information is true and accurate and commit to the reclamation of the aforementioned exploration project as required by the Utah Mined Land Reclamation Act (40-8) and the rules as specified by the Board of Oil, Gas and Mining.

(Please check the box(s) and place your initials on the line(s) provided)

DKD X I have enclosed the required permit fee.

DKD X I have enclosed the appropriate reclamation surety amount or have made arrangements as to when the surety will be furnished.

DKD X I understand that I am not authorized to create any surface disturbance until the surety amount is posted and approved in writing from the Division of Oil, Gas and Mining and any other authorized regulatory agency.

DKD X I understand that the information in this notice, regarding the location, size and nature of the mineral deposit, will be protected as confidential information, **until** the file is closed (unless I give written release to divulge the information sooner).

(Note: If a company or corporation, this form must be signed by the owner or officer who is authorized to bind the company/corporation to this Notice.)

Magnum Holdings, LLC

Signature of Permittee / Operator/Applicant: **By:** David K. Detton

Name (typed or print): **David K. Detton**

Title/Position (if applicable): **Manager**

Date: **October 24, 2008**

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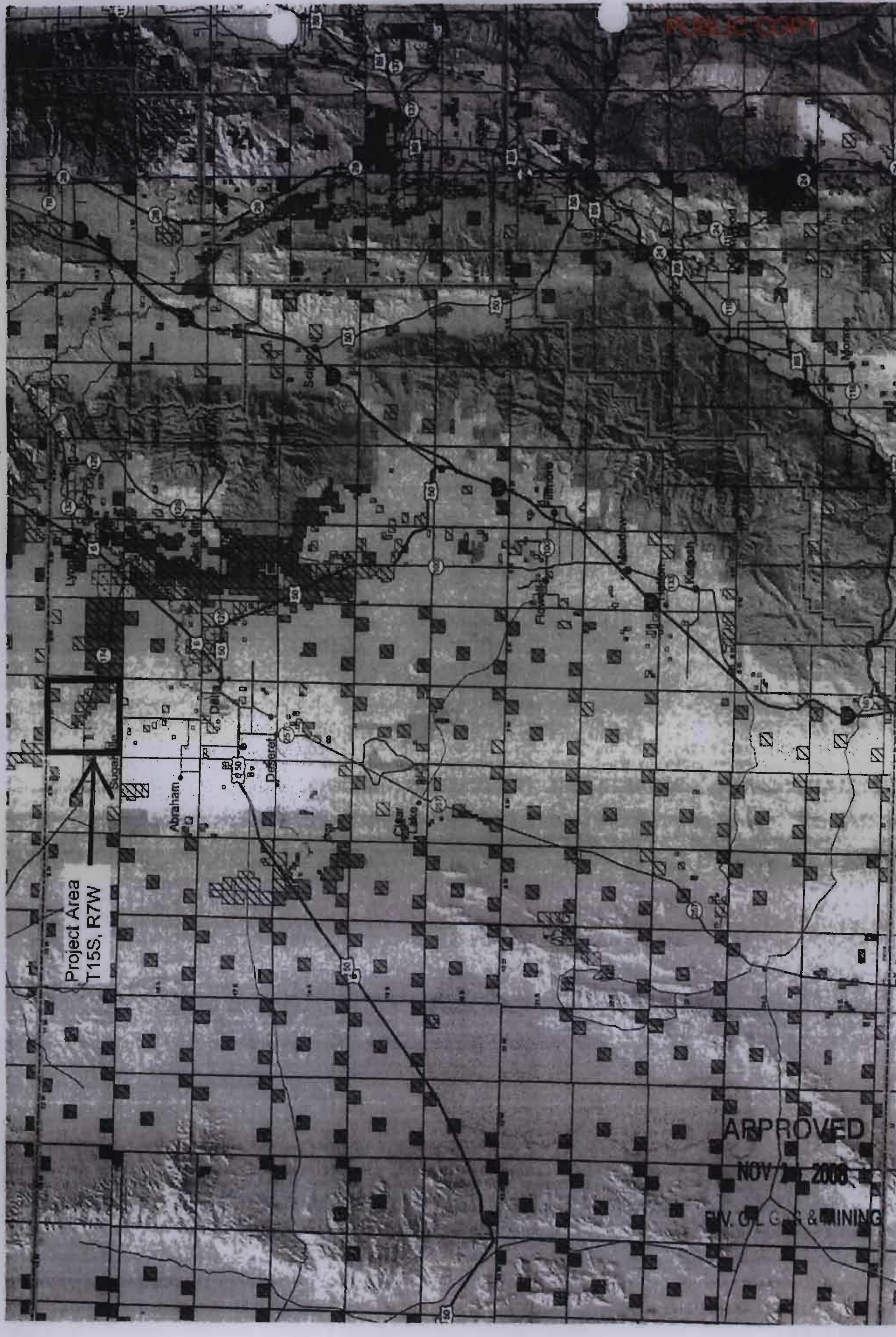
PUBLIC COPY
Project Area
T15S, R7W
Delta
Deseret
Abraham
Clear Lake
Fillmore
Meadow
Kanosh
Flowell
Scipio
Monroe
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NOV 2_ 2008
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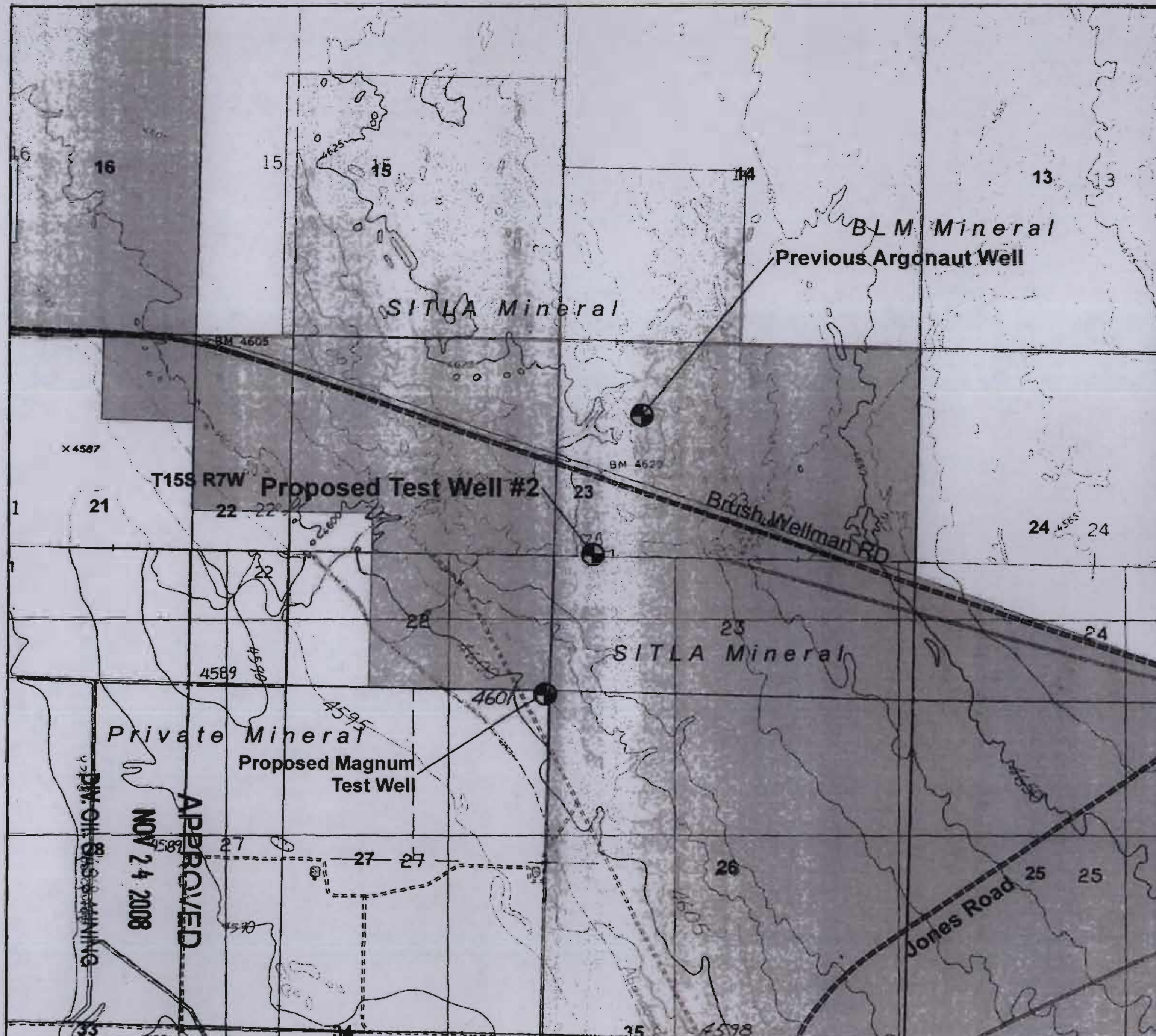

Legend

- Proposed Test Well
- Previous Argonaut Well
- Roads
- Jones Road
- Townships
- Section

SUB - SURFACE OWNER

- State
- Federal
- Private Owner Undefined

1:24,000

1 inch = 2,000 feet

0 500 1,000 2,000 Feet

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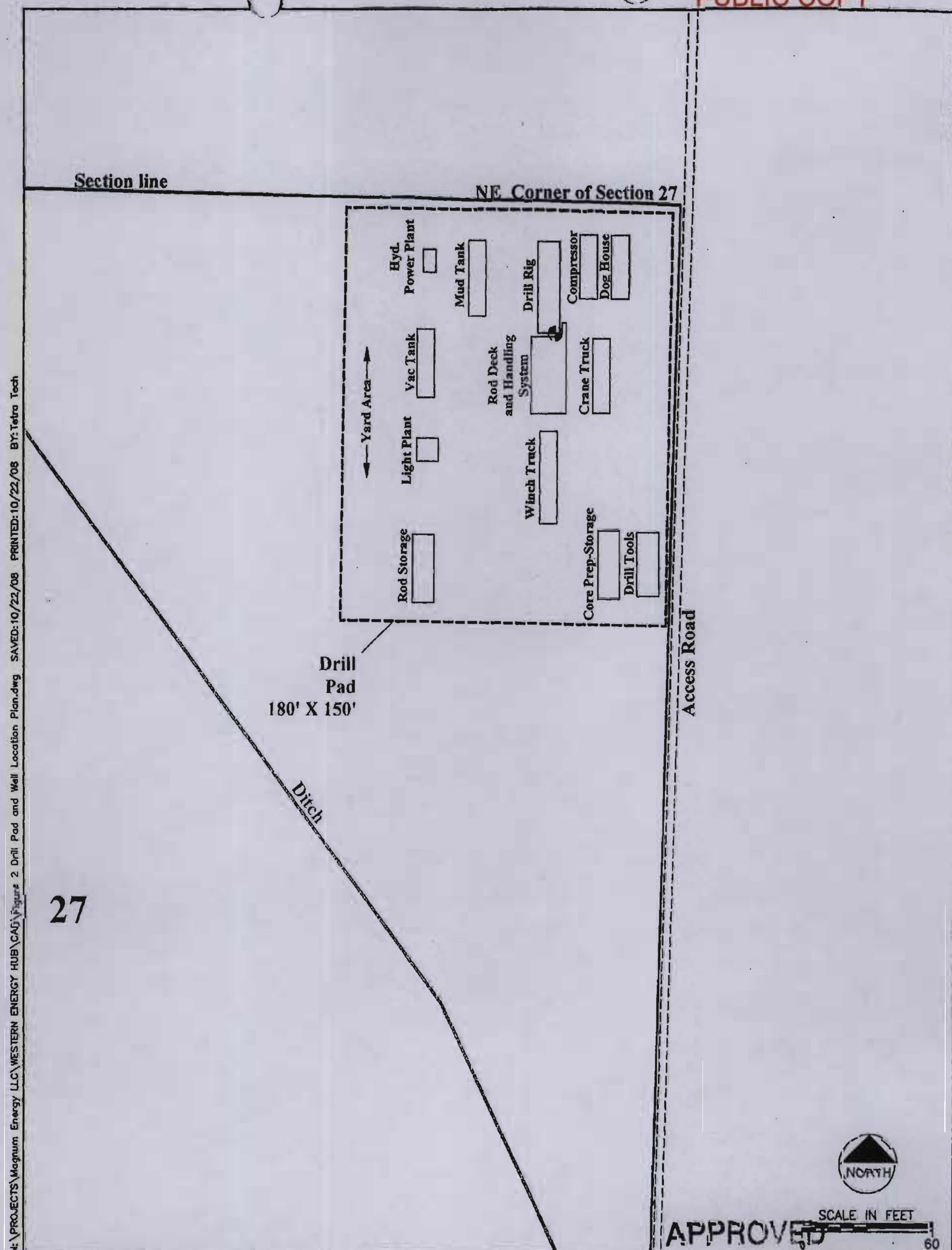
Project: MAGNUM ENERGY, LLC	
Source: AGRC Image Server >>> image.state.ut.us	
County: Millard / State: Utah	Location: T. 15 S. R. 7 W.
PRJ: NAD 83 UTM 12 Meters	Date: 09/24/2008

FIGURE 1
Proposed Test Well Locations
Western Energy Hub
Magnum Energy, LLC.

TETRA TECH, INC.



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October 21, 2008

FIGURE 2
Drill Pad and Well Location Plan

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FORM MR-EXP

(Revised July 11, 2007)

For Division Use Only
File Number E0270075

Date NOI Received ____________
Date NOI Approved ____________
Date NOI Expires ____________
DOGM Lead ____________
Permit Fee $ _______Ck# _______

STATE OF UTAH
DEPARTMENT OF NATURAL RESOURCES
DIVISION OF OIL, GAS AND MINING
1594 West North Temple Suite 1210
Box 145801
Salt Lake City, Utah 84114-5801
Telephone: (801) 538-5291 - Fax: (801) 359-3940

NOTICE OF INTENTION TO CONDUCT EXPLORATION

****

The informational requirements of this form are based on provisions of the Mined Land Reclamation Act, Title 40-8, Utah Code Annotated, 1953, as amended, and the General Rules as promulgated under the Utah Minerals Regulatory Program.

PLEASE NOTE: All information provided in this Notice of Intention shall be protected as confidential information by the Division. If extra space is required to completely answer any section, please attach additional sheets and include cross-referenced page numbers as necessary. The Permittee / Operator may submit this information on an alternate form, but the same or similar format and content must be used.

R647-1-106 - "Exploration" means surface disturbing activities conducted for the purpose of discovering a deposit or mineral deposit, delineating the boundaries of a deposit or mineral deposit, and identifying regions or specific areas in which deposits or mineral deposits are most likely to exist. "Exploration" includes, but is not limited to: sinking shafts; tunneling; drilling holes and digging pits or cuts; building of roads, and other access ways;" (and constructing and operating other facilities related to these activities).

I. GENERAL INFORMATION (Rule R647-2-104)

1. **Name of Mine:** **Western Energy Hub**

2. **Name of Entity Applying for Permit:** **Magnum Holdings, LLC**
Contact (Authorized Officer): **David K. Detton**
Address: **2150 South 1300 East, Suite 500**
City, State, Zip: **Salt Lake City, UT 84106**
Phone: **(801) 699.9209** Fax: **(801) 292-7789**
E-mail Address: **dave@westernenergyhub.com**

Entity is a: Corporation ( ) LLC (**X**) Sole Proprietorship (dba) ( )
Partnership ( ) General or limited
Individual ( ) Other (specify type)

Entity must be registered (and maintain registration) with the State of Utah, Division of Corporations www.commerce.utah.gov.
Are you currently registered to do business in the State of Utah? **X** Yes No
Entity # **7003317-0160**
Local Business License # **(Not yet required.)**
Issued by: County or City

Registered Utah Agent (as identified with the Utah Department of Commerce):
Name: **Robert W. Webster**
Address: **1248 East Yale Ave.**
City, State, Zip: **Salt Lake City, UT 84105**
Phone: **(801) 557-5444** Fax: **(801) 665-1584**
E-mail Address: **rob@westernenergyhub.com**

3. **Entity's Representative (if different from #2)**
Name: **David K. Detton**
Address: **2018 Maple Grove Way**
City, State, Zip: **Bountiful, UT 84010**
Phone: **(801) 699.9209** Fax: **(801) 292-7789**
E-mail Address: **dave@westernenergyhub.com**

4. **If Partnership or Sole Proprietor:**
Name of 1st partner / Sole Proprietor:
Name
Address:
City, State, Zip:
Phone: Fax:
E-mail Address:

If Partnership:
Name of 2nd Partner:
Address:
City, State, Zip:
Phone: Fax:
E-mail Address:

If Corporation:
Name of Officers: Title:
Title:
Title:
Title:

If Limited Liability Company: Member Managed Manager Managed **X**
Name of 1st Member/Manager: **David K. Detton**
Address: **2018 Maple Grove Way**
City, State, Zip: **Bountiful, UT 84010**
Phone: **(801) 699.9209** Fax: **(801) 292-7789**
E-mail Address: **dave@westernenergyhub.com**

Name of 2nd Member/Manager: **Robert W. Webster**
Address: **1248 East Yale Ave.**
City, State, Zip: **Salt Lake City, UT 84105**
Phone: **(801) 557-5444** Fax: **(801) 665-1584**
E-mail Address: **rob@westernenergyhub.com**

Name of 3rd Member/Manager:
Address:
City, State, Zip:
Phone: Fax:
E-mail Address:

5. **Ownership of Land Surface:**

Private (Fee) **X** Public Domain (BLM) National Forest (USFS)
State Trust Land/School Sections State Sovereign Lands
Other (please describe):

Name	**Magnum Holdings, LLC**	Address	**2150 South 1300 East, Suite 500**
Name		Address	**Salt Lake City, UT 84106**
Name		Address	
Name		Address	

6. **Ownership of Minerals:**

Private (Fee) **X** Public Domain (BLM) National Forest (USFS)
State Trust Land/School Sections State Sovereign Lands
Other (please describe):

Name	**Magnum Holdings, LLC**	Address	**2150 South 1300 East, Suite 500**
Name		Address	**Salt Lake City, UT 84106**
Name		Address	
Name		Address	

BLM Lease or Project File Number(s) and/or USFS assigned Project Number(s):

BLM Claim Numbers

Utah State Lease Number(s):

Name of Lessee(s)

7. **Have the above surface and mineral owners been notified in writing?**
Yes No **X**

If no, why not? **Permittee is the sole owner of 100% of the Surface and Minerals**

Please be advised that if State Trust Lands are involved, notification to the Division of Oil, Gas and Mining alone does not satisfy the notification requirements of Mineral Leases upon State Trust Lands. Exploration or mining activity on State Trust Lands requires a minimum of 60 days notice to the Trust Lands Administration ***prior*** *to commencing any activities. Please contact the School Institutional Trust Lands Administration (SITLA) at (801) 538-5100 for notification requirements.*

8. **Does the Entity have legal right to enter and conduct mining operations on the land covered by this notice?** Yes **X** No

II. PROJECT LOCATION & MAP (Rule R647-3-105)

1. **Project Location** (legal description):

   County(ies): **Millard**

NE 1/4, of	**NE** 1/4, of	**NE** 1/4:	Section: **27**	Township: **15S**	Range: **7W**
1/4, of	1/4, of	1/4:	Section:	Township:	Range:
1/4, of	1/4, of	1/4:	Section:	Township:	Range:

   UTM East **361433** (if known) UTM North **4372658** (If known)

   Name of Quad Map for Location: **DELTA NE**

2. A general location map (USGS 7.5 Minute Series - scale 1"=2000') that shows project location and proposed access route (include existing and/or proposed roads).

3. An operations map (scale 1"=200', or other scale as approved by the Division) that identifies:
   a. The area to be disturbed,
   b. The location of any existing and proposed operations, including locations of access roads, drill holes, pits, adits, portals, trenches, shafts, cuts, waste dumps, tailing ponds, overburden and soil stockpiles, work areas, etc.,
   c. The location of any adjacent previous disturbances for which the operator is not responsible (provide photo documentation of these areas).

4. The proposed (5 acre or less) disturbed area boundary (including access/haul roads) **should** be marked in the field ON THE GROUND with metal T-Posts (or with some other marker of equal effectiveness). Markers should be appropriately spaced so that the next marker in either direction is clearly visible with the naked eye.

5. **Have the above surface and mineral owners been notified in writing**? Yes No **X**
   If no, why not? **Permittee is the sole owner of 100% of the Surface and Minerals**

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6. **Does the Permittee / Operator have legal right to enter and conduct exploration on the land covered by this notice**? Yes **X** No .

III. PROJECT DESCRIPTION (Rule 647-2-106)

1. **Minerals to be explored: Salt (Sodium and Associated Minerals)**
2. **Amount of material to be extracted, moved or proposed to be moved: ~ 17 cu. yds.**
3. **Identify the type or method of exploration proposed** (place an "X"):
   Cuts Pits Trenches Shafts Tunnels
   Air Drilling **X** Fluid Drilling

Other (describe)

4. **Proposed Disturbances** (Approximate):

Drill Pads: How many? **1** Width **185** (ft) Length **200** (ft)

Drill Holes: How many? **1** Depth ~ **6,500** (ft) Diameter **6 1/8** (in) **(for 4" cores)**
[Depths above projected salt structure (Surface to ~ 3,200 ft) will be tested for water only under a separate permit for a Non-Production Well issued by the Division of Water Rights.]

Shafts, trenches, pits, cuts, or other types of disturbance. **None**

Describe type, how many of each, and general dimensions.

New Road(s): Length (ft) Width (ft)
Improved Road(s) Length (ft) Width (ft)

Total project acreage to be disturbed ~ **0.86** (acres)

5. **Proposed exploration schedule** (dates):
Begin: **December 1, 2008** End: **December 1, 2009**

IV. <u>OPERATION AND RECLAMATION PRACTICES</u> (Rules R647-2-107, 108, and 109)

An exploration site is required to be kept in a clean and safe condition. Upon completion of exploration, the land is to be reclaimed to a useful condition with at least 70 percent of the original vegetative ground cover. To accomplish this, the Permittee / Operator will need to do the following work where applicable:

1. *Keep the exploration site in a safe, clean, and environmentally stable condition.*
2. *Permanently seal all shafts and tunnels to prevent unauthorized or accidental entry.*
3. *Plug drill holes with a five foot cement surface plug. Holes that encounter fluids are to be plugged in the subsurface to prevent aquifer contamination, in accordance with R647-2-108.*
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11. *Stabilize highwalls by backfilling or rounding to 45 degrees or less, where feasible; reshape the land to near its original contour, and redistribute the topsoil and suitable overburden.*

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13. *Reseed disturbed areas with adaptable species. The Division recommends a mixture of species of grass, forb, and browse seed, and will provide a specific species list if requested.*

14. *Plant the seed with a rangeland or farm drill, or broadcast seed. Fall is the preferred time to seed.*

V. **VARIANCE REQUEST** (Rule R647-2-110) Yes No **X**

Any variance must be approved by the Division in writing.
Rules R647-2-107, Operation Practices; R647-2-108, Hole Plugging Requirements; and R647-2-109, Reclamation Practices are summarized on the preceding page. Any planned deviations from these rules should be identified below and justification given for the variance request(s).

Item Number Variance Request Justification

VI. **SURETY** (Act 40-8-7(1)[c])

The surety must be provided to and approved by the Division prior to commencement of operations.

The Utah Mined Land Reclamation Act (40-8-7 (1)[c] and 40-8-14 provides the authority that all mining operations furnish and maintain reasonable surety to guarantee that the land affected is reclaimed according to approved *notices* consistent with on-site conditions. The surety amount is based on the nature, extent and duration of operations.

Acceptable forms of surety may include: certificates of deposit, letters of credit, surety bonds & cash.

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Exploration Notices require a $150.00 fee which must accompany this application or it cannot be processed by the Division.

NOTICE: The following person(s) are authorized and designated to receive Notices of Violations, Cessation Orders and all other Notices required by the Division to be given to the Permittee or Operator:

Name:		**David K. Detton**
Address:		**2018 Maple Grove Way**
City, State, Zip:		**Bountiful, UT 84010**
Phone:	**(801) 699.9209**	Fax: **(801) 292-7789**
E-mail Address:	**dave@westernenergyhub.com**	

Name:		**Robert W. Webster**
Address:		**1248 East Yale Ave.**
City, State, Zip:		**Salt Lake City, UT 84105**
Phone:	**(801) 557-5444**	Fax: **(801) 665-1584**
E-mail Address:	**rob@westernenergyhub.com**	

VIII. SIGNATURE REQUIREMENT

I hereby verify that the foregoing information is true and accurate and commit to the reclamation of the aforementioned exploration project as required by the Utah Mined Land Reclamation Act (40-8) and the rules as specified by the Board of Oil, Gas and Mining.

(Please check the box(s) and place your initials on the line(s) provided)

- **X** I have enclosed the required permit fee.
- **X** I have enclosed the appropriate reclamation surety amount or have made arrangements as to when the surety will be furnished.
- **X** I understand that I am not authorized to create any surface disturbance until the surety amount is posted and approved in writing from the Division of Oil, Gas and Mining and any other authorized regulatory agency.
- **X** I understand that the information in this notice, regarding the location, size and nature of the mineral deposit, will be protected as confidential information, **until** the file is closed (unless I give written release to divulge the information sooner).

(Note: If a company or corporation, this form must be signed by the owner or officer who is authorized to bind the company/corporation to this Notice.)

Magnum Holdings, LLC

Signature of Permittee / Operator/Applicant:	**By:** David K. Detton
Name (typed or print):	**David K. Detton**
Title/Position (if applicable):	**Manager**
Date:	**November 25, 2008**

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ATTACHMENT C-1.3

Initial Water Quality and Testing of Well MH-1

THE FOLLOWING INFORMATION IS CONFIDENTIAL

Well MH-1 Start-up,
Test Pumping and Evaluation

Water Quality

Water quality data was collected for well MH-1 during selected phases of development and at the conclusion of zonal pump testing of the aquifers identified between 1,650 and 2,240 feet. As shown in cuttings logs, the identified zones contain various mixes of sand, pebbles and gravel, conditions that are significantly different from the clays and silts found throughout the remainder of the log.

During development, two preliminary water samples were collected and analyzed at the following depth intervals. Collected data is provided in Attachment C-1.2.

Sample #	Date	Depth Tested
1	April 5, 2009	1,950-2,020'
2	April 6, 2009	2,180-2,240'

Isolated packer pump tests (with packers both above and below the perforated zones) were conducted for the purpose of identifying pumping capacity and general water quality of each pumped zone. Pump tests were originally designed to isolate each of the following zones.

Test #	Intended Test Interval
1	1,650-1,680'
2	1,840-2,020'
3	2,180-2,240'

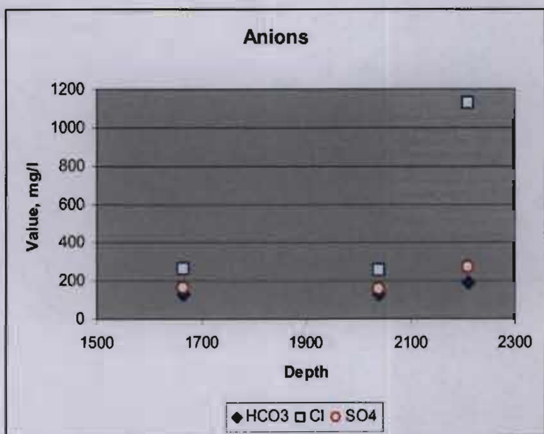
The pump test program was modified however when a nitrogen leak was discovered in the air line feeding the lower packer during the initial test. Although the driller affirms that pressure to the lower packer was maintained during the first test, the leak caused inconsistent readings in water level data within the aquifer zone being tested. Subsequent tests were therefore conducted without inflating the lower packer which resulted in contribution of flows from lower zones 2 and 3 during the test #2. The pump tests were successful in withdrawing an approximate flow of 425 gpm from each tested zone over the 24 hour pumping period. A discussion of the pump test and results is included later in this section.

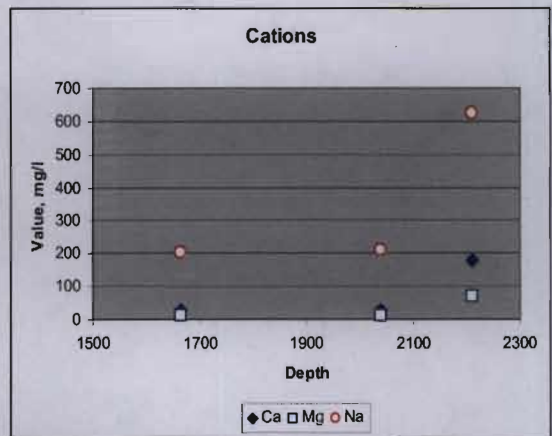
Water quality samples including the following parameters were collected at the end of each test just prior to test completion.

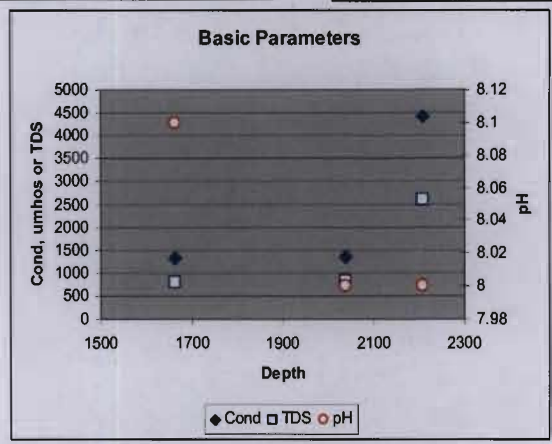
Alkalinity-Bicarbonate	Potassium, Total
Chloride	Sodium, total
Sulfate	Conductivity
Calcium, Total	pH
Iron, Total	Total Dissolved Solids
Magnesium, Total	

Accounting for the nitrogen leak and lack of isolation in subsequent testing, the water quality collected during the pump tests (included within Attachment C-1.2) and shown in the following graphs likely represent the zones as identified.

Sample #	Date	Target Zone	Depth Tested
1	April 10, 2009	1,650-1,680'	1,650-1,680'
2	April 11, 2009	1,840-2,020	1,840-2,240'
3	April 12, 2009	2,180-2,240	2,180-2,240'







As seen in the graphs, major increases in Chloride, Sodium, Conductivity and TDS were noted to have occurred between the middle and lower test comprising Samples 2 and 3. A similar but reversed trend is also noted in pH between the first sample and deeper samples 2 and 3. Notable but less drastic changes are also noted with depth for Bicarbonate, Sulfate, Magnesium, and Calcium.

Pump Tests

Three packer pump tests were conducted on well MH-1 at the 1,650-1,680, 1,840-2,020, and 2,180-2,240 foot intervals wherein potential aquifers were identified. The date, zone tested and packer placement were as follows.

Test	Date	Target Zone	Upper Packer	Lower Packer	Flow (gpm)	Length of Test (Hrs)
1	April 10, 2009	1,650'-1,680'	1,492'	1,700'	440	48
2	April 11, 2009	1,840'-2,020'	1,820'	Not Inflated	440	1.5
3	April 12, 2009	2,180'-2,240'	2,'060'	Not Inflated	440	3

The goals for these tests were to identify to a reasonable degree individual aquifer characteristics, and respective potential pumping rates, draw downs, and water quality.

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Water quality was discussed above. It was also a goal to determine whether there was any measurable effect on aquifers above and below the isolated pumping zone.

A graphical well casing schematic for well MH-1 is provided in Attachment C-1.2. A tabular representation of the well showing grouted and perforated zones and packer placements is shown below. Grouted zones are shown in black, Upper and Lower Packers are shown with red diagonal hatching. Perforated zones are shown with vertical hatching, and Tested Zones are shown with blue horizontal hatching. Due to depths involved, pressure transducers were placed within the well at a depth of approximately 650 feet and connected to the zones above, within and below the isolated screens via tubing. The upper transducer recorded levels above the Upper Packer, while the middle and lower transducers were connected to piping that penetrated the upper and lower packer assemblies respectively.

TEST 1		
Depth	Well	Comment
0-1395		Blank Casing
1395-1405		Screen
1405-1420		Blank Casing
1420-1500		Grout
1492		Upper Packer
1500-1580		Grout
1580-1650		Blank Casing
1650-1680		Screen
1680-1700		Blank Casing
1700		Lower Packer
1700-1710		Blank Casing
1710-1740		Grout
1740-1840		Blank Casing
1840-1870		Screen
1870-1950		Blank Casing
1950-2020		Screen
2020-2050		Grout
2050-2180		Blank Casing
2180-2240		Screen
2240-3300		Blank Casing

TEST 2		
Depth	Well	Comment
0-1395		Blank Casing
1395-1405		Screen
1405-1420		Blank Casing
1420-1580		Grout
1580-1650		Blank Casing
1650-1680		Screen
1680-1710		Blank Casing
1710-1740		Grout
1740-1830		Blank Casing
1820		Upper Packer
1830-1840		Blank Casing
1840-1870		Screen
1870-1950		Blank Casing
1950-2020		Screen
2020-2030		Grout
2030		Lower Packer
2030-2050		Grout
2050-2180		Blank Casing
2180-2240		Screen
2240-3300		Blank Casing

TEST 3		
Depth	Well	Comment
0-1395		Blank Casing
1395-1405		Screen
1405-1420		Blank Casing
1420-1580		Grout
1580-1650		Blank Casing
1650-1680		Screen
1680-1710		Blank Casing
1710-1740		Grout
1740-1840		Blank Casing
1840-1870		Screen
1870-1950		Blank Casing
1950-2020		Screen
2020-2050		Grout
2060		Upper Packer
2050-2180		Blank Casing
2180-2240		Screen
2240-2250		Grout
2250		Lower Packer
2250-3300		Blank Casing

• - Lower Packer Deflated for Test

TEST 1 - 1,650-1,680 Isolated Test

The testing of Zone 1 was considered the most important test of the series since it could help provide data which would help indicate potential influence of pumping on upper aquifers that are currently used within the region for industrial and agricultural purposes.

1,395-1,405 Foot Aquifer

Figure C-1.1 entitled "1,650-1,680 – Upper Transducer" shows water levels within the 1,395 to 1,405 perforated zone, located above the tested zone and separated by approximately 245 feet of clay. The figure shows a small decline in water levels that resulted from the stabilization of water levels once the packer was set in place. The initial levels were influenced by the potentiometric surface of the tested zones which at the time of testing was producing an approximate 3 feet of artesian head, and was higher than the recorded potentiometric surface within the 1,395 to 1,405 foot perforated zone. The decline in water level represents the flow of well column water into the 1,395-1,405 foot zone after the inflation of the packer. The data response at this well is typical of a slug test where water level decline is noted following the injection of a slug of water into a well casing. Note that no inflection points are noted in the data, indicating that there was no influence noted on the zone above the upper packer during the period of the test.

Conclusion – No impact on aquifers above 1,405 feet due to pumping the 1,650 – 1,680 aquifer at a rate of between 425 and 440 gpm.

1,650-1,680 Foot Aquifer

Figure C-1.2 entitled "1,650-1,680 – Middle Transducer" represents water levels within the 1,650 to 1,680 foot pumped zone. The figure shows a typical response and declining water level immediately following pumping which may have begun to stabilize with about 42 feet of drawdown. However, the figure shows that water levels increased between midnight and 6:00 am on April 9th returning to their near pre-pumping levels and remained constant thereafter. This increase and continued stabilization was the result of a leaky lower packer into which nitrogen was fed. Data variations shown in the far right portion of the figure are readings collected following termination of the test and during movement of the packer set to test #2.

Conclusion – A water production rate of approximately 425-440 gpm resulted in a level decline on the order of 42 feet during the test.

1,840-2,240 Foot Aquifers

Figure C-1.3 entitled "1,840-2,240 – Lower Transducer" represents water levels within the aquifers below the 1,650 to 1,680 foot pumped zone. The figure shows a typical drawdown and recovery responses during the pump test with an approximate 15 foot drawdown. Caution however must be given when interpreting this figure since the lower packer was leaking during and it is uncertain what impact if any, the leak had on transducer readings. Assuming the leak did not affect this lower zone, there is evidence of interconnections between the pumped zone and lower zones as seen through the steps in the data. Overall, these lower aquifers show an approximate 20 foot decline due to pumping during the 48 hour test. Although data shown in the far right portion of the figure show what could be considered a typical recovery curve, it is influenced by movement of the test string following termination of the test.

Conclusion – A water production rate of approximately 425-440 gpm resulted in a level decline on the order of 20 feet during the test.

TEST 2 - 1,840-2,020 Isolated Test

1,395-1,680 Foot Aquifers

Figure C-1.4 entitled "1,840-2,020 – Upper Transducer" shows water levels within the combined 1,395 to 1,680 foot perforated zones. Similar to data shown within the preceding section, the figure shows typical drawdown and recovery data during and after the 1½ hour test. Total drawdown resulting from pumping 425 to 440 gpm was about 1 foot. This data helps conclude that there may be significant isolation between the 1,650-1,680 and 1,840-2,020 foot aquifers. It should be recognized that the recovery data shown in the right portion of the figure includes combined impacts from all perforated aquifer zones since both packers were deflated at the conclusion of the pumping test. It should also be noted that pumping impacts on these upper aquifers are limited to the 1,650-1,680 foot aquifer since test #1 showed no pumping impact between the 1,395-1,405 and 1,650-1,680 foot aquifers.

Conclusion – A water production rate of approximately 425-440 gpm resulted in a water level decline on the order of 1 foot during the test.

1,840-2,020 Foot Aquifer

Figure C-1.5 entitled "1,840-2,020 – Middle Transducer" shows water levels within the combined 1,840 to 2,020 foot perforated zones, with some influence from the 2,180-2,240 foot zone since the lower packer was deflated during the test. Similar to data shown within the preceding section, the figure shows typical drawdown and recovery data during and after the 1½ hour test. Total drawdown resulting from pumping 425 to 440 gpm was about 15 feet. It is important to note however that this data shows some restriction was created during the test by the lower deflated packer between the pumped zone and the aquifers located below 2,020 feet. This is observed through a comparison of middle and lower transducer readings. As stated, data from the pumped zone show a drawdown of about 15 feet. Data from the lower transducer (discussed below) show a drawdown of about 30 feet. Recovery data shown in the right portion of the figure include combined impacts from all perforated aquifer zones since both packers were deflated at the conclusion of the pumping test.

Conclusion – A water production rate of approximately 425-440 gpm resulted in a water level decline on the order of 15 feet during the test. It is also concluded that the pumped zone may have more production potential than the lower 2,180-2,240 foot zone.

2,180-2,240 Foot Aquifer

Figure C-1.6 entitled "1,840-2,020 – Lower Transducer" shows water levels within the combined 2,180 to 2,240 foot perforated zone. The figure shows typical drawdown and recovery data during and after the 1½ hour test. Total drawdown resulting from pumping the 1,840-2,020 foot zone at 425 to 440 gpm was about 35 feet. As with other tests, recovery data shown in the right portion of the figure include combined impacts from all perforated aquifer zones since both packers were deflated at the conclusion of the pumping test.

Conclusion – A water production rate of approximately 425-440 gpm resulted in a water level decline on the order of 35 feet during the test.

TEST 3 - 2,180-2,240 Isolated Test

With the upper packer in place and the lower portion of the well sealed from potential aquifers, this test effectively evaluated the production and water quality characteristics of the identified zone.

1,395-2,020 Foot Aquifers

Figure C-1.7 entitled "2,180-2,240 – Upper Transducer" shows responding water levels within the combined 1,395 to 2,020 foot perforated zones. Total drawdown within these upper aquifers resulting from pumping 425 to 440 gpm for 2½ hours was only about 1 foot. This data helps conclude that there is significant isolation between the aquifers above 2,020 feet and the pumped 2,180-2,240 foot aquifer.

Conclusion – A water production rate of approximately 425-440 gpm resulted in a water level decline on the order of 1 foot within aquifers above 2,020 feet during the test.

2,180-2,240 Foot Aquifer

Figure C-1.8 entitled "2,180-2,240 – Lower Transducer" shows water levels within the isolated 2,180 to 2,240 foot perforated zone. The figure shows typical drawdown and recovery data during and after the 2½ hour test. Total drawdown resulting from pumping this zone at 425 to 440 gpm was about 55 feet. Recovery data shown in the right portion of the figure shows a typical end of test response with a fairly rapid recovery.

Conclusion – A water production rate of approximately 425-440 gpm resulted in a water level decline on the order of 55 feet during the test. This zone is not as productive as upper zones as was hypothesized during testing of test zones 1 and 2.

General conclusions reached as a result of the isolated testing described above are:

- Aquifers found at depth below 1,650 feet have significant isolation from overlying aquifers historically developed above 1,400 feet. No impact on overlying existing aquifers was noted during the 48 hour test.
- Testing of the two main aquifer zones between 1,650 and 2,020 feet were found to produce an approximate 425-440 gpm with a resulting drawdown of between 30 and 40 feet during the tests.
- The lowermost aquifer found between 2,180-2,240 is the least productive having a specific capacity of about ½ of those found between 1,650 and 2,020 feet.
- It is projected that the identified aquifers may be able to produce a combined sustainable flow of approximately 1,000 gpm when properly equipped.

Following completion of the original Class III Permit application to the State, a more extensive pump test was conducted on well MH-1. In summary, the report substantiates the findings documented above in that it shows that pumping of the well MH-1 at an extended flow rate of 1,100 gpm for a 13 day period (followed by a 5 day recovery period) showed no impact on the IPP, Delta Egg Farm nor Stock Pond wells, nor did it show impact on a USGS monitoring well that is located just north of Brush Wellman Road. A complete copy of the report is included within Attachment C-1.3.

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MAGNUM GAS STORAGE PROJECT

WELL MH-1
START-UP, TEST PUMPING AND EVALUATION

FINAL REPORT

MARCH 2010

HANSEN ALLEN & LUCE inc
ENGINEERS

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ATTACHMENT D-1

Well MH-1 Grouting Isolation

GROUTING ISOLATION

MH-1 Well (Maintained as a Source Water Production Well) – Extensive efforts were made during the drilling and completion of MH-1 to isolate various zones for the purpose of preventing the vertical movement of fluids between well zones. As shown in the well schematic for MH-1 included within Attachment C-1.2, grout was installed both within the outer casing annulus as well as within the completed well casings. Outer annulus grout was placed at depths of 0-220, 650-689, 852-868, 1,002-1,020, 1,245-1,271, 1,387-1,425, 1,428-1,450, 1,720-1,735, 2,026-2,050, and 2,700-3,294 feet. The bottom of the 7" well casing was plugged with a permanent plug overlain by 38 gallons of neat cement from a depth of 3,250 to 3,280 feet. The 594 feet of well grout placed at the bottom of the cased well bridges the basement aquifer and salt structure zones indentified within this report, overlapping each zone by approximately 300 feet. This grout seal will provide an effective barrier between the salt structure and cavern zones from potential overlying USDW's.

Attachment D **Plan for Plugging and Abandonment of Class III Solution Mining Wells and Caverns before Gas Storage**

The following procedures are provided as a general guideline. Actual plugging measures would be submitted in advance to DWQ (prior to commencement of gas storage).

1. At least 45 days before the planned plugging, Magnum will notify the DWQ Executive Secretary of the proposed plugging with a Well Condition Report and a well-specific Plugging and Abandonment Plan.
2. All nitrogen or other blanket material will be removed and the cavern will be filled with saturated brine water.
3. All free hanging tubing will be pulled from the well.
4. The exact depth to the bottom of the cemented production casing will be determined.
5. 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.
6. All cement plugs to be Class G cement with no additives and slurry weight of 14.5 pounds per gallon or more.
7. The entire wellbore from the bridge plug to surface will be filled with cement.
8. In the event the cemented casing is determined to be leaking, the casing will be perforated at the level of the leak and cement squeezed into the perforations.
9. An alternative technique which could be used involves setting the following plugs.
    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 50-foot plug from 50 feet below surface grade upward to surface.
    d. The casing between each of the plugs shall be filled with a noncorrosive mud slurry of at least 10 pounds per gallon weight.
10. Upon completion of the plugging operation, all reports will be filed in accordance with DWQ rules as applicable.

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ATTACHMENT E-1

Part E – Formation Testing Program

THE FOLLOWING INFORMATION IS CONFIDENTIAL

Hydrofracture Testing at Well MH-1
Golder Associates, Inc.

Part E – Formation Testing Program

The target injection zone consists of a salt structure over 5,000 feet in vertical thickness that is not naturally water-bearing. The fracture pressure of the salt was determined by in-situ hydrofracture testing performed for Magnum by Golder Associates, Inc., in March, 2009. The hydraulic fracture tests were mostly based on the standard *ASTM D4645-89: Standard Test Method for Determination of the In-Situ Stress in Rock using the Hydraulic Fracturing Method* with some minor adaptations to account for site specific conditions.

Seven tests were performed at intervals from 3,357 feet below ground surface (bgs) to 5,511 feet bgs. As would be expected given the visco-elastic nature of salt, the observed fracture pressures varied with depth and indicated lithostatic conditions or higher, ie., the fracture pressures were at or above the calculated pressures associated with the weight of the overburden at that depth. Golder's report of the procedures used and results of this hydrofracture testing program is included within this attachment.

The injection wells and resulting salt caverns will be engineered to operate within a pressure range of 0.25 to 0.90 x the calculated lithostatic pressure at the bottom of the casing string cemented into the salt structure (the casing shoe). With an overburden pressure of about 1 psi per foot, the calculated operating overburden pressure ranges at a depth of 4,000 feet will be 1,000 to 3,600 psi. Per Part H however initial operating procedures will involve direct injection with operating pressures anticipated to be about 1,000 psi. Following initial cavern creation, the process will change to a reverse mode with pressures increasing to about 950 psi.

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ATTACHMENT G-1

THE FOLLOWING INFORMATION IS CONFIDENTIAL

Final Solution Mining Plan for
Development of Magnum Gas Storage Caverns
At Delta, Utah

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ATTACHMENT G-2

Well Drilling Details

THE FOLLOWING INFORMATION IS CONFIDENTIAL

Underground Front End Engineering Design (FEED) Casing Design
Well Construction Plan
Plugging and Abandonment Program
Cavern Well P & ID
Typical Cavern Well Piping Plan
Gas Storage Wellhead

The maximum injection pump pressure is anticipated to be about [redacted] psi on the water side of the well. The brine will be produced at a pressure of about [redacted] psi.

The maximum external pressure exerted on the cemented casing by the formation fluid will be about [redacted] psi. This is less then the maximum external pressure of [redacted] psi that could be exerted on the last cemented casing string during cementing operations if there should be a blowout during cementing operations.

The anticipated casing pressures and preliminary casing design are given in "Underground Front End Engineering Design (FEED) Casing Design" which is included within Attachment G-2. As presented in the report, the larger casing strings [redacted] will be threaded joints. The last casing string cemented into the salt will have welded connections.

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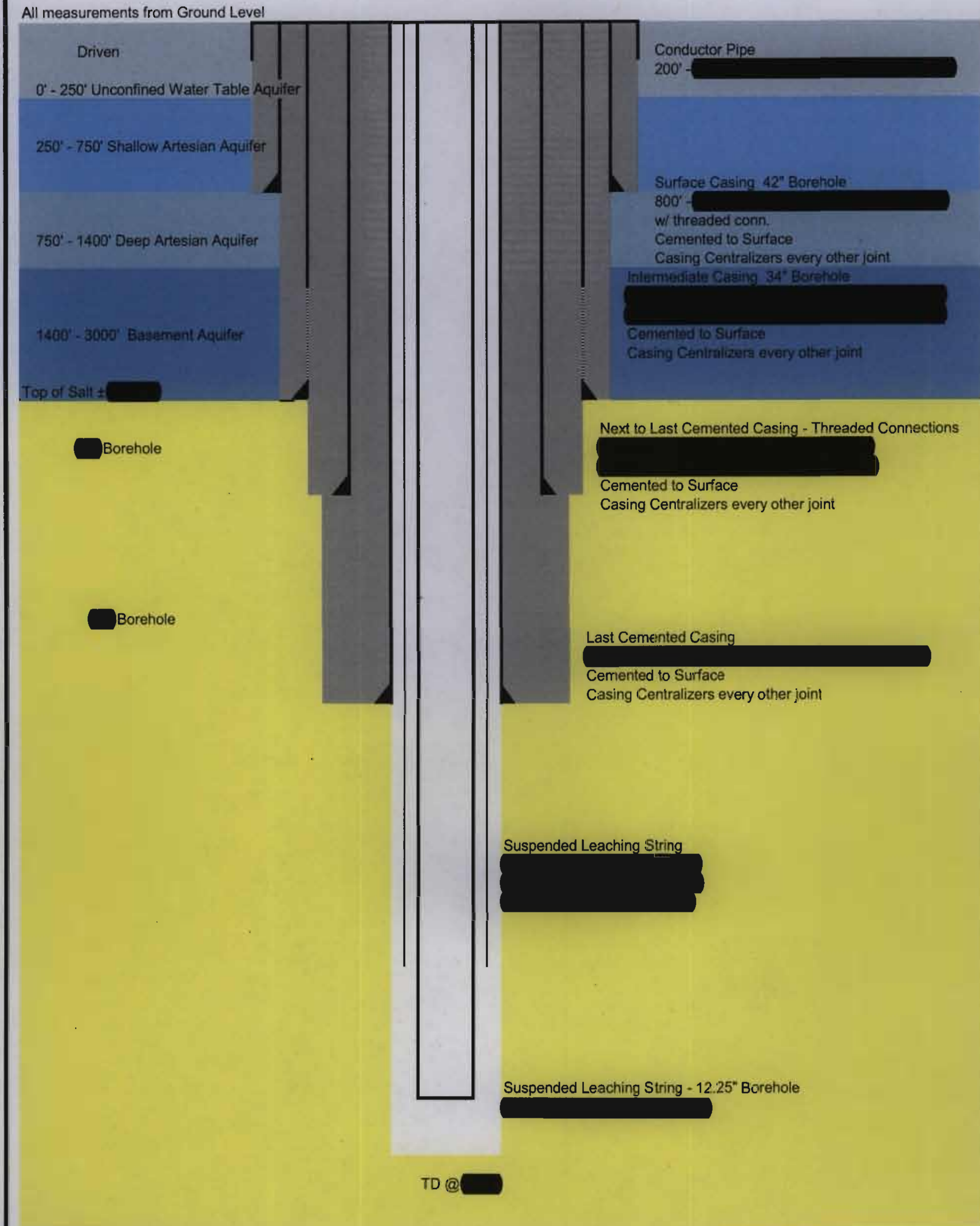

PB - ENERGY STORAGE SERVICES, INC.	Magnum

Gas Storage Well Casing Design

DRAWN: M Meece	Updated: D. Hansen	DATE: 10/10	SCALE: NONE	JOB NO. 50747

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Well Construction Plan

The following is the general program to be used to drill Magnum Gas Storage Wells 1, 2, 3 and 4. Depths shown are approximate, from Rotary Kelly Bushing.

1. Rig up drilling rig.
2. Drive 48" conductor casing to approximately 200 feet or refusal.
3. Drill a 17-1/2" hole to [redacted] feet and log.
4. Open 17-1/2" hole up to [redacted] with hole openers of increasing size.
5. Run and cement [redacted] feet of [redacted] pipe. Centralizers to be placed every other casing section.
6. After the cement sets, cut off the [redacted] casing and weld on a [redacted] reducer and [redacted] flange. Nipple up a [redacted] annular BOP.
7. Drill a 17-1/2" hole to top of salt structure estimated to be ± [redacted] feet. Lost circulation may occur over this interval; control as necessary by the use of lost circulation material, cement plugs or drill without returns.
8. Run gamma ray, SP induction and resistivity logs as specified.
9. Open the 17-1/2" hole to [redacted] with hole openers and underreamers of increasing size.
10. Run X-Y caliper log.
11. Run and cement ± [redacted] or equivalent pipe to top of salt structure. Use the stab-in cementing method. Centralizers to be placed every other casing section.
12. After the cement sets, pressure test the casing in accordance with the approved MIT testing protocol.
13. Cut off the [redacted] casing and weld on a [redacted] reducer and [redacted] Nipple up a [redacted] annular BOP.
14. Switch to salt saturated mud after [redacted] casing is set at top of salt structure or at the depth where salt structure is encountered during drilling.
15. Drill a [redacted]
16. Run gamma ray, SP induction, neutron and bulk density logs as specified.
17. Open the [redacted] with hole openers and underreamers of increasing size.
18. Run X-Y caliper log.
19. Run and cement [redacted] section.
20. Allow the cement to set 72 hours. Pressure test the casing in accordance with the approved MIT testing protocol.
21. Cut off the [redacted] reducer and [redacted] flange. Nipple up a [redacted] annular BOP.
22. Drill a [redacted] feet.
23. Run gamma ray, SP induction, neutron and bulk density logs as specified.
24. Open the [redacted] using hole openers and underreamers.
25. Run X-Y caliper log.

26. Run and cement [redacted] pipe. Use the stab-in cementing method. Centralizers to be placed every other casing section.
27. Allow the cement to set 72 hours. Pressure test the casing in accordance with the approved MIT testing protocol.
28. Drill out plug and ten feet of salt formation.
29. Pressure test casing shoe in accordance with the approved MIT testing protocol.
30. Drill a [redacted] feet. Note: there are [redacted] cores that will be taken in this interval.
31. Log cuttings and check for loss of drilling fluid indicating a porous formation is encountered. If so, perform a tightness test over this interval.
32. Run gamma ray, neutron and bulk density logs as specified.
33. If logs indicate a porous zone in the salt section, perform tightness test over the zone.
34. Under ream the [redacted] feet.
35. Run X-Y caliper log.
36. Run casing inspection logs in [redacted] casing from shoe to surface.
37. Run in approx. [redacted] Casing.
38. Install and test the upper wellhead assembly.
39. Run in approx. [redacted] feet of [redacted]
40. Install remainder of wellhead.
41. Rig down and move out rig from location.
42. Clean up location.

CASING AND LIFT RING WELDING PROTOCOL

This specification describes the requirements for welding of lift rings on 20" last cemented casing, double jointing, and welding of the 20" last cemented casing. All work will be performed from a land rig located near Delta UT beginning in November 2010.

WELL REQUIREMENTS:

Casing to be welded consists of: [redacted] ft. Last Cemented Casing.

Provide all labor, equipment, and materials necessary to provide the following services:

Welding of lift rings to [redacted]' final cemented casing.
Weld one lift ring to each double joint of [redacted] casing, approximately 4' from one end. Allow a maximum gap of 1/16 inch between lift rings and the curvature of the pipe. Welding to take place well in advance of running the casing and shall therefore be

performed during daylight hours. Lift rings will be provided by PB ESS. See attached lift ring welding drawing.

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.

Double Jointing of [redacted]' casing.
Casing double joint welding shall be performed in accordance with API Standard 1104 Welding of Pipelines and Related Facilities, 2005 edition. 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 his beginning to weld. 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".

Double joint (pipe in horizontal position) approximately 3840' (96 jts) of 20" x 1.0" last cemented casing. The double jointing will take place well in advance of running the pipe, therefore, done during daylight hours.

Adequate pipe supports shall be used to support the pipe in a level "aligned" condition. All double-jointed casing lengths shall be examined and shall be as straight as possible.

Use alignment clamps to ensure proper alignment. Give special attention to ensure straightness is within 0.2 percent of the length or less than 1" of deviation in 40' length.

Check double-jointed casing lengths for straightness by using a taut string. Deviation from straight or chord height shall not exceed two inches. The taut string shall be run from the bottom end of the joint to the bottom side of the lift ring on the other end. The measurement is to be read adjacent to the double-joint weld bead. A series of readings shall be taken to find the maximum deviation. Any double-joint with more than two inches of deviation, shall have the weld cut out, beveled by machine (portable flame cutter or machine tool) and re-welded at the double-jointing contractors expense.

Welding of [redacted]' double joints while running casing.

Casing welding shall be performed in accordance with API Standard 1104 Welding of Pipelines and Related Facilities. Pipe base material's carbon equivalentcy 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 his beginning to weld. 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".

Weld double joints with pipe in vertical position from rig floor. Approximately 48 double joints to be welded. This welding will take place while running the casing to the design depth and will be a 24 hour per day operation.

Use alignment clamps to ensure proper alignment. Give special attention to ensure straightness is within 0.2 percent of the length.

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SUBMITTALS

Submit the following "Submittals" to PB Energy Storage Services for review and approval:

Welding procedure specifications.

Welding procedure qualification records; submit prior to start of work.

Welder qualifications for each welder for each procedure the welder is to use.

CONDITIONS

Provide weather protection around welding areas to isolate welding from wind and rain. Do not weld in wet or excessively windy conditions that cannot be prevented.

Pipe ends that are field beveled or beveled by cutting torch shall be reported to the PB ESS representative.

SPECIFICATIONS FOR CEMENTING SERVICES AND MATERIALS

Provide all the labor, equipment, and materials necessary to provide the following services:

Proposed wellbore configuration

[redacted]

1. Cement specifications for the [redacted] Surface casing. Cement job will pumped through a stabbed-in 5" 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 ft3/sack
Excess	50% Open Hole Volume (4 Arm Caliper Available)

2. Cement specifications for the [redacted] Intermediate. Cement job will pumped through a stabbed-in 5" 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 ft3/sack
Excess	50% Open Hole Volume (4 Arm Caliper Available)

3. Cement specifications for the [redacted] Next to Last Casing. Cement job will pumped through a stabbed-in 5" DP.

Cement to surface: Class G (Premium) + [redacted] (if deemed necessary).

Water Ratio	5.2 gals/sk
Slurry Weight	16.3 lbs/gal.
Slurry Volume	1.24 ft3/sack
Excess	30% Open Hole Volume (4 Arm Caliper Available)

4. Cement specifications for the [redacted] Next to Last Casing. Cement job will pumped through a stabbed-in 5" DP.
   Cement to surface: Class G (Premium) + [redacted] (if deemed necessary).

Water Ratio	5.2 gals/sk
Slurry Weight	16.3 lbs/gal.
Slurry Volume	1.24 ft3/sack
Excess	30% Open Hole Volume (4 Arm Caliper Available)

REPORT

The casing cement jobs shall be documented by an affidavit from the cementing company showing the amount and type of cementing materials and the method of placement.

WELL CONDITIONING

Before commencing drilling operations (spudding the well), Magnum will provide detailed procedures for conditioning the hole prior to cementing casing. The pre-flush procedure will ensure that the wellbore is properly conditioned for cementing operations in accordance with recommendations from the cementing contractor.

The well is conditioned to circulate the drilling fluids, sweep cuttings out of the hole, obtain consistent fluid properties, and adjust the fluid viscosity and density in an attempt to prevent cement channeling through the fluid. Detailed procedures for this process have not been written at this time as it is a typical task during drilling, but when the drilling fluids contractor is hired his mud engineer will be tasked to write a program for the fluids.

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Plan for Plugging and Abandonment of Class III Solution Mining Wells and Caverns before Gas Storage

The following procedures are provided as a general guideline. Actual plugging measures would be submitted in advance to DWQ (prior to commencement of gas storage).

1. At least 45 days before the planned plugging, Magnum will notify the DWQ Executive Secretary of the proposed plugging with a Well Condition Report and a well-specific Plugging and Abandonment Plan.
2. The Well Condition Report will include a discussion of the following:
   a. The results of the well's most recent mechanical integrity test,
   b. The location of any leaks or perforations in the casing,
   c. The location of any vertical migration of fluids behind the casing, and
   d. The adequacy of casing cement bonding across the salt formation, as determined from cement bond logs run at the time of well construction or just prior to well abandonment.
3. All nitrogen or other blanket material will be removed and the cavern will be filled with saturated brine water.
4. All free hanging tubing will be pulled from the well.
5. The exact depth to the bottom of the cemented production casing will be determined.
6. 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.
7. All cement plugs to be Class G cement with no additives and slurry weight of 14.5 pounds per gallon or more.
8. The entire wellbore from the bridge plug to surface will be filled with cement.
9. In the event the cemented casing is determined to be leaking, the casing will be perforated at the level of the leak and cement squeezed into the perforations.
10. An alternative technique which could be used involves setting the following plugs.
    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 50-foot plug from 50 feet below surface grade upward to surface.
    d. The casing between each of the plugs shall be filled with a noncorrosive mud slurry of at least 10 pounds per gallon weight.
11. Upon completion of the plugging operation, all reports will be filed in accordance with DWQ rules as applicable.

[redacted]

GENERAL NOTES

NOTE 1
NORMAL FLOW CONTROL, VALVE CLOSE ON ALARM LOW FLOW & LOW UPSTREAM PRESSURE. (FISHER V-200)

NOTE 2
ESD VALVE CLOSE ON PAHH OR FAHH HAND OPEN LOCALLY w/PNEUMATIC VALVE

NOTE 3
POWER SUPPLY TO CONTROL VALVES CV-1 & CV-2 WILL BE PROVIDED FROM RESPECTIVE PUMP CONTROL PANELS AT THE WATER WELLS

REFERENCE DRAWINGS	REV. NO.	REVISIONS	DRAWN BY	DRAWN DATE	CHECKED BY	CHECKED DATE	APPROVED BY	APPROVED DATE
	A	PRELIMINARY	SB	03/16/10	TB	3/24/10		

MAGNUM SOLUTIONS, LLC

PB Energy Storage Services, Inc.
16285 PARK TEN PLACE, SUITE 400
HOUSTON, TEXAS 77084

CAVERN WELLS-P & ID
MAGNUM SOLUTIONS, LLC
SOLUTION MINING FACILITY
3300 GPM W/EXPANSION CAPACITY

DESIGN BY: TR DATE: 01/28/10	DRAWN BY: SB DATE: 01/28/10	SCALE: NONE	
CHECKED BY: TB DATE: 3/24/10	APPROVED BY: DATE:	PROJECT No: 50747A	
FILE NAME: 50747A-MD-808-3300	DRAWING No. 50747A-MD-808	LATEST REVISION	A

[redacted]

GENERAL NOTES		REFERENCE DRAWINGS
	50747A-MP-101	SITE PLAN
	50747A-MP-104	WELL PAD ARRANGEMENT

REV. NO.	REVISIONS	ISSUED BY	ISSUED DATE	CHECKED BY	CHECKED DATE	APPROVED BY	APPROVED DATE
A	PRELIMINARY	SB	03/18/10				

THIS DRAWING PREPARED FOR

MAGNUM SOLUTIONS, LLC

PB Energy Storage Services, Inc.
16285 PARK TEN PLACE, SUITE 400
HOUSTON, TEXAS 77084

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TYPICAL CAVERN WELL PIPING PLAN
LEACH PLANT - PHASE I
MAGNUM SOLUTIONS, LLC
SOLUTION MINING FACILITY
3300 GPM w/EXPANSION CAPACITY

DESIGN BY: TR DATE: 02/23/10	DRAWN BY: SB DATE: 02/23/10	SCALE:	
CHECKED BY: TR DATE: 02/26/10	APPROVED BY: DATE:	PROJECT No: 50747A	
FILE NAME: 50747A-MP-105-3300	DRAWING No. 50747A-MP-105	LATEST REVISION: A	

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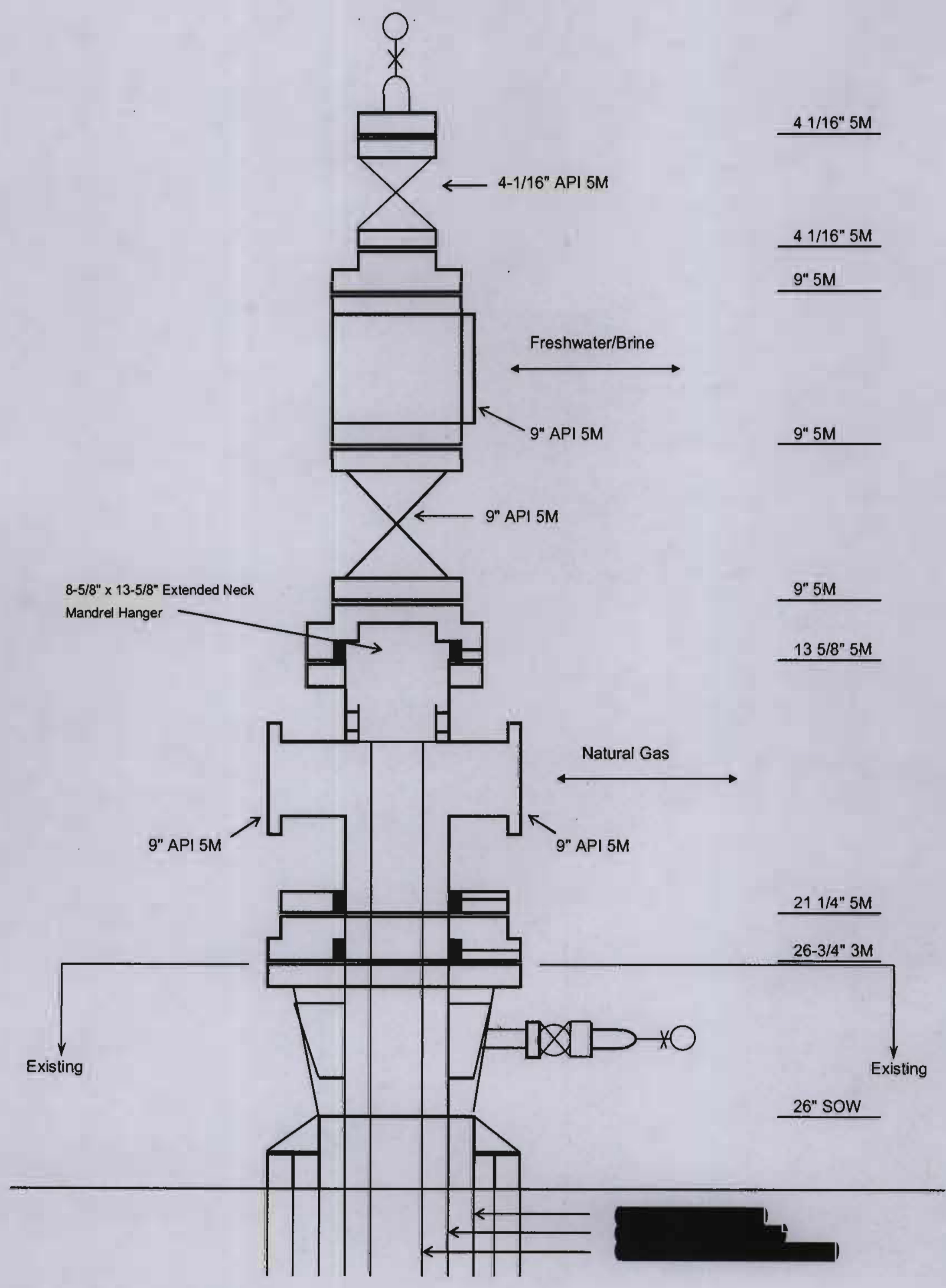
PB Energy Storage Services, Inc. A Parsons Brinckerhoff Company	SPECIFICATION	Number 50747B
	MAGNUM SOLUTIONS LLC CAVERN WELLS 1 & 2	Date 4/16/10
	GAS STORAGE WELLHEAD	Page 3 of 3



PREPARED BY	DATE	CHECKED BY	DATE	APPROVED BY	DATE	REVISION	DATE
Buschbom/McHenry	4/7/10	Meece	4/10	Meece	4/10	3	12/18/07

ATTACHMENT H

MECHANICAL INTEGRITY TEST PLAN

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Mechanical Integrity Test Plan

Several testing methods shall be employed to demonstrate mechanical integrity of the well/cavern system. These methods vary depending upon the stage of development of the well or cavern.

During Drilling

After cementing the 20" production casing, the casing will be tested before continuing drilling. A hydraulic pressure test of the 20" production casing will be conducted before drilling out the plug (shoe) and after waiting on cement at least 72 hours to allow the cement to set. The operator shall test the casing at a pump pressure in pounds per square inch (psi) calculated by multiplying the length of the casing by 0.2. The maximum pressure required however, unless otherwise ordered by the commission need not exceed 1500 psi (Texas Rule 3.13 (b)(1)(D)). This rule would require a surface pressure of 800 psi. Although this is less than maximum allowable operating pressure at the casing shoe, it is high enough to detect a leak in the casing. The test shall last 30 minutes. The test will be considered good if the pressure loss is less than 10%.

After drilling out the cement plug and completing the hole, the integrity test as outlined hereafter will verify the casing/cement shoe/borehole at maximum operating pressure.

Test of the 20" Casing and the Cavern during Development

Magnum Solutions LLC will utilize the guidelines for Mechanical Integrity Testing used by the State of Kansas as attached hereto. Any changes to the testing procedure will be coordinated and discussed, with the regulatory agency and approval obtained prior to implementation.

Storage Operations

Following the mechanical integrity test after completion of mining the caverns will be tested on a periodic basis using methods and procedures in accordance with requirements set forth by the State of Utah.

Reply to: (785) 296-7254 FAX (785) 296-5509
Bureau of Water - Geology Section
1000 S. W. Jackson, Ste. 420
Topeka, KS 66612-1367

KANSAS DEPARTMENT OF HEALTH & ENVIRONMENT

NITROGEN/BRINE INTERFACE MECHANICAL INTEGRITY TEST (MIT)
PART I: CASING (INTERNAL) MIT
PART II: CAVERN (EXTERNAL) MIT

Procedure #: UICLPG-20
(6/06)

Narrative:

K.A.R. 28-45-16 requires that each well and each cavern be tested for integrity every five years. 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 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
NITROGEN/BRINE INTERFACE MECHANICAL INTEGRITY TEST (MIT)
PART I: CASING (INTERNAL) MIT
PART II: CAVERN (EXTERNAL) MIT

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 any supporting data required by KDHE may result in the test being considered invalid by KDHE. An invalid test will not meet the regulatory requirement.

Submit a test plan as specified in Procedure #UICLPG-21 to KDHE 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 Kansas Department of Health and Environment (KDHE).

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 (feasible) from the cavern prior to conducting the test.
- Note the presence of any product in the annulus.
- Coordinate the test time with KDHE so that KDHE may have the opportunity to witness the test.

PRE-PRESSURIZATION: (Typically for cavern test)

Prepressure 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 regulatory MAOP of either 0.75 or 0.8 psi/ft. K.A.R. 28-45-12 requires that a wellhead be equipped with a continuous pressure monitoring system that is capable of maintaining a pressure history before the well can be operated with a MAOP greater than 0.75 psi/ft. The well should be tested at the MAOP allowed by regulation.
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. 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 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.

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

T = Duration of test in hours
V = Unit annular volume of casing, bbls/ft
R = Resolution of the interface tool in feet
Note: reference programs or tables and show calculations for converting weight or volume (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, relog 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):

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

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)

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

CNLR = Calculated nitrogen leak rate
T = test duration, 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 test finish (psia)
CNLR (bbls/yr) = CNLR (bbls/day) * 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 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:

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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).

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

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):

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

CNLR = Calculated nitrogen leak rate
T = test duration, days
VS = nitrogen volume at test start (bbls)
VF = nitrogen volume at test finish (bbls)
PS = nitrogen pressure at the test finish (psia)
PF = nitrogen pressure at test start (psia)
CNLR (bbls/yr) = CNLR (bbls/day) * 365 days/year

References:

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

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1000 S. W. Jackson, Ste. 420
Topeka, KS 66612-1367

KANSAS DEPARTMENT OF HEALTH & ENVIRONMENT

NITROGEN/BRINE INTERFACE TEST PLAN

Procedure #: UICLPG-21
(6/06)

Narrative:

K.A.R. 28-45-16 requires that each well and each cavern be tested for integrity. Each cavern with a single casing must be tested for integrity every five years. Each cavern with double casing protection must be tested every ten years. The nitrogen/brine interface test is designed to evaluate the integrity of the underground hydrocarbon storage well and/or cavern.

Submit a test plan to KDHE for review and approval at least 30 days prior to test commencement. Use the following format. Do not alter the 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 and test pressures:	Formulas and calculations:
Proposed changes to FIELD PROCEDURE (UICLPG-22):	

TEST DESIGN:	Casing test and/or Cavern test (Circle)	
Estimate nitrogen for cool down:	Interval Depth:	Test Duration:
	1.	
Estimate compressibility:	2.	
Estimate nitrogen volume for test:	3	
	4.	

Submit the final report in the format specified in Procedure # UICLPG-23 to KDHE within 45 days after completion of the test.

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KANSAS DEPARTMENT OF HEALTH & ENVIRONMENT

FIELD PROCEDURE REPORT
NITROGEN/BRINE INTERFACE TEST

Procedure #: UICLPG-22
(6/06)

Narrative:

The following field procedure for the nitrogen/brine interface test must be completed and submitted with the final report (Procedure #UICLPG-23). Do not alter the format.

Type of MIT:	Well Casing	Cavern	Casing/Cavern
Facility:		Well:	

TEST PREPARATION	Date/time:
Wellhead inspection results: external corrosion, faulty valves, gasket leaks, etc)	
Removal of product Date:	
Check wellhead, piping, and connection for leaks. Describe results.	

PRE-PRESSURIZATION Date/time:					
Brine pressure		Product pressure			
Cavern compressibility:					
Cavern pressure change < 10 psi/day					
PRE-NITROGEN INJECTION					
Nitrogen cool down volume					
Base temperature log from surface to 50 ft below expected interface	Date/time:		Temperature (F):		
Base 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)			

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PART 1: 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		
	N 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		
	N 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		
	N 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 2: 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:
K.A.R. 28-45-16 requires that a licensed professional engineer or licensed geologist, or a licensed professional engineer's or licensed geologist's designee supervise all test procedures and associated field activity.
Supervised by: (Print name)
Company/Title:
Signature: **Date:**

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KANSAS DEPARTMENT OF HEALTH & ENVIRONMENT

FINAL REPORT
NITROGEN/BRINE INTERFACE TEST

Procedure #: UICLPG-23
(6/06)

Narrative:

Submit the final report in the format specified to KDHE within 45 days after completion of the nitrogen/brine interface test. Do not alter this format.

Test Results	
Show formula and calculation for MDLR:	Compare MDLR and NLR:
Show formula and calculation for 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 (UICLPG-22)
Submit all required logs.
Submit supporting data, including graphs for stabilization, temperatures, pressures, injection, etc. Submit appropriate charts.
Submit calibration charts for gauges and meters.

K.A.R. 28-45-16 requires that a licensed professional engineer or licensed geologist review all test results.

Submit the final report to KDHE within 45 days after completion of the test.

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ATTACHMENT J-1

UIC MONITORING, RECORDING, AND REPORTING PLAN

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ATTACHMENT J - UIC MONITORING, RECORDING AND REPORTING PLAN

1.0 REQUIREMENTS

Submit a monitoring, recording, and reporting plan, including maps, for meeting the monitoring and reporting requirements of R317-7-10.3(B), 40CFR146.33, 40CFR146.8, and R317-7-10(B). In the plan

- Identify types of tests, methods, and equipment used to generate monitoring data
- Address the proper use, maintenance, and installation of monitoring equipment
- Propose the type, intervals, and frequency sufficient to yield data that are representative of monitored activity.

2.0 PHYSICAL AND CHEMICAL CHARACTERISTICS OF INJECTED FLUID

The Magnum Wells will be solution mined using fresh water produced from water wells located on the Magnum facility. The salinity of the injected fluid will be measured, along with the fluid temperature on a daily basis. Specific gravity and temperature will be monitored using calibrated hydrometers and thermometers. Hydrometers will be calibrated and maintained in accordance with ASTM Al26-05a and thermometers will be calibrated and maintained in accordance with ASTM E77-07.

The data will be trended to ensure that no changes in the injected water take place during the duration of the solution mining operations.

3.0 MONITORING OF INJECTION PRESSURE AND FLOW

Injection pressures, injection flow rates, injection temperature, brine pressure, brine flow rate, brine temperature and the nitrogen blanket pressure will be monitored continuously by instrumentation in the control room. The information will be recorded at least once per day as a daily summary. The daily summary will be included in quarterly reports. This data will be used to calculate the growth of the cavern and provide a daily check on well integrity by ensuring that the water inflow and brine outflow balance. All the recorded data will be available to the Executive Secretary upon request.

All pressure monitoring, temperature monitoring, and flow rate monitoring instrumentation calibration will be done in accordance with manufacturer recommendations.

4.0 DEMONSTRATION OF MECHANICAL INTEGRITY

Prior to initiating solution mining and at the completion of leaching, the cavern will be tested using the nitrogen mechanical integrity technique. The test pressure at the shoe of the [redacted] cemented casing will be slightly above (about 0.92 psi per foot of depth) the permitted operating pressure (0.90 psi per foot of depth) to ensure that the casing and cement are not leaking. The nitrogen mechanical integrity test technique essentially involves pressuring the cavern or well to the desired test pressure, and injecting nitrogen in the outer annulus of the well (the space between the cemented [redacted] casing and the hanging [redacted] tubing) to a depth 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 then 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 the test.

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 100 barrels per year of nitrogen.

All pressure monitoring instruments will be calibrated in accordance with manufacturer's recommendations. Testing will be performed under the supervision of a degreed engineer and the report submitted to the Executive Secretary within 30 days of test completion.

Following the mechanical integrity test after completion of mining the caverns will be tested on a periodic basis using methods and procedures in accordance with requirements set forth by the State of Utah.

5.0 MONITORING OF CAVERN DEVELOPMENT

During solution mining of the caverns, the development of the cavern will be controlled by monitoring of the fluid injection and production quantities (Item 3.0 above) and periodic performance of sonar caliper surveys. The measured quantity of water injected and salinity of the produced brine will be used to calculate the daily increase in cavern volume. The sonar caliper surveys will be run at least once a year and at completion of mining in each cavern. The sonar survey will provide a check on the calculated cavern volume and the shape of the cavern.

6.0 MONITORING OF FLUID LEVEL IN FORMATION

This section is not applicable for solution mining wells since the well is ull at all times. 7.0 QUARTERLY REPORTING ON MONITORING WELLS IN SUBSIDENCE ZONES

No monitoring wells are planned for the Magnum project.

Subsidence will be monitored on an annual_basis by Magnum and will be evaluated by a degreed engineer who is thoroughly experienced in subsidence of cavern storage facilities. Subsidence measurements will begin with a baseline survey that will be run prior to starting solution mining. Subsidence surveys will be conducted throughout the life of the facility. The subsidence report will be submitted to the Executive Secretary on an annual basis.

Subsidence surveys will be conducted by measuring precise elevations of fixed points within the cavern field, the total Magnum facility and along public right-of-ways. The elevations of the points in and adjacent to the cavern field will be measured from a benchmark located at a distance from the facility that will not be impacted by any subsidence related to the caverns.

8.0 QUARTERLY REPORTING — EXECUTIVE SECRETARY

Daily summaries of water and brine pressures, temperatures, fluid volumes, and space created as well as the nitrogen blanket pressure will be reported to the Executive Secretary on a quarterly basis. Total volume of water injected and brine withdrawn from the storage cavern will be reported to the Executive Secretary on a quarterly basis.

MAGNUM
Enabling Renewables

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The following major permit modification application is appended to the original technical report of the original permit.

October 20, 2011

Candace C. Cady
Environmental Scientist,
Department of Environmental Quality
195 North 1950 West
Salt Lake City, Utah 84114-4870

Candice,

Enclosed is Magnum's Application for a Permit Modification to the Underground Injection Control Class III Area Permit UTU-27-AP-9232389. As discussed during the October 13, 2011, joint consultation meeting with yourself and representatives from the Division of Oil, Gas, and Mining, Magnum is requesting the permit modification to include the solution mining of two additional 16-inch injection wells within the previously approved project area. The two 16-inch wells will be used to create caverns that will store natural gas liquids such as propane and butane.

Per this discussion, the application has been organized to correspond with the technical report submitted with the original permit application. The supplemental application information presented includes updated project area maps depicting the general locations of the additional wells within the project area and the required solution mining plan, drilling plan, and casing program for the 16-inch wells. To facilitate the application review, Magnum has also included a table that lists the original UIC permit components and a column that indicates if any corresponding update or supplemental information is provided in this application.

If there are any questions, please feel free to contact me.

Thank you,

Tiffany A. James
Director of Government Relations
And Environmental Services
tjames@westernenergyhub.com
801.993.7001 office
801.719.9131 cellular

STATE OF UTAH

UNDERGROUND INJECTION CONTROL PROGRAM

CLASS III
INJECTION WELL

Modification for
UIC Permit # - UTU-27-AP-9232389

Addition of Two (2) 16-inch Injection Wells

PERMIT APPLICATION PACKAGE

Last Revised 5/10/2011

Table of Contents

Contents | Page

GENERAL INSTRUCTIONS

The Utah Underground Injection Control (UIC) Administrative Rules (UAC R317-7) regulate the injection of fluids into the subsurface. The following instructions outline the procedures, documents, and information needed for a Class III injection well permit application.

1. The applicant shall submit an original Permit Application and a Technical Report. Both documents are to be submitted in duplicate (one hard copy and one pdf format) to the:

   Utah Department of Environmental Quality
   Division of Water Quality
   195 North 1950 West
   P.O. Box 144870
   Salt Lake City, Utah 84114-4870

   ATTN: Underground Injection Control (UIC) Program

   Telephone inquiries: (801) 536-4300

2. Signature on Application: The person who signs the application form will often be the applicant; when another person signs on behalf of the applicant, his/her title or relationship to the applicant should be shown in the space provided. In all cases, the person signing the form should be authorized to do so by the applicant. An application submitted by a corporation must be signed by a principal executive officer of at least the level of vice president or his duly authorized representative, if such representative is responsible for the overall operation of the facility from which the activity described in the form originates. In the case of a partnership or a sole proprietorship, the application must be signed by a general partner or the proprietor, respectively. In the case of a municipal, state, federal or other public facility, the application must be signed by either a principal executive officer, ranking elected official or other duly authorized employee. The Division shall require a person signing an application on behalf of an applicant to provide proof of authorization (40 CFR Part 144.32).

3. An application will not be processed until all information required to properly review the application has been obtained. When an application is severely lacking in detail or the applicant fails to submit additionally requested information in a timely manner, the application may be returned.

4. An application which involves the injection of a fluid containing radioactive materials shall be accompanied by a letter or other instrument in writing from the Utah Division of Radiation Control, stating that either the applicant has a license from the Division of Radiation Control governing the disposal of radioactive materials; or that the applicant does not need a license. In the case of radioactive materials disposal, the Division of Radiation Control must receive a copy of the application for an injection permit. The copy should be mailed to:

   Utah Department of Environmental Quality
   Division of Radiation Control
   P.O. Box 144850
   195 North 1950 West
   Salt Lake City, Utah 84114-4850

5. The Attachment contains some of the federal regulations adopted by Utah that will also be considered in evaluating the permit application. The federal regulations included are only a portion of those applicable to underground injection activities, and are provided as reference to assist in the preparation of the permit application. The complete federal regulations covering underground injection can be found in the Code of Federal Regulations (CFR) Title 40 with updates available in the Federal Register.

PROCEDURAL INFORMATION

The staff will review the application for completeness. During the completeness review, the applicant may be contacted for clarification or additional information. When all pertinent information is present, a notice that an application has been received may be given to other state agencies and local governmental entities interested in water quality control and industrial waste management. A draft permit that may include a Statement of Basis will be prepared by the Division and transmitted to the applicant for review. Comments from the applicant may result in changes to the draft permit, after concurrence by the Executive Secretary. After Executive Secretary approval, the draft permit will be subjected to public comment and/or a public hearing. In either case, a notice will be provided to inform the public that a draft permit has been prepared.

Requirements for the public notice include:

1. That a public notice be published for each draft permit, permit amendment, or permit renewal that has been prepared. The notice will appear within each county where the proposed facility or discharge is located and each county affected by the discharge.

2. The Executive Secretary will mail notice of the application to affected persons and certain governmental entities.

A public hearing will be scheduled regarding an application when requested by the Water Quality Board (Board), the Executive Secretary, the applicant, or any affected person within thirty (30) days following newspaper publication.

The Board may act upon a permit application, a draft permit, a major permit modification, or renewal of a permit without holding a public hearing when:

1. Adequate public notice and comment period has been provided, including: (a) notice of the application has been mailed to persons possibly affected by the proposed permit; (b) notice has been published at least once in a newspaper, regularly published or circulated within each county where the proposed facility or discharge is located and in each county affected by the discharge; and

2. Within thirty (30) days following publication of the Board's notice the Executive Secretary, the applicant, or an affected person has not requested a public hearing; or

3. An application to modify a permit will result in an improvement of the quality of the fluid authorized to be injected and if the applicant does not seek to increase significantly the quantity of fluid to be injected or to change materially the pattern or place of injection.

After resolution of any public comment the Executive Secretary shall issue or deny the draft permit, permit amendment, or permit renewal. Within thirty (30) days of issuance, a copy of the permit or permit denial will be mailed to the applicant.

The information required in 40 CFR 146.34 will be considered by the Executive Secretary before authorizing Class III injection wells.

UTAH DEPARTMENT OF ENVIRONMENTAL QUALITY
Division of Water Quality
1422 Underground Injection Control (UIC) Program

CLASS III INJECTION WELL PERMIT APPLICATION

(Reference to R317-7 and 40 CFR in parentheses indicates sections of Utah UIC Administrative Code and Code of Federal Regulations, respectively, requiring information.)

1. Type of Permit Application (check one)

   ☐ Initial Application

   ☐ Permit Renewal, Original Permit No. ______

   ■ Permit Modification, Original Permit No. UTU-27-AP-9232389

2. Type of Permit (check one)

   ☐ Individual (Single) Well Permit ■ Area (Multiple Wells) Permit

3. Facility Operator (Applicant must be the operator if owner/operator are different)
   (R317-7-9.1(B); R317-7-9.1(D)(4) and 40CFR144.31(b))

   Name: Magnum Solution Mining, LLC, fka Magnum Solutions, LLC
   (Individual, Corporation or Other Legal Entity)

   Address: 3165 East Millrock Drive, Suite 330
   (Permanent Mailing Address)

   City: Holladay State: Utah Zip: 84121

   Telephone Number: 801-993-7001

4. Facility Owner
   (R317-7-9.1(D)(4) and 40CFR144.31(e)(4))

   Name Magnum Solution Mining, LLC, fka Magnum Solutions, LLC
   (Individual, Corporation or Other Legal Entity)

   Address: 3165 East Millrock Drive, Suite 330
   (Permanent Mailing Address)

   City: Holladay State: Utah Zip: 84121

   Telephone Number: 801-993-7001

5. Facility status: Federal ______ State ______

   Private X ______ Public ______ Other ______

   (R317-7-9.1(D)(4) and 40CFR144.31(e)(4)) (Indicate)

6. List those persons or firms authorized to act for the applicant during the processing of the permit application. Include a complete mailing address and telephone number:

   Samuel Quigley and Tiffany James
   Magnum Solution Mining, LLC
   3165 E Millrock Drive, Suite 330
   Salt Lake City, Utah 84121
   (801) 993-7001

7. List all activities conducted at this facility that require an environmental permit under federal, state, or local statutes, rules or ordinances.
   (R317-7-9.1(D)(1) and 40CFR144.31(e)(1))

   SEE ORIGINAL PERMIT FOR ACTIVITIES AND PERMIT TABLE

8. List all environmental permits or construction approvals received or applied for relevant to this facility or this location under federal, state, or local statutes, rules or ordinances.
   (R317-7-9.1(D)(6) and 40CFR144.31(e)(6))

   MAGNUM SOLUTION MINING, LLC ("MS") fka MAGNUM SOLUTIONS, LLC received the following environmental permits or construction approvals for the Magnum Gas Storage Project:

   a. SITLA, Seismic Exploration Permit No. 5198 (October 13, 2008);
   b. UDNR, Non-Production Well Permit (October 15, 2008);
   c. USACE Section 404 Permit the Storage Site (August 2010 and January 2011);
   d. USFWS and UDWR Federal and State Threatened and Endangered Species Clearances (March 17, 2011);
   e. FERC 7(c) Certificate of Public Convenience and Necessity (March 17, 2011);
   f. BLM Right-of-Way Grant (February 22, 2011);
   g. NHPA Cultural Resource Clearance- Agency Approval Granted on May 14, 2010, SHPO Concurrence (June 7, 2011); and
   h. Millard County Conditional Use Permit for the Storage Site (March 28, 2011);

9. Provide a brief description of the solution mining operation (s) (include appropriate North American Industry Classification System (NAICS) Codes).
   (R317-7-9.1(D)(3) and 40CFR144.31(e)(3) and (8))
   NAICS Code 486210 – Pipeline Transportation of Natural Gas for Gas Storage

10. Location of Proposed Solution Mining Operation
    (R317-7-9.1(D)(2) and (40CFR144.31(e)(2))

    Facility name: Magnum Gas Storage Project

    Facility mailing address: Rural

    Facility location description: Southwest Corner of Intersection of Highway 174 (Brush-Wellman Road) and Jones Road, approximately 3 ½ miles east-northeast of Sugarville, Utah or 9 miles north of Delta, Utah

Street address: 500 West 9200 North

City: Delta, Utah 84624

County: Millard Lease:

No. of Wells* : One well per cavern is proposed for a total of 6 wells at the below identified locations.

For each well provide the following:

Township; Range; Section; and 1/4, 1/4 Section:
T15S. R7W. Section 23, SW4 of SW4
T15S. R7W. Section 23, SE4 of SW4
T15S. R7W. Section 26, NW4 of NE4
T15S. R7W. Section 26, NE4 of NW4
T15S. R7W. Section 23, SW4 of SW4
T15S. R7W. Section 26, NW4 of NW4

UTM Northing (NAD 83 UTM 12, Meters):

UTM Easting (NAD 83 UTM 12, Meters):

Well #	UTM Easting, Northing
1	361722.097, 4372871.594
2	361970.705, 4372983.303
3	361943.087, 4372712.197
4	362192.204, 4372824.684
5	361439.3362, 4372917.122
6	361473.6229, 4372737.485

* Location(s) of injection well(s) should be identified on all maps included in the Technical Report.

11. Are the proposed injection well(s) located on Indian land? ☐ Yes ■ No
(R317-7-9.1(D)5) and 40CFR144.31(e)(5))

12. Submit the Technical Report with Application (R317-7-6.9).
13. Certification of information submitted on application form and in the Technical Report (R317-7-9.3 and 40CFR144.32).

David K. Detton
(Name of Company Official: Type or Print Legibly)

Sr. Vice President
(Title)

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, or 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.

Signature: David K. Detton

Date: October 20, 2011

SUBSCRIBED AND SWORN to before me this 20th day of October, 2011.

My commission expires on the 20 day of October, 2011.

Paige Halligan
Notary Public in and for

Salt Lake County, Utah

(SEAL) NOTARY PUBLIC
Paige Halligan
583645
My Commission Expires
August 16, 2014
STATE OF UTAH

Part A

Magnum Solution Mining, LLC

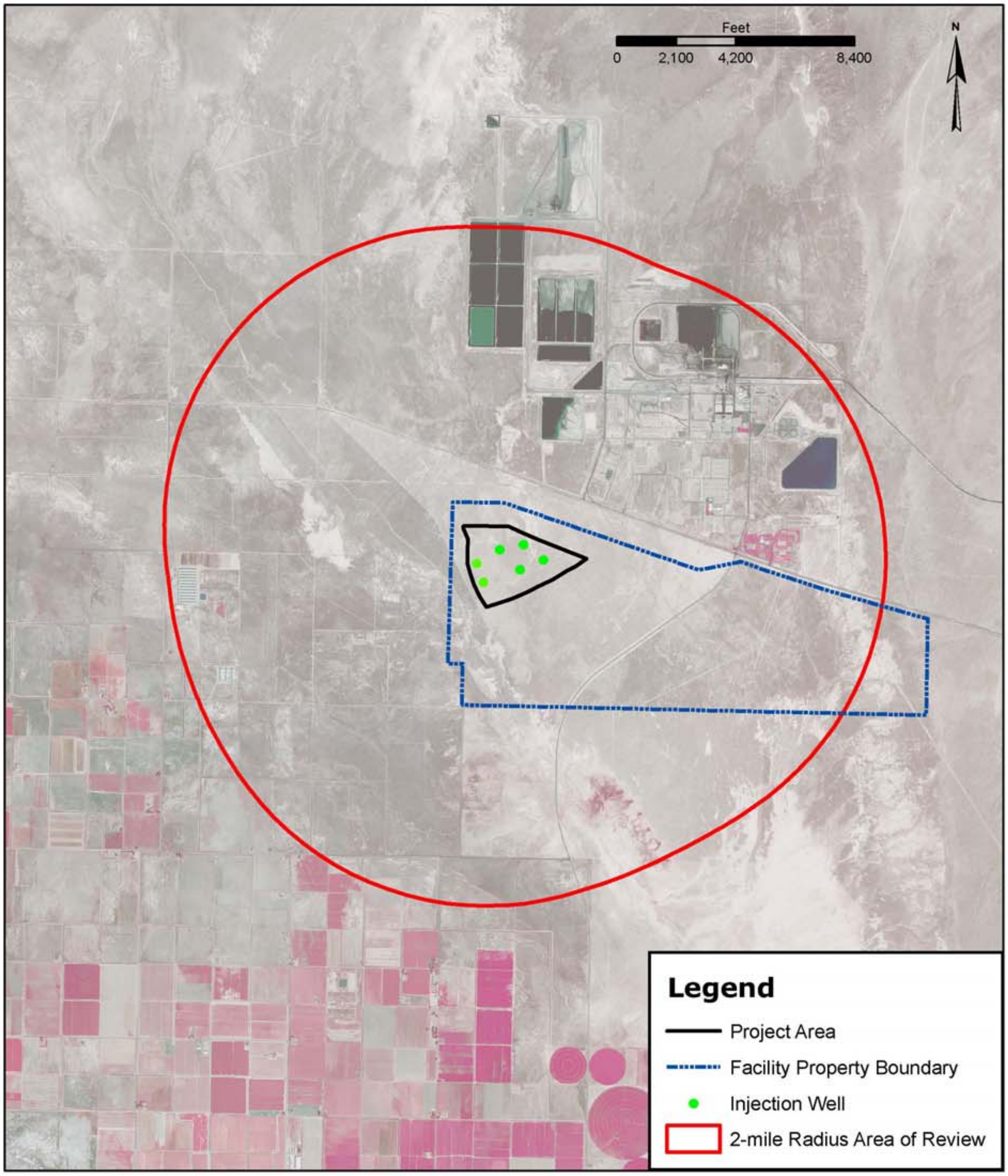
Millard County, Utah

Magnum Gas Storage Project

Determination of Area of Review with Two (2) Additional 16-inch Injection Wells

Part A - Determination of Area of Review (AOR) with Two (2) Additional 16-inch Injection Wells

Per Utah regulation, a fixed radius Area of Review (AOR) of 2 miles around the proposed injection well field area (Project Area) has been used for this application. As noted on **Map A-1.1,** Magnum is proposing to solution mine six caverns, four of which were previously approved. Specifics for two additional wells are included in this application. As can be seen from the map, the entire Project Area encompasses an area larger than that identified by the six individual wells. The entire Project Area has been defined herein as that area wherein it is projected that injection/cavern wells could be constructed within the salt structure. The area as defined is bounded on the west by a buffer zone offset from 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, on the south and east by the downward dip of the salt structure at 3,000 feet, and on the north by buffer zones between existing and potential future power lines and the Project Area (see Updated **Map A-1.1**).



MAGNUM
Enabling Renewables

Project Area, Facility Property Boundary & Area of Review

MAP A-1.1

Part B

Magnum Solution Mining, LLC

Millard County, Utah

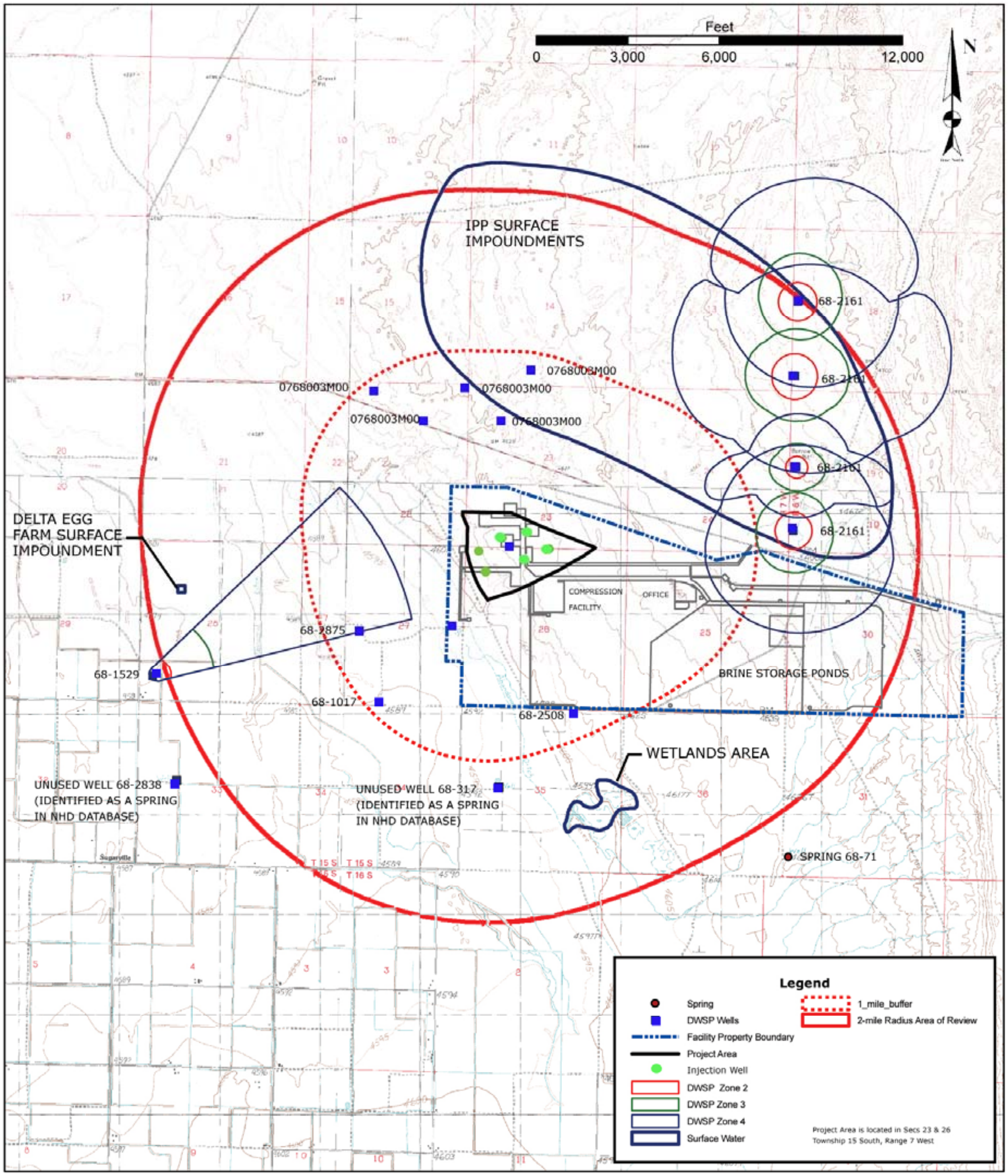
Magnum Gas Storage Project

Amended Permit Application Maps Depicting Two (2) Additional 16-inch Injection Wells

Part B - Amended Permit Application Maps depicting Two (2) Additional 16-inch Injection Wells

1. Map of Facility and Project Area

Map B-1.1 shows an updated USGS 7 ½ minute topography extending a minimum of one mile beyond the Project Area that includes two (2) additional 16-inch injection wells in the Project Area.



Map of Facility and Project Area

MAP B-1.1

Part G

Magnum Solution Mining, LLC

Millard County, Utah

Magnum Gas Storage Project

16-inch Injection Well Construction Plan, Cementing, and Casing Program

Part G - 16-inch Injection Well Solution Mining Plan

The solution mining program presented herein is based on the SANSMIC cavern simulation model performed by Thomas Eyermann. See the "Solution Mining Plan Using 16-inch Injection Well at Delta, Utah" in **Attachment G-1** for details.

16-inch Injection Well Drilling Program

The drilling program presented herein is based on lithologic information available from the Argonaut and Magnum MH-1 wells provided in the initial permit. See the "Well Construction Plan" in **Attachment G-2** for details.

16-inch Injection Well Cementing and Casing Program

A report outlining the basic well casing program, entitled "Conceptual Casing Program for 16-inch Injection Well", prepared by Thomas Eyermann, is included within **Attachment G-2**. **Figure G-2.1** has been inserted to provide a well schematic showing the anticipated casing construction plan outlined in the Attachment, including casing depths, diameters, weight and grade of steel. Information related to the cementing program is also provided in **Attachment G-2** within the documents entitled "Well Construction Plan" and "Specifications for Cementing Services and Materials".

Attachment G-1

- Solution Mining Plan for Development of Magnum Storage Caverns at Delta, Utah Using a 16-inch Injection Well

Table of Contents

Solution Mining Plans for Development of 16-inch Injection Wells at Delta, Utah

Introduction

This report presents a solution mining plan ("Mining Plan")for the development of additional 16-inch injection wells to create salt storage caverns at the proposed Magnum facility located near Delta, Utah. The caverns will be developed in a bedded salt deposit that has been thickened as a result of tectonics.

The salt deposit has been explored by at least two boreholes; one drilled for oil and gas exploration (Argonaut) and the second drilled by Magnum to explore the salt deposit. The Magnum Holdings (MH-1) well was a deviated well. It encountered the top of salt at about [redacted] feet. The well then deviated to the northwest. At a drilled depth of [redacted] feet, the true vertical depth (TVD) was [redacted] feet.

As a part of the drilling program, 11 core runs were made with the core runs spaced from the top of salt to about 6,000 feet. Portions of the cores were analyzed for insoluble content. This information was used to estimate the insoluble content for the entire drilled salt section from data on the gamma and density logs.

MH-1 and Argonaut are approximately [redacted] feet west of the proposed location of the 16" injection wells. Based on geophysical surveys of the area, the salt at the proposed liquid wells is estimated to be shallower than was encountered in these two wells.

For the Mining Plan the final cemented casing string will be set at least [redacted] feet into the salt. The top of the storage caverns will be at about [redacted] feet below the final cemented casing. The maximum diameter of the storage caverns is limited to about [redacted] feet. The cavern will have a final volume of up to [redacted] barrels.

Methodology

Cavern Simulation Model

The study utilized the SANSMIC cavern simulation model to project the development of salt storage caverns utilizing a single well. SANSMIC is an axisymmetric (two-dimensional) numerical simulation code which approximates the dissolution of salt by water. SANSMIC is a widely used cavern-modeling program developed by Sandia National Laboratories.

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, SANSMIC cannot fully evaluate continued growth in such a region. However, the simulated growth can be interpreted to closely approximate future growth in regions of concern once shape data from sonar surveys of caverns has been obtained.

As with all numerical models, SANSMIC does not fully represent the actual salt caverns. This is due to:

1. The axisymmetric assumption in the model (that the cavern will develop evenly about the central wellbore), and
2. Limitations in the equations for flow within the cavern.

The axisymmetric assumption is not necessarily a significant limitation to modeling the development of salt caverns in domal or bedded salts. Most caverns developed in salt domes tend to be uniform in horizontal cross-sections when developed by means of a single well. In bedded salts the caverns tend to be elongated in the updip direction if the salt is not lying horizontally. In most salt caverns there are localized exceptions to the symmetry.

The salt deposit at Delta has characteristics of both bedded and domal salt. The remnant bedding is not flat lying and may influence the horizontal cross-section of the caverns. This issue is not addressed in this report.

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, higher than [redacted] gpm utilized in this study.

For this model, the cavern interval from [redacted] feet depth below top of salt was divided into a series of twenty-five foot tall cells. The final cemented casing was 16 inches. The inner string was to be [redacted]-inch tubing and the outer string to be [redacted] inch 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 [redacted] gpm. A normal dissolution factor of "1" was used for the salt with an assumed cavern brine temperature of 90° F.

The insoluble content of the salt was set at 9%. The model assumes a generic particle size for the insolubles and carries a portion of the insoluble material out of the cavern based on modeled fluid velocities in the cavern.

Cavern Development Plan

General

The Mining Plan begins from a borehole completed into the salt, with [redacted]nch diameter casing cemented at about [redacted] feet below the top of salt and [redacted]feet above the proposed roof of the cavern. Alternatives were developed for caverns of two sizes. The plans are similar to each other, with differences being the size of the cavern. The two plans were:

- Develop the cavern to [redacted] barrels capacity, and
- Develop the cavern to [redacted] barrels capacity.

For both plans the total drilled depth of the well is assumed to be abou[redacted]feet below the top of salt. Solution mining is assumed to occur at a constant rate of [redacted] gpm.

Solution Mining Plan

Mining begins with the inner tubing string set close the bottom of the borehole, about ~~1300~~ feet below the top of salt. The outer string is set about [redacted] o[redacted] feet above the inner string, depending upon the size of cavern being developed. A nitrogen roof blanket is set at about ~~200~~ feet below the final roof peak, or [redacted] feet below the last cemented casing string. The setting depths relative to the top of salt for the tubing strings and blanket are shown in Tables 1 and 2 for all steps of each of the two cavern sizes.

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 initial mining step begins development of the chimney where the main cavern will be located. This step lasts about [redacted] days depending upon the size of cavern to be developed as shown in **Tables 3** and **4**.

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. 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. Midway through the stage, the roof blanket should be moved uphole abou[redacted] feet.

Mining continues for each step until development of the planned space as shown in **Tables 3** and **4**.

Table 1 Setting Depths Relative to Top of Salt for One Million Barrel Cavern

Mining Step	Blanket Setting – Feet	Production Setting - Feet	Injection Setting - Feet	Insoluble Setting – Feet
Sump/Chimney 1A	[redacted]	[redacted]	[redacted]	[redacted]
Sump/Chimney 1B	[redacted]	[redacted]	[redacted]	[redacted]
Reverse	[redacted]	[redacted]	[redacted]	[redacted]

Table 2 Setting Depths Relative to Top of Salt for Two Million Barrel Cavern

Mining Step	Blanket Setting – Feet	Production Setting - Feet	Injection Setting - Feet	Insoluble Setting – Feet
Sump/Chimney 1A	[redacted]	[redacted]	[redacted]	[redacted]
Sump/Chimney 1B	[redacted]	[redacted]	[redacted]	[redacted]
Reverse	[redacted]	[redacted]	[redacted]	[redacted]

Table 3 Duration and Volumes for Development of One Million Barrel Cavern

Mining Step	Step Time – Days	Total Mining Time – Days	Gross Mined Volume - Barrels	Open Cavern Volume – Barrels	Gross Cavern Volume - Barrels	Cumulative Brine Produced – MMbbls
Sump/Chimney 1A	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Sump/Chimney 1B	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Reverse	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Table 4 Duration and Volumes for Development of Two Million Barrel Cavern

Mining Step	Step Time – Days	Total Mining Time – Days	Gross Mined Volume - Barrels	Open Cavern Volume – Barrels	Gross Cavern Volume - Barrels	Cumulative Brine Produced – MMbbls
Sump/Chimney 1A	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Sump/Chimney 1B	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Reverse	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

At the completion of the sump/chimney stage, a workover is not required to reposition the tubing strings. Instead, the inner string will be cut about 50 feet above the insolubles. Before resuming mining the blanket should be reset about 100 feet above its previous position, or about the final desired roof peak. The desired depths are shown in **Tables 1** and **2**.

Mining is resumed in reverse – water is injected in the outer shallow tubing and brine produced from the inner, deep string. This method of mining continues until the final desired volume of the cavern has been developed. Cavern volume, not elapsed time, is the key indicator for changes in blanket depth to form the cavern roof.

Figures 1 and **2** show the shape of the cavern at completion of described steps of the mining program.

At completion of mining, a workover will be required to remove the mining string and install the brine dewatering string. A mechanical integrity test will also need to be conducted before injecting natural gas liquids for storage.

The Mining Plan concludes designs for two cavern sizes which differ 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. The maximum diameter and open height of each of the two cavern sizes is listed in **Table 5**.

As shown in Table 5, 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. For of the proposed cavern sizes, a permanent brine pool of about 1[redacted] barrels should be considered as remaining in the caverns.

Table 5 Parameters for Magnum Caverns at Completion

Cavern	Maximum Diameter – Feet	Depth Relative to Top of Salt of Maximum Diameter – Feet	Open Height – Feet	Open Cavern Volume – Barrels	Product Storage Volume – Barrels
1,000,000 bbl Cavern	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2,000,000 bbl Cavern	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

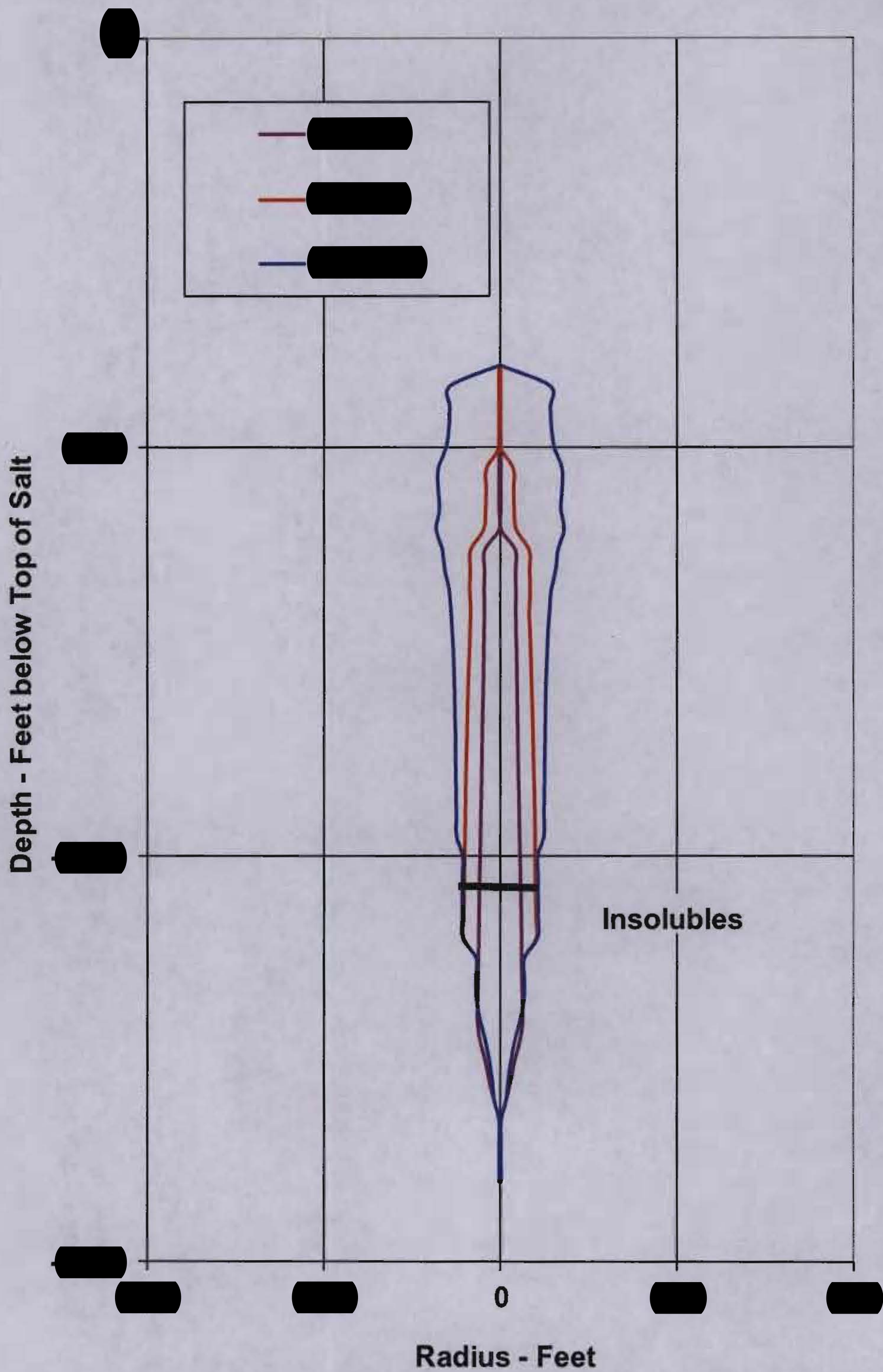


Figure 1: SANSMIC Simulation of One Million Barrel Cavern during Mining

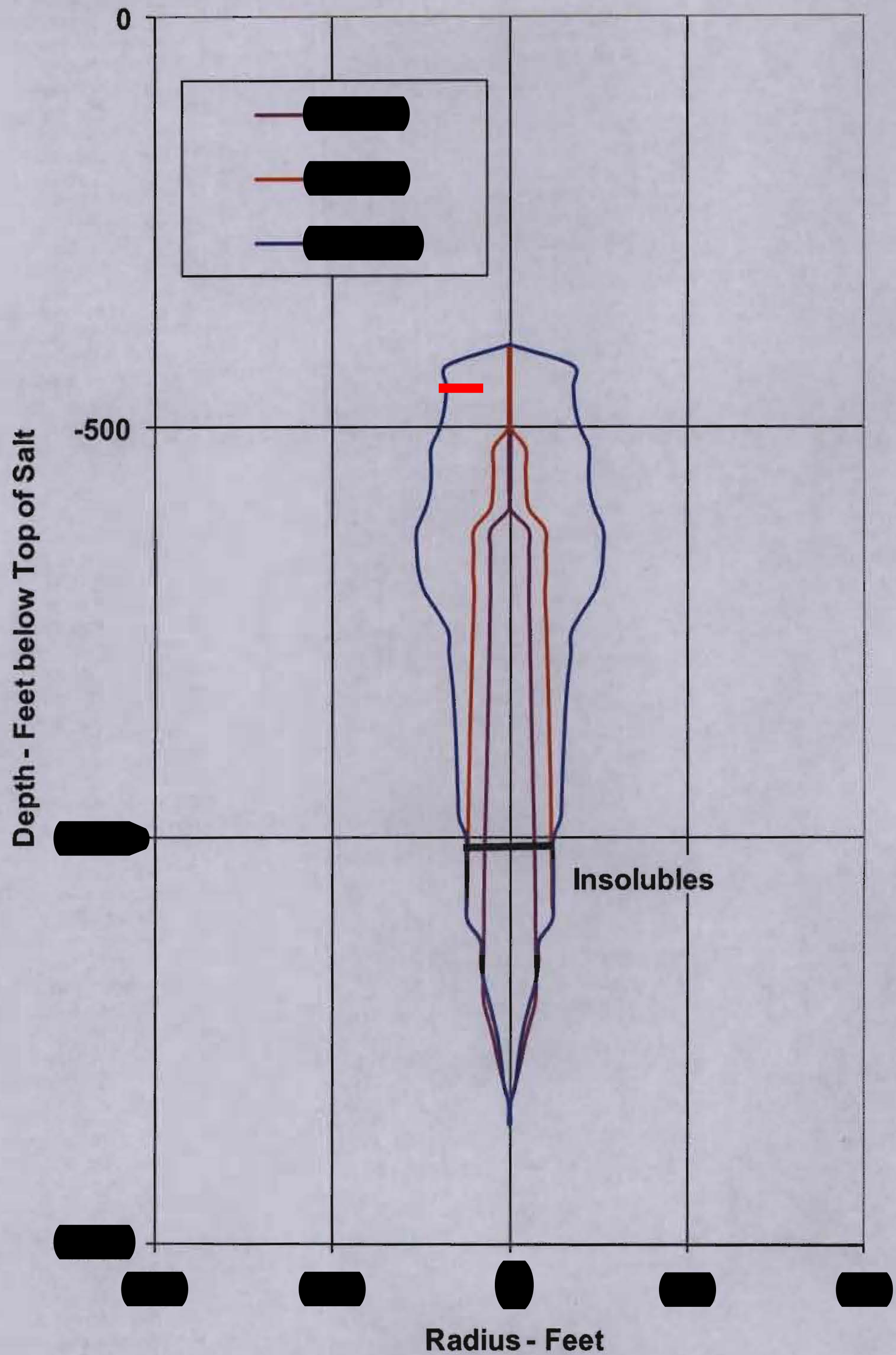


Figure 2: SANSMIC Simulation of Two Million Barrel Cavern during Mining

Cavern Development

The development of a 1,000,000-barrel storage cavern will require about [redacted] days to complete at a water injection rate of [redacted] gpm. A [redacted]-barrel storage cavern will require about [redacted] solution mining days to complete at a water injection rate of [redacted] gpm. This time is exclusive of any unplanned workovers or other down times. "Solution mining days" are days when water is injected at [redacted] gpm without interruption for 24 hours. The rate of development of each cavern is shown in Figure 3.

Approximately [redacted] barrels of brine are produced during development of the [redacted] barrel caver. [redacted] barrels of brine are produced during development of the [redacted] barrel cavern in addition to the brine that will be displaced during gas fill. Figure 3 shows the change in brine strength as the cavern is developed and when the flow regime is changed from direct to reverse circulation.

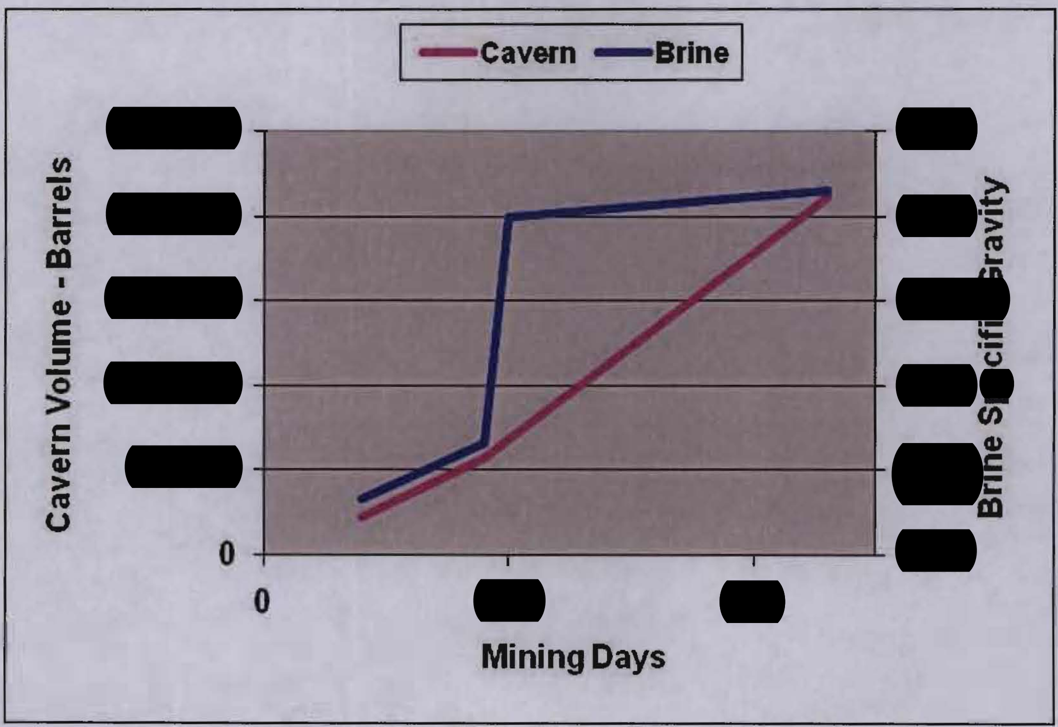


Figure 3: Rate of Cavern Development and Increase in Brine Strength for Two Million Barrel Cavern

Contingency

Contingency is an allowance for delays that may result from unforeseen events or from reasonably expected events with unknown durations or frequencies. Unforeseen events may be something such as loss of a tubing string due to thread failure, which will result in loss of time to procure new tubulars and a workover to install them. Other events, such as power outages that will interrupt water injection or brine disposal, can be expected during the period of development, but the timing and duration of these outages are unpredictable.

Most developers of solution-mining projects increase the estimated solution-mining time by an additional 10 percent to 15 percent to account for various interruptions that are likely to occur. As the scope of the mining portion of the project becomes better defined, the contingency may be reduced.

Major upsets, such as loss of the roof blanket due to an anomalous zone in the salt, may have a drastic impact on schedule. However, the likelihood of such an event is small and the impact on the schedule is unpredictable. These major upsets are not provided for in a contingency allowances in Table 6 below.

Schedule

The time required to develop the caverns will involve the time for mining, workovers, unknown shutdown times, logging episodes, and mechanical integrity testing at the end. The total mining time to develop each of the caverns in the Magnum Storage Site field is given in Tables 3 and 4. The times in these tables do not include logging, workovers, contingency or testing time.

Table 6 lists cavern development times for each of the caverns including contingency, blanket movements with no workovers during the mining. A workover at a specific time is not necessarily required, but it is very likely that the caverns will require a workover sometime during mining to repair damaged tubing or to allow sonar surveys to be conducted. To be conservative on timing, a workover could be included in the schedule for cavern development.

Table 6 Estimated Times to Develop Caverns to Storage Use

Mining Plan	Mining Time (days)	Workover Time (days)	Contingency (15%)(days)	Logging and Blanket Movement Time (days)	Mechanical Integrity Test & Completion Workover Time (days)	Total Time (days)
1,000,000 bbl Cavern	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2,000,000 bbl Cavern	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Discussion of Concerns and Further Refinements

The Mining Plan presented in this report is preliminary. Further effort is required to develop more specific plans for each cavern that match the geology determined after the well for each cavern is drilled. This additional work includes:

1. Refinement of the insoluble component of the salt at the location where the liquid storage wells will be drilled.
2. Development of a model to account for the dip of the salt beds.
3. More detailed design of the roof development program.

The insoluble content of the salt has been estimated from an average of the salt content in MH-1. The total quantity, as well as the distribution within the salt, of insolubles at a new location may change. This may impact the mining plans for smaller caverns. For actual well development, a specific plan for each well should be developed based on the geology at that well.

The Delta salt deposit is a tectonically modified bedded salt. The bedding in the salt is not horizontal. Caverns developed in non-horizontally bedded salts tend to develop with an elongation to the up-dip direction. The elongation is generally, though not always, proportional to the degree of dip - more steeply dipping salts resulting in more elongated caverns. A three dimensional model of a cavern will be developed to determine the possible extent of the elongation. Without pre-existing caverns to base dissolution factors on, the model will be of limited use but will illustrate the possible elongation.

Attachment G-2

- 16-inch Injection Well Construction Plan
- 16-inch Injection Well Cementing Plan
- Conceptual Casing Program for the 16-inch Injection Wells
- Figure G-2.1 - 16-inch Wellhead Casing Design
- 16-inch Injection Wellhead
- 16-inch Blowout Preventer Equipment

16-inch Injection Well Construction Plan

The following is the general program to be used to drill the Magnum 16-inch injection wells. Depths shown are approximate, **from Ground Level**.

1. Rig up drilling rig.
2. Drive 36-inch conductor casing to approximately 150 feet or refusal.
3. Drill a 17-1/2-inch hole to ±[redacted] feet and log.
4. Open 17-1/2-inch hole up to [redacted]-inch with hole openers of increasing size.
5. Run and cement [redacted] feet of [redacted]-inch O.D., [redacted]-inch wall thickness, [redacted] Centralizers to be placed every other casing section.
6. Allow the cement to set a minimum of 18 hours. Pressure test the casing in accordance with State rules.
7. After the cement sets, cut off the [redacted]-inch casing and weld on a [redacted]-inch x [redacted]-inch reducer and [redacted]-inch flange. Nipple up a [redacted]-inch annular BOP.
8. Drill a 17-1/2-inch hole to slightly above top of salt structure estimated to be ± [redacted] feet. Lost circulation may occur over this interval; control as necessary by the use of lost circulation material, cement plugs or drill without returns.
9. Run gamma ray, SP induction and resistivity logs as specified.
10. Open the 17-1/2-inch hole to [redacted]-inch with hole openers of increasing size.
11. Run X-Y caliper log.
12. Run and cement ±[redacted] feet of [redacted]-inch O.D., 1-inch wall thickness, and [redacted] feet of [redacted]-inch O.D. [redacted]-inch wall thickness [redacted] or equivalent threaded and coupled pipe to top of salt structure. Use the stab-in cementing method. Centralizers to be placed every other casing section.
13. After the cement sets, pressure test the casing in accordance with State rules.
14. Cut off the [redacted]-inch casing and weld on a [redacted]-inch x [redacted]-inch reducer and [redacted] inch flange. Nipple up a [redacted]-inch annular BOP.
15. Switch to salt saturated mud after [redacted]-inch casing is set at top of salt structure or at the depth where salt structure is encountered during drilling.
16. Drill a 17-1/2-inch hole to ± [redacted] feet.
17. Run gamma ray, SP induction, neutron and bulk density logs as specified.
18. Open the 17-1/2-inch hole to [redacted]-inch with hole openers and under reamers of increasing size.
19. Run X-Y caliper log.
20. Run and cement [redacted] feet of [redacted]-inch O.D., [redacted]-inch wall thickness, ~~API~~ [redacted] and [redacted] feet of [redacted]-inch O.D. and [redacted]-inch wall thickness, ~~X-56,~~ T&C threaded and coupled line pipe. Use the stab-in cementing method. Centralizers to be placed every other casing section.
21. Allow the cement to set a minimum of 72 hours. Pressure test the casing in accordance with State rules.

22. Cut off the [redacted]-inch casing and weld on a [redacted]-inch flange. Nipple up [redacted] annular BOP.
23. Drill a 17-1/2-inch hole to ±[redacted] feet.
24. Run gamma ray, SP induction, neutron and bulk density logs as specified.
25. Open the 17-1/2-inch hole up to [redacted]-inch using hole openers and underreamers.
26. Run X-Y caliper log.
27. Run and cement [redacted] feet of [redacted]-inch O.D. [redacted]-inch and [redacted]eet of [redacted]-inch O.D. [redacted]-inch wall thickness, API [redacted] casing. Use the stab-in cementing method. Centralizers to be placed every other casing section.
28. Allow the cement to set a minimum of 72 hours. Pressure test the casing in accordance with State rules.
29. Drill out plug and ten feet of salt formation.
30. Pressure test casing shoe in accordance with the State rules and regulations.
31. Drill a [redacted]-inch hole to ±[redacted] feet.
32. Log cuttings and check for loss of drilling fluid indicating a porous formation is encountered. If so, perform a tightness test over this interval.
33. Run gamma ray, neutron and bulk density logs as specified.
34. If logs indicate a porous zone in the salt section, perform tightness test over the zone.
35. Under ream the [redacted]-inch hole to [redacted]-inch down to a depth of [redacted] feet.
36. Run X-Y caliper log.
37. Run casing inspection and cement bond logs i[redacted]nch casing from shoe to surface.
38. Run in approx. [redacted]&C Casing.
39. Install and test the upper wellhead assembly.
40. Run in approx. [redacted]0 feet of [redacted]-inch, [redacted]b/ft, [redacted]Casing.
41. Install remainder of wellhead.
42. Rig down and move out rig from location.
43. Clean up location.

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".

SPECIFICATIONS FOR CEMENTING SERVICES AND MATERIALS

This specification covers the requirements to supply cement, equipment and services for storage wells located near Delta, UT. The work will be conducted from a land rig. Cement bond logs cannot be used with reliability on the [redacted]-inch plus well casings proposed for the gas storage wells and therefore will not be run on the larger casings. A review of cement bonding capabilities with PB Energy Storage Systems has confirmed that there are no test methods currently available to conduct a bond log. Therefore, cementing operations will be visually verified at the time of cementing via the observance of cement rising within the outer well annulus to the surface.

Proposed wellbore configuration (Depths RKB)

[redacted]-inch Conductor Pipe: 0 - Approx. 150 feet (Driven to refusal)

[redacted]-inch Surface Casing: [redacted] feet (Approx. [redacted]-inch Open Hole)

[redacted]-inch Intermediate Casing: [redacted] feet (Approx. [redacted]-inch Open Hole)

[redacted]inch Next to Last Casing: [redacted] feet (Approx. [redacted]-inch Open Hole)

[redacted]-inch Last Cemented Casing: [redacted] feet (Approx. [redacted]-inch Open Hole)

Top of Salt: Approx. [redacted] feet

1. Cement specifications for the [redacted]-inch Surface casing. Cement job will be pumped through a stabbed-in 5-inch 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 (4 Arm Caliper Available)

2. Cement specifications for the [redacted]-inch Intermediate. Cement job will be pumped through a stabbed-in 5-inch 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 (4 Arm Caliper Available)

3. Cement specifications for the [redacted]-inch Next to Last Casing. Cement job will be pumped through a stabbed-in 5-inch DP.
   Cement to surface: Class G (Premium) + 37.2% Salt + Defoamer (if deemed 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 (4 Arm Caliper Available)

4. Cement specifications for the [redacted]-inch Last Casing. Cement job will be pumped through a stabbed-in 5-inch DP.
   Cement to surface: Class G (Premium) + 37.2% Salt + Defoamer (if deemed 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 (4 Arm Caliper Available)

WELL CONDITIONING

Before commencing drilling operations (spudding the well), Magnum will provide detailed procedures for conditioning the hole prior to cementing casing. The pre-flush procedure will ensure that the wellbore is properly conditioned for cementing operations in accordance with recommendations from the cementing contractor.

The well is conditioned to circulate the drilling fluids, sweep cuttings out of the hole, obtain consistent fluid properties, and adjust the fluid viscosity and density in an attempt to prevent cement channeling through the fluid. Detailed procedures for this process have not been written at this time as it is a typical task during drilling, but when the drilling fluids contractor is hired his mud engineer will be tasked to write a program for the fluids.

REPORT

During Drilling the casing cement jobs shall 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 intermediate and salt casings shall be collected in suitable sized and shaped containers so that the hardened cement can be tested for compressive strength.

16" Injection Well Proposed Casing and Cementing Program

16" Injection Well Proposed Casing and Cementing Program

Hole Size Casing Size	Driven 36"	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Mud Weight Type	N/A	9.5 ppg Fresh Water	10.2 ppg Fresh Water	10.2 ppg Saturated Brine (>1800')	10.2 ppg Saturated Brine (>3000')	10.4 ppg Saturated Brine
Slurry Weight	N/A	15.6 ppg Fresh Water	15.6 ppg Fresh Water	16.3 ppg Saturated Brine (>3000')	16.3 ppg Saturated Brine (>3000')	16.3 ppg Saturated Brine
Cement Type	N/A	Standard (Type I)	Standard (Type I)	Class G Salt Saturated	Class G Salt Saturated	Class G Salt Saturated
Cement Yield Cement Volume	N/A	887 sks 1.18 cu ft/sk	3,077 sks 1.18 cu ft/sk	1,464 sks 1.18 cu ft/sk	2,598 sks 1.24 cu ft/sk	3,460 sks 1.24 cu ft/sk

Conceptual Casing Program for the 16" Injection Wells

Prepared for

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Salt Lake City, Utah

By

Thomas Eyermann

October 18, 2011

Table of Contents

Conceptual Casing Program for the 16-inch Injection Wells

General Well Design

The 16-inch injection wells for the Magnum salt storage caverns will be drilled from surface to more than a thousand feet into the salt. The wells will have a water protection string or surface casing and two casing strings (intermediate and production casings) cemented into the upper section of the salt. The casing string will be run in a wellbore of slightly larger diameter than the casing and cemented into place. The drilling and cementing programs are presented in **Attachment G-2**.

The surface casing is sized so as to allow for a second contingent intermediate string in the event that a problem zone is encountered during drilling that requires a casing string to seal it off. The well in general is sized so as to allow product injection into and production from the completed cavern at [redacted] gpm with a velocity of less than [redacted] feet per second. The casing sizes also allow use of tubing strings for mining that will maintain fluid velocities at about [redacted] feet per second. This is an acceptable range for mining operations.

The various casing strings are sized to withstand foreseeable collapse, burst and tensile forces that might act upon the casing. The goal of the design was to specify casing sizes and grades that allow a safety factor of about 1.0 for collapse, 1.0 for burst and 1.6 for tensile forces based on published strength data.

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 [redacted] 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 mining tubing string, the collapse pressures result from the use of nitrogen as a blanket material. The nitrogen roof blanket pressures will be greatest at the start of mining when the nitrogen roof 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 [redacted]-inch tubing with a vacuum on the inside. The tubing has been sized to withstand this type of worst case event to mitigate the low potential for occurrence.

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 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 conceptual casing program designed for the Magnum 16-inch injection wells are summarized in **Table 1**. In the event that these casing and pipe sizes are not available, the next higher grade or increased wall thickness should be chosen. Calculations for forces acting on the various strings are shown in Appendix A. The safety factors for the various loading scenarios are summarized in **Table 2**.

Table 1 Summary of Casings for Magnum Gas Storage Well

Casing String	Size - inches	Weight - pounds/foot	Grade	Depth - feet
Conductor	[redacted]	[redacted]	[redacted]	[redacted]
Surface	[redacted]	[redacted]	[redacted]	[redacted]
Intermediate	[redacted]	[redacted]	[redacted]	[redacted]
Intermediate Final cemented depth [redacted] feet	[redacted]	[redacted]	[redacted]	[redacted]
First Salt	[redacted]	[redacted]	[redacted]	[redacted]
First Salt Final cemented depth [redacted] feet	[redacted]	[redacted]	[redacted]	[redacted]
Production (2^{nd} Salt)	[redacted]	[redacted]	[redacted]	[redacted]
Production (2^{nd} Salt) Final cemented depth [redacted] feet	[redacted]	[redacted]	[redacted]	[redacted]
Outer Mining String	[redacted]	[redacted]	[redacted]	[redacted]
Inner Mining String	[redacted]	[redacted]	[redacted]	[redacted]

Table 2 Summary of Calculated Factors of Safety

	Safety Factor		
Casing String	**Collapse – 1.0**	**Burst – 1.0**	**Tensile – 1.6**
[redacted]-inch Conductor	N/A	N/A	N/A
[redacted]-inch Surface	1.48	5.67	15.53
[redacted]-inch Intermediate	1.10	2.26	4.54
[redacted]-inch Intermediate	1.21	2.30	N/A
[redacted]-inch First Salt String	1.05	4.66	3.15
[redacted]-inch First Salt String	1.08	1.97	N/A
[redacted]-inch Production (2nd Salt String)	1.29	4.58	3.67
[redacted]-inch Production (2nd Salt String)	1.26	3.36	N/A
[redacted]-inch Outer Mining String	1.33	1.67	5.53
[redacted]-inch Inner Mining String	N/A	N/A	4.08

Sources

Lone Star Steel, 2002; OCGT 23rd Edition

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

Appendix A

Casing Design Calculations

Conductor Pipe

[redacted]-Inch, Wall thickness [redacted], [redacted], Plain end, welded pipe from 0 feet to approximately 150 feet.

Pipe is to be driven by pile driver to refusal.

Surface Casing

[redacted]0-Inch, [redacted] lb/ft, Wall Thicknes[redacted]inch, [redacted] Plain end, welded, pipe from 0 feet t[redacted] feet.

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. [redacted] feet) ([redacted] psi/ft) (15.6 lb/gal cement) = 608 psi hydrostatic pressure exerted on the exterior of the [redacted]-inch casing, at [redacted] feet.
2. 0 psi hydrostatic pressure exerted on the interior of the [redacted]inch casing, at [redacted] feet.
3. Differential pressure, (collapse pressure) annulus pressure verses pressure inside the [redacted]-inch casing equals: 608 psi - 0 psi = 608 psi.
   The [redacted]-inch surface casing has a collapse rating of 898 psi. According to the above differential calculations, the proposed [redacted]-inch surface casing to be used has a collapse rating greater than any outside pressure that will be exerted against the exterior of the casing.

Burst Calculations:

Assume that the bottom hole depth of the [redacted]-inch surface casing is at [redacted] feet from surface, with a welded float shoe located at the bottom of the casing string. The [redacted]-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. [redacted] feet) ([redacted] psi/ft/lb/gal) (9.5 lb/gal drilling mud) = 371 psi hydrostatic pressure exerted on the interior of th[redacted]inch casing, at [redacted] feet.
2. Differential pressure, (burst pressure) inside pressure verses annulus pressure on the outside of th[redacted]inch casing equals: 371 psi - 0 psi = 371 psi.

According to API Bulletin 5L, the [redacted]-inch surface casing has a minimum test pressure of 2,100 psi. According to the above differential calculations, the proposed [redacted]-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.

Tensile Calculations:

The proposed [redacted]-inch surface casing weighs [redacted] lb/ft and will be set at approximately [redacted] feet, for a total string weight of 176,000 lbs. The [redacted]inch, welded surface casing proposed has a tensile rating of 2,730,000 lbs, which is greater than tensile weight exerted by the weight of the casing.

Intermediate String Casing:

[redacted]-inch, [redacted] lb/ft, Wall Thickness [redacted]-inch, [redacted] Plain end fitted with threaded connections from 0 feet t[redacted] feet.

[redacted]-inch, [redacted] lb/ft, Wall Thickness [redacted]-inch[redacted] Grade, Plain end fitted with threaded connections from [redacted] feet to [redacted] feet.

Collapse Calculations:

Assume that the bottom hole depth of the [redacted]-inch [redacted] lb/ft casing (pipe) at [redacted] 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 [redacted]-inch surface casing.

1. [redacted] feet) [redacted] psi/ft/lb/gal) (15.6 lb/gal cement) = 2,028 psi hydrostatic pressure exerted on the exterior of the [redacted]-inch casing, at [redacted] feet.

1a. ([redacted] feet) (0.052 psi/ft/lb/gal) (15.6 lb/gal cement) = 2,596 psi hydrostatic pressure exerted on the exterior of th[redacted]-inch casing, at [redacted] feet.

2. Differential pressure, (collapse pressure) annulus pressure verses pressure inside the [redacted]-inch casing at [redacted] feet equals: 2,028 psi – 0 psi = 2,028 psi.

2a. Differential pressure, (collapse pressure) annulus pressure verses pressure inside the [redacted]-inch casing at [redacted]feet equals: 2,758 psi – 0 psi = 2,596 psi.

According to API Bulletin 5L, th[redacted]-inch outer string casing at [redacted] feet has a collapse rating of 2,230 psi and at [redacted] feet a collapse rating of 3,130 psi. According to the above differential calculations, the proposed [redacted]inch outer string casing to be used has a collapse rating equal to or greater than any outside pressure that will be exerted against the exterior of the casing.

Burst Calculations:

Assume that the bottom hole depth of the [redacted]-inch surface casing is at [redacted] feet from surface, with a welded float shoe located at the bottom of the casing string. The [redacted]-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 [redacted] 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. ([redacted] feet) (0[redacted] psi/ft/lb/gal) (10.2 lb/gal drilling mud) = 1,326 psi hydrostatic pressure exerted on the interior of the 24-inch casing, at 2,500 feet.

1a. ([redacted] feet) (0[redacted] psi/ft/lb/gal) (10.2 lb/gal drilling mud) = 1,697 psi hydrostatic pressure exerted on the interior of the [redacted]-inch casing, at [redacted] feet.

2. Differential pressure, (burst pressure) inside pressure verses annulus pressure on the outside of the [redacted]-inch casing at [redacted] feet equals: 1,326 psi - 0 psi = 1,326 psi.

2a. Differential pressure, (burst pressure) inside pressure verses annulus pressure on the outside of the [redacted]-inch casing at [redacted] feet equals: 1,803 psi - 0 psi = 1,803 psi.

According to API Bulletin 5L, the 1-inch [redacted]-inch outer string casing has a minimum test pressure of 3,000 psi and the 1.25-inch outer string has a minimum test pressure of 3,902. According to the above differential calculations, the proposed [redacted]-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.

Tensile Calculations:

The proposed [redacted]-inch outer string casing weighs [redacted] lb/ft or [redacted]/ft and will be set at approximately [redacted] feet, for a total string weight of 827,000 lbs.

The proposed [redacted], welded intermediate casing has a tensile rating of 3,757,000 lbs, which is greater than tensile weight exerted by the weight of the casing.

First Salt String Casing:

[redacted]-Inch [redacted]t, Wall Thickness [redacted]-inch, [redacted] Grade, Buttress connection, Casing from [redacted] feet.

[redacted]-Inch, [redacted] lb/ft, Wall Thickness [redacted]-inch, [redacted] Grade, Threaded pipe, from [redacted] feet.

Collapse Calculations:

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

Above [redacted] feet the casing will be 133 lb/ft [redacted] casing. From [redacted] feet to [redacted] feet the casing will be [redacted] lb/ft [redacted] line pipe. This string will have buttress connections above [redacted] feet and proprietary connections on the line pipe. The worst-case scenario for collapse pressure would be a full column of cement in the casing/hole annulus, and an empty inside th[redacted]inch surface casing.

1. [redacted] feet) (0[redacted] psi/ft/lb/gal) (16.3 lb/gal cement) = 1,526 psi hydrostatic pressure exerted on the exterior of the 20-inch casing, at [redacted] feet.
1a. [redacted] feet) (0.[redacted] psi/ft/lb/gal) (16.3 lb/gal cement) = 2,839 psi hydrostatic pressure exerted on the exterior of the [redacted]-inch casing, at [redacted] feet.
2. At [redacted] feet, the differential pressure equals: 1,526 psi - 0 psi = 1,526 psi. According to Lone Star Steel, the [redacted]-inch [redacted] lb/ft casing has a collapse rating of 1,600 psi. According to the above differential calculations, the proposed [redacted]-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 [redacted] feet, the differential pressure equals: 2,839 psi - 0 psi = 2,839 psi. The [redacted]-inch [redacted] lb/ft pipe has a collapse rating of 3,080 psi. According to the above differential calculations, the proposed [redacted]-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.

Burst Calculations:

Assume that the bottom hole depth of the [redacted]-inch surface casing is at [redacted] feet from surface, with a welded float shoe located at the bottom of the casing string. The [redacted]-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 [redacted] 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. [redacted] feet) (0[redacted] psi/ft/lb/gal) (10.2 lb/gal drilling mud) = 955 psi hydrostatic pressure exerted on the interior of the [redacted]-inch casing, at [redacted] feet.
1a. [redacted] feet) [redacted]psi/ft/lb/gal) (10.2 lb/gal drilling mud) = 1,777 psi hydrostatic pressure exerted on the interior of the [redacted]-inch casing, at [redacted] feet.
2. Differential pressure (burst pressure), inside pressure verses annulus pressure on the outside of the [redacted]-inch casing equals: 955 psi - 0 psi = 955 psi.
2a. Differential pressure (burst pressure), inside pressure verses annulus pressure on the outside of the [redacted]-inch casing equals: 1,777 psi - 0 psi = 1,777 psi.

The [redacted]-inch pipe has a minimum test pressure of 4,450 psi above [redacted] feet and [redacted] psi for the lower segment. According to the above differential calculations, the proposed [redacted]-inch casing to be used has a minimum test pressure greater than any inside pressure that will be exerted against the interior of the casing.

Tensile Calculations:

The [redacted] inch surface casing proposed weighs [redacted] lb/ft set at [redacted] feet and [redacted] lb/ft set at approximately [redacted] feet, for a total string weight of 535,000 lbs.

API TR5C3 provides a tensile strength for the [redacted] buttress end casing at the top of the string of 1,685,000 pounds; which exceeds the above-calculated weight of the [redacted]-inch casing.

Production String Casing:

[redacted]-Inch, [redacted] lb/ft, [redacted], wall thickness [redacted]6-inch, buttress connection, casing from 0 to [redacted] feet.

[redacted]-Inch, 118 lb/ft, [redacted], wall thickness [redacted]-inch, buttress connection, casing from [redacted] feet.

Collapse Calculations:

Assume that the bottom hole depth of the [redacted] inch production string of casing is at [redacted] 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 [redacted]-inch surface casing.

1. ([redacted] feet) [redacted] psi/ft/lb/gal) (16.3 lb/gal cement) = 1,695 psi hydrostatic pressure exerted on the exterior of the [redacted]-inch casing, at [redacted] feet.

1a. [redacted] feet) [redacted] psi/ft/lb/gal) (16.3 lb/gal cement) = 2,924 psi hydrostatic pressure exerted on the exterior of the [redacted] inch casing, at [redacted] feet.

2. Differential pressure, collapse pressure), annulus pressure verses pressure inside the [redacted]-inch casing equals: 1,695 psi – 0 psi = 1,695 psi. According to Lone Star Steel, the [redacted] casing has a collapse rating of 2,180 psi.

2a. Differential pressure, collapse pressure), annulus pressure verses pressure inside the [redacted]-inch casing equals: 2,924 psi – 0 psi = 2,924 psi. According to Lonestar, the [redacted]t casing has a collapse rating of 3,680 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.

Burst Calculations:

Assume that the bottom hole depth of the [redacted]-inch surface casing is at ± [redacted] 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 [redacted] 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. ([redacted] feet) ([redacted] psi/ft/lb/gal) (10.4 lb/gal drilling mud) = 1,082 psi hydrostatic pressure exerted on the interior of the [redacted]-inch casing, at [redacted] feet.

1a. [redacted] feet) ([redacted] psi/ft/lb/gal) (10.4 lb/gal drilling mud) = 1,866 psi hydrostatic pressure exerted on the interior of the [redacted]-inch casing, at [redacted] feet.

2. Differential pressure (burst pressure), inside pressure verses annulus pressure on the outside of the [redacted]-inch casing equals: 1,082 psi – 0 psi = 1,082 psi. The [redacted]-inch casing above [redacted] feet has a minimum test pressure of 4,950 psi. According to the above differential calculations, the proposed [redacted]-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 [redacted]-inch casing equals: 1,866 psi – 0 psi = 1,866 psi. According to Lone Star Steel, the 16-inch casing has a minimum test pressure of 6,260 psi. According to the above differential calculations, the proposed [redacted]-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 [redacted]-inch casing annulus will be filled with nitrogen used as a blanket during mining operations. At the surface, the maximum gas pressure will be about 2,028 psi / (e ^ (0.00003347 * 0.58 * depth) = 1,900 psi. The wellhead gas pressure is below the rated burst pressure of 4,950 psi of the [redacted]-inch casing at the surface.

Tensile Calculations:

The [redacted]-inch surface casing will be set at approximately [redacted] feet, for a total string weight of 391,000 lbs.

Lone Star Steel provides a tensile strength for buttress end casing of 1,326,000 pounds; which greatly exceeds the above-calculated weight of the [redacted]-inch casing.

Outer String of Mining Tubing:

[redacted]-inch, [redacted] b/ft, wall thickness [redacted]-inch, [redacted] grade, buttress connection, casing from [redacted] feet.

Collapse Calculations:

Assume that the nitrogen roof blanket will be at a depth of [redacted] feet from surface, the maximum differential pressure exerted against the [redacted]-inch casing will be at the surface.

The worst-case scenario for collapse pressure would be a column of freshwater 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. [redacted]feet) ([redacted]psi/ft/lb/gal) (10.0 lb/gal brine) = 2,028 psi hydrostatic pressure exerted on the exterior of the [redacted]-inch casing, at [redacted]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 [redacted]-inch at the surface is (nitrogen blanket pressure) / (1.000316 ^ blanket level depth) = 2,028 / (1.0000316 ^ [redacted]) = 1,902 psi.

2. [redacted] feet) ([redacted] psi/ft/lb/gal) (10.0 lb/gal brine) = 2,028 psi hydrostatic pressure exerted on the interior of the [redacted]-inch casing, at [redacted] feet.

3. Differential pressure, collapse pressure), annulus pressure verses pressure inside the [redacted]-inch casing at the surface equals: 1,902 psi - (-100 psi) (vacuum) = 2,002 psi. According to API Bulletin 5C2, the [redacted]-inch string casing has a collapse rating of 2,670 psi. According to the above differential calculations, the proposed [redacted]-inch casing to be used has a collapse rating greater than the pressure that will be exerted against the exterior of the casing.

Burst Calculations:

Assume that the bottom hole depth of the [redacted]-inch surface casing is at [redacted] feet from surface, with an open end of the casing string. The [redacted]-inch surface casing will be loaded with 10.0 lb per gallon brine during reverse mining steps. The worst case for burst considerations would be if the nitrogen blanket bled off and the bottom of the [redacted]-inch tubing was salted into the [redacted]-inch production casing during normal operations. This could potentially leave a column of low-pressure gas along the outside of the tubing and high-pressure brine on the inside of the tubing string.

1. Zero psi hydrostatic pressure exerted on the exterior of the [redacted]-inch casing, at the [redacted]-inch casing shoe.
2. Pump pressure (Value unknown but assumed) 1,200 psi exerted on the [redacted]-inch casing.
3. Fluid pressure at [redacted] feet of ([redacted] feet) (0[redacted]psi/ft/lb/gal) (10.0 lb/gal brine) = 2,028 psi exerted on the interior of the [redacted]-inch casing at [redacted] feet.
4. Differential pressure (burst pressure), inside pressure verses annulus pressure on the outside of the [redacted]-inch casing equals: 2,028 psi + 1,200 psi (assumed pump pressure) - 0 psi = 3,228 psi. According to API Bulletin 5C2, the [redacted]-inch casing has a minimum test pressure of 5,380 psi. According to the above differential calculations, the proposed [redacted]-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.

Tensile Strength:

At this time, the depth for the outer string tubing is [redacted] lb/ft casing to [redacted] feet. Based on these depths, the maximum string weight will be 306,000 lbs. This is well below the maximum tensile strength at the surface of 1,693,000 lbs.

Inner String of Mining Tubing:

[redacted] inch, [redacted] lb/ft, wall thickness [redacted] buttress connection, casing from [redacted] feet.

Burst & Collapse:

The [redacted] inch inner wash string has the similar circumstance as the [redacted]-inch outer string tubing, 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 [redacted]-inch tubing will not have nitrogen acting against it.

Tensile Strength:

At this time, the deepest depth for the inner tubing [redacted] ft) is estimated at approximately [redacted] feet. Based on this depth, the maximum string weight will be 169,000 lbs. This is well below the maximum tensile 690,000 lbs.

Sources: OCTG Products, 23rd Edition, Lone Star Steel

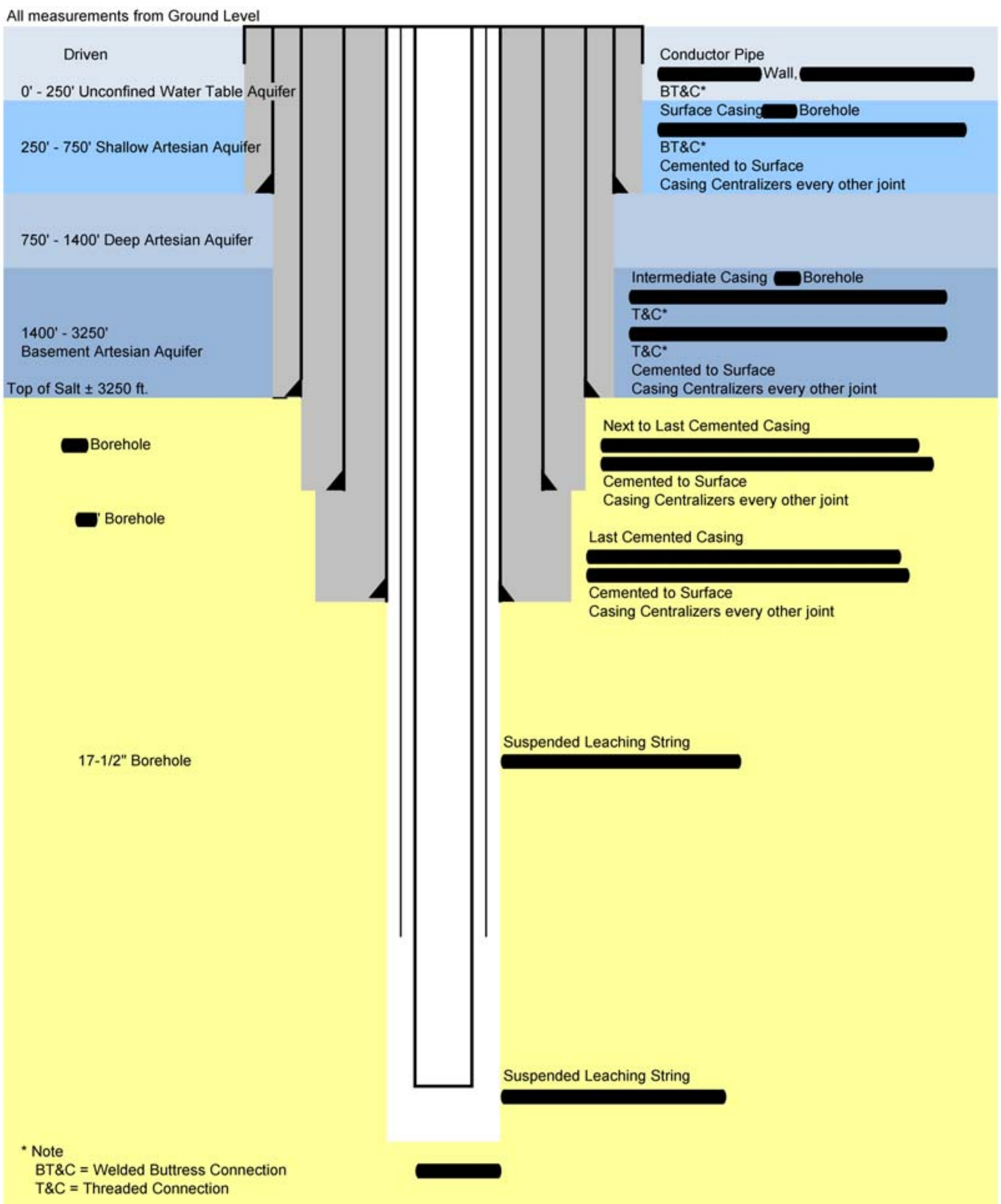
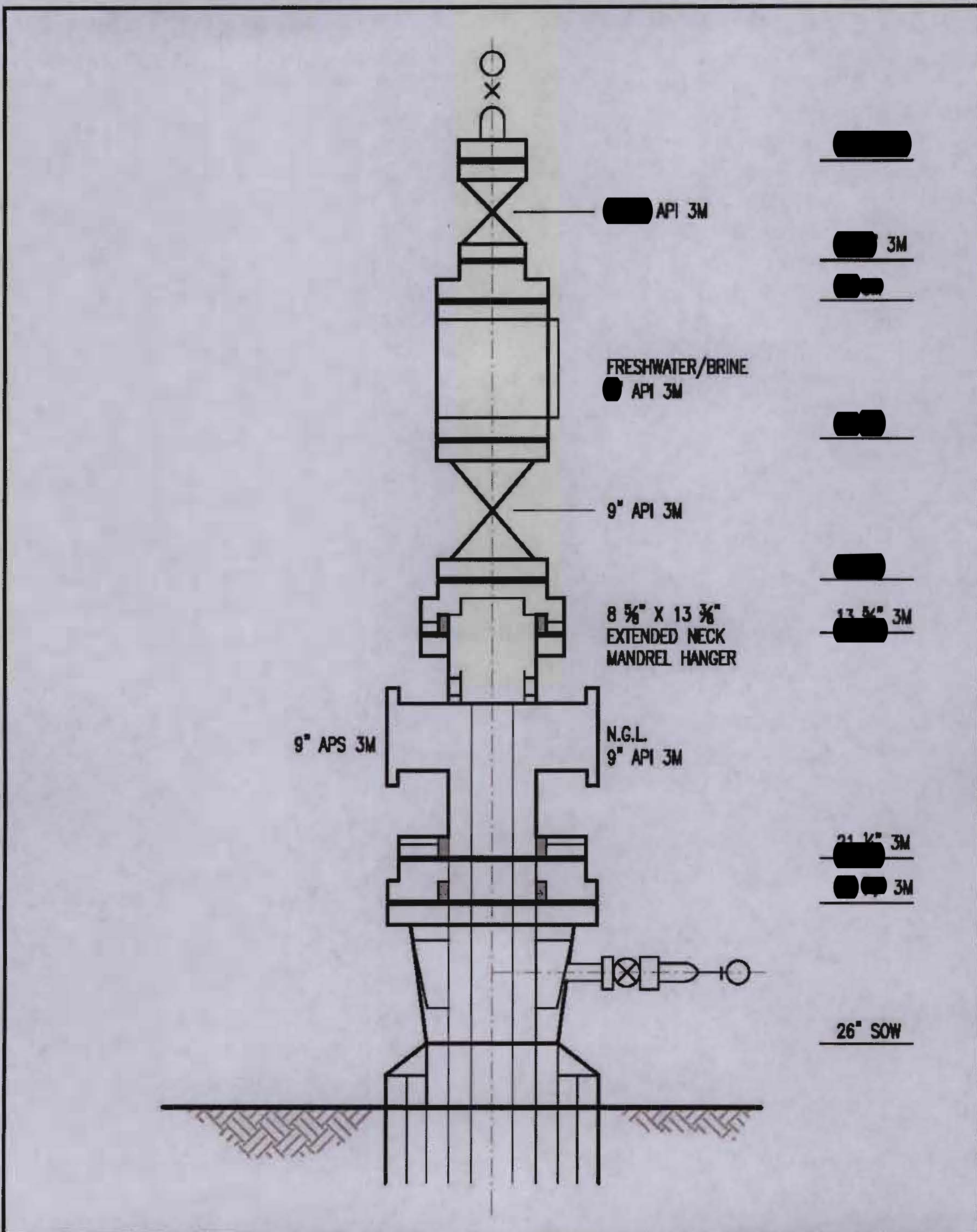


Figure G-2.1

Natural Gas Liquids Storage Well Casing Design

DRAWN: T. Eyermann	DATE: 9/18/11	SCALE: NONE	



MAGNUM

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

16-inch Injection Wellhead

NUMBER:	00000	SHEET NO:
DATE:	09/20/11	
PREPARED:	AG/TE	
APPROVED:	DB/TE	

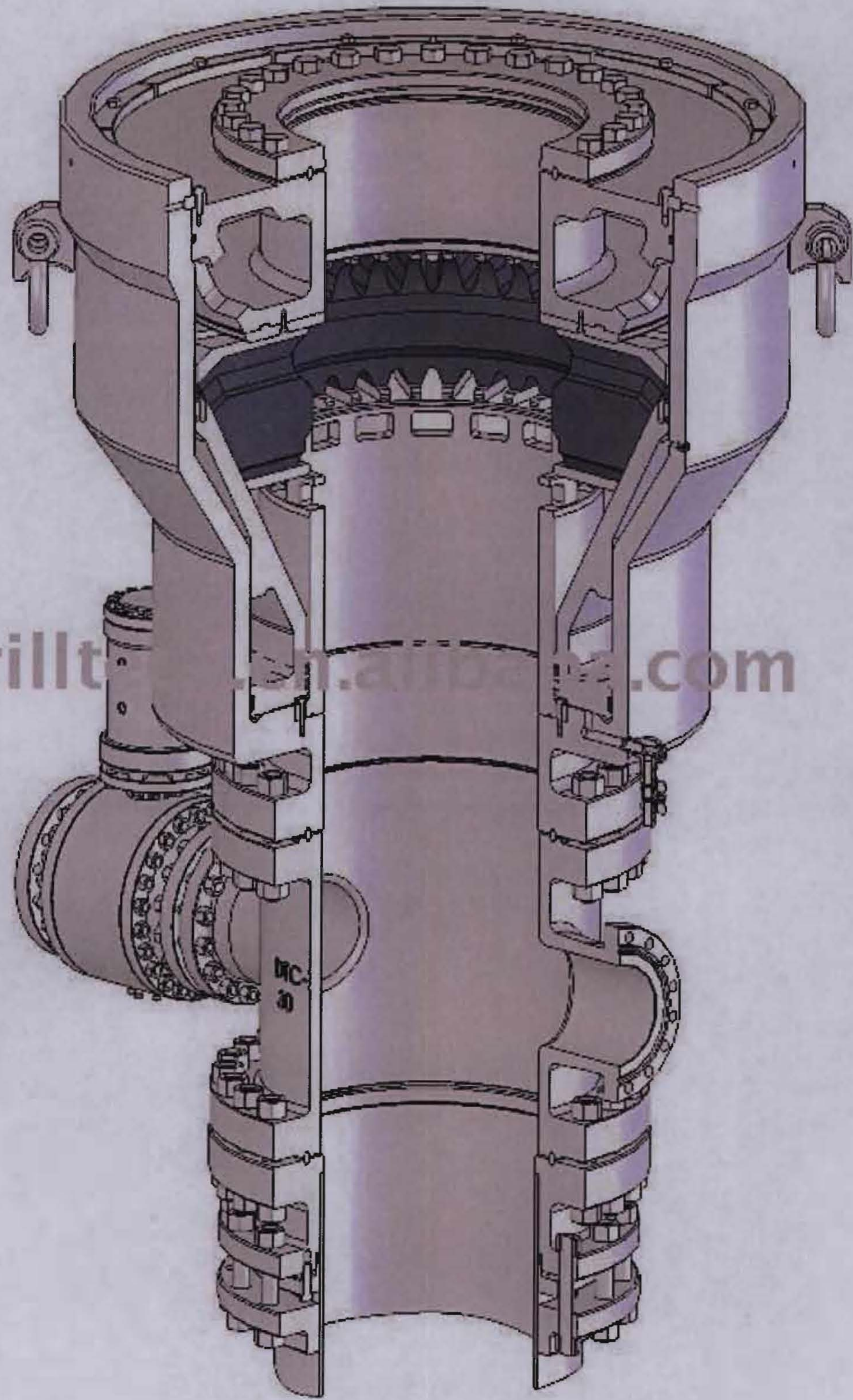
16-inch Well Blowout Preventer Equipment for Magnum Salt Cavern Drilling

Wells drilled into salt generally utilize some well control equipment. The well control equipment almost always includes an annular, bag-type blowout preventer. Magnum will follow industry practice and use an annular blowout preventer (BOP) when drilling the cavern wells near Delta, Utah. The geology of the area is known from the nearby Magnum test well and the Argonaut Well as well as the nearby industrial water wells. These wells demonstrate that the formations to be drilled above the salt, as is the salt itself, are gas-free. The Argonaut Well penetrated the entire sequence of salt and the Magnum well penetrated the salt to a depth over 1,000 feet deeper than the intended storage well depth. Additionally, the geophysical lines that run over the area show there are no structures present in the overlying formations that could trap gas. This is typical of the basin and range deposits that have been explored for hydrocarbon production. Consequently, additional equipment used in deep oil and gas wells such as shear and pipe rams will not be needed for the storage wells.

The size of the storage wells require that bottom hole assembly be run into the well, the BOP equipment be stripped over the drilling assembly and then the BOP installed on the casing. The exact size of the annular preventer to be used will be determined by availability at the time drilling commences, but will be at least [redacted]-inch, 5000 psi. Once the BOP is installed, testing of the equipment then follows oil and gas industry standards. The BOP equipment must be stripped off and then put back over the drilling string whenever a bit change is required.

The preventer will be installed on the surface casing after it is cemented in place. The preventer will be installed on a temporary flange welded to the last string of casing in the well at the time. Functionality testing of the equipment is conducted every time it is installed. The preventer will be connected to the closing unit by high-pressure hydraulic hoses. A joint of drillpipe will be picked up by the rig and run into the preventer. The preventer will then be closed from the control unit and checked that the bag has sealed around the drillpipe. If the closing is visually correct, the preventer will be opened, the drillpipe removed and rig activities will then continue.

Blowout Preventer Equipment



Part H

Magnum Solution Mining, LLC

Millard County, Utah

Magnum Gas Storage Project

16-inch Injection Well Construction Details and Mechanical Integrity Testing

Part H – 16-inch Injection Well Construction Details

A schematic showing basic injection well casing details was discussed within Part G and shown in **Figure G-2.1**. During the initial stage of mining which will be done in direct mode, the average injection pressure will be about 2,500 psi. The average injection pressure during the long second phase of solution mining, which will be in reverse mode, will be about 725 psi.

Mechanical Integrity Testing

Several testing methods will be employed to demonstrate mechanical integrity of the well/cavern system. These methods vary depending upon the stage of development of the well or cavern.

1.0 During Drilling

After cementing the 16-inch production casing, the casing will be tested before continuing drilling. A hydraulic pressure test of the [redacted]-inch production casing will be conducted before drilling out the plug (shoe) and after waiting at least 72 hours to allow the cement to set. The test pressure shall be 125% of the anticipated working pressure during product storage, about 2,020 psi at the cement plug or about 405 psi at the surface. The test will last 30 minutes. The test will be considered good if the pressure loss is less than 5%.

After drilling out the cement plug and drilling about 10 feet of salt below the casing shoe, a hydraulic pressure test of casing seat and cement in [redacted]-inch production casing will be run. The surface test pressure will be 80% of the lithostatic pressure as calculated at the casing seat minus the hydrostatic pressure of the test fluid, or about 870 psi. The test will last 60 minutes. The test will be considered good if the pressure loss is less than 5%.

2.0 Test of the 16-inch Casing and the Cavern during Development

Prior to initiating solution mining and again at the completion of solution mining, the cavern will be tested using the nitrogen mechanical integrity technique. The test pressure at the shoe of the [redacted]-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 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 [redacted]nch tubing) to a depth 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 500 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.

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. The report will be submitted to the Executive Secretary within 60 days of completion of the test.

3.0 Storage Operations

Following the post-completion mechanical integrity test, the caverns will be tested on a periodic basis using methods and procedures in accordance with requirements set forth by the State of Utah.

Part I

Magnum Solution Mining, LLC

Millard County, Utah

Magnum Gas Storage Project

16-inch Injection Well Operation Plan and Procedures

Part I – 16-inch Injection Well Operation Plan and Procedures

The injection well operating plan and procedures is outlined within the report "Solution Mining Plans for Development of 16-inch Injection Wells at Delta, Utah" presented within Part G, and included within **Attachment G-1**. A Cavern Well Schematic is also shown in **Figure G-2.1**. The report generally defines the following operating criteria:

Average Daily Rate: [redacted] gpm

Maximum Daily Rate: [redacted] gpm

Volume of Fluid to be Injected:

[redacted]

Average Injection Pressure: [redacted] psi

Maximum Injection Pressure: [redacted] psi

The report included within **Attachment G-1** also includes information related to the mining methods and stages, tubing placements, testing, and information related to potential problems that could be associated with cavern creation.

Injected water will be obtained from local ground water sources within confined aquifers located generally at depths greater than [redacted] feet. Representative water quality data collected from exploratory well MH-1 within potential source zones was previously discussed in Part C of the original application and water quality data is provided within **Attachment C-1.2**. Because the source of water is a new source, no quality range data is available for the source. However, little variation is expected due to the limiting nature of the confined aquifer.

Part J

Magnum Solution Mining, LLC

Millard County, Utah

Magnum Gas Storage Project

16-inch Injection Well Monitoring, Recording, and Reporting Plan

Part J – 16-inch Injection Well UIC Monitoring, Recording, and Reporting Plan

1.0 REQUIREMENTS

Submit a monitoring, recording, and reporting plan, including maps, for meeting the monitoring and reporting requirements of R317-7-10.3(B), 40CFR146.33, 40CFR146.8, and R317-7-10(B). In the plan:

1. Identify types of tests, methods, and equipment used to generate monitoring data
2. Address the proper use, maintenance, and installation of monitoring equipment
3. Propose the type, intervals, and frequency sufficient to yield data that are representative of monitored activity.

2.0 PHYSICAL AND CHEMICAL CHARACTERISTICS OF INJECTED FLUID

The Magnum salt storage caverns will be solution mined using fresh water produced from water wells located on the Magnum facility. The salinity of the injected fluid will be measured, along with the fluid temperature on a daily basis. Specific gravity and temperature will be monitored using calibrated hydrometers and thermometers. Hydrometers will be calibrated and maintained in accordance with ASTM Al26-05a and thermometers will be calibrated and maintained in accordance with ASTM E77-07.

The data will be trended to ensure that no changes in the injected water take place during the duration of the solution mining operations.

3.0 MONITORING OF INJECTION PRESSURE AND FLOW

Injection pressures, injection flow rates, injection temperature, brine pressure, brine flow rate, brine temperature and the nitrogen blanket pressure will be monitored continuously by instrumentation in the control room. The information will be recorded at least once per day as a daily summary. The daily summary will be included in quarterly reports. This data will be used to calculate the growth of the cavern and provide a daily check on well integrity by ensuring that the water inflow and brine outflow balance. All the recorded data will be available to the State of Utah DWQ Executive Secretary upon request.

All pressure monitoring, temperature monitoring, and flow rate monitoring instrumentation calibration will be done in accordance with manufacturer recommendations.

4.0 DEMONSTRATION OF MECHANICAL INTEGRITY

Prior to initiating solution mining and at the completion of leaching, the cavern will be tested using the nitrogen mechanical integrity technique. The test pressure at the shoe of the 16-inch cemented casing will be slightly above (about 0.92 psi per foot of depth) the permitted operating pressure (0.90 psi per foot of depth) to ensure that the casing and cement are not leaking. The nitrogen mechanical integrity test technique essentially involves pressuring the cavern or well to the desired test pressure, and injecting nitrogen in the outer annulus of the well (the space between the cemented [redacted]-inch casing and the hanging [redacted]-inch tubing) to a depth 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 wire line 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 the test.

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 500 barrels per year of nitrogen.

Prior to the commencement of testing all pressure monitoring instruments will be calibrated in accordance with manufacturer's recommendations. Testing will be performed under the supervision of a degreed engineer and the report submitted to the Executive Secretary within 30 days of test completion.

Following the post-completion mechanical integrity test the caverns will be tested on a periodic basis using methods and procedures in accordance with requirements set forth by the State of Utah.

5.0 MONITORING OF CAVERN DEVELOPMENT

During solution mining of the caverns, the development of the cavern will be controlled by monitoring of the fluid injection and production quantities (Item 3.0 above) and periodic performance of sonar caliper surveys. The measured quantity of water injected and salinity of the produced brine will be used to calculate the daily increase in cavern volume. The sonar caliper surveys will be run at least once a year and at completion of mining in each cavern. The sonar survey will provide a check on the calculated cavern volume and the shape of the cavern.

6.0 MONITORING OF FLUID LEVEL IN FORMATION

This section is not applicable for solution mining wells since the well is full at all times.

7.0 QUARTERLY REPORTING ON MONITORING WELLS IN SUBSIDENCE ZONES

No monitoring wells are planned for the Magnum project. Subsidence will be monitored on an annual basis by Magnum and will be evaluated by a degreed engineer who is thoroughly experienced in subsidence of cavern storage facilities. Subsidence measurements will begin with a baseline survey that will be run prior to starting solution mining.

Subsidence surveys will be during operations of the facility. The subsidence report will be submitted to the Executive Secretary on an annual basis. Subsidence surveys will be conducted by measuring precise elevations of fixed points within the cavern field, the total Magnum facility and along public right-of-ways. The elevations of the points in and adjacent to the cavern field will be measured from a benchmark located at a distance from the facility that will not be impacted by any subsidence related to the caverns.

8.0 QUARTERLY REPORTING —EXECUTIVE SECRETARY

Daily summaries of water and brine pressures, temperatures, fluid volumes, and space created as well as the nitrogen blanket pressure will be reported to the Executive Secretary on a quarterly basis. Total volume of water injected and brine withdrawn from the storage cavern will be reported to the Executive Secretary on a quarterly basis.

Part K

Magnum Solution Mining, LLC

Millard County, Utah

Magnum Gas Storage Project

16-inch Injection Well Contingency Plan

Part K – 16-inch Injection Well UIC Contingency Plan

1.0 REQUIREMENTS

Magnum will submit a monitoring, recording, and reporting plan, including maps, for meeting the monitoring and reporting requirements of R317-7-10.3(B), 40CFR146.33, 40CFR146.8, and R317-7-10(B). The contingency plan is for measures to be taken in the event of a loss of cavern/well integrity. The plan has three main purposes:

- Identify the methods used to monitor well data
- Identify the monitoring equipment to be used
- Propose the actions to be taken in the event of a loss of cavern/well integrity.

2.0 MONITORING AND ACTIONS DURING WELL CONSTRUCTION

During drilling, the wells will be monitored continuously by observing fluid levels in the mud system. A loss of fluid level will indicate drilling mud is leaving the borehole. In this event, the appropriate measures will be taken to stop the lost circulation. These measures could include adding various substances to the drilling mud as it is pumped down the hole. These substances are generally inert materials such as cotton seed hulls, cellophane chips or bentonite gel that are designed to plug pores in the rock. If the fluid loss cannot be contained by conventional mud additives, it may be necessary to set a cement plug across the problem zone or set and cement a string of casing through the loss zone.

3.0 METHODS USED TO MONITOR WELL DATA DURING CAVERN DEVELOPMENT

The wells will be monitored during solution mining on a continuous basis. The well/cavern pressures will be collected continuously at the wellhead(s) and transmitted to a central control facility. Cavern flow rates and temperatures will be monitored by individual flow meters on the water and brine lines of each cavern. The pressure, temperature and flow data will be recorded on a regularly timed basis and stored.

4.0 MONITORING OF INJECTION PRESSURE AND FLOW

Well/Cavern water pressures (static or flowing), water flow rates, water temperature, brine pressure, brine flow rate, and brine temperature will be continuously monitored. Pressures will be measured using electronic pressure indicators. Flow rates will be measured with meters (ultrasonic or orifice type) capable of measurement in injection or withdrawal operations. All pressure monitoring, temperature monitoring, and flow rate monitoring instrumentation will be calibrated in accordance with manufacturer recommendations.

5.0 ACTION(S) TAKEN IN THE OF LOSS OF CAVERN/WELL INTEGRITY

If a loss of pressure integrity is indicated in a cavern/well, the system will be depressured to a point that will minimize the loss of nitrogen. This will preclude the flow of brine out of the Cavern/Well system and into the overlaying fresh water formations. This may necessitate reversing the direction of flow in the well to ensure that water fills the [redacted] inch annulus that is normally filled with nitrogen. Further testing and evaluation will then be undertaken to assess further actions with the approval of the State of Utah DWQ Executive Secretary.

In the event of a major loss of integrity in the cavern/well, mining will be stopped and the cavern depressured to a zero pressure at the wellhead. Further testing and evaluation will then be conducted with the approval of the Executive Secretary.

Part L

Magnum Solution Mining, LLC

Millard County, Utah

Magnum Gas Storage Project

16-inch Injection Well Plugging and Abandonment Plan

Part L – 16-inch Injection Well Plugging and Abandonment Plan

The following procedures are provided as a general guideline. Actual plugging measures will be submitted in advance to DWQ (prior to commencement of product storage) or DOGM (after commencement of storage operations) for approval.

1. Form DOGM-9 will be submitted (after commencement of product storage) for procedural approval.
2. All stored product will be removed and the cavern will be filled with saturated brine water.
3. All free hanging tubing will be pulled from the well.
4. The exact depth to the bottom of the cemented production casing will be determined.
5. 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.
6. 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.
7. The casing between each of the plugs shall be filled with a non-corrosive mud slurry of at least 10 pounds per gallon weight.
8. An alternative technique that could be used involves filling the entire wellbore with cement.
9. Upon completion of the plugging operation, all reports will be filed in accordance with DWQ or DOGM rules as applicable.

Attachment D

Magnum Solutions, LLC

Millard County, Utah

Magnum Gas Storage Project

Plan for Plugging and Abandonment of Class III Solution Mining Wells and Caverns before Gas Storage

Plan for Plugging and Abandonment of Class III Solution Mining Wells and Caverns before Gas Storage

The following procedures are provided as a general guideline. Actual plugging measures would be submitted in advance to DWQ (prior to commencement of gas storage).

1. At least 45 days before the planned plugging, Magnum will notify the DWQ Executive Secretary of the proposed plugging with a Well Condition Report and a well-specific Plugging and Abandonment Plan.
2. The Well Condition Report will include a discussion of the following:
    a. The results of the well's most recent mechanical integrity test,
    b. The location of any leaks or perforations in the casing,
    c. The location of any vertical migration of fluids behind the casing, and
    d. The adequacy of casing cement bonding across the salt formation, as determined from cement bond logs run at the time of well construction or just prior to well abandonment.
3. All nitrogen or other blanket material will be removed and the cavern will be filled with saturated brine water.
4. All free hanging tubing will be pulled from the well.
5. The exact depth to the bottom of the cemented production casing will be determined.
6. 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.
7. All cement plugs to be Class G cement with no additives and slurry weight of 14.5 pounds per gallon or more.
8. The entire wellbore from the bridge plug to surface will be filled with cement.
9. In the event the cemented casing is determined to be leaking, the casing will be perforated at the level of the leak and cement squeezed into the perforations.
10. An alternative technique which could be used involves setting the following plugs.
    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 50-foot plug from 50 feet below surface grade upward to surface.
    d. The casing between each of the plugs shall be filled with a noncorrosive mud slurry of at least 10 pounds per gallon weight.
11. Upon completion of the plugging operation, all reports will be filed in accordance with DWQ rules as applicable.

Part L – 16-inch Injection Well Plugging and Abandonment Plan

The following procedures are provided as a general guideline. Actual plugging measures will be submitted in advance to DWQ (prior to commencement of product storage) or DOGM (after commencement of storage operations) for approval.

1. Form DOGM-9 will be submitted (after commencement of product storage) for procedural approval.
2. All stored product will be removed and the cavern will be filled with saturated brine water.
3. All free hanging tubing will be pulled from the well.
4. The exact depth to the bottom of the cemented production casing will be determined.
5. 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.
6. 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.
7. The casing between each of the plugs shall be filled with a non-corrosive mud slurry of at least 10 pounds per gallon weight.
8. An alternative technique that could be used involves filling the entire wellbore with cement.
9. Upon completion of the plugging operation, all reports will be filed in accordance with DWQ or DOGM rules as applicable.

Attachment E

Magnum Solutions, LLC

Millard County, Utah

Magnum Gas Storage Project

Financial Assurance for Plugging and Abandonment

(original documents at Utah DNR DOGM)

FA will be submitted by Magnum according to permit compliance schedule Part III B 1

Attachment F

Magnum Solutions, LLC

Millard County, Utah

Magnum Gas Storage Project

Well Construction Plans

The blacked out portions of the wells construction plan are considered Confidential Business Information by the permit applicant.

Well construction details for the 16" wells and the natural gas liquid storage caverns are presented at the end of this attachment.

PUBLIC COPY

Well Construction Plan

The following is the general program to be used to drill Magnum Gas Storage Wells 1, 2, 3 and 4. Depths shown are approximate, from Rotary Kelly Bushing.

1. Rig up drilling rig.
2. Drive 48" conductor casing to approximately 200 feet or refusal.
3. Drill a 17-1/2" hole to [redacted] feet and log.
4. Open 17-1/2" hole up to [redacted] with hole openers of increasing size.
5. Run and cement [redacted] feet of [redacted] pipe. Centralizers to be placed every other casing section.
6. After the cement sets, cut off the [redacted] casing and weld on a [redacted] reducer and [redacted] flange. Nipple up a [redacted] annular BOP.
7. Drill a 17-1/2" hole to top of salt structure estimated to be ±[redacted] feet. Lost circulation may occur over this interval; control as necessary by the use of lost circulation material, cement plugs or drill without returns.
8. Run gamma ray, SP induction and resistivity logs as specified.
9. Open the 17-1/2" hole to [redacted] with hole openers and underreamers of increasing size.
10. Run X-Y caliper log.
11. Run and cement ±[redacted] or equivalent pipe to top of salt structure. Use the stab-in cementing method. Centralizers to be placed every other casing section.
12. After the cement sets, pressure test the casing in accordance with the approved MIT testing protocol.
13. Cut off the [redacted] casing and weld on a [redacted] reducer and [redacted] Nipple up a [redacted] annular BOP.
14. Switch to salt saturated mud after [redacted] casing is set at top of salt structure or at the depth where salt structure is encountered during drilling.
15. Drill a [redacted]
16. Run gamma ray, SP induction, neutron and bulk density logs as specified.
17. Open the [redacted] with hole openers and underreamers of increasing size.
18. Run X-Y caliper log.
19. Run and cement [redacted] section.
20. Allow the cement to set 72 hours. Pressure test the casing in accordance with the approved MIT testing protocol.
21. Cut off the [redacted] reducer and [redacted] flange. Nipple up a [redacted] annular BOP.
22. Drill a [redacted] feet.
23. Run gamma ray, SP induction, neutron and bulk density logs as specified.
24. Open the [redacted] using hole openers and underreamers.
25. Run X-Y caliper log.

26. Run and cement [redacted] pipe. Use the stab-in cementing method. Centralizers to be placed every other casing section.
27. Allow the cement to set 72 hours. Pressure test the casing in accordance with the approved MIT testing protocol.
28. Drill out plug and ten feet of salt formation.
29. Pressure test casing shoe in accordance with the approved MIT testing protocol.
30. Drill a [redacted] feet. Note: there are [redacted] cores that will be taken in this interval.
31. Log cuttings and check for loss of drilling fluid indicating a porous formation is encountered. If so, perform a tightness test over this interval.
32. Run gamma ray, neutron and bulk density logs as specified.
33. If logs indicate a porous zone in the salt section, perform tightness test over the zone.
34. Under ream the [redacted] feet.
35. Run X-Y caliper log.
36. Run casing inspection logs in [redacted] casing from shoe to surface.
37. Run in approx. [redacted] Casing.
38. Install and test the upper wellhead assembly.
39. Run in approx. [redacted] feet of [redacted]
40. Install remainder of wellhead.
41. Rig down and move out rig from location.
42. Clean up location.

CASING AND LIFT RING WELDING PROTOCOL

This specification describes the requirements for welding of lift rings on 20" last cemented casing, double jointing, and welding of the 20" last cemented casing. All work will be performed from a land rig located near Delta UT beginning in November 2010.

WELL REQUIREMENTS:

Casing to be welded consists of: [redacted] ft. Last Cemented Casing.

Provide all labor, equipment, and materials necessary to provide the following services:

<u>Welding of lift rings</u> to [redacted]' final cemented casing.
Weld one lift ring to each double joint of [redacted] casing, approximately 4' from one end. Allow a maximum gap of 1/16 inch between lift rings and the curvature of the pipe. Welding to take place well in advance of running the casing and shall therefore be

performed during daylight hours. Lift rings will be provided by PB ESS. See attached lift ring welding drawing.

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.

<u>Double Jointing</u> of [redacted]' casing.

Casing double joint welding shall be performed in accordance with API Standard 1104 Welding of Pipelines and Related Facilities, 2005 edition. 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 his beginning to weld. 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".

Double joint (pipe in horizontal position) approximately 3840' (96 jts) of 20" x 1.0" last cemented casing. The double jointing will take place well in advance of running the pipe, therefore, done during daylight hours.

Adequate pipe supports shall be used to support the pipe in a level "aligned" condition. All double-jointed casing lengths shall be examined and shall be as straight as possible.

Use alignment clamps to ensure proper alignment. Give special attention to ensure straightness is within 0.2 percent of the length or less than 1" of deviation in 40' length.

Check double-jointed casing lengths for straightness by using a taut string. Deviation from straight or chord height shall not exceed two inches. The taut string shall be run from the bottom end of the joint to the bottom side of the lift ring on the other end. The measurement is to be read adjacent to the double-joint weld bead. A series of readings shall be taken to find the maximum deviation. Any double-joint with more than two inches of deviation, shall have the weld cut out, beveled by machine (portable flame cutter or machine tool) and re-welded at the double-jointing contractors expense.

Welding of [redacted]' double joints while running casing.

Casing welding shall be performed in accordance with API Standard 1104 Welding of Pipelines and Related Facilities. Pipe base material's carbon equivalentcy 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 his beginning to weld. 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".

Weld double joints with pipe in vertical position from rig floor. Approximately 48 double joints to be welded. This welding will take place while running the casing to the design depth and will be a 24 hour per day operation.

Use alignment clamps to ensure proper alignment. Give special attention to ensure straightness is within 0.2 percent of the length.

SUBMITTALS

Submit the following "Submittals" to PB Energy Storage Services for review and approval:

Welding procedure specifications.

Welding procedure qualification records; submit prior to start of work.

Welder qualifications for each welder for each procedure the welder is to use.

CONDITIONS

Provide weather protection around welding areas to isolate welding from wind and rain. Do not weld in wet or excessively windy conditions that cannot be prevented.

Pipe ends that are field beveled or beveled by cutting torch shall be reported to the PB ESS representative.

SPECIFICATIONS FOR CEMENTING SERVICES AND MATERIALS

Provide all the labor, equipment, and materials necessary to provide the following services:

Proposed wellbore configuration

[redacted]

1. Cement specifications for the [redacted] Surface casing. Cement job will pumped through a stabbed-in 5" 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 ft3/sack
Excess	50% Open Hole Volume (4 Arm Caliper Available)

2. Cement specifications for the [redacted] Intermediate. Cement job will pumped through a stabbed-in 5" 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 ft3/sack
Excess	50% Open Hole Volume (4 Arm Caliper Available)

3. Cement specifications for the [redacted] Next to Last Casing. Cement job will pumped through a stabbed-in 5" DP.

Cement to surface: Class G (Premium) + [redacted] (if deemed necessary).

Water Ratio	5.2 gals/sk
Slurry Weight	16.3 lbs/gal.
Slurry Volume	1.24 ft3/sack
Excess	30% Open Hole Volume (4 Arm Caliper Available)

4. Cement specifications for the [redacted] Next to Last Casing. Cement job will pumped through a stabbed-in 5" DP.
   Cement to surface: Class G (Premium) + [redacted] (if deemed necessary).

Water Ratio	5.2 gals/sk
Slurry Weight	16.3 lbs/gal.
Slurry Volume	1.24 ft3/sack
Excess	30% Open Hole Volume (4 Arm Caliper Available)

REPORT

The casing cement jobs shall be documented by an affidavit from the cementing company showing the amount and type of cementing materials and the method of placement.

WELL CONDITIONING

Before commencing drilling operations (spudding the well), Magnum will provide detailed procedures for conditioning the hole prior to cementing casing. The pre-flush procedure will ensure that the wellbore is properly conditioned for cementing operations in accordance with recommendations from the cementing contractor.

The well is conditioned to circulate the drilling fluids, sweep cuttings out of the hole, obtain consistent fluid properties, and adjust the fluid viscosity and density in an attempt to prevent cement channeling through the fluid. Detailed procedures for this process have not been written at this time as it is a typical task during drilling, but when the drilling fluids contractor is hired his mud engineer will be tasked to write a program for the fluids.

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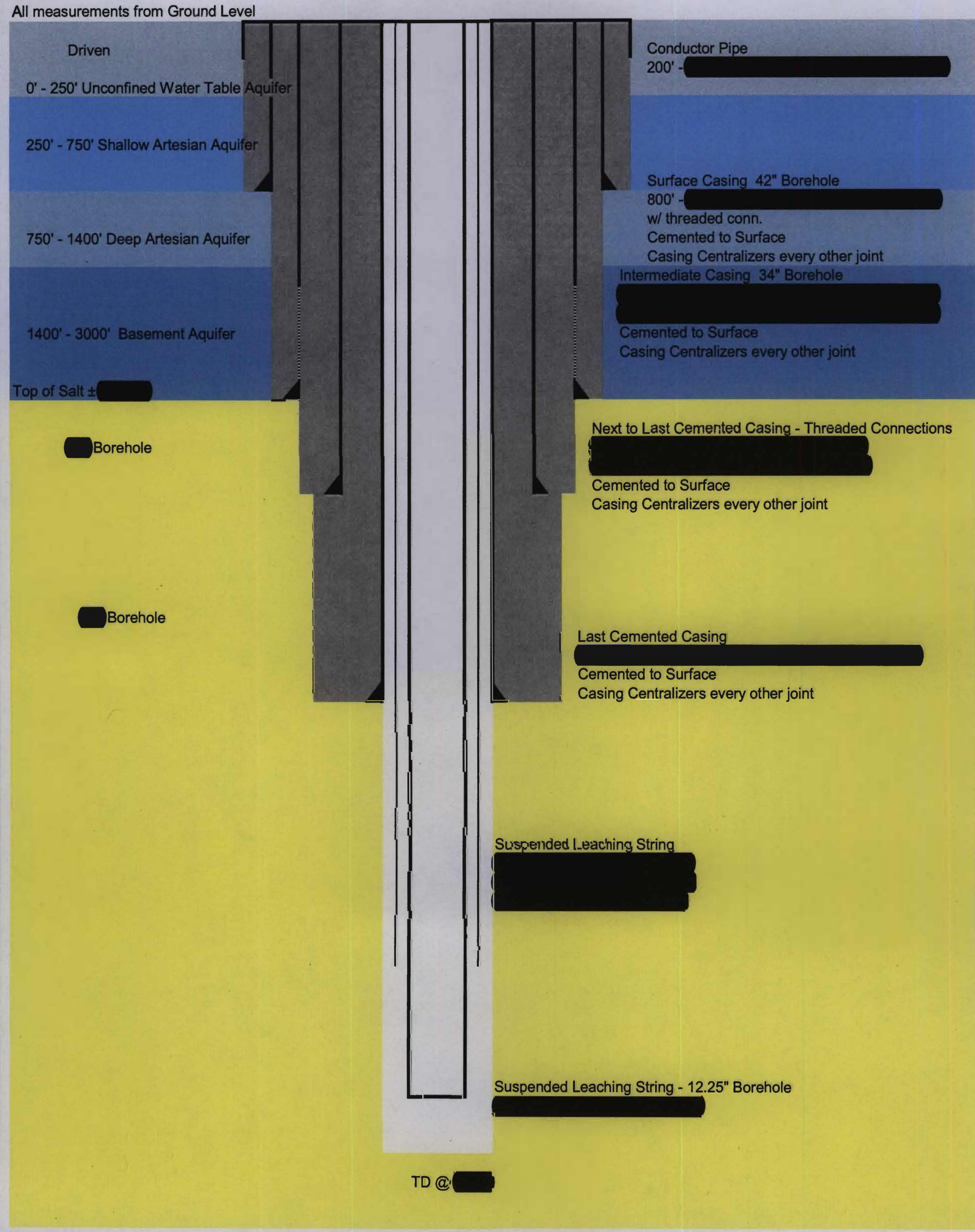

PB Energy Storage Services, Inc. — PB - ENERGY STORAGE SERVICES, INC.		Magnum		
Gas Storage Well Casing Design				
DRAWN: M Meece	Updated: D. Hansen	DATE: 10/10	SCALE: NONE	JOB NO. 50747

16-inch Injection Well Construction Plan

The following is the general program to be used to drill the Magnum 16-inch injection wells. Depths shown are approximate, **from Ground Level**.

1. Rig up drilling rig.
2. Drive 36-inch conductor casing to approximately 150 feet or refusal.
3. Drill a 17-1/2-inch hole to ±[redacted] feet and log.
4. Open 17-1/2-inch hole up to [redacted]-inch with hole openers of increasing size.
5. Run and cement [redacted] feet of [redacted]-inch O.D., [redacted]-inch wall thickness, [redacted] [redacted] Centralizers to be placed every other casing section.
6. Allow the cement to set a minimum of 18 hours. Pressure test the casing in accordance with State rules.
7. After the cement sets, cut off the [redacted]-inch casing and weld on a [redacted]-inch x [redacted]-inch reducer and [redacted]-inch flange. Nipple up a [redacted]-inch annular BOP.
8. Drill a 17-1/2-inch hole to slightly above top of salt structure estimated to be ± [redacted] feet. Lost circulation may occur over this interval; control as necessary by the use of lost circulation material, cement plugs or drill without returns.
9. Run gamma ray, SP induction and resistivity logs as specified.
10. Open the 17-1/2-inch hole to [redacted]-inch with hole openers of increasing size.
11. Run X-Y caliper log.
12. Run and cement ±[redacted] feet of [redacted]-inch O.D., 1-inch wall thickness, and [redacted] feet of [redacted]-inch O.D. [redacted]-inch wall thickness [redacted] or equivalent threaded and coupled pipe to top of salt structure. Use the stab-in cementing method. Centralizers to be placed every other casing section.
13. After the cement sets, pressure test the casing in accordance with State rules.
14. Cut off the [redacted]-inch casing and weld on a [redacted]-inch x [redacted]-inch reducer and [redacted]-[redacted]inch flange. Nipple up a [redacted]-inch annular BOP.
15. Switch to salt saturated mud after [redacted]-inch casing is set at top of salt structure or at the depth where salt structure is encountered during drilling.
16. Drill a 17-1/2-inch hole to ± [redacted] feet.
17. Run gamma ray, SP induction, neutron and bulk density logs as specified.
18. Open the 17-1/2-inch hole to [redacted]-inch with hole openers and under reamers of increasing size.
19. Run X-Y caliper log.
20. Run and cement [redacted] feet of [redacted]-inch O.D., [redacted]-inch wall thickness, [redacted] [redacted]- [redacted] and [redacted] feet of [redacted]-inch O.D. and [redacted]-inch wall thickness, [redacted] T&C threaded and coupled line pipe. Use the stab-in cementing method. Centralizers to be placed every other casing section.
21. Allow the cement to set a minimum of 72 hours. Pressure test the casing in accordance with State rules.

22. Cut off the [redacted]-inch casing and weld on a [redacted]-inch flange. Nipple up [redacted] annular BOP.
23. Drill a 17-1/2-inch hole to ±[redacted] feet.
24. Run gamma ray, SP induction, neutron and bulk density logs as specified.
25. Open the 17-1/2-inch hole up to [redacted]-inch using hole openers and underreamers.
26. Run X-Y caliper log.
27. Run and cement [redacted] feet of [redacted]-inch O.D. [redacted]-inch and [redacted]feet of [redacted]-inch O.D. [redacted]-inch wall thickness, API [redacted] casing. Use the stab-in cementing method. Centralizers to be placed every other casing section.
28. Allow the cement to set a minimum of 72 hours. Pressure test the casing in accordance with State rules.
29. Drill out plug and ten feet of salt formation.
30. Pressure test casing shoe in accordance with the State rules and regulations.
31. Drill a [redacted]-inch hole to ±[redacted] feet.
32. Log cuttings and check for loss of drilling fluid indicating a porous formation is encountered. If so, perform a tightness test over this interval.
33. Run gamma ray, neutron and bulk density logs as specified.
34. If logs indicate a porous zone in the salt section, perform tightness test over the zone.
35. Under ream the [redacted]-inch hole to [redacted]-inch down to a depth of [redacted] feet.
36. Run X-Y caliper log.
37. Run casing inspection and cement bond logs in [redacted]nch casing from shoe to surface.
38. Run in approx. [redacted]&C Casing.
39. Install and test the upper wellhead assembly.
40. Run in approx. [redacted]0 feet of [redacted]-inch, [redacted]b/ft, [redacted]Casing.
41. Install remainder of wellhead.
42. Rig down and move out rig from location.
43. Clean up location.

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".

SPECIFICATIONS FOR CEMENTING SERVICES AND MATERIALS

This specification covers the requirements to supply cement, equipment and services for storage wells located near Delta, UT. The work will be conducted from a land rig. Cement bond logs cannot be used with reliability on the [redacted]-inch plus well casings proposed for the gas storage wells and therefore will not be run on the larger casings. A review of cement bonding capabilities with PB Energy Storage Systems has confirmed that there are no test methods currently available to conduct a bond log. Therefore, cementing operations will be visually verified at the time of cementing via the observance of cement rising within the outer well annulus to the surface.

Proposed wellbore configuration (Depths RKB)

[redacted]-inch Conductor Pipe: 0 - Approx. 150 feet (Driven to refusal)

[redacted]-inch Surface Casing: [redacted] feet (Approx. [redacted]-inch Open Hole)

[redacted]-inch Intermediate Casing: [redacted] feet (Approx. [redacted]-inch Open Hole)

[redacted]inch Next to Last Casing: [redacted] feet (Approx. [redacted]-inch Open Hole)

[redacted]-inch Last Cemented Casing: [redacted] feet (Approx. [redacted]-inch Open Hole)

Top of Salt: Approx. [redacted] feet

1. Cement specifications for the [redacted]-inch Surface casing. Cement job will be pumped through a stabbed-in 5-inch 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 (4 Arm Caliper Available)

2. Cement specifications for the [redacted]-inch Intermediate. Cement job will be pumped through a stabbed-in 5-inch 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 (4 Arm Caliper Available)

3. Cement specifications for the [redacted]-inch Next to Last Casing. Cement job will be pumped through a stabbed-in 5-inch DP.
   Cement to surface: Class G (Premium) + 37.2% Salt + Defoamer (if deemed 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 (4 Arm Caliper Available)

4. Cement specifications for the [redacted]-inch Last Casing. Cement job will be pumped through a stabbed-in 5-inch DP.
   Cement to surface: Class G (Premium) + 37.2% Salt + Defoamer (if deemed 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 (4 Arm Caliper Available)

WELL CONDITIONING

Before commencing drilling operations (spudding the well), Magnum will provide detailed procedures for conditioning the hole prior to cementing casing. The pre-flush procedure will ensure that the wellbore is properly conditioned for cementing operations in accordance with recommendations from the cementing contractor.

The well is conditioned to circulate the drilling fluids, sweep cuttings out of the hole, obtain consistent fluid properties, and adjust the fluid viscosity and density in an attempt to prevent cement channeling through the fluid. Detailed procedures for this process have not been written at this time as it is a typical task during drilling, but when the drilling fluids contractor is hired his mud engineer will be tasked to write a program for the fluids.

REPORT

During Drilling the casing cement jobs shall 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 intermediate and salt casings shall be collected in suitable sized and shaped containers so that the hardened cement can be tested for compressive strength.

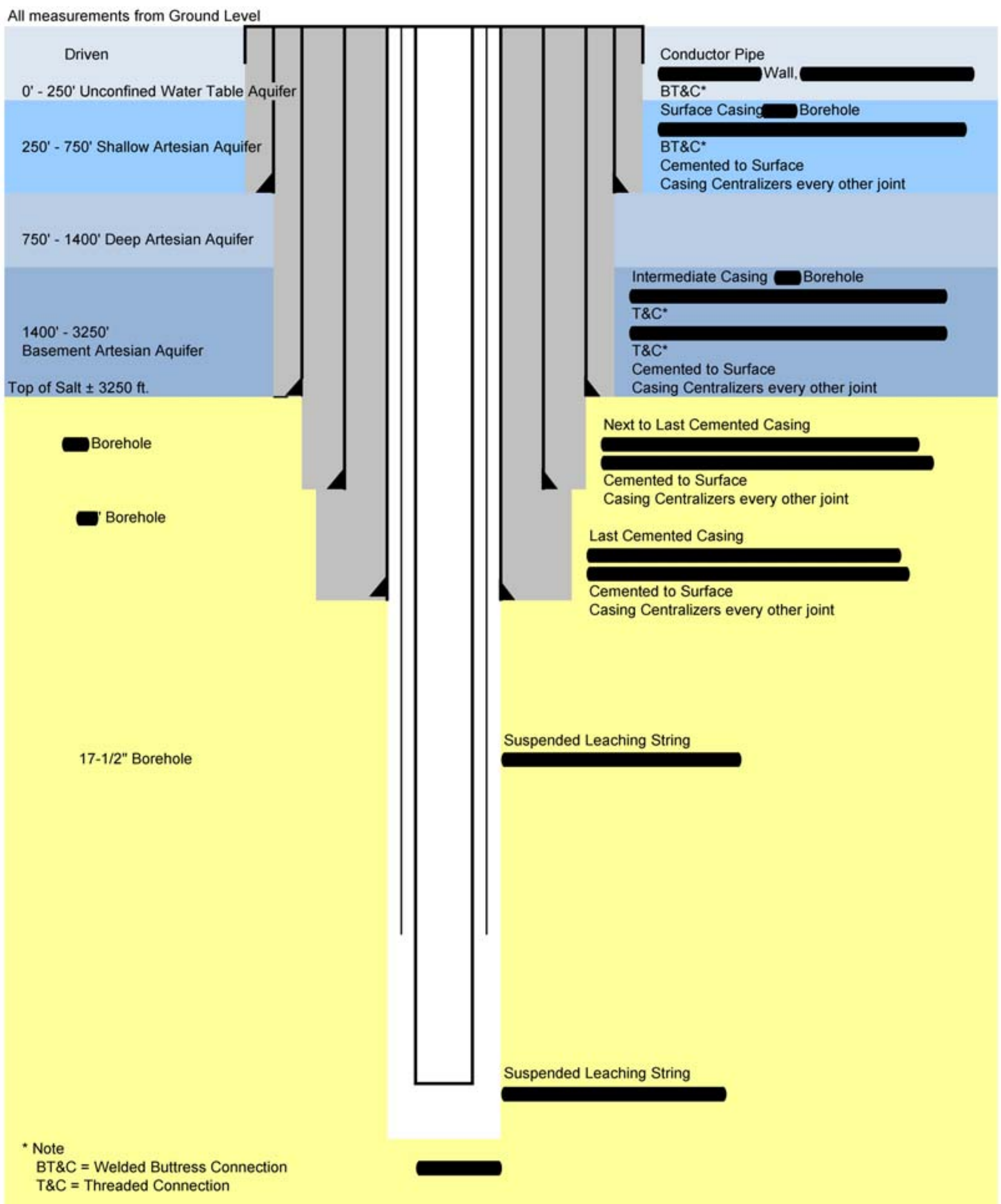

Figure G-2.1

Natural Gas Liquids Storage Well Casing Design

DRAWN: T. Eyermann	DATE: 9/18/11	SCALE: NONE

Attachment G

Magnum Solutions, LLC

Millard County, Utah

Magnum Gas Storage Project

Monitoring Protocols
Mechanical Integrity Testing (MIT)
Protocol

The Magnum Solution Mining, LLC facilities manager will prepare check lists and accompanying documentation to ensure consistency in performance of all monitoring required by this permit. These documents will be maintained on site and will be reviewed by DWQ staff during the annual facility inspection

MIT and Monitoring Protocols for the 16" wells are presented at the end of this attachment.

Mechanical Integrity Test Plan

Several testing methods shall be employed to demonstrate mechanical integrity of the well/cavern system. These methods vary depending upon the stage of development of the well or cavern.

During Drilling

After cementing the 20” production casing, the casing will be tested before continuing drilling. A hydraulic pressure test of the 20" production casing will be conducted before drilling out the plug (shoe) and after waiting on cement at least 72 hours to allow the cement to set. The operator shall test the casing at a pump pressure in pounds per square inch (psi) calculated by multiplying the length of the casing by 0.2. The maximum pressure required however, unless otherwise ordered by the commission need not exceed 1500 psi (Texas Rule 3.13 (b)(1)(D)). This rule would require a surface pressure of 800 psi. Although this is less than maximum allowable operating pressure at the casing shoe, it is high enough to detect a leak in the casing. The test shall last 30 minutes. The test will be considered good if the pressure loss is less than 10%.

After drilling out the cement plug and completing the hole, the integrity test as outlined hereafter will verify the casing/cement shoe/borehole at maximum operating pressure.

Test of the 20" Casing and the Cavern during Development

Magnum Solutions LLC will utilize the guidelines for Mechanical Integrity Testing used by the State of Kansas as attached hereto. Any changes to the testing procedure will be coordinated and discussed, with the regulatory agency and approval obtained prior to implementation.

Storage Operations

Following the mechanical integrity test after completion of mining the caverns will be tested on a periodic basis using methods and procedures in accordance with requirements set forth by the State of Utah.

Reply to: (785) 296-7254 FAX (785) 296-5509
Bureau of Water - Geology Section
1000 S. W. Jackson, Ste. 420
Topeka, KS 66612-1367

KANSAS DEPARTMENT OF HEALTH & ENVIRONMENT

NITROGEN/BRINE INTERFACE MECHANICAL INTEGRITY TEST (MIT)
PART I: CASING (INTERNAL) MIT
PART II: CAVERN (EXTERNAL) MIT

Procedure #: UICLPG-20
(6/06)

Narrative:

K.A.R. 28-45-16 requires that each well and each cavern be tested for integrity every five years. 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 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
NITROGEN/BRINE INTERFACE MECHANICAL INTEGRITY TEST (MIT)
PART I: CASING (INTERNAL) MIT
PART II: CAVERN (EXTERNAL) MIT

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 any supporting data required by KDHE may result in the test being considered invalid by KDHE. An invalid test will not meet the regulatory requirement.

Submit a test plan as specified in Procedure #UICLPG-21 to KDHE 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 Kansas Department of Health and Environment (KDHE).

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 (feasible) from the cavern prior to conducting the test.
- Note the presence of any product in the annulus.
- Coordinate the test time with KDHE so that KDHE may have the opportunity to witness the test.

PRE-PRESSURIZATION: (Typically for cavern test)

Prepressure 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 regulatory MAOP of either 0.75 or 0.8 psi/ft. K.A.R. 28-45-12 requires that a wellhead be equipped with a continuous pressure monitoring system that is capable of maintaining a pressure history before the well can be operated with a MAOP greater than 0.75 psi/ft. The well should be tested at the MAOP allowed by regulation.
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. 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 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.

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

T = Duration of test in hours
V = Unit annular volume of casing, bbls/ft
R = Resolution of the interface tool in feet
Note: reference programs or tables and show calculations for converting weight or volume (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, relog 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):

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

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)

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

CNLR = Calculated nitrogen leak rate
T = test duration, 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 test finish (psia)
CNLR (bbls/yr) = CNLR (bbls/day) * 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 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).

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

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):

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

CNLR = Calculated nitrogen leak rate
T = test duration, days
VS = nitrogen volume at test start (bbls)
VF = nitrogen volume at test finish (bbls)
PS = nitrogen pressure at the test finish (psia)
PF = nitrogen pressure at test start (psia)
CNLR (bbls/yr) = CNLR (bbls/day) * 365 days/year

<u>References:</u>

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

Reply to: (785) 296-7254 FAX (785) 296-5509
Bureau of Water - Geology Section
1000 S. W. Jackson, Ste. 420
Topeka, KS 66612-1367

KANSAS DEPARTMENT OF HEALTH & ENVIRONMENT

NITROGEN/BRINE INTERFACE TEST PLAN

Procedure #: UICLPG-21
(6/06)

Narrative:

K.A.R. 28-45-16 requires that each well and each cavern be tested for integrity. Each cavern with a single casing must be tested for integrity every five years. Each cavern with double casing protection must be tested every ten years. The nitrogen/brine interface test is designed to evaluate the integrity of the underground hydrocarbon storage well and/or cavern.

Submit a test plan to KDHE for review and approval at least 30 days prior to test commencement. Use the following format. Do not alter the 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 and test pressures:	Formulas and calculations:	
Proposed changes to FIELD PROCEDURE (UICLPG-22):		
TEST DESIGN:	Casing test and/or Cavern test (Circle)	
Estimate nitrogen for cool down:	Interval Depth:	Test Duration:
	1.	
Estimate compressibility:	2.	
Estimate nitrogen volume for test:	3	
	4.	

Submit the final report in the format specified in Procedure # UICLPG-23 to KDHE within 45 days after completion of the test.

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KANSAS DEPARTMENT OF HEALTH & ENVIRONMENT

FIELD PROCEDURE REPORT
NITROGEN/BRINE INTERFACE TEST

Procedure #: UICLPG-22
(6/06)

Narrative:

The following field procedure for the nitrogen/brine interface test must be completed and submitted with the final report (Procedure #UICLPG-23). Do not alter the format.

Type of MIT:	**Well Casing**	**Cavern**	**Casing/Cavern**
Facility:		**Well:**	

TEST PREPARATION	**Date/time:**
Wellhead inspection results: external corrosion, faulty valves, gasket leaks, etc)	
Removal of product **Date:**	
Check wellhead, piping, and connection for leaks. Describe results.	

PRE-PRESSURIZATION **Date/time:**				
Brine pressure		**Product pressure**		
Cavern compressibility:				
Cavern pressure change < 10 psi/day				
PRE-NITROGEN INJECTION				
Nitrogen cool down volume				
Base temperature log from surface to 50 ft below expected interface	**Date/time:**		**Temperature (F):**	
Base 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)		

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PART 1: 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		
	N 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		
	N 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		
	N 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 2: 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:	
K.A.R. 28-45-16 requires that a licensed professional engineer or licensed geologist, or a licensed professional engineer's or licensed geologist's designee supervise all test procedures and associated field activity.	
Supervised by: (Print name)	
Company/Title:	
Signature:	Date:

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Reply to: (785) 296-7254 FAX (785) 296-5509
Bureau of Water - Geology Section
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KANSAS DEPARTMENT OF HEALTH & ENVIRONMENT

FINAL REPORT
NITROGEN/BRINE INTERFACE TEST

Procedure #: UICLPG-23
(6/06)

Narrative:

Submit the final report in the format specified to KDHE within 45 days after completion of the nitrogen/brine interface test. Do not alter this format.

Test Results	
Show formula and calculation for MDLR:	Compare MDLR and NLR:
Show formula and calculation for 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 (UICLPG-22)
Submit all required logs.
Submit supporting data, including graphs for stabilization, temperatures, pressures, injection, etc. Submit appropriate charts.
Submit calibration charts for gauges and meters.

K.A.R. 28-45-16 requires that a licensed professional engineer or licensed geologist review all test results.

Submit the final report to KDHE within 45 days after completion of the test.

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ATTACHMENT J - UIC MONITORING, RECORDING AND REPORTING PLAN

1.0 REQUIREMENTS

Submit a monitoring, recording, and reporting plan, including maps, for meeting the monitoring and reporting requirements of R317-7-10.3(B), 40CFR146.33, 40CFR146.8, and R317-7-10(B). In the plan

- Identify types of tests, methods, and equipment used to generate monitoring data
- Address the proper use, maintenance, and installation of monitoring equipment
- Propose the type, intervals, and frequency sufficient to yield data that are representative of monitored activity.

2.0 PHYSICAL AND CHEMICAL CHARACTERISTICS OF INJECTED FLUID

The Magnum Wells will be solution mined using fresh water produced from water wells located on the Magnum facility. The salinity of the injected fluid will be measured, along with the fluid temperature on a daily basis. Specific gravity and temperature will be monitored using calibrated hydrometers and thermometers. Hydrometers will be calibrated and maintained in accordance with ASTM Al26-05a and thermometers will be calibrated and maintained in accordance with ASTM E77-07.

The data will be trended to ensure that no changes in the injected water take place during the duration of the solution mining operations.

3.0 MONITORING OF INJECTION PRESSURE AND FLOW

Injection pressures, injection flow rates, injection temperature, brine pressure, brine flow rate, brine temperature and the nitrogen blanket pressure will be monitored continuously by instrumentation in the control room. The information will be recorded at least once per day as a daily summary. The daily summary will be included in quarterly reports. This data will be used to calculate the growth of the cavern and provide a daily check on well integrity by ensuring that the water inflow and brine outflow balance. All the recorded data will be available to the Executive Secretary upon request.

All pressure monitoring, temperature monitoring, and flow rate monitoring instrumentation calibration will be done in accordance with manufacturer recommendations.

4.0 DEMONSTRATION OF MECHANICAL INTEGRITY

Prior to initiating solution mining and at the completion of leaching, the cavern will be tested using the nitrogen mechanical integrity technique. The test pressure at the shoe of the [redacted] cemented casing will be slightly above (about 0.92 psi per foot of depth) the permitted operating pressure (0.90 psi per foot of depth) to ensure that the casing and cement are not leaking. The nitrogen mechanical integrity test technique essentially involves pressuring the cavern or well to the desired test pressure, and injecting nitrogen in the outer annulus of the well (the space between the cemented [redacted] casing and the hanging [redacted] tubing) to a depth 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 then 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 the test.

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 100 barrels per year of nitrogen.

All pressure monitoring instruments will be calibrated in accordance with manufacturer's recommendations. Testing will be performed under the supervision of a degreed engineer and the report submitted to the Executive Secretary within 30 days of test completion.

Following the mechanical integrity test after completion of mining the caverns will be tested on a periodic basis using methods and procedures in accordance with requirements set forth by the State of Utah.

5.0 MONITORING OF CAVERN DEVELOPMENT

During solution mining of the caverns, the development of the cavern will be controlled by monitoring of the fluid injection and production quantities (Item 3.0 above) and periodic performance of sonar caliper surveys. The measured quantity of water injected and salinity of the produced brine will be used to calculate the daily increase in cavern volume. The sonar caliper surveys will be run at least once a year and at completion of mining in each cavern. The sonar survey will provide a check on the calculated cavern volume and the shape of the cavern.

6.0 MONITORING OF FLUID LEVEL IN FORMATION

This section is not applicable for solution mining wells since the well is full at all times. 7.0 QUARTERLY REPORTING ON MONITORING WELLS IN SUBSIDENCE ZONES

No monitoring wells are planned for the Magnum project.

Subsidence will be monitored on an annual basis by Magnum and will be evaluated by a degreed engineer who is thoroughly experienced in subsidence of cavern storage facilities. Subsidence measurements will begin with a baseline survey that will be run prior to starting solution mining. Subsidence surveys will be conducted throughout the life of the facility. The subsidence report will be submitted to the Executive Secretary on an annual basis.

Subsidence surveys will be conducted by measuring precise elevations of fixed points within the cavern field, the total Magnum facility and along public right-of-ways. The elevations of the points in and adjacent to the cavern field will be measured from a benchmark located at a distance from the facility that will not be impacted by any subsidence related to the caverns.

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8.0 QUARTERLY REPORTING — EXECUTIVE SECRETARY

Daily summaries of water and brine pressures, temperatures, fluid volumes, and space created as well as the nitrogen blanket pressure will be reported to the Executive Secretary on a quarterly basis. Total volume of water injected and brine withdrawn from the storage cavern will be reported to the Executive Secretary on a quarterly basis.

Part J

Magnum Solution Mining, LLC

Millard County, Utah

Magnum Gas Storage Project

16-inch Injection Well Monitoring, Recording, and Reporting Plan

Part J – 16-inch Injection Well UIC Monitoring, Recording, and Reporting Plan

1.0 REQUIREMENTS

Submit a monitoring, recording, and reporting plan, including maps, for meeting the monitoring and reporting requirements of R317-7-10.3(B), 40CFR146.33, 40CFR146.8, and R317-7-10(B). In the plan:

1. Identify types of tests, methods, and equipment used to generate monitoring data
2. Address the proper use, maintenance, and installation of monitoring equipment
3. Propose the type, intervals, and frequency sufficient to yield data that are representative of monitored activity.

2.0 PHYSICAL AND CHEMICAL CHARACTERISTICS OF INJECTED FLUID

The Magnum salt storage caverns will be solution mined using fresh water produced from water wells located on the Magnum facility. The salinity of the injected fluid will be measured, along with the fluid temperature on a daily basis. Specific gravity and temperature will be monitored using calibrated hydrometers and thermometers. Hydrometers will be calibrated and maintained in accordance with ASTM AI26-05a and thermometers will be calibrated and maintained in accordance with ASTM E77-07.

The data will be trended to ensure that no changes in the injected water take place during the duration of the solution mining operations.

3.0 MONITORING OF INJECTION PRESSURE AND FLOW

Injection pressures, injection flow rates, injection temperature, brine pressure, brine flow rate, brine temperature and the nitrogen blanket pressure will be monitored continuously by instrumentation in the control room. The information will be recorded at least once per day as a daily summary. The daily summary will be included in quarterly reports. This data will be used to calculate the growth of the cavern and provide a daily check on well integrity by ensuring that the water inflow and brine outflow balance. All the recorded data will be available to the State of Utah DWQ Executive Secretary upon request.

All pressure monitoring, temperature monitoring, and flow rate monitoring instrumentation calibration will be done in accordance with manufacturer recommendations.

4.0 DEMONSTRATION OF MECHANICAL INTEGRITY

Prior to initiating solution mining and at the completion of leaching, the cavern will be tested using the nitrogen mechanical integrity technique. The test pressure at the shoe of the 16-inch cemented casing will be slightly above (about 0.92 psi per foot of depth) the permitted operating pressure (0.90 psi per foot of depth) to ensure that the casing and cement are not leaking. The nitrogen mechanical integrity test technique essentially involves pressuring the cavern or well to the desired test pressure, and injecting nitrogen in the outer annulus of the well (the space between the cemented [redacted]-inch casing and the hanging 16-inch tubing) to a depth about [redacted] 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 wire line 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 the test.

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 500 barrels per year of nitrogen.

Prior to the commencement of testing all pressure monitoring instruments will be calibrated in accordance with manufacturer's recommendations. Testing will be performed under the supervision of a degreed engineer and the report submitted to the Executive Secretary within 30 days of test completion.

Following the post-completion mechanical integrity test the caverns will be tested on a periodic basis using methods and procedures in accordance with requirements set forth by the State of Utah.

5.0 MONITORING OF CAVERN DEVELOPMENT

During solution mining of the caverns, the development of the cavern will be controlled by monitoring of the fluid injection and production quantities (Item 3.0 above) and periodic performance of sonar caliper surveys. The measured quantity of water injected and salinity of the produced brine will be used to calculate the daily increase in cavern volume. The sonar caliper surveys will be run at least once a year and at completion of mining in each cavern. The sonar survey will provide a check on the calculated cavern volume and the shape of the cavern.

6.0 MONITORING OF FLUID LEVEL IN FORMATION

This section is not applicable for solution mining wells since the well is full at all times.

7.0 QUARTERLY REPORTING ON MONITORING WELLS IN SUBSIDENCE ZONES

No monitoring wells are planned for the Magnum project. Subsidence will be monitored on an annual basis by Magnum and will be evaluated by a degreed engineer who is thoroughly experienced in subsidence of cavern storage facilities. Subsidence measurements will begin with a baseline survey that will be run prior to starting solution mining.

Subsidence surveys will be during operations of the facility. The subsidence report will be submitted to the Executive Secretary on an annual basis. Subsidence surveys will be conducted by measuring precise elevations of fixed points within the cavern field, the total Magnum facility and along public right-of-ways. The elevations of the points in and adjacent to the cavern field will be measured from a benchmark located at a distance from the facility that will not be impacted by any subsidence related to the caverns.

8.0 QUARTERLY REPORTING —EXECUTIVE SECRETARY

Daily summaries of water and brine pressures, temperatures, fluid volumes, and space created as well as the nitrogen blanket pressure will be reported to the Executive Secretary on a quarterly basis. Total volume of water injected and brine withdrawn from the storage cavern will be reported to the Executive Secretary on a quarterly basis.

Attachment H

Magnum Solutions, LLC

Millard County, Utah

Magnum Gas Storage Project

Reporting Tables

Table of Reporting and Notification Requirements for Well Construction

Utah UIC Permit Number: UTU-27-AP-9232389; Magnum Solution Mining, LLC

Triggering Event	Time Frame	Permittee Response	Utah DWQ Response
Claims of Confidential Business Information	At the time of submittal	Stamp the words "Confidential Business Information" on each page of submittal	Written Approval/Response
Permittee becomes aware that he failed to submit any relevant facts or submitted incorrect information in any report to the Executive Secretary.	Within 10 days after permittee becomes aware of the event	Submit such facts or information. Submittal must be signed and certified in accordance with UAC R317-7-9.3 (40 CFR 144.32).	Written Acknowledgement of Receipt and Response, if Appropriate
Completion of Well Construction	Within 60 days after the completion of well construction	Submit an "As-Constructed" Well Report signed and certified in accordance with UAC R317-7-9.3 (40 CFR 144.32)..	Written Acknowledgement of Receipt and Response, if Appropriate (Check for deviations from the approved plan.)
	Within 90 days after the completion of well construction	Submit modified Plan for Abandonment of Class III Wells to include plans for well and a reliable cost estimate to P&A well based on current well condition. Plan must be signed and certified in accordance with UAC R317-7-9.3 (40 CFR 144.32).	Require amendment to Financial Assurance when contingency is exceeded.
Any spill, leak or noncompliance of a permit condition that may endanger human health or the environment.	Within 24 hours after the permittee becomes aware of the event	Orally report to Executive Secretary or representative at **801-536-4387 (during normal business hours) or at 801-536-4123 (for reporting at all other times)**	Oral Response and Reminder of Written Report
	Within 5 days after the permittee becomes aware of the event	Submit written report including description of the spill, leak or noncompliance and its cause, exact dates and times, steps taken to mitigate the effects, and steps taken or planned to prevent a re-occurrence. If a leak or noncompliance is ongoing, the submission shall indicate the anticipated time it is expected to continue. Report must be signed and certified in accordance with UAC R317-7-9.3 (40 CFR 144.32).	Written Acknowledgement of Receipt and Response, if Appropriate
Commencement of injection into new well	After receiving written approval from DWQ to commence injection.	Permittee has fulfilled all applicable conditions of this permit pertaining to new injection wells of the permit	Written Approval to commence injection

Table of Reporting and Notification Requirements for Plugging and Abandonment

Utah UIC Permit Number: UTU-27-AP-9232389; Magnum Solution Mining, LLC

Triggering Event	Time Frame	Permittee Response	Utah DWQ Response
Claims of Confidential Business Information	At the time of submittal	Stamp the words "Confidential Business Information" on each page of submittal	Written Approval/Response
Any spill, leak or noncompliance of a permit condition that may endanger human health or the environment.	Within 24 hours after the permittee becomes aware of the event	Orally report to Executive Secretary or representative at **801-536-4387 (during normal business hours) or at 801-536-4123 (for reporting at all other times)**.	Oral Response and Reminder of Written Report
	Within 5 days after the permittee becomes aware of the event	Submit written report including description of the spill, leak or noncompliance and its cause, exact dates and times, steps taken to mitigate the effects, and steps taken or planned to prevent a re-occurrence. If a leak or noncompliance is ongoing, the submission shall indicate the anticipated time it is expected to continue. Report must be signed and certified in accordance with UAC R317-7-9.3 (40 CFR 144.32).	Written Acknowledgement of Receipt and Response, if Appropriate
Permittee becomes aware that he failed to submit any relevant facts or submitted incorrect information in any report to the Executive Secretary.	Within 10 days after permittee becomes aware of the event	Submit such facts or information. Submittal must be signed and certified in accordance with UAC R317-7-9.3 (40 CFR 144.32).	Written Acknowledgement of Receipt and Response, if Appropriate
Plugging and Abandonment of Injection Well	No less than 45 days prior to the planned conversion or abandonment of the well	Submit written notice of intent to plug and abandon to DWQ including Well Condition Report with supporting documentation and individual plugging and abandonment plans. Well Condition Report must be signed and certified in accordance with UAC R317-7-9.3 (40 CFR 144.32).	Written Approval/Response
	Within 60 days after completion of the plugging and abandonment of the well.	Submit a Plugging and Abandonment ("As-Plugged") Report to DWQ including the certification of accuracy and statement of compliance with approved P&A plan or statement justifying deviation from approved P&A plan. As-Plugged Report must be signed and certified in accordance with UAC R317-7-9.3 (40 CFR 144.32).	Written Acknowledgement of Receipt and Response, if Appropriate

Table of Reporting and Notification Requirements for Plugging and Abandonment

Utah UIC Permit Number: UTU-27-AP-9232389; Magnum Solution Mining, LLC

Triggering Event	Time Frame	Permittee Response	Utah DWQ Response
Emergency Well Conversion or Plugging and Abandonment	No less than 24 hours before the emergency action	Orally report to Executive Secretary or representative at **801-536-4387 (during normal business hours) or at 801-536-4123 (for reporting at all other times)**.	Oral Approval/Response
	Within 5 days after receiving oral approval from DEQ	Submit a written request for approval of emergency action including justification. Submittal must be must be signed and certified in accordance with UAC R317-7-9.3 (40 CFR 144.32).	Written Approval/Response
	Within 60 days after completion of the emergency action	Submit a Plugging and Abandonment ("As-Plugged") Report to DWQ including the certification of accuracy and statement of compliance with approved P&A plan or statement justifying deviation from approved P&A plan. As-Plugged Report must be signed and certified in accordance with UAC R317-7-9.3 (40 CFR 144.32).	Written Acknowledgement of Receipt and Response, if Appropriate
Inactive Wells - Cessation of injection activities for 2 years	After 2 years of inactivity	Plug and abandon the injection well unless a variance has been requested and received before the end of the 2 year period	Written Response to Request for Variance
	At the end of the second. Fourth, sixth, etc. year of this permit	Review and evaluate inactive wells to ensure compliance with conditions for allowing inactive wells to remain unplugged. Submit Inactive/Temporarily Abandoned Well Evaluation Report to DWQ signed and certified in accordance with UAC R317-7-9.3 (40 CFR 144.32).	Written Acknowledgement of Receipt and Response, if Appropriate
Reactivation of Inactive Well	No less than 45 days prior to the planned reactivation of an inactive well	Submit written notice of intent to reactivate well to DWQ and demonstrate mechanical integrity of the well in accordance with Part III (H) of this permit.	Written Approval/Response
Temporary Abandonment/Plugging	No less than 45 days prior to the planned temporary abandonment of the well	Submit written notice of intent to temporarily abandon to DWQ including Well Condition Report with supporting documentation and individual temporary plugging plans. Well Condition Report must be signed and certified in accordance with UAC R317-7-9.3 (40 CFR 144.32).	Written Approval

Table of Reporting and Notification Requirements for Plugging and Abandonment

Utah UIC Permit Number: UTU-27-AP-9232389; Magnum Solution Mining, LLC

Triggering Event	Time Frame	Permittee Response	Utah DWQ Response
	Within 60 days after completion of the temporary abandonment of the well	Submit a Plugging and Abandonment ("As-Plugged") Report to DWQ including the certification of accuracy and statement of compliance with approved P&A plan or statement justifying deviation from approved P&A plan. As-Plugged Report must be signed and certified in accordance with UAC R317-7-9.3 (40 CFR 144.32).	Written Acknowledgement of Receipt and Response, if Appropriate
	At the end of the second,fourth, sixth, etc. year of this permit	Review and evaluate temporarily abandoned wells to ensure compliance with conditions for allowing wells to remain temporarily abandoned. Submit Inactive/Temporarily Abandoned Well Evaluation Report to DWQ signed and certified in accordance with UAC R317-7-9.3 (40 CFR 144.32).	Written Acknowledgement of Receipt and Response, if Appropriate
Reactivation of Temporarily Abandoned Well	No less than 45 days prior to the planned reactivation of a temporarily abandoned well.	Submit written notice of intent to reactivate well to DWQ and demonstrate mechanical integrity of the well in accordance with Part III (H) of this permit.	Written Approval/Response

Table of Reporting and Notification Requirements for Mechanical Integrity Testing (MIT)

Utah UIC Permit Number: UTU-27-AP-9232389; Magnum Solution Mining, LLC

Triggering Event	Time Frame	Permittee Response	Utah DWQ Response
Claims of Confidential Business Information	At the time of submittal	Stamp the words "Confidential Business Information" on each page of submittal	Written Approval
Permittee becomes aware that he failed to submit any relevant facts or submitted incorrect information in any report to the Executive Secretary.	Within 10 days after permittee becomes aware of the event	Submit such facts or information. Submittal must be signed and certified in accordance with UAC R317-7-9.3 (40 CFR 144.32).	
Placing of a new well into operation	Prior to well operation	Demonstration/documentation of MIT	Written Approval
Loss of Mechanical Integrity	Immediately	Cease operation immediately	
	Immediately	Take steps to prevent losses of brine through the leaks caused by high hydrostatic head or pressure	
	Within 15 days after loss of mechanical integrity.	Submit to the Executive Secretary a schedule indicating what will be done to restore mechanical integrity to the well, or if it will be plugged.	Written Acknowledgement of Receipt and Response, if Appropriate
	Within 90 days after loss of mechanical integrity	Restore mechanical integrity to the well, or plug and abandon the well in accordance with a plugging and abandonment plan approved by the Executive Secretary.	Written Approval
Loss of Mechanical Integrity which may potentially endanger an USDW and/or Any spill, leak or noncompliance of a permit condition that may endanger human health or the environment.	Within 24 hour s after the permittee becomes aware of the event	Orally report to Executive Secretary or representative at **801-536-4387 (during normal business hours) or at 801-536-4123 (for reporting at all other times)**.	Oral Response and Reminder of Written Report
	Within 5 days after the permittee becomes aware of the event	Submit written report including description of the spill, leak or noncompliance and its cause, exact dates and times, steps taken to mitigate the effects, and steps taken or planned to prevent a re-occurrence. If a leak or noncompliance is ongoing, the submission shall indicate the anticipated time it is expected to continue. Report must be signed and certified in accordance with UAC R317-7-9.3 (40 CFR 144.32).	Written Acknowledgement of Receipt and Response, if Appropriate

Table of Reporting and Notification Requirements for Mechanical Integrity Testing (MIT)

Utah UIC Permit Number: UTU-27-AP-9232389; Magnum Solution Mining, LLC

Triggering Event	Time Frame	Permittee Response	Utah DWQ Response
MIT Frequency	Every 5 years	Test for casing leaks and vertical flow behind casing according to Part III H of the permit	Written Acknowledgement of Receipt and Response, if Appropriate
	Prior to new well operation	Prior to placing a new well into operation	Written Acknowledgement of Receipt and Response, if Appropriate
	Prior to well operation	Following any repair or workover of a well	Written Acknowledgement of Receipt and Response, if Appropriate
MIT Requests	At any time		The Executive Secretary may require an MIT
MIT Inspections	No less than 30 days prior to MIT	Notify DWQ of intent to perform MIT	Written Acknowledgement of Receipt and Response, if Appropriate
MIT Reporting	Within 60 days after completion of MIT	Submit results of MIT.	Written Acknowledgement of Receipt and Response, if Appropriate

Table of Reporting and Notification Requirements for Other Permit Activities

Utah UIC Permit Number: UTU-27-AP-9232389; Magnum Solution Mining, LLC

Triggering Event	Time Frame	Permittee Response	Utah DWQ Response
Operator Change of Address	No less than 15 days prior to the effective date of the event	Submit written notice to the Executive Secretary	Not Applicable
Claims of Confidential Business Information	At the time of submittal	Stamp the words "Confidential Business Information" on each page of submittal	Written Approval
Planned physical alterations or additions to the UIC permitted facilities	No less than 30 days prior to implementing the event	Submit written notice to the Executive Secretary	Written Approval
Any spill, leak or noncompliance of a permit condition that may endanger human health or the environment.	Within 24 hours after the permittee becomes aware of the event	Orally report to Executive Secretary or representative at **801-536-4387 (during normal business hours) or at 801-536-4123 (for reporting at all other times)**.	Oral Response and Reminder of Written Report
	Within 5 days after the permittee becomes aware of the event	Submit written report including description of the spill, leak or noncompliance and its cause, exact dates and times, steps taken to mitigate the effects, and steps taken or planned to prevent a re-occurrence. If a leak or noncompliance is ongoing, the submission shall indicate the anticipated time it is expected to continue.	Written Acknowledgement of Receipt and Response, if Appropriate
Receipt of this permit	Within 30 days after receipt of this permit	Report to the Executive Secretary that the person(s) designated to implement the requirements of this permit has read and is personally familiar with all terms and conditions of this permit	Not Required
Permittee becomes aware that he failed to submit any relevant facts in the permit application or submitted incorrect information in a permit application or in any report to the Executive Secretary.	Within 10 days after permittee becomes aware of the event.	Submit such facts or information. Submittal must be signed and certified in accordance with UAC R317-7-9.3 (40 CFR 144.32).	Written Acknowledgement of Receipt and Response, if Appropriate
Cessation of injection activities	after 2 years of inactivity	Plug and abandon the injection well unless a variance has been obtained prior to the end of the 2 year period	
Anticipated Noncompliance	As soon as the permittee becomes aware of the event	Give advance notice of any planned change in the permitted facility or activity that may result in a noncompliance with permit requirements.	Written Acknowledgement of Receipt and Response, if Appropriate

Table of Reporting and Notification Requirements for Other Permit Activities

Utah UIC Permit Number: UTU-27-AP-9232389; Magnum Solution Mining, LLC

Triggering Event	Time Frame	Permittee Response	Utah DWQ Response
Endangering Noncompliance	Within 24 hours after permittee becomes aware of event	Provide oral report of any monitoring data or other information, noncompliance with a permit condition, malfunction of injection system which may cause endangerment to USDW; also report annual mine cavity brine level tests that show three consecutive drops in brine level.	Oral Response and Reminder of Written Report
	Within 5 days after permittee becomes aware of event	Submit written report describing the endangering noncompliance; its cause; the period of noncompliance, including the exact time and dates; whether or not it has been corrected; the anticipated time it is expected to continue; and steps taken or planned to reduce, eliminate, and prevent a recurrence of the noncompliance.	Written Acknowledgement of Receipt and Response, if Appropriate
Other Noncompliance	Next Quarterly Monitoring Report	Submit written report describing the noncompliance; its cause; the period of noncompliance, including the exact time and dates; whether or not it has been corrected; the anticipated time it is expected to continue; and steps taken or planned to reduce, eliminate, and prevent a recurrence of the noncompliance.	Written Acknowledgement of Receipt and Response, if Appropriate
Quarterly Monitoring Reports	1st Qtr (Jan thru March) – April 15 2nd Qtr (April thru June) – July 15 3rd Qtr (July thru Sept) – October 15 4th Qtr (Oct thru December) – January 15	Quarterly reports shall include: 1. Monthly Wash Reports 2. Injectate Characterization 3. MIT Reports 4. Sonar Survey Reports 5. Report of Nitrogen/Brine Interface 6. Report of Tightness Tests 7. Report of Geophysical Logging and Testing of Wells 8. Other Reports not otherwise submitted according to permit requirements 9. Report of NonEndangering NonCompliance	Written Acknowledgement of Receipt and Response, if Appropriate
Renewal of Financial Responsibility		Demonstrate the adequacy of the financial assurance to close, plug and abandon all wells not permanently plugged and abandoned by the permittee in compliance with this permit.	Written Acknowledgement of Receipt and Response, if Appropriate

Table of Reporting and Notification Requirements for Other Permit Activities

Utah UIC Permit Number: UTU-27-AP-9232389; Magnum Solution Mining, LLC

Triggering Event	Time Frame	Permittee Response	Utah DWQ Response
Insolvency of Financial Institution	Within 60 days after either 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 instrument is suspended or revoked.	Submit an alternate demonstration of financial responsibility acceptable to the Executive Secretary	Written Acknowledgement of Receipt and Response, if Appropriate
Upward fluid migration through well bore of any previously unknown or improperly plugged or unplugged well	Immediately upon permittee becoming aware of the event	Cease injection until proper plugging of the well can be performed.	Written Acknowledgement of Receipt and Response, if Appropriate
Submittal of Reports		All reports or other information, submitted as required by this permit or requested by the Executive Secretary, shall be signed and certified in accordance with UAC R317-7-9.3 (40 CFR 144.32).	