Ohio Environmental Protection Agency

DIVISION OF DRINKING AND GROUND WATERS

UNDERGROUND INJECTION CONTROL PERMIT TO OPERATE: CLASS I NON-HAZARDOUS WELL

Ohio Permit No.:	UIC 04-16-017-PTO-I
Date of Issuance:	
Effective Date:	
Date of Expiration:	
Name of Applicant:	Buckeye Brine, LLC
Facility Location:	23986 Airport Road Coshocton Ohio 43812
Mailing Address:	2630 Exposition BLVD, Suite 117 Austin, Texas 78703
County:	Coshocton
Township:	Keene
Well Number:	Adams #1
Well Location:	40°18'4.3524" N/-81°50'54.387" W
Total Depth:	7270 feet below ground level (BGL) to Mt. Simon. Ground level elevation 763 feet above sea level.
Injection Interval:	Gull River to the Mt. Simon from 5898 to 7270 feet (BGL)
Containment Interval:	Trenton to Gull River from 5210 to 5898 feet (BGL)
Injection Zone:	Gull River to Mt. Simon, from 5860 to 7270 feet (BGL)
Confining Zone:	Trenton from 5210 to 5860 feet (BGL)

Pursuant to the Underground Injection Control rules of the Ohio Environmental Protection Agency codified at Chapter 3745-34 of the Ohio Administrative Code (OAC), the applicant (Permittee) indicated above is hereby authorized to operate a Class I non-Hazardous injection well at the above location upon the express conditions that the permittee meet the restrictions set forth herein.

All references to Chapter 3745-34 of the OAC are to all rules that are in effect on the date that this permit is effective. The following attachments are incorporated into this permit: A, B, C, D, E.

This permit shall become effective on ________________ and shall remain in full force and effect during the life of the permit, unless the Agency promulgates rules pursuant to these sections which withdraw or otherwise condition the authorization in this permit, or this permit is otherwise revoked, terminated, modified or reissued pursuant to OAC Rules 3745-34-23 and 3745-34-24. Nothing in this permit shall be construed to relieve the permittee of any duties under applicable state and federal law or regulations. This permit and the authorization to inject shall expire at midnight, unless terminated, on the date of expiration indicated.

____
Anne M. Vogel, Director
Ohio Environmental Protection Agency

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PART I
GENERAL PERMIT COMPLIANCE

A. EFFECT OF PERMIT

The permittee is authorized to engage in the operation of underground injection in accordance with the conditions of this permit. Notwithstanding any other provisions of this permit, the permittee authorized by this permit shall not construct, operate, maintain, convert, plug, abandon, or conduct any other activity in a manner that allows the movement of fluids into underground sources of drinking water (USDW). Any underground injection activity not specifically authorized in this permit is prohibited. Compliance with this permit during its term constitutes compliance for purposes of enforcement, with Sections 6111.043 and 6111.044 of the Ohio Revised Code (ORC). Such compliance does not constitute a defense to any action brought under ORC Sections 6109.31, 6109.32 or 6109.33 or any other common or statutory law other than ORC Sections 6111.043 and 6111.044. Issuance of this permit does not convey property rights of any sort or any exclusive privilege; nor does it authorize any injury to persons or property, any invasion or other private rights, or any infringement of state or local law.

This permit does not relieve the permittee of its obligation to comply with any additional regulations or requirements under the Resource Conservation and Recovery Act (RCRA) as amended or Chapter 3734 of the ORC and rules promulgated thereunder. This permit does not authorize any above ground generating, handling, storage, treatment or disposal facilities. Such activities must receive separate authorization under regulations promulgated pursuant to Chapter 3745 of the Revised Code and Part C of the federal RCRA.

B. PERMIT ACTIONS

1. <u>Modification, Revocation, Reissuance and Termination.</u> The Director may, for cause or upon request from the permittee, modify, revoke, and reissue, or terminate this permit in accordance with Ohio Administrative Code (OAC) Rules 3745-34-07, 3745-34-23, and 3745-34-24, and 3745-34-26. Also, the permit is subject to minor modifications for cause as specified in OAC Rule 3745-34-25. The filing of a request for a permit modification, revocation and reissuance, or termination, or the notification of planned changes, or anticipated non-compliance on the part of the permittee does not stay the applicability or enforceability of any permit condition.

2. <u>Transfer of Permits.</u> This permit may be transferred to a new owner or operator only if it is modified or revoked and reissued pursuant to OAC 3745-34-22(A), 3745-34-23, or 3745-34-25(D) as applicable.

C. SEVERABILITY

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

D. CONFIDENTIALITY

In accordance with 40 CFR Part 2 and OAC Rule 3745-34-03, any information obtained by the Ohio EPA 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 Ohio EPA may make the information available to the public without further notice. It a claim is asserted, documentation for the claim must be tendered and the validity of the claim will be assessed in accordance with the procedures in OAC Rule 3745-34-03. If the documentation for the claim of confidentiality is not received, the Ohio EPA may deny the claim without further inquiry. Claims of confidentiality for the following information will be denied.

1. The name and address of the permittee; and

2. Information which deals with the existence, absence or level of contaminants at the permitted facility.

E. DUTIES AND REQUIREMENTS

1. <u>Duty to Comply.</u> The permittee shall comply with all applicable UIC regulations and conditions of this permit, except to the extent and for the duration such non-compliance is authorized by an emergency permit issued in accordance with OAC Rule 3745-34-19. The permittee shall take all reasonable steps to minimize or correct any adverse impact on the environment resulting from implementation of or noncompliance with this permit. Any permit noncompliance constitutes a violation of ORC Chapter 6109 or 6111 and is grounds for enforcement action, permit termination, revocation and reissuance, or modification. Such non-compliance may also be grounds for enforcement action under other applicable state and federal law.

2. <u>Penalties for Violations of Permit Conditions.</u> Any person who violates a permit requirement is subject to injunctive relief, civil penalties, fines, and/or other enforcement action under ORC Chapter 6111, 6109 or 3734. Any person who knowingly or recklessly violates permit conditions may be subject to criminal prosecution.

3. <u>Continuation of Expiring Permits.</u>
   a. Duty to Reapply. If the permittee wishes to continue an activity regulated by this permit after the expiration date of this permit, the permittee must submit a complete application for a new permit at least 180 days before this

permit expires.

b. Permit Extensions. The condition of an expired permit shall continue in force in accordance with ORC Section 119.06 until the effective date of a new permit, if:

   i. The permittee has submitted a timely and complete application for a new permit; and
   ii. The Director has not acted on said application.

c. Enforcement. When the permittee is not in compliance with the conditions of the expiring or expired permit the Director may:

   i. Initiate enforcement action based upon the permit which has been continued;
   ii. Issue a notice of intent to deny the new permit. If a final action becomes effective to deny the permit, the owner or operator shall immediately cease operation of the well or be subject to enforcement action for operation of a Class I injection well without a permit;
   iii. Issue a new permit under ORC Section 6111.044 with appropriate conditions; or
   iv. Take other actions authorized by underground injection control regulations set forth in OAC Chapter 3745-34 or any other applicable regulation or laws.

4. <u>Need to Halt or Reduce Activity Not a Defense.</u> 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 or any order issued by the Director or a court of appropriate jurisdiction.

5. <u>Duty to Mitigate.</u> The permittee shall take all reasonable steps to minimize or correct any adverse impact on the environment resulting from noncompliance with this permit. This may include accelerated or additional monitoring or testing or both. If such is performed, the data collected shall be submitted to Ohio EPA in a written report within sixty (60) days of the collection of the data unless an alternate timeline is approved by Ohio EPA.

6. <u>Proper Operation and Maintenance.</u> 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. The permittee shall document staff training related to the operation of Class I injection wells including the type of training, the staff who were trained the date the training occurred and

how the training assists in compliance with the permit and rule requirements. This training documentation shall be submitted to Ohio EPA, which may be done during an onsite inspection, annually on or by December 1 and made available upon request.

7. Duty to Provide Information. The permittee shall furnish to the Director, within a time specified, any information which the Director may request to determine whether cause exists for renewing, modifying, revoking and reissuing, or terminating this permit. To determine compliance with this permit, or to issue a new permit the permittee also shall furnish to the Director, upon request, copies of records required to be kept by this permit or applicable state or federal law.

8. Inspection and Entry. The permittee shall allow the Director, or an authorized representative, upon the presentation of credentials and other documents as may be required by law to:
   a. Enter permittee's premises where a regulated facility or activity is located or conducted, or where records are kept under the conditions of this permit;
   b. Have access to and copy, at reasonable times, any records that are kept under the conditions of this permit;
   c. Inspect, including photographing, at reasonable times any facilities, equipment (including monitoring and control equipment), activity, 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 ORC Chapter 6111 and OAC Chapter 3745-34, any substances or parameters at any location.

9. Records.
   a. The permittee shall retain copies of records of all monitoring information, including all calibration and maintenance records and all original recordings for continuous monitoring instrumentation and copies of all reports required by this permit for a period of at least three (3) years from the date of the sample, measurement or report. This period may be extended by request of the Director.
   b. The permittee shall maintain copies of records of all data required to complete the permit application form for this permit and any supplemental information submitted under OAC Rules 3745-34-12, 3745-34-13, and 3745-34-15 for a period of at least three (3) years from the date the application was submitted. This period may be extended by request of the Director.
   c. The permittee shall retain copies of records concerning the nature and composition of all injected fluids pursuant to Part I (E)(10) and Part II (D)(1) of this permit until three (3) years after the completion of well closure which has been carried out in accordance with the approved closure plan, and consistent with OAC 3745-34-61 (F)(5).
   d. Records of monitoring information shall include:

      i. The date, exact place, and time of sampling or measurements;
      ii. The name(s) of the individual(s) who performed the sampling or measurements;

iii. A precise description of both sampling methodology and the handling and custody of samples;
iv. The date(s) analyses or measurements were performed;
v. The name(s) of the individual(s) who performed the analyses or measurements and the laboratory that performed the analyses or measurements;
vi. The analytical techniques or methods used; and
vii. All results of such analyses.

10. Monitoring. Samples of injected fluids and measurements taken for the purpose of monitoring shall be representative of the monitored activity. Monitoring results shall be reported monthly in accordance with OAC Rule 3745-34-38 in a format acceptable to the Director and as set forth in paragraph 12 below.

    a. Monitoring the nature of injected fluids shall comply with the applicable analytical methods cited and described in Table I of 40 CFR 136.3 or in Appendix III of 40 CFR Part 261 or (in certain circumstances) by other methods that have been approved by the Administrator of U.S. EPA, or by the Director.
    b. The monitoring information shall include conditions of quality assurance for each type of measurement required for reporting by the operator. Reference to established, published criteria shall be made wherever possible.
    c. Sampling and analysis shall comply with the specifications of the Waste Analysis Plan required in Part II (D)(3) of this permit and OAC Rule 3745-34-57.

11. Signatory Requirements. All applications, reports or other information, required to be submitted by this permit, requested by the Director or submitted to the Director, shall be signed and certified in accordance with OAC Rule 3745-34-17.

12. Reporting Requirements.

    a. Planned Changes. The permittee shall give written notice to the Director, as soon as possible, of any planned physical alterations or additions to the permitted facility. Replacement of equipment that is equivalent to existing equipment is not included in this requirement.
    b. Anticipated Noncompliance. The permittee shall give advance notice to the Director of any planned changes in the permitted facility or activity which may result in noncompliance with permit requirements. Written notice shall include discussion of the changes or activity to occur, the time frame it is expected to occur, the nature of the suspected noncompliance, and planned back-up readings, if applicable. Submittal of notice of noncompliance does not stay the applicability of any permit requirement.
    c. Compliance Schedules. Reports of compliance or noncompliance with, or any progress reports on, interim and final requirements contained in any compliance schedule of this permit shall be submitted in writing no later than thirty (30) days following each schedule date.
    d. Twenty-four (24) Hour Reporting.

i. The permittee shall report to the Director any noncompliance which may endanger health or the environment. All available information shall be provided orally within 24 hours from the time the permittee becomes aware of such noncompliance. The following events shall be reported orally within 24 hours:

1. Any monitoring or other information which indicates that any contaminant may cause an endangerment to an underground source of drinking water; or
2. Any noncompliance with a permit condition, or malfunction of the injection system, which may cause fluid migration into or between underground sources of drinking water; or
3. Any failure to maintain mechanical integrity of the well as defined by OAC Rule 3745-34-34.

ii. A written submission also shall be provided within five (5) business days of the time the permittee becomes aware of instances of noncompliance identified in paragraph 12 (d) (i) above. The written submission shall contain a description of the noncompliance and its cause; the period of noncompliance, including exact dates and times, the anticipated time it is expected to continue; whether the noncompliance has or has not been corrected and steps taken or planned to reduce, eliminate and prevent recurrence of the noncompliance.

e. Other Noncompliance. The permittee shall report all other instances of noncompliance not otherwise reported at the time monitoring reports are submitted. The reports shall contain the information listed in permit condition 12 (d) (ii) above.

f. Other Information. When the permittee becomes aware of failure to submit any relevant facts in the permit application or that incorrect information was submitted in a permit application or in any report to the Director, the permittee shall submit such facts and corrected information in writing within ten (10) days or unless specified otherwise by the Director.

g. Monthly reports specified in OAC Rule 3745-34-38 shall be submitted by the fifteenth day of the following month. Quarterly reports shall be submitted in accordance with Part II (E) of this permit.

h. Within thirty (30) days of receipt of this permit, the person designated as responsible for submission of reports pursuant to OAC Rule 3745-34-17 shall certify to the Director that he or she has read and is personally familiar with all terms and conditions of this permit. The Director shall be notified immediately, in writing, if the designee or position is changed.

F. CLOSURE (OAC RULES 3745-34-36 AND 3745-34-60)

1. Closure Plan. A plan for closure of the well that includes the assurance of financial responsibility and information shall be approved by the Director. A plan for closure of the well is included as Attachment C of this permit and shall be referenced in regards to this permit and the permit to operate conditions. The implementation of an approved closure plan is a condition of this permit; however, the permittee must receive the approval of the Director to proceed before implementing this plan. The permittee shall maintain and comply with this plan and all applicable closure requirements, in accordance with OAC Rule 3745-34-60. The obligation to implement this Closure Plan survives the termination of this permit of the cessation of injection activities.

2. Revision of Closure Plan. Any revisions to the Closure Plan shall be approved by the Director. The permittee shall submit a revised Closure Plan for approval by the Director with the notice of intent to close per Part I (F)(3) of this permit, unless a shorter period is approved by the Director.

3. Notice of Intent to Close. The permittee shall notify the Director of its intent to close an injection well at least sixty (60) calendar days before closure of the well, unless a shorter notice period is approved by the Director.

4. Temporary Disuse. A permittee who wishes to cease injection for longer than twenty-four (24) months may keep the well open only if the permittee:

   a. Has received written authorization from the Director; and
   b. Has submitted a plan to the Director, for approval, that the owner or operator will follow to ensure that the well will not endanger USDWs during the period of temporary disuse. These actions and procedures shall include compliance with the technical requirements applicable to active injection wells unless waived by the Director. The owner or operator of a Class I injection well that has ceased operations for more than two (2) years shall notify the Director at least thirty (30) days prior to resuming operation of the well.

5. Closure Report. The permittee shall submit a closure report to the Director within the time frame established in OAC Rule 3745-34-60(C). The report shall be certified as accurate by the permittee and by the person who performed the closure operation (if other than the owner or operator). Such report shall consist of either:

   a. A statement that the well was closed in accordance with the most recently Director's approved Closure and Post Closure Plan of this permit; or
   b. Where actual closure differed from the most recently Director's approved Closure and Post Closure Plan of his permit, a written statement specifying the differences between the most recently Director's approved Closure and Post Closure Plan and the actual closure.

6. Standards for Well Closure. As documented in the Closure Plan required by Part

I (F)(1) of this permit, prior to closing the well, the permittee shall:

a. Observe and record the pressure decay for a time and by a method specified by the Director and report this information to the Director;
b. Conduct appropriate mechanical integrity and other testing of the well to ensure the integrity of that portion of the long string casing and cement that will be left in the ground after closure. Testing methods may include but are not limited to:

   i. Pressure tests with liquid or gas;
   ii. Radioactive tracer survey;
   iii. Temperature log;
   iv. Casing inspection log;
   v. Cement bond log; and
   vi. Any other test required by the Director.

c. Flush the well with a suitable buffer fluid.

7. Financial Responsibility for Closure. The owner or operator shall comply with closure financial assurance requirements of OAC 3745-34-36(D) and OAC Rule 3745-34-62. The obligation to maintain financial responsibility for closure survives the termination of this permit or cessation of injection.

G. POST CLOSURE CARE (OAC RULE 3745-34-61)

1. Post-Closure Plan. Post-closure activities shall be documented in the approved Closure Plan required per Part I (F)(1) of this permit. The obligation to implement an approved post-closure plan will be part of the administrative record of this permit and the permittee shall maintain and comply with this plan as if it were fully set forth herein. The obligation to maintain, implement, and comply with the post-closure plan survives the termination of this permit or the cessation of injection activities.

   The post-closure activities documented in the approved closure plan shall include the following information:

   a. The pressure in the injection zone before injection began;
   b. The anticipated pressure in the injection zone at the time of closure;
   c. The predicted time until pressure in the injection zone decays to the point that the well's cone of influence no longer intersects the potentiometric surface of the lowermost USDW;
   d. Predicted position of the waste front at closure;
   e. The status of any corrective action for wells in the area of review;
   f. The estimated cost of proposed post-closure care; and
   g. An assurance of financial responsibility as required by OAC Rule 3745-34-62.

2. Post-Closure Corrective Action. The permittee shall continue and complete any corrective action required under OAC Rules 3745-34-30 and 3745-34-53.

3. Duration of Post-Closure Period. The permittee shall continue post-closure maintenance and monitoring of any ground water monitoring wells and seismic monitoring instrumentation required under this permit for at least one (1) year and until pressure in the injection zone decays to the point that the well's cone of influence no longer intersects the potentiometric surface of the lowermost USDW, as identified in the administrative record for this permit. The Director may modify these requirements if a demonstration is made that the formation pressure will not decrease below the potentiometric surface of the lowermost USDW due to the injection into Class I well or Class VI injection well at a nearby property where the injection well is not controlled by the permittee. The Director may extend the period of the post-closure monitoring upon a finding that ending the post-closure period could allow the endangerment of a USDW.

4. Survey Plat. The permittee shall submit a current plat map to the local zoning authority upon plugging the well in accordance with the approved closure plan required in Part I (F) of this permit. The plat map shall indicate the location of the well relative to permanently surveyed benchmarks. A copy of the plat map shall be submitted to the Director.

5. Notification to State and Local Authority. The permittee shall provide appropriate notification and information to the Ohio Department of Natural Resources - Division of Mineral Resources Management, the Coshocton County Health Department, and any other State of local authority designated by the Director upon plugging the well in accordance with the approved closure plan required in Part I (F) of this permit.

6. The Retention of Records. The permittee shall retain, for a period of three (3) years following well closure, records reflecting the nature, composition and volume of all injected fluids. The records shall be delivered to the Director at the end of the retention period.

7. Notice of Deed to Property. Upon plugging the well in accordance with the approved closure plan required in Part I (F) of this permit, the permittee must record a notation on the deed to the facility property, or on some other instrument which is normally examined during title search, that will in perpetuity provide any potential purchaser of the property with the following information:

   a. The fact that land has been used to manage and dispose non-hazardous waste(s) in deep wells;
   b. The name(s) of the state agencies or local authorities with which the plat map was filed; and
   c. The type and volume of waste injected, the injection interval into which it was injected, and the period over which injection occurred.

8. Financial Responsibility for Post-Closure Care. The permittee shall submit as part of the Closure Plan required by Part I (F)(1) of this permit, a demonstration of financial responsibility for post-closure care, as required by OAC 3745-34-27(B)(7) and OAC Rule 3745-34-62. Any required updates of the financial assurance

documentation in the approved Closure Plan will not require approval from the Director as long as the updates are in compliance with OAC 3745-34-27(B)(7) and OAC Rule 3745-34-62. The owner of operator shall comply with the post-closure financial assurance requirements of the OAC Rule 3745-34-62. The obligation to maintain financial responsibility for post-closure care survives the termination of this permit or the cessation of injection.

H. MECHANICAL INTEGRITY (OAC RULE 3745-34-34)

1. Standards. Each injection well shall maintain mechanical integrity as defined by OAC Rule 3745-34-34. The Director or his or her authorized representative shall be present during the test for demonstration of mechanical integrity, unless the Director or his or her authorized representative waives this requirement before the test occurs. In accordance with OAC 3745-34-56(D), the owner or operator of a Class I injection well shall maintain mechanical integrity of the injection well at all times.

2. Periodic Mechanical Integrity Testing [OAC Rule 3745-34-57]. Unless otherwise approved by the Director, the permittee shall conduct the mechanical integrity testing as follows:

   a. Long string casing, injection tubing and annular seal shall be tested by means of an approved pressure test in accordance with OAC 3745-34-57(I)(1) within thirty (30) days of the anniversary date of the last field approved demonstration, and whenever there has been a well workover in which tubing is removed from the well, the packer is reset, or when loss of mechanical integrity becomes suspected during operation;
   b. The bottom hole cement shall be tested by means of an approved radioactive tracer survey in accordance with OAC 3745-34-57(I)(2) within thirty (30) days of the anniversary date of the last field approved demonstration;
   c. An approved temperature, noise or other approved log shall be run in accordance with OAC 3745-34-57(I)(3) within thirty (30) days of the three (3) year anniversary date of the last approved field demonstration to test for movement of fluid along the bore hole. The Director may require such tests whenever the well is worked over;
   d. An approved casing inspection log shall be run for the entire length of the long string casing in accordance with OAC 3745-34-57(I)(4) whenever the owner or operator conducts a workover in which the injection string is pulled, unless the Director waives this requirement due to well construction or other factors which limit the test's reliability or based upon the satisfactory results of a casing inspection log run within the previous five (5) years, if he or she has reason to believe that the integrity of the long string casing of the well may be adversely affected by naturally occurring or man-made events;
   e. The permittee may request the Director to use any other test approved by the Administrator of the U.S. EPA in accordance with the procedures in OAC 3745-34-34(D) and 3745-34-57(I)(5).
   f. The Director may require additional or alternative tests if the test results presented by the permittee are not satisfactory to the Director to

demonstrate that there is no movement of fluid into or between USDWs resulting from the injection activity.

3. Prior Notice and Report.

a) The permittee shall notify the Director of intent to demonstrate mechanical integrity at least thirty (30) calendar days prior to such demonstration. For those tests required in Part I (H)(2)(a, b, and c) above, the permittee shall submit the planned test procedures to the Director for approval at the time of notification. Thirty (30) calendar days prior notification also shall be provided for any planned casing inspection log. At the discretion of the Director a shorter time period may be allowed. Reports of mechanical integrity demonstrations which include well logs shall include an interpretation of results by a knowledgeable log analyst. Such reports shall be submitted in accordance with the reporting requirements established in Part II (E)(3) of this permit.

b) The Director may require a specific type of testing, testing parameters, and/or specific technology based on what the Director determines, on a site-specific basis, to be the most appropriate type or method to evaluate the condition of the well and associated components.

The permittee shall notify the Director of its intent to conduct any well stimulation at least 45 days prior to such procedures. A shorter time period may be allowed at the Director's discretion. A plan for well stimulation shall be submitted to the Director for review and approval at the time of notification. Reports on well stimulations shall be submitted in accordance with the reporting requirements established in Part II (E)(3) of this permit.

4. Gauges. The Permittee shall calibrate all gauges used in mechanical integrity demonstrations to within one-half percent of full scale prior to each required test of mechanical integrity or barring any damage to the gauge, every six (6) months. A copy of the calibration certificate shall be submitted to the Director or his or her representative at the time of demonstration and every time the gauge is calibrated. The gauge shall be marked in no greater than ten (10) psi increments.

5. Loss of Mechanical Integrity. If the permittee or the Director or the Director's authorized representative makes a finding in accordance with Part I (H)(1), that the well fails to demonstrate mechanical integrity during a test or fails to maintain mechanical integrity during injection operations, or that a loss of mechanical integrity as defined by OAC Rule 3745-34-34 is indicated during injection operations, the permittee shall halt injection immediately and follow the reporting requirements as directed in Part I (E)(12) of this permit. The permittee shall not resume injection until mechanical integrity is demonstrated and the Director of the Director's authorized representative gives approval to recommence injection.

6. Mechanical Integrity Testing on Request from the Director. The permittee shall demonstrate mechanical integrity at any time upon written request from the

Director.

I. FINANCIAL RESPONSIBILITY (OAC Rule 3745-34-62)

1. Financial Responsibility. The permittee shall comply with the closure and post-closure financial responsibility requirements of OAC 3745-34-27(B)(7) and OAC Rule 3745-34-62. The permittee shall submit this demonstration of compliance as part of the Closure Plan required by Part 1 (F)(1) of this permit. Any required updates of the financial assurance documentation in the approved Closure Plan will not require approval from the Director as long as the updates are in compliance with OAC 3745-34-27(B)(7) and OAC Rule 3745-34-62.

   a. The permittee shall maintain written cost estimates, in current dollars, for the waste liability, closure and post-closure plans as specified in OAC Chapter 3745-34. The waste liability coverage shall comply with the substantive requirements of OAC Rule 3745-55-47. The closure and post-closure estimates shall equal the maximum cost of closure and post-closure at any point in the life of the facility operation.
   b. The permittee shall adjust the cost estimate of closure and post-closure for inflation annually. This annually adjusted closure and post-closure cost shall be submitted with the annual financial assurance to the Director in accordance with requirements set forth in OAC Rules 3745-55-42 through 3745-55-45.
   c. The permittee must revise the closure and/or post-closure cost estimate whenever a change in the closure plan and/or post-closure plan increases the cost of closure and/or post-closure. The revised cost estimates must be adjusted for inflation as specified above in permit condition Part I (I) (1) (b).
   d. If the revised closure and post-closure estimates exceed the current amount of the financial assurance mechanism, the permittee shall submit a revised mechanism to cover the increased cost within thirty (30) business days after the revision specified in permit condition Part I (I) (1) (b) and (c) above.
   e. The permittee shall keep on file at the facility a copy of the latest closure and post-closure cost estimate prepared in accordance with OAC 3745-34-09(B)(9) and OAC Rule 3745-34-62 during the operating life of the facility. Said estimate shall be available for inspection in accordance with the procedures in permit condition Part I (E)(8)(b) of this permit.

2. Insolvency. In the event of:

   a. The bankruptcy of the trustee or issuing institution of the financial mechanism (not applicable to permittees using a financial statement); or
   b. Suspension or revocation of the authority of the trustee institution to act as trustee; or
   c. The institution issuing the financial mechanism losing its authority to issue such an instrument, the permittee must notify the Director, in writing, within ten (10) business days.

The owner or operator must establish other financial assurance or liability coverage acceptable to the Director, within sixty (60) days after such an event.

An owner or operator must also notify the Director by certified mail of the commencement of voluntary or involuntary proceedings under Title 11 (Bankruptcy), U.S. Code naming the owner or operator as debtor, within ten (10) business days after the commencement of the proceeding. A guarantor of a corporate guarantee must make such a notification if named as debtor, as required under the terms of the guarantee.

J. CORRECTIVE ACTION

1. Wells in the Area of Review. The permittee shall comply with the corrective action requirements found in Attachment E of this permit and with OAC Rules 3745-34-07, 3745-34-30 and 3745-34-53.

2. §3004 (u) of the Resource Conservation and Recovery Act. The permittee shall comply with applicable corrective action requirements for the permitted well as required by the Resource Conservation and Recovery Act.

K. FEES

The permittee shall annually submit required fees in accordance with OAC Rule 3745-34-63. These said fees are non-refundable under any circumstance.

Part II
WELL SPECIFIC CONDITIONS

A. CONSTRUCTION

1. Siting [OAC Rule 3745-34-51]. The injection well shall directly place injectate only into the injection interval as defined on the cover page of this permit. At no time shall injection occur directly into any formation(s) above the injection interval.

2. Casing and Cementing [OAC 3745-34-37(B) and Rule 3745-34-54]. Notwithstanding any other provisions of this permit, the permittee shall maintain casing and cement in the well in such a manner as to prevent the movement of fluids into or between underground sources of drinking water. The casing and cement used in the construction of Adams #1 are shown in Attachment B of this permit. Notification of any planned changes shall be submitted by the permittee for the approval of the Director before installation.

3. Tubing and Packer Specifications [OAC 3745-34-54(D)]. Injection shall take place only through approved tubing with an approved packer/seal assembly set within the casing at the bottom of the long string casing at a point approved by the Director immediately above or within the injection interval. Tubing and packer/seal assembly specifications shall be as represented in engineering drawings contained in Attachment B of this permit. Notification of any planned changes shall be submitted by the permittee for the approval of the Director before installation.

4. Wellhead Specifications. A quarter-inch (1/4") female coupling shall be maintained on the wellhead, to be used for independent injection pressure readings.

B. FORMATION DATA

In accordance with OAC 3745-34-57(J), the permittee shall monitor the pressure buildup in the injection zone annually. The permittee shall schedule pressure buildup testing such that one (1) of the permittee's two (2) Class I injection wells is used for testing each year and each well shall be tested at least once every twenty-four (24) months unless otherwise approved by the Director. This shall include, at a minimum, a shut-down of the well for a time sufficient to conduct a valid observation of the pressure fall-off curve. A plan for such monitoring shall be submitted for the Director's review and approval at least thirty (30) days prior to initiating monitoring or testing. The results of this test shall be used to calculate the following:

a. The transmissivity of the injection zone;
b. the formation or reservoir pressure; and
c. the skin effect.

The results of this test and the permittee's interpretation of the results shall be submitted to the Ohio EPA in accordance with OAC 3745-34-58(B) and Part II (E) (3) of this permit.

C. OPERATIONS

1. Injection Interval. Injection shall be limited to the approximate subsurface interval between 5898 feet and 7270 feet ground level (BGL) for Adams #1.

2. Injection Pressure Limitation [OAC 3745-34-38(A) and Rule 3745-34-56].

   a. Injection pressure at the wellhead shall not exceed a maximum which shall be calculated so as 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 injection pressure initiate fractures, or propagate existing fractures in the confining zone, or cause the movement of injection or formation fluids into an underground source of drinking water.

   b. Bottom hole pressure shall be limited so that a maximum of 4423 psi is never exceeded, calculated with a fracture gradient of 0.75 psi/foot applied at a depth of 5898 feet BGL. The injection pressure shall be limited so that a maximum pressure of 1869 psig (measured at the surface) is not exceeded. The maximum surface injection pressure limit shall be adjusted downward if fluid specific gravity increases above 1.0, in accordance with the calculation set forth in Attachment D of this permit. Downward adjustments in injection pressure shall be made based on injectate specific gravity measurements made and recorded at least once every four (4) hours.

3. Injection Volume Limitation. The combined monthly flow rate for all permitted Class I injection wells at this facility shall not exceed 290 gallons per minute.

4. Additional Injection Limitation. No substances other than those identified and deemed acceptable for receipt and defined as non-hazardous shall be injected. The following wastes shall not be injected:
   a. Waste that is identified and regulated as a hazardous waste under ORC 3743.01(J) and Title 40 of the Code of Federal Regulations (CFR) Section 261.3, and Rule 3745-51-03 of the OAC;
   b. Sewage generated by Buckeye Brine as defined within OAC Rule 3745-34-01(S)(5);
   c. Infectious waste as defined per OAC Rule 3745-27-01(I)(6);
   d. Radioactive wastes other than naturally occurring radioactive material (NORM) or technologically enhanced naturally occurring radioactive material (TENORM) as defined by the Ohio Department of Health;
   e. PCB wastes as defined in the federal Toxic Substances Control Act (TSCA),
   f. Any hazardous waste resulting from an action taken under the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA) or the Superfund Amendments and Reauthorization Act (SARA),
   g. Non-infectious medical wastes;
   h. Explosives;
   i. Military or civilian ordnance;
   j. Gaseous wastes in high pressure cylinders; or

k. Waste of unknown origin.

The permittee shall submit a certified statement attesting to compliance with this requirement at the time of the annual report. The only exception to this limitation is the injection of fluids recovered from monitor wells and other fluid required for approved well testing and/or monitoring, or fluids approved by Ohio EPA for well treatment/stimulation. The composite waste stream shall meet all compatibility requirements of OAC Rule 3745-34-57.

5. Annulus Fluids and Pressure [OAC 3745-34-56(C)]. Except during workovers, the annulus between the injection tubing and the long string casing shall be filled with an inert, non-reactive fluid. The pressure on the annulus shall be at least fifty (50) psig (calculated) higher than injection pressure at all times throughout the injection tubing length to the top of the packer/seal assembly, for the purpose of leak detection.

6. Automatic Warning and Shut-Off System.

a. The permittee shall continuously operate and maintain an automatic warning and shut-off system required by OAC Rule 3745-34-56 which shall stop injection in the following situations:

i. Injection pressure measured at the wellhead equals or exceeds the limit established in Part II (C)(2) of this permit; and

ii. When injection/annulus pressure differential falls below fifty (50) psig positive differential from the injection pressure and during conditions specified above in Part II (C).

iii. If a 30% loss of injection pressure is experienced over a sixty (60) second period, the injection well will be shut in and all injection activities will cease. Adams 1 shall not resume injection until the issue has been thoroughly investigated and documented that Buckeye Brine is in full compliance with all state permits and statutes.

b. The permittee shall test the automatic warning and shut-off system within thirty (30) days of the anniversary date of the last field approved demonstration. This test must involve subjecting the system to simulated failure conditions and shall be witnessed by the Director or the Director's authorized representative. The permittee shall notify the Director of its intent to test the automatic warning and shut-off system at least thirty (30) calendar days prior to such a demonstration. At the discretion of the Director a shorter time period may be allowed. The permittee shall submit the planned automatic warning and shut-off system test procedures to the Director for approval at the time of notification.

c. If an automatic alarm or shutdown is triggered, the owner or operator shall immediately investigate and identify the cause of the alarm or shutoff. If, upon such investigation, the well appears to be lacking mechanical integrity, or if monitoring required under OAC 3745-34-56(F) otherwise indicates that the well may be lacking mechanical integrity, the owner or operator shall:

i. Immediately cease injection of waste fluids unless authorized by the Director to continue or resume injection; and
ii. Take all necessary steps to determine the presence or absence of a leak; and
iii. Notify the Director within twenty-four (24) hours after an alarm or shutdown, in accordance with Part I (E)(12) of this permit.

7. Precautions to Prevent Well Blowouts. The permittee shall, at all times, maintain a pressure at the wellhead which will prevent the return of the injection fluid to the surface. If there is a gas formation in the injection zone near the well bore, such gas must be prevented from entering the casing or tubing. The well bore must be filled with a high specific gravity fluid during workovers to maintain a positive (downward) gradient and/or a plug shall be installed which can resist the pressure differential. A blowout preventer must be kept in proper operational status during workovers.

8. Well Stimulation. A well stimulation plan submitted by Buckeye Brine (BB) and approved by Ohio EPA January 9, 2024. If a future proposed stimulation substantially differs from the January 9, 2024 approval, Ohio EPA must be notified with a new plan within forty-five (45) days prior to conducting the stimulation event. BB must notify Ohio EPA within forty-eight (48) hours ahead of when the stimulation event under an approved stimulation plan is scheduled to take place in the waste disposal wells. Reports on well stimulations shall be submitted in accordance with Part II (E)(3) of this permit. These reports shall include the amount and type of fluid injected during the well stimulation procedure. With the exception of the fluid injected, all other conditions of the permit shall be complied with during the well stimulation including the maximum surface injection pressure and the annulus differential pressure requirements, unless approved by the Director.

D. MONITORING

1. Monitoring Requirements [OAC 3745-34-38(B) and 3745-34-57(A)-(F)]. Samples and measurements taken for the purpose of monitoring shall be representative of the monitored activity. The permittee shall perform all monitoring required by OAC Rules 3745-34-38 and 3745-34-57, and any other monitoring required by applicable rule or this permit. The method used to obtain a representative sample of any fluid to be analyzed and the procedure for analysis of the sample shall be the one described in Appendix I and III of 40 CFR Part 261 or an equivalent method approved by the Director.

2. Injection Fluid Analysis [OAC Rules 3745-34-38 and 3745-34-57]. The injection fluids shall be analyzed in accordance with the Ohio EPA approved waste analyses plan. Results of the most recent analyses shall be submitted with each monthly operating report. The report must include statements demonstrating that the permittee is in compliance with the requirements of Part I(E)(10) and Part II (C)(4)(a) and (b) of this permit.

3. Waste Analysis Plan.

a. The permittee has developed and maintained a written waste analysis plan which describes the procedures in which they will comply with permit conditions (D)(1) and (D)(2) above and OAC Rule 3745-34-57. The latest revision of this plan was submitted on July 12, 2024 and was approved by the Director on January 24, 2025. A copy of the approved plan shall be kept at the facility and available for inspection. The sampling and analyses shall be performed in a manner protective of human health, safety and the environment and shall produce results representative of the chemical composition of the waste analysis stream and that will identify incompatible wastes. At a minimum, the plan must specify:

i. How wastes identified as chemically incompatible with one another will be handled and stored so as to prevent the release of the waste or reaction products outside of the tanks, pipes or other containment structures at the facility.

ii. A demonstration that:

a. The waste stream and its anticipated reaction products will not alter the permeability, thickness or other relevant characteristics of the confining or injection zones such that they would no longer meet the requirements specified in OAC rule 3745-34-51; and

b. The waste stream will be compatible with the well materials with which the waste is expected to come into contact.

iii. A description of the methodology used to make the compatibility demonstrations required pursuant to OAC Rule 3745-34-57.

vi. The parameters for which the waste stream will be analyzed and the rationale for the selection of these parameters;

v. The test methods which will be used to test for these parameters; and

vi. The sampling method which will be used to obtain a representative sample of the waste to be analyzed.

vii. The injectate sampling location.

b. The permittee shall identify the types of tests and methods used to generate the monitoring data. The monitoring program shall conform to the one described in the approved Waste Analysis Plan. The permittee shall abide by the Quality Assurance Form (Attachment D) of this permit. This form must be completed and submitted to the Director within thirty (30) days of the effective date of this permit.

c. The permittee shall assure that the waste analysis plan remains accurate and the analyses of any fluid sampled remain representative.

d. Revisions to the approved Waste Analysis Plan shall be submitted to Ohio EPA and approved by the Director prior to implementation.

4. Continuous Monitoring and Recording Devices [OAC 3745-34-38(B)(2) and 3745-34-56(F)]. The permittee shall follow the deepwell monitoring requirements provided in Attachment A of this permit. Continuous monitoring and recording devices shall be maintained and operated to monitor surface injection pressure,

flow rate, the pressure in the annulus between the tubing and the long string of casing, and the temperature of the injectate. Continuous monitoring devices shall also be maintained and operated to monitor the injected volume. The total injected volume for the well shall be recorded at least daily.

During periods where the permittee is unable to continuously monitor the required parameters, the permittee shall implement its Ohio EPA approved deep well monitoring contingency plan. Nothing in the contingency monitoring plan shall relieve the owner or operator of their obligation to comply with requirements under applicable state and federal law or regulations.

The Contingency Monitoring plan was submitted on January 17, 2025 and approved by the Director on January 31, 2025The Contingency Monitoring Plan shall be implemented and referenced in regard to this permit and the permit to operate conditions. Revisions to the approved Contingency Monitoring Plan shall be submitted to and approved by the Director prior to implementation.

5. Monitoring Wells. The permittee submitted a ground water monitoring plan for protection of the underground sources of drinking water. The plan was approved by Ohio EPA on October 1, 2019. A copy of the most recently approved plan shall be kept at the facility and be made available for inspection upon request. Revisions to toe approved Ground Wate Monitoring Plan shall be submitted to and approved by the Director prior to implementation.

   A copy of the approved ground water monitoring plan shall be kept at the facility and available for inspection.

6. Compatibility of Well Material. The permittee shall monitor continuously for corrosion of the construction materials by a method approved by the Director in accordance with OAC Rule 3745-34-57. The permittee shall follow the protocol outlined in the Ohio EPA approved corrosion monitoring plan. The plan was submitted to Ohio EPA on April 15, 2024 and was approved January 31, 2025. The approved corrosion monitoring plan shall be implemented and referenced in regard to this permit and the permit to operate conditions. At a minimum, the permittee shall report loss of mass, thickness, cracking, pitting, and other signs of corrosion at least quarterly in accordance with Part II (E)(2) of this permit. Revisions to the Corrosion Monitoring Plan shall be submitted to and approved by the Director prior to implementation.

7. Seismic Monitoring.

   a. Seismic Reflection Data. The permittee has completed a seismic reflection data study to the Director's satisfaction. The purpose of this study was to establish the presence or absence of significant geological structural features such as faults and/or fractures in the uppermost Precambrian rock units and the overlying Paleozoic rock units within the area of review at the Coshocton, Ohio, Class I injection well facility.

If the area of review for this facility changes during the operational life of this well, the permittee shall re-evaluate the data obtained from the existing study. If after re-evaluation of the existing data, the Director determines the study to be inadequate to determine the presence or absence of geologic faults or fractures within the altered area of review, the permittee shall submit such additional seismic reflection data as the Director determines to be necessary.

b. Seismic Monitoring System. The permittee shall maintain the existing seismic monitoring system, unless an alternate system is approved by the Director. If periodic downtime is encountered as a result of component failure or equipment maintenance, the permittee shall provide the following in the subsequent quarterly report: date(s), duration, cause of the downtime, a schedule for repair activities and the anticipated date that the monitoring system will be returned to service. Data collected by the system shall be submitted quarterly, accompanied by the permittee's interpretation of the data. During the system downtime, the permittee shall provide seismic data from available local or regional monitoring sources in the quarterly report. A complete analysis and interpretation of the data shall be submitted within thirty (30) days after the completion of the quarter. The permittee shall adhere to the Ohio EPA approved seismic monitoring plan, as received by the agency on August 23, 2019 and approved on October 1, 2019 at all times. Revisions to the approved seismic monitoring plan shall be submitted to and approved by the Director prior to implementation.

c. If the Director determines that injection activities at the subject site may be inducing seismic activity capable of risk to human health and the environment, the permittee shall immediately suspend injection operations upon written notification from the Director. Injection would not be authorized to resume unless the Director indicates in writing that it is acceptable to do so based on the evaluation of the seismic data.

E. REPORTING REQUIREMENTS (OAC Rules 3745-34-38 and 3745-34-58)

1. Monthly Reports. The permittee shall submit monthly reports to the Director containing, at a minimum, all of the following information:

a. Results of the monthly injection fluid analysis specified in permit condition Part II (D)(2).
b. Daily and monthly average values for injection pressure, flow rate and volume, annular pressure, and temperature of the combined waste stream.
c. Daily and monthly maximum and minimum values for injection pressure, annulus pressure, and flow rate of the waste stream.
d. Daily minimum differential pressure.
e. The combined monthly average flow rate for all wells.
f. The results of continuous monitoring of injection pressure, annulus pressure, flow rate and injectate temperature required in permit condition Part II (D)(4). These data shall be digitized and submitted on a single graph

using contrasting symbols or colors for annulus pressure, injection pressure, flow rate and injectate temperature.

g. Total fluid volume of the combined waste stream injected daily, monthly, and the cumulative volume of fluid injected for the life of the well.
h. Date, time and volume of annulus fluid addition to or removal from the annulus system.
i. Annulus sight glass level readings noted daily at a specified time.
j. For each daily minimum and maximum injection rate reported, list the corresponding injection pressure and annulus pressure occurring during the time the well was operating at that minimum and maximum rate.
k. A listing of the duration and cause of any non-operating period for the well during the month.
l. Any procedures conducted at the injection well other than routine operational procedures.
m. Daily determinations of (injectate) pH, including monthly maximum and minimum values.
n. Determinations of injectate specific gravity a minimum of every four (4) hours.
o. Any noncompliance with conditions of this permit, including but not limited to:

    i. A description of any event that violates operating parameters for annulus pressure, injection pressure or annulus/injection pressure differential as specified in this permit; or
    ii. A description of any event which triggers an alarm or shutdown device required in Part II (C)(6) of this permit, accompanied by a description of the response taken for each event.

2. Quarterly Reports [OAC Rule 3745-34-58]. The permittee shall report all of the following each calendar quarter:

    a. Results of the continuous corrosion monitoring system and an interpretation of the results, as stipulated in Part II (D) of this permit, within fifteen (15) days after the end of the quarter;
    b. Results of ground water monitoring, and an interpretation of the results, as specified in an approved ground water monitoring plan, required in Part II (D)(5) of this permit, within fifteen (15) days after the end of the quarter.
    c. Results of seismic monitoring, and an interpretation of the results, required in Part II (D)(7)(b), within thirty (30) days after the end of the quarter.

3. Reports on Well Tests and Workovers. Within thirty (30) calendar days after the activity the permittee shall submit to the Director the field results of demonstrations of mechanical integrity, any well workover or results of other tests required by the permit. Field log copies shall be made available the day of any geophysical well logging at the request of the Director or the Director's authorized representative. A formal written report and interpretation of demonstrations of mechanical integrity (excluding annulus pressure tests), any well workover, or results of other tests, except those reports that include pressure buildup monitoring data and analysis, required by this permit or otherwise

required by the Director shall be submitted to the Director within forty-five (45) calendar days after completion of the activity. Those reports that include data and analysis of pressure buildup monitoring of the injection zone shall be submitted to the Director within sixty (60) days after completion of the activity.

4. The permittee shall submit all required reports to:

   Ohio Environmental Protection Agency
   Division of Drinking and Ground Waters
   Underground Injection Control Unit
   50 West Town Street, Suite 700
   P.O. Box 1049
   Columbus, Ohio 43216-1049

   Reports, documents and files can be submitted electronically directly to the UIC program's assigned inspector that oversees the facility. Submit all documents electronically to the inspector's official first.last@epa.ohio.gov email address.

5. The permittee shall adhere to the reporting requirements specified in Attachment A and Part II of this permit for reporting under permit condition Part II (E) above.

F. WASTE MINIMIZATION

The permittee shall comply with Section 6111.045 of the Ohio Revised Code concerning the preparation, adoption and maintenance of a waste minimization and treatment plan. The plan shall be retained at the facility and shall be made available for inspection. Every three (3) years, on or before the anniversary date of the adoption of the plan, the permittee is required to submit to the Director a revised executive summary of the plan. This plan was recently revised and submitted in May of 2024 and approved by Ohio EPA on January 30, 2025.

Attachment A

I. Operating, Monitoring, and Reporting Requirements
II. Waste Permitted for Injection

Attachment A

I. Operating, Monitoring, and Reporting Requirements

Adams #1

CHARACTERISTIC REQUIREMENTS	LIMITATION Maximum	LIMITATION Minimum	MINIMUM MONITORING REQUIREMENTS Frequency	MINIMUM REPORTING REQUIREMENTS Frequency
*Maximum Allowable Injection Pressure Not to be exceeded	1869 psig		continuous	monthly
**Bottom-hole Pressure $_{(max)}$	4423 psig		*calculated	monthly
Annulus Pressure	50 psig higher than injection pressure throughout entire tubing length from the surface to the top of the packer		continuous	monthly
Flow Rate	290 gpm (combined monthly average)		continuous	monthly
***Flow Volume			continuous	monthly
Temperature			continuous	monthly
+Specific Gravity			continuous	monthly
Sight Glass Level			daily	monthly
Corresponding Annulus Pressure			daily	monthly
Corresponding Waste Temperature			daily	monthly
Corresponding Injection Pressure			daily	monthly
Corresponding Flow Rate			daily	monthly
pH			daily	monthly
****Chemical Composition of Injectate			monthly	monthly

*Injection Pressure: (maximum allowable surface injection pressure = MASIP)

MASIP = 5898 x [0.75 - (0.433 x 1.0)] where:

5898 = depth to the top of the injection interval in true vertical depth feet

0.75 = applied fracture gradient in psi/ft

.443 = Pressure Gradient of 1 Foot of Water at 62 Degrees Fahrenheit

1.0 = fluid specific gravity

**Bottom-hole Pressure: The maximum allowable bottom-hole pressure (BHP_{max}) shall be calculated using the following formula:

BHP_{max} = (0.75) (5898)

***Flow Volume: The combined monthly injection volume for the Class I wells on site must not exceed 12,710,700 million gallons, unless otherwise approved by the Director.

**** Chemical Composition: Chemical analysis shall be conducted for parameters which characterize the waste water and in accordance with the Sampling and Waste Analysis Plan after it is approved by the Director. Include monthly analysis with monthly report each month.

+ Specific Gravity: Specific gravity of the injectate shall be monitored continuously and the data recorded at a frequency approved by the Director. A daily maximum, minimum and average shall be reported monthly. As the specific measurement increases above 1.0, the maximum injection pressure measured at the well head shall be adjusted downward accordingly such that a bottom-hole pressure of 4423 psi is not exceeded.

Attachment A

II. Wastes Permitted for Injection

Section 3: Acceptable Waste Codes

The BBL facility accepts only materials not subject to identification and regulation under "Ohio Revised Code, Title 37, Chapter 3734.01 (J)" and "40 CFR § 261.3 (Definition of hazardous waste)" in the facility.

Waste characterized by codes assigned by local/state regulations that do not meet the criteria as defined in Ohio Revised Code, Title 37, Chapter 3734.01 (J) and 40 CFR § 261.3 may be accepted on a case by case basis.

The following wastes shall not be injected:

- Waste that is identified and regulated as a hazardous waste under ORC 3734.01(J) and Title 40 of the Code of Federal Regulations (CFR) Section 261.3, and Rule 3745-51-03 of the OAC;
- Sewage generated by Buckeye Brine as defined within OAC Rule 3745-34-01(S)(5);
- Infectious waste as defined per OAC Rule 3745-27-01(1)(6);
- Radioactive wastes other than naturally occurring radioactive material (NORM) or technologically enhanced naturally occurring radioactive material (TENORM) as defined by the Ohio Department of Health;
- PCB wastes as defined in the federal Toxic Substances Control Act (TSCA),
- Non-infectious medical wastes;
- Explosives;
- Military or civilian ordnance;
- Gaseous wastes in high pressure cylinders; or
- Waste of unknown origin.

Attachment B

Well Construction Specifications

The data provided in this attachment was extracted from the UIC permit to operate applications. This attachment represents a condensed summary.

III. INJECTION WELL CONSTRUCTION AND OPERATION

III.A. Construction and Completion Summary for Adams # 1

This UIC permit application is being prepared and submitted to authorize the continued operation of a Class I non hazardous waste disposal well known as the Adams #1 which is located withing a facility constructed and operated by Buckeye Brine, LLC in Coshocton, Ohio. The Adams #1 well was spudded on 12/21/2011 and completed on 1/19/2012.

III.A.1. Well Schematic for Adams # 1

The current configuration of the Adams #1 well is depicted on Figure III.A. The schematic shows borehole sizes, tubular sizes, liners, depths, specification and cementing information. Following the discovery of a small leak discovered in the 7" longstring casing during a routine mechanical integrity test, Buckeye proposed a procedure for installing a liner inside the longstring casing. The proposed procedure was approved by the OEPA and the 4.5" liner was installed in September 2020. A copy of the final report on the lining installation is included as Attachment III.A to this section of the report.

III.A.2. Adams #1 Total Depth

The Adams #1 well was drilled to a total depth of 7,288 feet. During routine mechanical integrity testing performed in October of 2016, wireline tools encountered resistance at a depth of 7049 feet. The obstruction is most likely fill and does not impair the ability to perform RTS, falloff, and other diagnostic testing.

III. A.3. Well Casing and Tubing Strings

The Adams #1 well was designed to exceed the current requirements for Class I injection wells and is constructed with conductor casing, surface casing, longstring casing and injection tubing, consisting of steel casing and tubing. Different factors have been incorporated into the proposed casing and tubing program including:

- Hole sizes;
- Injection zone and injection interval depths;
- Depth of lowermost underground source of drinking water (USDW);
- Injected waste and formation fluid composition, corrosiveness and compatibilities;

- Injection rates and operating pressures (annular and wellhead);
- Casing and tubing sizes, weights, grades and mechanical strength properties; and
- Types and grades of cement.
-

III.A.3.a. Casing and Injection Tubing- Type, Weight, Grade, Wall Thickness, End Finish, Set Depth, and Life Expectancy

The casing and tubing strings will be made up of conductor pipe, surface casing, longstring casing, and injection tubing.

Conductor Pipe

Size (OD)	16 inches
Internal Diameter	15.376 inches (15.188" drift ID)
Weight	55 lb/ft
Grade	A-53 Grade B
End Finish	Welded
Setting Depth	126 feet
Life Expectancy	>30 years (life of well)

Surface Casing

Size (OD)	11.75 inch OD
Internal Diameter	11.084 (10.928" drift ID)
Weight	42 lb/ft
Grade	H40
Coupling Size	11.75 inches
Thread	ST & C
Setting Depth	894 feet (564' below lowermost USDW)
Life Expectancy	>30 years (life of the well)

Longstring Casing

Size (OD)	7 inch OD
Weight	23 lb/ft
Grade	N-80
Thread	LT & C
Setting Depth	5,898 feet
	0 – 5,898 23lb/ft, N-80) Packer top at 5,819 feet
Life Expectancy	>30 years (life of the well)

Liner installed 9/13/2020

Size (OD)	4.5
Internal Diameter	4.000 inches (3.927" drift ID)
Weight	11.6 lbs/ft
Grade	J-55
Setting Depth	0 to 5879

*(source: IPSCO On-Line Handbook: Dimensions and Performance Properties for Tubing and Casing)

Injection Tubing –Replaced following 2020 liner install

Size (OD)	2.875
Weight	6.5 lbs/ft
Grade	J-55
Setting Depth	0 to 5848 (top of packer)

(Resource: IPSCO On-Line Handbook: Dimensions and Performance Properties for Tubing and Casing)

Note Tail Pipe (60) ft) installed below packer. As this tubig will not be subject to annulus pressure a lighter grade of tubing was considered appropriate for this tail section.

III.A.3.b. Tubulars- Collapse Resistance, Internal Yield Pressure, Joint Strength, Yield Strength

The casing and tubing strings will be made up of conductor pipe, surface casing, longstring casing and lined injection tubing.

Conductor Pipe (16", 55 lb/ft, A53 Grade B)

Collapse	290 psi
Burst (internal yield)	850 psi
Joint Strength	258,000 lbs
Yield Strength	384,000 lbs

***(Source: IPSCO On-Line Handbook: Dimensions and Performance Properties for Tubing and Casing)**

Surface Casing (11.75", 42 lb/ft, H40 ST&C)

Collapse	1,070 psi
Burst (internal yield)	1,980 psi
Joint Strength	307,000 lbs
Yield Strength	478,000 lbs

***(Source: IPSCO On-Line Handbook: Dimensions and Performance Properties for Tubing and Casing)**

Longstring Casing 7 ", 23 lb/ft, N-80, LT&C

Collapse	3,830 psi

*(source: IPSCO On-Line Handbook: Dimensions and Performance Properties for Tubing and Casing)

Injection Tubing –Replaced following 2020 liner install

Size (OD)	2.875
Weight	6.5 lbs/ft
Grade	J-55
Setting Depth	0 to 5848 (top of packer)

(Resource: IPSCO On-Line Handbook: Dimensions and Performance Properties for Tubing and
Casing)

Note Tail Pipe (60) ft) installed below packer. As this tubig will not be subject to annulus pressure a lighter grade of tubing was considered appropriate for this tail section.

III.A.3.b. Tubulars- Collapse Resistance, Internal Yield Pressure, Joint Strength, Yield Strength

The casing and tubing strings will be made up of conductor pipe, surface casing, longstring casing and lined injection tubing.

Conductor Pipe (16”, 55 lb/ft, A53 Grade B)

Collapse	290 psi
Burst (internal yield)	850 psi
Joint Strength	258,000 lbs
Yield Strength	384,000 lbs

***(Source: IPSCO On-Line Handbook: Dimensions and Performance Properties for Tubing and Casing)**

Surface Casing (11.75”, 42 lb/ft, H40 ST&C)

Collapse	1,070 psi
Burst (internal yield)	1,980 psi
Joint Strength	307,000 lbs
Yield Strength	478,000 lbs

***(Source: IPSCO On-Line Handbook: Dimensions and Performance Properties for Tubing and Casing)**

Longstring Casing 7 ”, 23 lb/ft, N-80, LT&C

Collapse	3,830 psi

Burst (internal yield)	6,340 psi
Joint strength	442,000 lbs.
Yield Strength	532,000 lbs.

Liner 4" 11.6 lb/ft J-55 LT

Collapse	4,960 psi
Burst (internal yield)	5350 psi
Joint Strength	162,000 lbs.
Yield Strength	184,000 lbs

Injection Tubing –Replaced following 2020 liner install
2.875 " 6.5 lbs/ft, J-55 ww internal joint

Collapse	7,680 psi
Burst (internal yield)	7,260 psi
Joint Strength	72,580 lbs
Yield Strength	7,260 lbs

***(Source: IPSCO On-Line Handbook: Dimensions and Performance Properties for Tubing and Casing)**

III.A.3.c. Casings and Injection Tubing- Maximum External and Internal Pressures and Axial Loading Conditions during Construction, Operation, and Closure

The casing and tubing strings will be subject to different stresses during the different phases of construction, operation, and closure. An analysis is presented below to determine the maximum stresses during any of these phases. For any other condition, the stresses on the component will be less. The assumptions made here maximize the calculated stress on the component and will represent the maximum during construction, operation, and closure procedures.

External Pressures - Casings

For the maximum external pressure, it is conservatively assumed that somehow the inside of the casing in question has become entirely evacuated from surface to its total depth with only atmospheric pressure on the inside, and that a maximum formation hydrostatic pressure (assuming a 10 lb/gal equivalent mud weight) is exerted against the external surface of the casing. This condition is assumed to occur during the casing installation phase, but could also occur during jet-back cleanout operations and during closure. In any event, these conditions are very unlikely to occur, but are nonetheless presented here to provide a conservative outcome.

Design Formation Pressure

For the purposes of the casing and tubing design, the formation pressure gradient is assumed to be 0.52 psi/ft or a 10 lb/gal equivalent fluid density. See a justification for this pressure below.

Measured Ambient Formation Pressure from Existing Wells

Ambient pressure measurements have been obtained from all three wells during annual MI testing. The formation pressure gradient obtained from the October 18, 2016 ambient pressure monitoring in the Adams #1 is calculated to be 0.470 psi/ft (3,152 psig at 6,700 feet), or 9.25 lb/gal equivalent formation density. The pressure gradient obtained from the measurement of BHP in the Adams #3 on October 19, 2016 (one day after the Adams #1 measurement) is calculated to be 0.476 psi/ft (3,331 psig at 7,000 feet). For a conservative evaluation, we assumed that the ambient formation pressure gradient of 0.52 psi/ft (10 lb/gal equivalent density). The resulting equation is:

$$\mathbf{P_{ext} = 10\ lb/gal * 0.052\ psi/ft\ /\ lb/gal * Casing\ Depth}$$
$$\mathbf{= 0.52\ psi/ft * Casing\ Depth\ (ft)} \qquad \ldots\ \mathbf{(i)}$$

External Max Press$_{conductor}$ = 0.52 psi/ft * 126 ft   **= 65.52 psig**

External Max Press$_{surface}$ = 0.52 psi/ft * 894 ft   **= 465 psig**

External Max Press$_{longstring}$ = 0.52 psi/ft *5819 ft   **= 3,026 psig**

Note: The top of the packer is set at 5,848' BGL. The external and internal forces on the injection tubing and longstring casing are not active below this depth. For tensile strength comparisons on the injection tubing and longstring casing, the full installed length is used.

Internal Pressures - Casings

For the maximum internal pressure, it is conservatively assumed that somehow the outside of the casing has become entirely evacuated from surface to its total depth with only atmospheric pressure on the outside, and that a 10 lb/gal equivalent mud weight is exerted against the internal surface of the casing. The resulting equation is given by (same as previous):

P_{int} = 10 lb/gal*0.052 psi/ft / lb/gal* Depth of Casing

= 0.52 psi/ft * Depth of casing (ft) … (ii)

Internal Max $Press_{conductor}$ = 0.52 psi/ft * 126 ft **=65.52 psig**

Internal Max $Press_{surface}$ = 0.52 psi/ft * 894 ft **= 465 psig**

Internal Max $Press_{longstring}$ = 0.52 psi/ft *5898 ft. We chose to use the same depth for the liner which when cemented to the inside of the longstring casing make it essentially part of that seven inch casing. We compared that 4.5 inch liner to the pressures to which it would be possibly subject to if it could be slipped in and out of the borehole freely which it cannot., **= 3,067 psig**

Axial Loading – Casings and Liner

For the maximum load, it is conservatively assumed that the casing is "hanging in air" with no buoyant force exerted by the circulating fluid or surrounding formation in the borehole. This unrealistic condition could only be realized if the borehole somehow became fully evacuated of fluids, and had no circumferential contact with the walls of the borehole. In a similar fashion, we assumed thar the 4.5 inch liner could somehow become free of the longstring casing to which it is cemented, Nevertheless, it is used here for a worst possible case condition. The resulting equation is given by:

Max Tension Load = Weight of Casing (lb/ft)* Depth of Casing (ft) … (iii)

$MaxTensionLoad_{conductor}$ = 55 lb/ft * 126 ft   **= 6,930 lbs**

$MaxTensionLoad_{surface}$ = 42 lb/ft * 894 ft   **= 37,548 lbs**

<u>7 ", 23 lb/ft, N-80</u>	**$MaxTensionLoad_{longstring}$ = 23 lb/ft *5,898 ft**
	= 135,654 lbs
Liner 4.5" 11.6/lb/ft, J-55	**= 68,417 lbs**

<u>External Pressures - Injection Tubing</u>

For the maximum external pressure, it is conservatively assumed that maximum external pressure is equal to the maximum allowable surface injection pressure plus an additional 100 psi. At Buckeye Brine this pressure would be 1,459 psig (MASIP = 1,359 psig + 100 psig additional differential pressure). This represents the maximum possible condition during annulus pressure testing at Buckeye Brine. During injection operations, the well is operated with much less differential pressure. Additionally, it is assumed that the annulus fluid is a base solution in 10 lb/gal the maximum annulus fluid density, although it may actually be something less. Finally, it is assumed that there is no injection pressure (no injection), and that the tubing fluids are in equilibrium with the injection interval. At Buckeye Brine, the minimum static injection interval pressure in the Adams #1 is 3,152 psig at 6,700 feet, corresponding to a hydrostatic gradient of 0.470 psi/ft. Therefore, to calculate the maximum external (differential pressure at the bottom joint of injection tubing):

External $MaxPress_{inj.tubing}$ = 10 lb/gal*0.052 psi/ft / lb/gal* Depth of injection tubing (ft) + 1,459 psig – 0.470 psi/ft* injection tubing depth …(iv)

With the known proposed values:

External $MaxPress_{inj.tubing}$ =0.52 psi/ft*5,848 feet +1,459 psig – 0.470 *5,819 feet

Max External $Press_{inj.tubing}$ = 1,755 psig

<u>Internal Pressures - Injection Tubing</u>

For the maximum internal pressure exerted on the injection tubing, it is assumed that 10 lb/gal fluid is being injected into the well at the maximum allowable injection pressure (1,359 psig), and that the annulus is filled with fresh water. A column of water, in this case the annulus, exerts a downward and outward force of 0.433 psig/ft. With a column of fresh water inside the annulus and with no external pressure added at the surface, the pressure at the lowest point in the tubing above the packer would be 5,848 ft X 0.433 psig/ft. or 2532 psig at 5848 ft. The resulting equation which incorporates the weight of water in the annulus is given by:

Internal Max Press$_{inj.tubing}$= 0.52 psi/ft * tubing depth (ft) +1,359 psig - 0.433 psig/ft* depth of injection tubing ...(v)

Internal MaxPress$_{inj.tubing}$ =[(0.52 psi/ft*5,848 ft) +1,359 psig]- [0.433 psi x 5,848 ft]

Max Internal Press$_{inj.\ tubing}$ = 1,868 psig

Axial Loading - Injection Tubing

For the maximum tensile load, it is conservatively assumed that the injection tubing is latched into the packer with no buoyant force exerted by the annular fluid or fluid inside the injection tubing, and that there is no additional tensional loading pulled on the injection tubing (normally 10,000 – 15,000 lbs of slackoff weight is stacked onto the packer). Finally, it is assumed that the injection string is cooled by 50° F, relative to the ambient temperature at which it was landed. The resulting equation is given by:

Max Load = Tubing Wt. (lb/ft)*Tubing Depth (ft) + thermal contraction (lbs)

...(Calculate thermal contraction load from temperature change for 50° F cooling:

(vii)Thermal Tension (lbs) = 207* As * ΔT
(source: Baker Oil Tools Technical Handbook, 1995)

Where;

As = cross-sectional area of tubing = $(2.875^2 – 2.441^2) * \pi/4 = 12.56$

ΔT = temperature change (cooling in this case) = 50° F

207 = units conversion factor

$$= 207 * 12.56 \text{ in}^2 * 50° F$$

$$= 2600 \text{ lbs}$$

Finally, from equation (vii) above:

[2]Max Tensile Load$_{\text{injection tubing}}$ = 6.5 lbs/ft * 5,848 ft + 31,278 lbs

= 92,378 lbs

III.A.3.d. Detailed Factor of Safety Calculations for Each Tubular String

Given the strength of the materials that comprise the proposed well casings and injection tubing, along with the calculated maximum expected (although virtually impossible to actually occur), conditions calculated in equations (i) through (vii) above, the safety factors can be determined for each component through the equation:

SF = 1 + (Material Strength – Max. Calculated Stress) / Max calculated Stress (viii)

The casing strings (conductor, surface, liner and longstring) will be considered in I) through III) below and then the injection tubing will be considered.

I) Safety Factor for External Collapse Strength for Casings

Conductor Pipe (16", 55 lb/ft, A53)

$SF_{\text{conductor}}$ = 1 + (290 psi – 65.5 psi) / 65.5 psi

$SF_{\text{conductor}}$ =4.43

Surface Casing (11.75", 42 lb/ft, H40 ST&C)

$SF_{\text{surf casing}}$ = 1 + (1,070 psi – 465 psi) /465 psi

$SF_{surf\ casing}$ = 2.30

Longstring Casing (7 " 23.0 lb/ft, N-80 LT&C)

$SF_{longstring\ csaing}$ = 1 + (3,830 psi – 3,026psi) / 3,026 psi

$F_{longstringcasing}$ = 1.265

Liner 4" 11.6 lb/ft J-55 LT

SF_{lliner} - 1 + (4,960 -3026)/ 3026

$SF_{lliner\ =}$ 1.639

II) Safety Factor for Internal Yield Strength for Casings

Conductor Pipe (16", 55 lb/ft, A53)

$SF_{conductor}$ = 1 + (850 psi – 65.5 psi) / 65.6 psi

$SF_{conductor}$ = 12.97

Surface Casing (11.75", 42.0 lb/ft, H40 ST&C)

$SF_{surf\ casing}$ = 1 + (1,980 psi – 465psi) / 465 psi

$SF_{surf\ casing}$ = 4.26

Longstring Casing (7" 23 lb/ft, N80)

$SF_{longstring\ csaing}$ = 1 =+ (6,340 psi – 3,026 psi) / 3,026psi **$SF_{longstringcasing}$ = 2.10**

Liner 4" 11.6 lb/ft J-55 LT

SF_{lliner} - 1 + (4,960 -3026)/ 3026

$SF_{lliner\ =}$ 1.639

III) Safety Factor for Tensile Strength for Casings (use lessor of joint strength or yield

strength, as appropriate)

Conductor Pipe (16", 55 lb/ft, A53)

$SF_{conductor}$ = 1 + (258,000 lbs – 6,930 lbs) / 6,930 lbs

$SF_{conductor}$ = 37.2

Surface Casing (11.75", 42 lb/ft, H-40 ST&C, use joint strength)

$SF_{surf\ casing}$ = 1 + (307,000 lbs – 37,548 lbs) /37,548 lbs

$SF_{surf\ casing}$ = 8.18

Longstring Casing (7" 23 lb/ft, N80, use joint strength)

$SF_{longstring\ csaing}$ = 1 + (442,000 psi – 135,654 psi) / 135,654 psi

$SF_{longstring\ csaing}$ **= 3.26**

Liner 4" 11.6 lb/ft J-55 LT

SF_{lliner} - 1 + (162,000 -68,417)/ 68,417

$SF_{lliner\ =}$ 2.36

IV . Safety Factor for External Collapse Strength for Injection Tubing

SF = 1 + (4,010– 1,750psi) / 1,750 psi

$SF_{inj\ tubing}$ = 2.29

V) Safety Factor for Internal Yield Strength for Injection Tubing

$SF_{inj.tubing}$ = 1 + (4,790 psi – 1,865 psi) / 1,865 psi

$\mathbf{SF_{inj.tubing} = 2.57}$

III) Safety Factor for Tensile Strength for Injection Tubing

Includes load for weight and thermal contraction, as discussed in Section III.A.3.c above, for Maximum Injection Tubing Stress:

$$SF_{inj.tubing} = 1 + (132{,}000 \text{ lbs} - 92{,}378 \text{ lbs}) / 92{,}378 \text{ lbs}$$

$\mathbf{sSF_{inj.tubing} = 1.43}$

In summary, the sizes, weights, grades, coupling systems, and materials of construction for the proposed new well casings and injection tubing are more than adequate for use in the proposed new well at the Buckeye Brine facility, even when considering maximum calculated conditions that greatly exceed what is expected, or that is even possible in most cases.

III.A.3.e. Injection Packer Specifications- Size, Type, Life Expectancy, and Setting Depth

The packer is a 3.5-inch x 7-inch ASI-X set, with the top of the unit at 5,848 feet BGL. The specification sheet for the packer is attached as Figure III.B at the end of this section.

III.A.3.f. Selection of Tubulars

The well design includes tubular selected based on strengths, grade, and depths related to:

- Depths of lowermost USDW, injection interval, and zone;
- Volumes of wastes to be injected;
- Pressures under static and injection conditions;
- Fluid properties (density, composition, corrosive properties, temperature) of injection and formation fluids; and
- Subsurface conditions (pressures, temperatures).

As discussed above in the detailed calculations regarding strengths of the various casings and tubular components (Section III.A.3.d), the well components are of sufficient strength to withstand a reasonable potential stress projection with substantial multiples of design capability.

Lowermost USDW Protection

The lowermost USDW, defined to be 330 feet below ground surface (Section II) is covered by three separate casing strings (surface casing, longstring casing, liner), with each string extending through and below the USDW. A Cement Bond Log (CBL) run after cementing the surface casing indicates effective cement from the base of the surface casing (894 ft BGL) to 0 ft. BGL. A similar CBL performed on the long string casing indicates effective cement from the bottom of the long string casing (5,898 ft. BGL) to 906 ft. BGL. A 4.5" liner see was installed following a small leak detected in the 7" long string casing during a MI test of Adams #1. The liner is cemented in place between 0 ft BGL and 5879 ft BGL. A copy of this document, which has been sent to the OEPA previously, is enclosed in Appendix III to this application and titled **2020 Liner Installation and Mechanical Integrity Testing of Adams No. 1 (UIC 04-16-017-PTO-1).**

Adams #1 Construction Related Logs

The selection of the tubular and design calculations and factor of safety calculations given above considered current and maximum possible formation densities, injection pressures, and formation pressures (both maximum and minimum in the case of complete evacuation of the borehole due to loss of circulation).

Reservoir and Injected Fluid Temperature and Pressure Considerations

As discussed in Section IV (Reservoir Mechanics) the static bottom-hole temperature at TD was measured at 145° F before injection began in the well. Logs run during subsequent annual mechanical integrity tests indicate that the maximum temperature observed at 6,700 ft. BGL is approximately 135° F. During mechanical integrity testing performed on October 18, 2016, the static reservoir pressure at 6,700 ft. BGL was measured to be 3,152 psia. Coupling the pressure increase at the maximum allowable permitted injection pressure (1,359 psig) with a maximum permitted injection fluid specific gravity of 1.2 would result in a maximum bottom-hole reservoir pressure of 4,511 psig:

Measured BHP at depth 6,700 + surface pr

Liner 4" 11.6 lb/ft J-55 LT

SF_{lliner} - 1 + (4,960 -3026)/ 3026

SF_{lliner} = 1.639

pressure at MASIP =maximum bottom hole pressure

3,152 + 1,359 = 4,511 psig.

While there are no industry standards that define High Pressure High Temperature (HPHT) reservoir conditions, Schlumberger suggests that HPHT conditions begin above 300° F and 10,000 psig. These conditions are not present at Buckeye Brine, as described in the pressure discussion above and in Section IV. Furthermore, the design calculations and factor of safety calculations presented in Section III. A3.c-d demonstrate that the selected tubular are more than sufficient to meet the expected maximum possible adverse conditions at Buckeye Brine.

III.A.4. Type of Completion and Completion Interval

The type of completion used for the Adams #1 is an open-hole that begins at the bottom of the longstring casing (5,898 ft. BGL) and extends to 7,288 ft. BGL. A schematic of the well construction and configuration is provided as Figure III.A.

III.A.5. Centralization Program

A float shoe and float collar were run on the longstring casing to facilitate adequate cementing and cement bonding. A bottom joint float collar was installed 10 ft. from the bottom of the casing and centralizers were installed on the first 10 joints run into the well.

III.A.6. Annulus (Packer) Fluid

The packer fluid will consist of freshwater with a commercial corrosion inhibitor, and oxygen scavenger added at concentrations recommended by the supplier of the additives. The annulus fluid management system includes a 300 gallon poly tank for storage of the treated freshwater.

III.A.7. Drilling and Completion Procedure

The driller's daily log for the Adams #1 indicates that the well was spudded on December 21, 2011. The contents of the driller's daily log are provided as Table III.A.

Table III.3.A Drillers Log Adams #1

12/20/2011		*Moving In Wildcat Rig 1*
12/21/2011		*Finish Rigging Up ; Dig Pits ; Spud well 4:00 PM*
12/22/2011	7:00AM	*WOC ; Drilled to 125'; Run 124' - 16"Conductor Cement to surface ; good returns;Plug down 5:00AM*
12/23/2011	7:00AM	*Running 882' of 11 3/4" Surface Pipe; Drill to 937' Plug down; 46 Bbls. cement returns; cement standing up back side. Shut down for Christmas will restart drilling on Tuesday, January 3, 2012.*
1/3/2012		*Finish Blow Pit: Nippling Up; Should be Drilling by Noon*
1/4/2012	7:00AM	*1220' Drilling on Air; drilling 90'/Hr. Had problem nippling up. Got corrected ;Performed BOP test with ODNR inspector. Pressured to 595# Held for 15Mins. With no leak off.*
	1:30PM	*1701' Drilling 75'/Hr. ;Drilling with 9 7/8" VAREL PDC Bit*
1/5/2012	7:00AM	*2700' Dusting ; Top of Lime 2370' ; Current D/R 35'/Hr.*
1/6/2012	7:00AM	*3310' Soaping: D/R 1Hr. 15 Mins/Kelly ; Drilling slower than expected; 160' to be out of the Lime*
1/7/2012	2:00AM	*3688' trip bit; &;00AM back on bottom*
1/8/2012	7:00AM	*5039' Soaping*
1/9/2012	7:00AM	*Tripping out of hole; TD 9 7/8" Hole at 2:00 Am @ 5895"*
1/10/2012	7:00AM	*Cement trucks on location - mixing cement for 7". Ran 5898' 7".* Plug down at 11:30 a.m. on cement job.
1/11/2012	7:00AM	*W.O.C. ; Will run Bond Log Mid Afternoon;Unload Slim Hole DP Unload D/P ; Run bond log with Gray Wireline ; Start nippling Up*
1/12/2012	7:00 AM	*Tripping in slim hole pipe with 6 1/4" Varel 5 blade PDC Unloading hole on way in*
1/13/2012	7:00AM	*5898' -Drilling Float shoe ; Unload hole with air*
1/14/2012	7:00AM	*6457' – Soaping*
1/15/2012	7:00AM	*6810' on Fluid ; Switch to Fluid at 6538'; Pull 14 stands ,Remove string float; Water wt. 9.1#; Current* ROP *15'/Hr.; Lost 660 Bbls.* in 18 Hrs. since switching to fluid ; EST. TD Monday AM
1/16/2010	7:00AM	*7065' on fluid ; Current* ROP *16'/Hr.: Lost 220 Bbls. in 24 Hrs. Plan to TD @ 7200'*
1/17/2012	7:00AM	*Circulating hole;TD at 4:00AM 7270' Logging scheduled for 4:00PM*
1/18/2012	7:00AM	*Logger wrapping up. Preparing to run bottom hole packer on 4 1/2" pipe. Laid down and moved-out drill pipe. Completed logging.*

III.A.8. Cementing Program

The cementing program for the conductor, surface, and longstring casing was to circulate sufficient cement to see returns at the surface. Returns were observed by ODNR staff during the cementing of the conductor and surface casings (see ODNR completion records, casing ticket and permit forms in Appendix II of the 2017 PTO application).

During the cementing of the longstring casing, circulation was lost to the injection interval and returns were not observed at the surface. A cement bond log (copy provided in Appendix III) indicates that well-bonded cement is present behind the long string casing from 5,898 ft. BGL to 906 ft. BGL. A copy of the ODNR Casing Inspection Ticket, which contains information about the type and amount of cement that ODNR staff witnessed being used behind each size of casing installed, was submitted as Attachment III.B.6. in the Class 1 PTO application submitted for this well in 2017. The cementing of the liner in 2020 is detailed in the 2020 Liner Installation and Mechanical Integrity Testing of Adams # 1 Report which is enclosed in Appendix III of this application.

III.A.9. Collection of cores and formation fluids

No cores or samples of native formation fluids were collected during the drilling and completion of Adams #1. Buckeye Brine believes that the fact that over 4 million barrels of produced saltwater have been injected into the Adams #1 well to date is evidence that the injection interval has sufficient permeability and porosity.

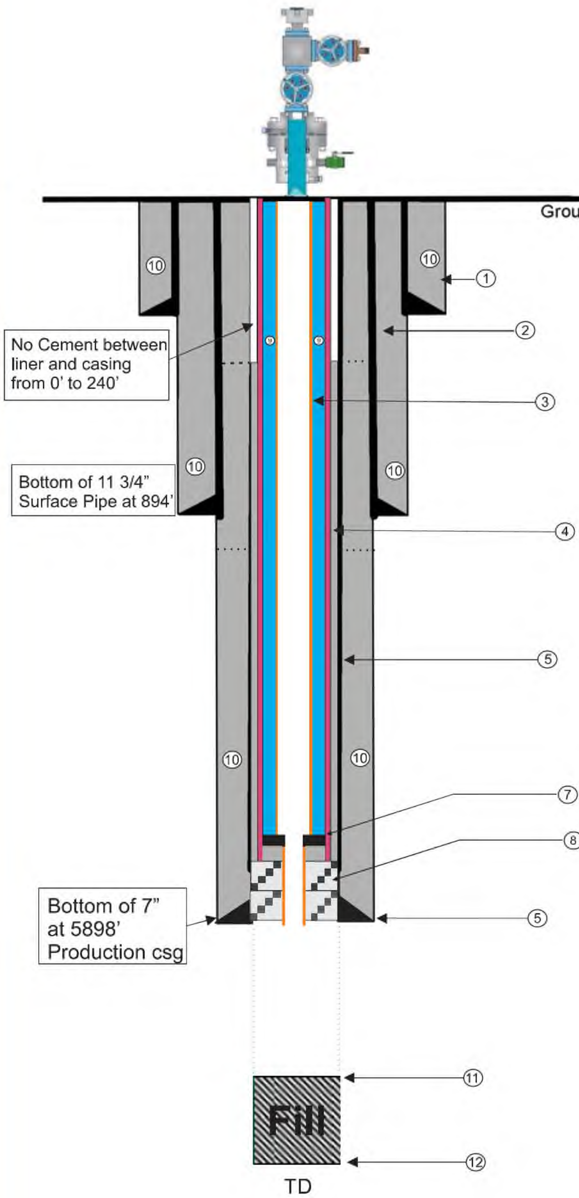
Class I wastes injected into the Adams #1 well in the future will be interacting initially with the injected produced saltwater as the native formation water has been displaced by the significant volumes (>10,000,000 bbls) injected into the three Adams wells since the beginning of operations in 2012.

Figure III.A

STATE OF OHIO
BRADLEY
PEKAS
E-83267
REGISTERED
PROFESSIONAL ENGINEER

Bradley S. Pekas 12/15/23

Bradley S. Pekas Date
Ohio PE License # E-83267



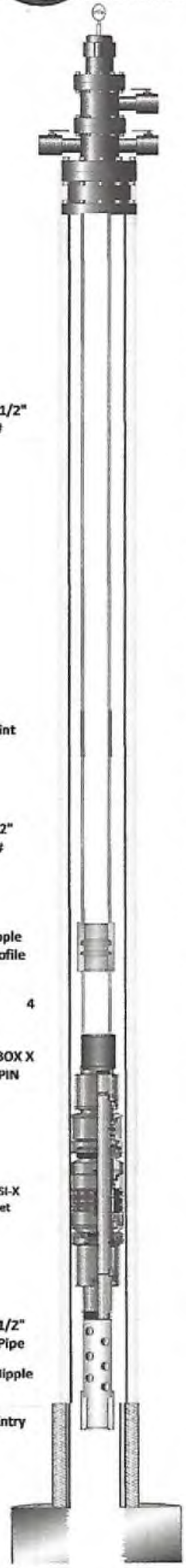
BELOW GROUND DETAIL

1. Conductor Casing: 16", ST&C from 0-126'. Cemented to surface.
2. Surface Casing: 11 3/4", ST&C from 0' to 894'. Cemented to surface.
3. Injection Tubing: 2 7/8" 6.5 #/ft J-55 tubing installed to top of packer, 5848'. 2 3/8" 4.7 #/ft tubing installed below packer, 5854' to ~5919'.
4. Liner: 4 1/2" 11.6 #/ft from 0-5879'
5. Protection/Longstring Casing (bottom to top): LT&C 7" 23# from 0-5898'. Cemented from 0'-5898' up to 906' (Bond Log). Cemented to surface in two stages on 9/12 & 9/13 2019.
7. Packer: From 5848' to 5854'
8. Bridge Plugs: From 5888' to 5898'. Cored through with 3 7/8" bit.
9. 10 #/Gal Inhibited Annulus Fluid:
10. Cement:
11. Fill: RAT tag **July 30,2023** at 67**62**'.
12. TD 7288' (fill in hole)

	CLIENT	PROJECT DESCRIPTION	FIGURE III.A
TiAlpha Environmental Services, LLC 311 East Cotton Street • Longview, Texas 75601 Phone (903) 234-8443 • Fax (903) 234-1641	Buckeye Brine, LLC	Adams #1 UIC 04-16-017-PTO-1	DATE: 9/14/20 Figure III.A

BLUE DOT ENERGY SERVICES LLC

Figure III.B Adams # 1 Packer Assembly Schematic (4/15/17)



Buckeye Brine

Well Name	Adams	#1		Date:	10/22/2015	KB
County:	Coshocton		State:	Ohio		
Company Rep.	Rex Baker		Tool Operator	P. Dean		
Casing Size	7"		Tubing Size	4 1/2"		
Casing Weight	26#		Tubing Weight	10.5		
Casing Grade	J-55		Tubing Grade	J-55		

Quanity	Description	Max O.D.	Min I.D.	Length	
1	3 1/2" Re-Entry Guide	4.480	2.992	0.47	5885.74
1	3 1/2" XN-Nipple w/ 2.812 Profile	4.470	2.812	1.06	5885.27
2	3 1/2" Perforated Tubing	4.500	2.992	64.78	5884.21
1	3 1/2" x 7" ASI-X Packer	6.125	2.992	7.90	5819.43
1	3 1/2" EUE Pin x 4 1/2" STC Box Sub	5.000	3.000	0.95	5811.53
1	4 1/2" Pup Joint	5.000	4.052	8.48	5810.58
1	4 1/2" X-Nipple w/ 3.813 Profile	5.000	3.813	1.77	5802.10
5	4 1/2" Casing—10.5#—J-55—STC	5.000	4.052	210.84	5800.33
1	4 1/2" Pup Joint	5.000	4.052	8.48	5589.49
127	4 1/2" Casing—10.5#—J-55—STC	5.000	4.052	5561.81	5581.01
2	4 12" Pup joint	5.000	4.052	19.20	19.20
	Top of Packer-5811'				
	Center of Packer-5815'				
	Bottom of Packer-5819'				
	Packer Set in 16K Compression				
			Total Footage	5885.74	

Modified to 2 7/8" tubing with a 4 1/2" Injection Packer during the 2020 Adams #1 Workover and Mechanical Integrity Testing as approved by the agency on 06/29/2020

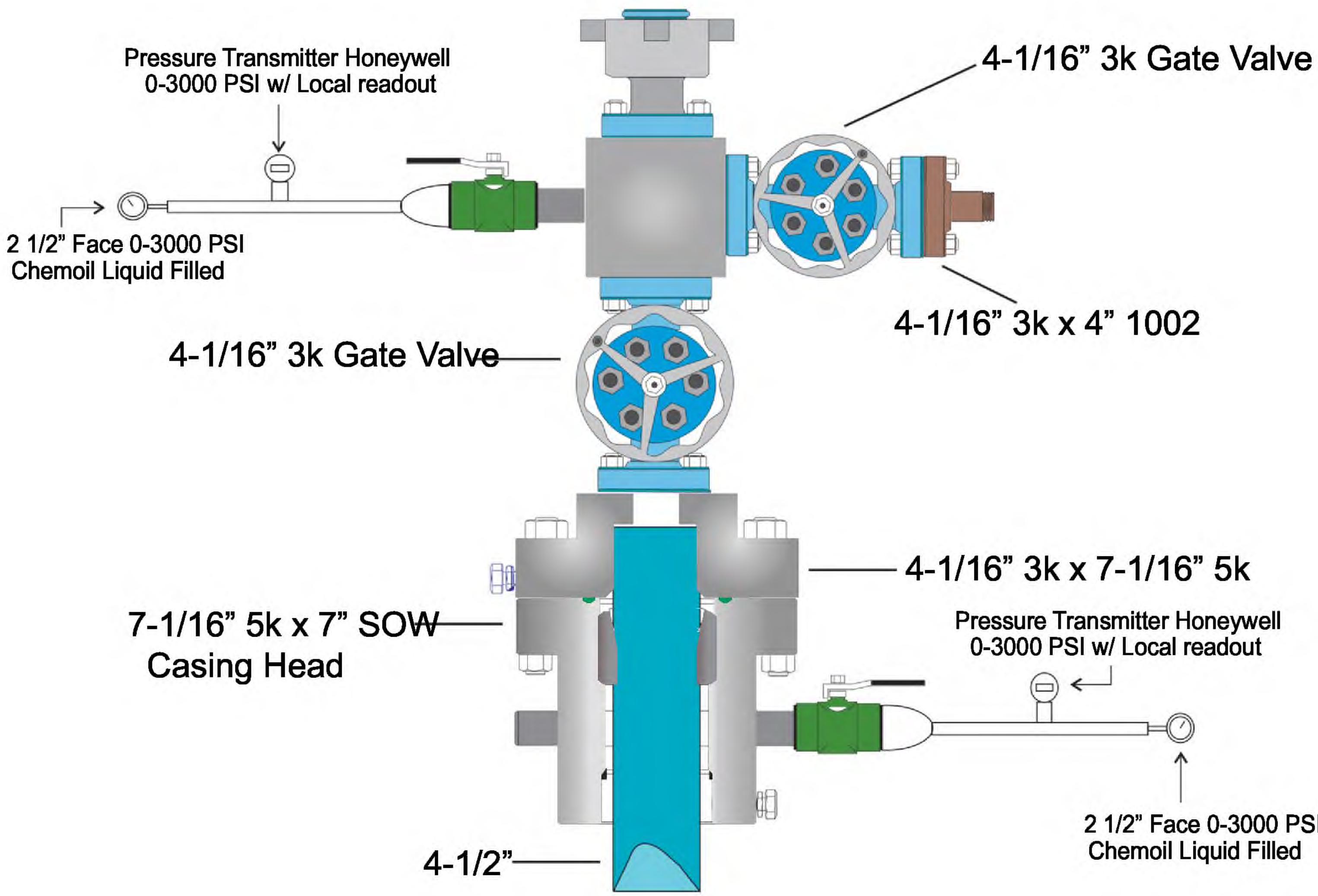
Figure III.C Adams #1 Wellhead Assembly
3/6/2018

UNIVERSAL WELLHEAD SERVICES, LLC.

Schematic

Buckeye Brine

Adams #1



Attachment III.B.6.

Ohio Department of Natural Resource
Division of Oil and Gas Resources Management
1855 Fountain Square Court, Building H3
Columbus, Ohio 43224
Form 55: Revised 12/97

Casing Ticket

API Well Number:

34-031-2-7177-00-00

Record of Casing, Cementing and Mudding

Well Owner: 8613 PREFERRED FLUIDS MGT LLC

Lease Name: ADAMS (SWIW #10) 1 Well No. 1

County: COSHOCTON Township: KEENE

Driller. WILDCAT DRILLING Tool Air Rotar

Refer Top Ground Level 775 Lat: 0.000000 Long: 0.000000

Date Spudded: 12/21/2011

Date Completed:

Inspector ROCKY KING

☐ AD Meets Requirements

☐ AD on Permit

Comments: TD surface 937'.

Strings

FLD *Conductor Pipe Field Entry **CONDITION** New

Bot 100 **Diam** 16 **Top** 0 **LENGTH** **Set Dt** 12/22/2011

String Comments Casing Condition, Weight and Cement Basket

Cement

BOC 100 **TOC** 0 ☑ **WITNESSED**

CMT_CON UNIVERSAL WELL SERVICES **INSPECTOR** ROCKY KING

CLASS_CMT: Class A Cement **SACKS** 50 **YIELD** 1.18 **WEIGHT** 15.6

Cement 1 Good returns

CLASS_CMT2: **SACKS2** **YIELD** **WEIGHT**

Cement 2

Strings

FLD	*Surface Casing Field Entry	CONDITION	New				
Bot	882	Diam	11.075	Top	0	LENGTH	
Set Dt	12/23/2011						

String Comments Casing Condition, Weight and Cement Basket

Cement

BOC	882	TOC	0	☑ WITNESSED			
CMT_CON	UNIVERSAL WELL SERVICES	INSPECTOR	ROCKY KING				
CLASS_CMT:	Class A Cement	SACKS	100	YIELD	1.18	WEIGHT	15.6
Cement 1	Good returns						
CLASS_CMT2:	Light/Standard Cement (50/50 C	SACKS2	437	YIELD		WEIGHT	13.6
Cement 2							

Strings

FLD	*Intermediate 1 Field Entry	CONDITION	New				
Bot	5898	Diam	7	Top	0	LENGTH	
Set Dt	1/9/2012						

String Comments Casing Condition, Weight and Cement Basket

Ran 5898' of L88 23 # 7" casing. Float shoe on bottom joint-float collar 10' from bottom of casing. Centralizers on first 10 joints of casing ran in hole.

Cement

BOC	5898	TOC	0	☑ WITNESSED			
CMT_CON	UNIVERSAL WELL SERVICES	INSPECTOR	ROCKY KING				
CLASS_CMT:	Class A Cement	SACKS	450	YIELD	1.19	WEIGHT	15.7
Cement 1	Well circulated gel then quit circulating with 152 barrel to pump.						
CLASS_CMT2:	Light/Standard Cement (50/50 C	SACKS2	1200	YIELD	1.82	WEIGHT	13.1
Cement 2							

Production Tubing Tally

					Tubing		Casing
Jts on Location		KOP		Description:	2 7/8 Tbg	Description:	4 1/2" Csg
		PBTD		Weight / ft:	6.5	Weight / ft:	10.5#
		TVD		O.D.:	2.875	O.D.:	4.50
Floor	5	90 deg		I.D.:	2.441	I.D.:	4
KB		ToeSub		Grade	J-55	Grade	J-55
BHA	65.46	Jt Ave. W/ BHA	32.12	Drift:	2.347	Drift:	3.942
Total	(5.00)	Jt Ave.	32.33	Capacity:	0.0058	Capacity:	0.0159

Well: **Date:**

Joint #	Description				Length per joint	Running Depth	Total Weight	Tubing Capacity	Annular Capacity	CAPACITY W/ TUBING	CAPACITY W/ OUT TUBING				
1	2 7/8 Tbg				40.50	35.50	230.75	.21	.27	.47	0.56	ASI-X	L-6.20	OD-3.77	ID-1.995
2	2 7/8 Tbg				32.62	68.12	442.78	.40	.51	.91	1.08	BX Nipple	L-1.12	OD-3.68	ID-2.331
3	2 7/8 Tbg				32.62	100.74	654.81	.58	.76	1.34	1.60				
4	2 7/8 Tbg				32.61	133.35	866.78	.77	1.00	1.78	2.12				
5	2 7/8 Tbg				32.60	165.95	1078.68	.96	1.25	2.21	2.64				
6	2 7/8 Tbg				32.58	198.53	1290.45	1.15	1.49	2.64	3.16				
7	2 7/8 Tbg				32.63	231.16	1502.54	1.34	1.74	3.08	3.68				
8	2 7/8 Tbg				32.53	263.69	1713.99	1.53	1.98	3.51	4.19				
9	2 7/8 Tbg				32.58	296.27	1925.76	1.72	2.23	3.94	4.71				
10	2 7/8 Tbg				32.64	328.91	2137.92	1.91	2.47	4.38	5.23				
11	2 7/8 Tbg				32.57	361.48	2349.62	2.10	2.72	4.81	5.75				
12	2 7/8 Tbg				32.59	394.07	2561.46	2.29	2.96	5.25	6.27				
13	2 7/8 Tbg				32.60	426.67	2773.36	2.47	3.21	5.68	6.78				
14	2 7/8 Tbg				32.58	459.25	2985.13	2.66	3.45	6.11	7.30				
15	2 7/8 Tbg				32.59	491.84	3196.96	2.85	3.70	6.55	7.82				
16	2 7/8 Tbg				32.65	524.49	3409.19	3.04	3.94	6.98	8.34				
17	2 7/8 Tbg				32.65	557.14	3621.41	3.23	4.19	7.42	8.86				
18	2 7/8 Tbg				32.70	589.84	3833.96	3.42	4.43	7.85	9.38				
19	2 7/8 Tbg				32.65	622.49	4046.19	3.61	4.68	8.29	9.90				
20	2 7/8 Tbg				32.60	655.09	4258.09	3.80	4.92	8.72	10.42				
21	2 7/8 Tbg				32.71	687.80	4470.70	3.99	5.17	9.16	10.94				
22	2 7/8 Tbg				32.60	720.40	4682.60	4.18	5.41	9.59	11.45				
23	2 7/8 Tbg				32.60	753.00	4894.50	4.37	5.66	10.02	11.97				
24	2 7/8 Tbg				32.69	785.69	5106.99	4.56	5.90	10.46	12.49				
25	2 7/8 Tbg				32.60	818.29	5318.89	4.75	6.15	10.89	13.01				
26	2 7/8 Tbg				32.68	850.97	5531.31	4.94	6.39	11.33	13.53				

10/28/2020

Well: **Date:**

Joint #	Description				Length per joint	Running Depth	Total Weight	Tubing Capacity	Annular Capacity	CAPACITY W/ TUBING	CAPACITY W/ OUT TUBING
27	2 7/8 Tbg				**32.65**	**883.62**	5743.53	5.12	6.64	11.76	14.05
28	2 7/8 Tbg				**32.69**	**916.31**	5956.02	5.31	6.88	12.20	14.57
29	2 7/8 Tbg				**32.70**	**949.01**	6168.57	5.50	7.13	12.63	15.09
30	2 7/8 Tbg				**32.68**	**981.69**	6380.99	5.69	7.38	13.07	15.61
31	2 7/8 Tbg				**32.75**	**1014.44**	6593.86	5.88	7.62	13.51	16.13
32	2 7/8 Tbg				**32.75**	**1047.19**	6806.74	6.07	7.87	13.94	16.65
33	2 7/8 Tbg				**32.61**	**1079.80**	7018.70	6.26	8.11	14.38	17.17
34	2 7/8 Tbg				**32.70**	**1112.50**	7231.25	6.45	8.36	14.81	17.69
35	2 7/8 Tbg				**32.54**	**1145.04**	7442.76	6.64	8.60	15.24	18.21
36	2 7/8 Tbg				**32.61**	**1177.65**	7654.73	6.83	8.85	15.68	18.72
37	2 7/8 Tbg				**32.62**	**1210.27**	7866.76	7.02	9.09	16.11	19.24
38	2 7/8 Tbg				**32.55**	**1242.82**	8078.33	7.21	9.34	16.55	19.76
39	2 7/8 Tbg				**32.58**	**1275.40**	8290.10	7.40	9.58	16.98	20.28
40	2 7/8 Tbg				**32.58**	**1307.98**	8501.87	7.59	9.83	17.41	20.80
41	2 7/8 Tbg				**32.55**	**1340.53**	8713.45	7.78	10.07	17.85	21.31
42	2 7/8 Tbg				**32.58**	**1373.11**	8925.22	7.96	10.32	18.28	21.83
43	2 7/8 Tbg				**32.58**	**1405.69**	9136.99	8.15	10.56	18.71	22.35
44	2 7/8 Tbg				**32.63**	**1438.32**	9349.08	8.34	10.81	19.15	22.87
45	2 7/8 Tbg				**32.58**	**1470.90**	9560.85	8.53	11.05	19.58	23.39
46	2 7/8 Tbg				**32.62**	**1503.52**	9772.88	8.72	11.30	20.02	23.91
47	2 7/8 Tbg				**32.61**	**1536.13**	9984.84	8.91	11.54	20.45	24.42
48	2 7/8 Tbg				**32.56**	**1568.69**	10196.49	9.10	11.79	20.88	24.94
49	2 7/8 Tbg				**32.54**	**1601.23**	10408.00	9.29	12.03	21.32	25.46
50	2 7/8 Tbg				**32.58**	**1633.81**	10619.77	9.48	12.28	21.75	25.98
51	2 7/8 Tbg				**32.54**	**1666.35**	10831.28	9.66	12.52	22.18	26.49
52	2 7/8 Tbg				**32.61**	**1698.96**	11043.24	9.85	12.76	22.62	27.01
53	2 7/8 Tbg				**32.55**	**1731.51**	11254.82	10.04	13.01	23.05	27.53
54	2 7/8 Tbg				**32.62**	**1764.13**	11466.85	10.23	13.25	23.49	28.05
55	2 7/8 Tbg				**32.60**	**1796.73**	11678.75	10.42	13.50	23.92	28.57
56	2 7/8 Tbg				**32.58**	**1829.31**	11890.52	10.61	13.74	24.35	29.09
57	2 7/8 Tbg				**32.55**	**1861.86**	12102.09	10.80	13.99	24.79	29.60
58	2 7/8 Tbg				**32.55**	**1894.41**	12313.67	10.99	14.23	25.22	30.12
59	2 7/8 Tbg				**32.55**	**1926.96**	12525.24	11.18	14.48	25.65	30.64
60	2 7/8 Tbg				**32.52**	**1959.48**	12736.62	11.36	14.72	26.09	31.16
61	2 7/8 Tbg				**32.58**	**1992.06**	12948.39	11.55	14.97	26.52	31.67
62	2 7/8 Tbg				**32.57**	**2024.63**	13160.10	11.74	15.21	26.95	32.19
63	2 7/8 Tbg				**32.58**	**2057.21**	13371.87	11.93	15.46	27.39	32.71

Well: **Date:**

Joint #	Description				Length per joint	Running Depth	Total Weight	Tubing Capacity	Annular Capacity	CAPACITY W/ TUBING	CAPACITY W/ OUT TUBING
64	2 7/8 Tbg				32.58	2089.79	13583.64	12.12	15.70	27.82	33.23
65	2 7/8 Tbg				32.57	2122.36	13795.34	12.31	15.95	28.26	33.75
66	2 7/8 Tbg				32.55	2154.91	14006.92	12.50	16.19	28.69	34.26
67	2 7/8 Tbg				32.52	2187.43	14218.30	12.69	16.43	29.12	34.78
68	2 7/8 Tbg				32.55	2219.98	14429.87	12.88	16.68	29.55	35.30
69	2 7/8 Tbg				32.59	2252.57	14641.71	13.06	16.92	29.99	35.82
70	2 7/8 Tbg				32.58	2285.15	14853.48	13.25	17.17	30.42	36.33
71	2 7/8 Tbg				32.66	2317.81	15065.77	13.44	17.41	30.86	36.85
72	2 7/8 Tbg				32.58	2350.39	15277.54	13.63	17.66	31.29	37.37
73	2 7/8 Tbg				32.54	2382.93	15489.05	13.82	17.90	31.72	37.89
74	2 7/8 Tbg				32.55	2415.48	15700.62	14.01	18.15	32.16	38.41
75	2 7/8 Tbg				32.55	2448.03	15912.20	14.20	18.39	32.59	38.92
76	2 7/8 Tbg				32.58	2480.61	16123.97	14.39	18.64	33.02	39.44
77	2 7/8 Tbg				32.50	2513.11	16335.22	14.58	18.88	33.46	39.96
78	2 7/8 Tbg				32.58	2545.69	16546.99	14.77	19.13	33.89	40.48
79	2 7/8 Tbg				32.62	2578.31	16759.02	14.95	19.37	34.33	41.00
80	2 7/8 Tbg				32.61	2610.92	16970.98	15.14	19.62	34.76	41.51
81	2 7/8 Tbg				32.59	2643.51	17182.82	15.33	19.86	35.19	42.03
82	2 7/8 Tbg				32.60	2676.11	17394.72	15.52	20.11	35.63	42.55
83	2 7/8 Tbg				32.45	2708.56	17605.64	15.71	20.35	36.06	43.07
84	2 7/8 Tbg				32.64	2741.20	17817.80	15.90	20.60	36.49	43.59
85	2 7/8 Tbg				32.56	2773.76	18029.44	16.09	20.84	36.93	44.10
86	2 7/8 Tbg				32.57	2806.33	18241.15	16.28	21.08	37.36	44.62
87	2 7/8 Tbg				32.62	2838.95	18453.18	16.47	21.33	37.80	45.14
88	2 7/8 Tbg				32.53	2871.48	18664.62	16.65	21.57	38.23	45.66
89	2 7/8 Tbg				32.62	2904.10	18876.65	16.84	21.82	38.66	46.18
90	2 7/8 Tbg				32.52	2936.62	19088.03	17.03	22.06	39.10	46.69
91	2 7/8 Tbg				32.63	2969.25	19300.13	17.22	22.31	39.53	47.21
92	2 7/8 Tbg				32.54	3001.79	19511.64	17.41	22.55	39.96	47.73
93	2 7/8 Tbg				32.59	3034.38	19723.47	17.60	22.80	40.40	48.25
94	2 7/8 Tbg				32.60	3066.98	19935.37	17.79	23.04	40.83	48.76
95	2 7/8 Tbg				32.60	3099.58	20147.27	17.98	23.29	41.27	49.28
96	2 7/8 Tbg				32.60	3132.18	20359.17	18.17	23.53	41.70	49.80
97	2 7/8 Tbg				32.58	3164.76	20570.94	18.36	23.78	42.13	50.32
98	2 7/8 Tbg				32.48	3197.24	20782.06	18.54	24.02	42.57	50.84
99	2 7/8 Tbg				32.56	3229.80	20993.70	18.73	24.27	43.00	51.35
100	2 7/8 Tbg				32.44	3262.24	21204.56	18.92	24.51	43.43	51.87

Well: **Date:**

Joint #	Description				Length per joint	Running Depth	Total Weight	Tubing Capacity	Annular Capacity	CAPACITY W/ TUBING	CAPACITY W/ OUT TUBING
101	2 7/8 Tbg				32.49	3294.73	21415.75	19.11	24.75	43.86	52.39
102	2 7/8 Tbg				32.54	3327.27	21627.26	19.30	25.00	44.30	52.90
103	2 7/8 Tbg				32.58	3359.85	21839.03	19.49	25.24	44.73	53.42
104	2 7/8 Tbg				32.60	3392.45	22050.93	19.68	25.49	45.16	53.94
105	2 7/8 Tbg				32.57	3425.02	22262.63	19.87	25.73	45.60	54.46
106	2 7/8 Tbg				32.58	3457.60	22474.40	20.05	25.98	46.03	54.98
107	2 7/8 Tbg				32.54	3490.14	22685.91	20.24	26.22	46.46	55.49
108	2 7/8 Tbg				32.56	3522.70	22897.55	20.43	26.47	46.90	56.01
109	2 7/8 Tbg				32.58	3555.28	23109.32	20.62	26.71	47.33	56.53
110	2 7/8 Tbg				32.57	3587.85	23321.03	20.81	26.96	47.77	57.05
111	2 7/8 Tbg				32.59	3620.44	23532.86	21.00	27.20	48.20	57.56
112	2 7/8 Tbg				32.58	3653.02	23744.63	21.19	27.45	48.63	58.08
113	2 7/8 Tbg				32.54	3685.56	23956.14	21.38	27.69	49.07	58.60
114	2 7/8 Tbg				32.57	3718.13	24167.85	21.57	27.93	49.50	59.12
115	2 7/8 Tbg				32.55	3750.68	24379.42	21.75	28.18	49.93	59.64
116	2 7/8 Tbg				32.55	3783.23	24591.00	21.94	28.42	50.37	60.15
117	2 7/8 Tbg				32.57	3815.80	24802.70	22.13	28.67	50.80	60.67
118	2 7/8 Tbg				32.57	3848.37	25014.41	22.32	28.91	51.23	61.19
119	2 7/8 Tbg				32.56	3880.93	25226.05	22.51	29.16	51.67	61.71
120	2 7/8 Tbg				32.58	3913.51	25437.82	22.70	29.40	52.10	62.22
121	2 7/8 Tbg				32.55	3946.06	25649.39	22.89	29.65	52.53	62.74
122	2 7/8 Tbg				32.50	3978.56	25860.64	23.08	29.89	52.97	63.26
123	2 7/8 Tbg				32.57	4011.13	26072.35	23.26	30.14	53.40	63.78
124	2 7/8 Tbg				32.53	4043.66	26283.79	23.45	30.38	53.83	64.29
125	2 7/8 Tbg				32.56	4076.22	26495.43	23.64	30.63	54.27	64.81
126	2 7/8 Tbg				32.56	4108.78	26707.07	23.83	30.87	54.70	65.33
127	2 7/8 Tbg				32.58	4141.36	26918.84	24.02	31.11	55.13	65.85
128	2 7/8 Tbg				32.55	4173.91	27130.42	24.21	31.36	55.57	66.37
129	2 7/8 Tbg				32.56	4206.47	27342.06	24.40	31.60	56.00	66.88
130	2 7/8 Tbg				32.57	4239.04	27553.76	24.59	31.85	56.44	67.40
131	2 7/8 Tbg				32.57	4271.61	27765.47	24.78	32.09	56.87	67.92
132	2 7/8 Tbg				32.54	4304.15	27976.98	24.96	32.34	57.30	68.44
133	2 7/8 Tbg				32.59	4336.74	28188.81	25.15	32.58	57.74	68.95
134	2 7/8 Tbg				32.52	4369.26	28400.19	25.34	32.83	58.17	69.47
135	2 7/8 Tbg				32.52	4401.78	28611.57	25.53	33.07	58.60	69.99
136	2 7/8 Tbg				32.55	4434.33	28823.15	25.72	33.32	59.03	70.51
137	2 7/8 Tbg				32.43	4466.76	29033.94	25.91	33.56	59.47	71.02

Well: **Date:**

Joint #	Description				Length per joint	Running Depth	Total Weight	Tubing Capacity	Annular Capacity	CAPACITY W/ TUBING	CAPACITY W/ OUT TUBING
138	2 7/8 Tbg				32.53	4499.29	29245.39	26.10	33.80	59.90	71.54
139	2 7/8 Tbg				32.53	4531.82	29456.83	26.28	34.05	60.33	72.06
140	2 7/8 Tbg				32.51	4564.33	29668.15	26.47	34.29	60.77	72.57
141	2 7/8 Tbg				32.55	4596.88	29879.72	26.66	34.54	61.20	73.09
142	2 7/8 Tbg				32.52	4629.40	30091.10	26.85	34.78	61.63	73.61
143	2 7/8 Tbg				32.55	4661.95	30302.68	27.04	35.03	62.07	74.13
144	2 7/8 Tbg				32.56	4694.51	30514.32	27.23	35.27	62.50	74.64
145	2 7/8 Tbg				32.57	4727.08	30726.02	27.42	35.52	62.93	75.16
146	2 7/8 Tbg				32.56	4759.64	30937.66	27.61	35.76	63.37	75.68
147	2 7/8 Tbg				32.62	4792.26	31149.69	27.80	36.01	63.80	76.20
148	2 7/8 Tbg				32.57	4824.83	31361.40	27.98	36.25	64.23	76.71
149	2 7/8 Tbg				32.55	4857.38	31572.97	28.17	36.49	64.67	77.23
150	2 7/8 Tbg				32.51	4889.89	31784.29	28.36	36.74	65.10	77.75
151	2 7/8 Tbg				32.53	4922.42	31995.73	28.55	36.98	65.53	78.27
152	2 7/8 Tbg				32.54	4954.96	32207.24	28.74	37.23	65.97	78.78
153	2 7/8 Tbg				32.58	4987.54	32419.01	28.93	37.47	66.40	79.30
154	2 7/8 Tbg				32.50	5020.04	32630.26	29.12	37.72	66.83	79.82
155	2 7/8 Tbg				32.55	5052.59	32841.84	29.31	37.96	67.27	80.34
156	2 7/8 Tbg				32.54	5085.13	33053.35	29.49	38.21	67.70	80.85
157	2 7/8 Tbg				32.51	5117.64	33264.66	29.68	38.45	68.13	81.37
158	2 7/8 Tbg				32.56	5150.20	33476.30	29.87	38.69	68.57	81.89
159	2 7/8 Tbg				32.58	5182.78	33688.07	30.06	38.94	69.00	82.41
160	2 7/8 Tbg				32.42	5215.20	33898.80	30.25	39.18	69.43	82.92
161	2 7/8 Tbg				32.56	5247.76	34110.44	30.44	39.43	69.86	83.44
162	2 7/8 Tbg				32.60	5280.36	34322.34	30.63	39.67	70.30	83.96
163	2 7/8 Tbg				32.55	5312.91	34533.92	30.81	39.92	70.73	84.48
164	2 7/8 Tbg				32.54	5345.45	34745.43	31.00	40.16	71.16	84.99
165	2 7/8 Tbg				32.53	5377.98	34956.87	31.19	40.41	71.60	85.51
166	2 7/8 Tbg				32.53	5410.51	35168.32	31.38	40.65	72.03	86.03
167	2 7/8 Tbg				32.54	5443.05	35379.83	31.57	40.89	72.46	86.54
168	2 7/8 Tbg				32.62	5475.67	35591.86	31.76	41.14	72.90	87.06
169	2 7/8 Tbg				32.57	5508.24	35803.56	31.95	41.38	73.33	87.58
170	2 7/8 Tbg				32.62	5540.86	36015.59	32.14	41.63	73.77	88.10
171	2 7/8 Tbg				32.60	5573.46	36227.49	32.33	41.87	74.20	88.62
172	2 7/8 Tbg				32.57	5606.03	36439.20	32.51	42.12	74.63	89.14
173	2 7/8 Tbg				32.57	5638.60	36650.90	32.70	42.36	75.07	89.65
174	2 7/8 Tbg				32.58	5671.18	36862.67	32.89	42.61	75.50	90.17

Well: **Date:**

Joint #	Description				Length per joint	Running Depth	Total Weight	Tubing Capacity	Annular Capacity	CAPACITY W/ TUBING	CAPACITY W/ OUT TUBING
175	2 7/8 Tbg				**32.53**	**5703.71**	37074.12	33.08	42.85	75.93	90.69
176	2 7/8 Tbg				**32.58**	**5736.29**	37285.89	33.27	43.10	76.37	91.21
177	2 7/8 Tbg				**32.59**	**5768.88**	37497.72	33.46	43.34	76.80	91.73
178	2 7/8 Tbg				**32.60**	**5801.48**	37709.62	33.65	43.59	77.24	92.24
179	2 7/8 Tbg				**8.04**	**5809.52**	37761.88	33.70	43.65	77.34	92.37
180	2 7/8 Tbg				**4.04**	**5813.56**	37788.14	33.72	43.68	77.40	92.44
181	2 7/8 Tbg				**32.60**	**5846.16**	38000.04	33.91	43.92	77.83	92.95

Attachment C

Closure and Post-Closure Plan with Cost Estimates

Plugging and Abandonment Plan

Revised: April 15, 2024

Version 1.0

Buckeye Brine, LLC

23986 Airport Road

Coshocton,

Ohio 43812

Phone: 740-295-9324

I.A.0 Mechanical Integrity Testing
At a minimum, an annular pressure test and Radioactive Tracer Survey (RTS) will be conducted on both wells to confirm the mechanical integrity of the wells prior to closure. Gauges used in these annulus pressure tests will be sensitive to changes equal to one-half of 1 percent of full scale readings.

Additional surveys and/or logs may also be run at the direction of the Director.

I.A.1 Plug and Abandonment Plan

Sections I.A.2 and I.A.3 outline the proposed plugging and abandonment procedures for the two Class I injection wells. Should it become necessary to make significant revisions to the method of closure described in the closure plan, Buckeye Brine will submit proposed changes to the Director of the Ohio EPA at least sixty (60) calendar days before closure, unless a shorter period of time is approved by the Director.

Cementing will consist of three separate cement plugs, using Class H cement (or equivalent).

I.A.2 Plug and Abandon Well Adams No. 1

a. Prepare well and location for plugging. Remove well house, well monitoring equipment, and wellhead injection piping as may be required to allow field activities.

b. Perform APT and RAT log.

c. Move in and rig up workover rig, mud pump, circulating pit, and pipe racks.

d. Remove tree and install blow out prevention (BOP) equipment.

e. Release ASi-X mechanical packer and circulate annular fluid from well with 45 barrels 9.0 lb./gal brine or brine of sufficient density to control well. Dispose of the sodium sulfite inhibited annular fluid (fluid may be bullheaded into injection formation and not circulated to surface).

f. Pull and lay down the ~6000' of 2 7/8" 6.4 lbs./ft. injection tubing and packer. Keep 2 7/8" tubing on site as the work string.

g. Run other logs if needed.

h. Make up a sliding valve cement retainer to set in 4 1/2" 11.6 lb./ft. casing on workstring. Run all of 2 7/8" workstring while running into well. Set cement retainer at bottom of casing +/- 5825'.

i. Mix and pump 310 sacks of Class A cement (yield 1.18 cf/sack) down the workstring tubing.

Squeeze approximately 280 sacks through retainer until a squeeze pressure of 500 psi is achieved or until 10 sacks of cement remain in tubing. Unstring from retainer (this action closes the sliding valve which removes the hydrostatic pressure from below the retainer) and spot remaining cement on top of retainer. Pull tubing to approximately 5620 ft. and reverse circulate until returns are clean. Trip out of hole with retainer stinger. Trip in hole with openended tubing. Wait for cement to harden a minimum of 8 hours.

j. Tag cement plug with tubing and note depth to top of plug. Anticipated cement top is approximately 5630 ft. Pressure test casing to 500 psi for 30 minutes.

k. Pull out of hole with work string, laying down joints until ~1100 ft. of workstring remains in the well and, mix and pump 50 sacks of Class A cement, and balance the plug. Pull up to approximately 950 ft. BGL and reverse circulate until clean returns. Trip out of hole standing workstring back in derrick. Wait for cement to harden a minimum of eight hours.

l. Trip into hole and tag cement plug with tubing and note depth to top of plug. Anticipated cement top is approximately 995 ft. Pressure test casing to 500 psi for 30 minutes.

m. Pull tubing up less than one joint and spot collar on rig floor mix and pump 150 sacks of Class A cement down workstring and circulate cement to fill hole with cement to surface. Pull workstring out of hole laying down each joint and washing cement off inside and out with fresh water. Note that as workstring is removed the cement will fall downhole until all pipe is removed, approximately 38'. Pump cement remaining in pump truck into casing to raise level and washout pump truck with fresh water.

n. Remove BOP and wellhead equipment. Cut casings off 3 ft. BGL. Use a string and weight to check depth to cement and fill with sack cement as needed. Weld an appropriately inscribed ½" steel plate on the casing.

o. Rig down and move out workover rig and equipment.

p. Clean and level location. Submit required plugging reports.

The closure report will certify that the well was closed as outlined in this plan, or where actual closure differed from this plan, a written statement specifying the differences between this plan and the actual closure will be provided. If both Buckeye Brine's injection wells are closed at the same time, Buckeye Brine will submit one report for both closures.

I.A.3 Plug and Abandon Well Adams No. 3

a. Prepare well and location for plugging. Remove well house, well monitoring equipment, and wellhead injection piping as may be required to allow field activity

b. Perform APT and RTS log.

c. Move in and rig up workover rig, mud pump, circulating pit, and pipe racks

d. Remove tree and install blow out prevention (BOP) equipment.

e. Release ASi-X mechanical packer and circulate annular fluid from well with 275 barrels 9.0 lb./gal brine or brine of sufficient density to control well. Dispose of the sodium sulfite inhibited annular fluid (fluid may be bullheaded into injection formation and not circulated to surface).

f. Pull and lay down the 5917' of 4-1/2" 10.5 lbs./ft. injection tubing and the packer. Remove 4-1/2" tubing from site. Unload approximately 7,100 ft. of workstring into pipe racks.

g. Run other logs if needed.

h. Make up a sliding valve cement retainer to set in 8 5/8" 36 lb./ft. casing on workstring. Tally workstring while running into well. Set cement retainer just above packer at 5910 ft. BGL.

i. Mix and pump 325 sacks Class A cement (yield 1.18 cf/sack) down the tubing. Squeeze approximately 320 sacks through retainer until a squeeze pressure of 500 psi is achieved or until 5 sacks of cement remain in tubing. Unstring from retainer, this closes the valve and relieves hydrostatic pressure under retainer, and spot remaining cement on top of retainer. Trip out of hole with retainer stinger. Trip in hole with open-ended tubing. Wait for cement to harden a minimum of 8 hours.

j. Tag cement plug with tubing and note depth to top of plug. Anticipated cement top is approximately 5895 ft. Pressure test casing to 500 psi for 30 minutes.

k. Pull out of hole laying down workstring tubing until 1100 ft., of tubing remains in the well then mix and pump 50 sacks of Class A cement, and balance the plug. Pull up to approximately 910 ft. BGL and reverse circulate until clean returns. Trip out of hole. Wait for cement to harden a minimum of 8 hours standing workstring tubing back in derrick.

l. Trip into hole with tubing and tag cement plug with tubing and note depth to top of plug. Anticipated cement top is approximately 919 ft. Pressure test casing to 500 psi for 30 minutes.

m. Pull tubing up one joint or less and spot collar on rig floor and mix and pump 150 sacks of Class A cement and pump cement down tubing to fill hole with cement to surface. Pull workstring out of hole laying down each joint and washing cement off inside and out with fresh water. Note that as the workstring is removed the cement will fall downhole until all pipe is removed, ~ 45'. Pump cement remaining in pump truck into casing to raise the level and washout pump truck.

n. Remove BOP and wellhead equipment. Cut casings off 3 ft. BGL. Use a string and weight to check depth to cement and fill with sack cement as needed. Weld an appropriately inscribed ½" steel plate on the casing.

o. Rig down and move out pulling unit and equipment.

p. Clean and level location. Submit required plugging reports.

UIC Class 1 Waste Injection Well

Estimate of Closure Costs (Plugging and Abandonment)

Total Costs are based on 2023 actual invoiced numbers where available

Calculation Date	**12/1/2023**	**12/1/2023**
Well	**Adams #1**	**Adams #3**
Permittee	**Buckeye Brine, LLC**	
Job	**Closure Cost Estimate**	
	Well Data	
Plugging method	None	None
Avg Well Inside Diameter (in)	6.366	7.725
Top of injection Interval (feet)	5832	5925
Pluggeg Back Total Depth (feet)	7305	7050
Hazardous Waste Well	No	No
Calculated Mud Vol (bbl)	295	420
Calculated Cement Vol (ft3)	394	467
	Closure Costs	
Consultant		
Preclosure and postclosure work	$ 9,000	$ 9,000
Wellsite @ $1350/day	$ 10,125	$ 10,125
Testing (MIT, pressure fall off)	$ 30,000	$ 30,000
Workover rig, etc.	$ 15,000	$ 18,000
Cement Retainer with sliding sleeve	$ 7,200	$ 8,800
Mud	$ 4,025	$ 6,200
Cement	$ 14,755	$ 16,225
Welding	$ 1,000	$ 1,000
Extra charge for Haz Waste Well	$ -	$ -
Consultant mark-up (12%)	$ 8,638	$ 9,627
Subtotal	$ 99,743	$ 108,977
Contingency (20%)	$ 19,949	$ 21,795
Total:	$ 119,691	$ 130,772

	Post Closure Costs
Groundwater sampling and analysis	$ 17,600
Plug monitor wells planning	$ 2,000
Cut off casing and weld ID plate	$ 7,000
Final report and Deed recording	$ 2,500

Monitoring well plugging cost (3 wells @ $2000)			$ 6,000	
Closure Sub-total			$ 35,100	
Contingency (20%)			$ 7,020	
Post-Closure Total (2023 dollars)			$ 42,120	
Total 2023 dollars	$ 119,691	$ 130,772	$ 42,120	$ 292,584

Attachment D

CORRECTIVE ACTION
(OAC Rules 3745-34-07 and 3745-34-30)

Protection of USDW

Should upward fluid migration occur through the wellbore of any previously unknown, improperly plugged or unplugged well in the area of review as a result of injection of fluids through the permitted well or should this migration of fluids threaten to contaminate an USDW, the injection well shall be shut-in until proper plugging can be accomplished. The Director shall determine the adequacy of the proposed corrective action of the Corrective Action Plan. Any flowage from such undiscovered wells will be considered noncompliance with this permit. Should any problem develop in the casing of the injection well, the injection well shall be shut-in until such repairs can be made to remedy the situation. If data from the ground water monitoring activities or other relevant data indicate either the upward migration of fluids from the injection interval, or a threat to or contamination of an USDW, the Director may require corrective action.

Attachment E

QUALITY ASSURANCE ACKNOWLEDGMENT

I hereby affirm that all chemical data submitted for injection Well Permit Number UIC 04-16-017-PTO-I is of known quality and was obtained from samples using methods prescribed in the Ohio EPA Quality Assurance Plan and the "Waste Analysis Plan" developed as required by OAC Rule 3745-34-57. I also acknowledge the right of Ohio EPA to inspect the sampling protocols, calibration records, analytic records and methods, and relevant quality assurance and quality control information for the monitoring operations required by this permit or Chapter 3745-34 of the OAC.

__________________________ ________________________________

Date Authorized Agent Signature

For ________________________________

Name of Company