DIVISION OF DRINKING AND GROUND WATERS,

UNDERGROUND INJECTION CONTROL PERMIT TO OPERATE: CLASS I HAZARDOUS WELL

Ohio Permit No.:	UIC 03-02-006-PTO-I
US EPA ID No.:	OHD 042157644
Date of Issuance:	
Effective Date:	
Date of Expiration:	
Name of Applicant:	INEOS Nitriles USA LLC Waste Disposal Well No. 4
Mailing Address:	P.O. Box 628 Lima, Ohio 45802-0628
Facility Location:	1900 Fort Amanda Road Lima, Ohio 45804
County:	Allen
Township:	Shawnee
Section:	11
Latitude/Longitude:	40º42'44"N/84º07'50"W
Injection Interval:	Mt. Simon from 2885 to 3159 feet (KB)
Containment Interval:	Eau Claire from 2430 to 2813 feet (KB)
Injection Zone:	Eau Claire, Mt. Simon, and Middle Run from 2430 to 3223 feet (KB)
Confining Zone:	Knox from 2100 to 2430 feet (KB)

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 (Permitee) indicated above is hereby authorized to operate a Class I injection well at the above location. The complex is divided into three operational groups on one contiguous site. The Nitriles production operations are owned and operated by INEOS Nitriles USA LLC (INEOS). The Nitrogen production process is owned and operated by PCS Nitrogen Ohio L.P. Fort Amanda Specialties LLC owns and operates an on-site facility that uses a by-product from the Nitriles process as a feed stock for their chemical manufacturing operations. The permittee is authorized to accept waste from the Nitriles production and Fort Amanda groups, 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, and F.

This permit shall become effective on ______________ and shall remain in full force and effect during the life of the permit, unless 1) the statutory provisions of Section 3004 (f), (g) or (m) of the Resource Conservation and Recovery Act ban or otherwise condition the authorizations in this permit; 2) the Agency promulgates rules pursuant to these sections which withdraw or otherwise condition the authorization in this permit; or 3) 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.

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Laurie A. Stevenson, Director
Ohio Environmental Protection Agency

PART I

GENERAL PERMIT COMPLIANCE

A. EFFECT OF PERMIT

The permittee is authorized to engage in 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 injection activity in a manner that allows the movement of injection, annulus or formation 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 owners and operators of hazardous waste injection wells of their obligation to comply with any additional regulations or requirements under the Resource Conservation and Recovery Act (RCRA) as amended or Chapter 3734 of the Ohio Revised Code 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 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 OAC Rules 3745-34-07, 3745-34-23, and 3745-34-24. 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 noncompliance 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) or Rules 3745-34-23 or 3745-34-24, 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 submitted to 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. If 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 in receiving water.

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 noncompliance is authorized by an emergency permit issued in accordance with OAC Rule 3745-34-19. Any permit noncompliance constitutes a violation of ORC Chapter 6111 and is grounds for enforcement action, permit termination, revocation and reissuance, modification, or denial of a permit renewal application. Such noncompliance 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. Any person who knowingly or recklessly violates permit conditions may be subject to criminal prosecution.

3. Continuation of Expiring Permits.

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 hazardous 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. Need to Halt or Reduce Activity Not a Defense. 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. Duty to Mitigate. 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 ninety (90) days of completion of all related activities.

6. Proper Operation and Maintenance. 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 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 will be required to be submitted annually and made available upon request.

7. <u>Duty to Provide Information.</u> 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. <u>Inspection and Entry.</u> 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 inspect and copy, at reasonable times, any records that are kept under the conditions of this permit;
   c. Perform inspections at reasonable times which may include taking photos, inspecting equipment (including monitoring and control equipment), practices, or operations regulated or required under this permit; and
   d. Sample or monitor at reasonable times for the purposes of assuring permit compliance or as otherwise authorized by ORC Chapter 6111 and OAC Chapter 3745-34, any substances or parameters at any location.

9. <u>Records.</u>

   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 five

(5) years from the date of the sample, measurement or report, or for the duration of the permitted life of the well, whichever is longer. 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 for this permit and any supplemental information submitted under OAC Rule 3745-34-12 for a period of at least five (5) years from the date the application was signed or for the duration of the permitted life of the well, whichever is longer. 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) 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. The permittee shall continue to retain such copies of records after the retention period specified by paragraphs (a) to (c) above, unless he or she delivers the records to the Director or obtains written approval from the Director to discard the records. At least ninety (90) days notice shall be provided prior to delivery of the records to the Director. The records shall be in a format acceptable to the Director.

e. The permittee shall continue to retain such copies of records after the retention period specified by paragraphs (a) to (c) above, unless he or she delivers the records to the Director or obtains written approval from the Director to discard the records. 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. <u>Monitoring.</u> 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. The permittee shall retain copies of records concerning the nature and composition of all injected fluids pursuant to Part II (D) of this permit until three years after completion of well closure which has been carried out in accordance with the approved Closure Plan.

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. Replacement of equipment that is equivalent to existing equipment is not included in this requirement. 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 assurance of financial responsibility and information relating to well closure has been submitted and is included in Attachment C of this permit. This plan is subject to final approval by Ohio EPA. 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 the Closure Plan survives the termination of this permit or the cessation of injection activities.

2. Revision of Closure Plan. The permittee shall submit any proposed significant revision to the method of closure described in the Closure Plan for approval by the Director no later than sixty (60) calendar days before closure, 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 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 hazardous waste injection well that has ceased operations for more than two years shall notify the Director at least thirty 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 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 then the owner or operator). Such report shall consist of either:

   a. A statement that the well was closed in accordance with Attachment C of this permit; or
   b. Where actual closure differed from Attachment C of this permit, a written statement specifying the differences between Attachment C and the actual closure.

6. Standards for Well Closure. 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 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:

   i. Pressure tests with liquid or gas;
   ii. Radioactive tracer surveys;
   iii. Noise, temperature, oxygen activation, pipe evaluation or cement bond logs;
   iv. Any other test required by the Director.

c. Flush the well with a suitable buffer fluid.

7. <u>Financial Responsibility for Closure</u>. The owner or operator shall comply with closure financial assurance requirements of OAC 3745-34-36(D) and 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. <u>Post-Closure Plan</u>. A plan for post-closure activities has been submitted and is included in Attachment C of this permit. The plan is subject to final approval by Ohio EPA. The obligation to implement an approved post-closure plan will be part of the Administrative Record for 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.

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

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

3. <u>Duration of Post-Closure Period</u>. The permittee shall continue post-closure maintenance and monitoring of any ground water monitoring wells required under this permit 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 extend the period of the post-closure monitoring upon a finding that the well may endanger 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 Allen 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 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, the name(s) of the generator(s) of the waste and the period over which injection occurred.

8. Financial Responsibility for Post-Closure Care. The permittee shall submit a demonstration of financial responsibility for post-closure care, as required by Chapter 3745-34 of the OAC, for approval by the Director. The 2015 financial assurance documentation has been submitted and is included in Attachment C. The owner or operator shall comply with post-closure financial assurance requirements of OAC Chapter 3745-34. The obligation to maintain financial responsibility for post-closure care survives the termination of this permit or the cessation of injection.

H. MECHANICAL INTEGRITY

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 hazardous waste injection well shall maintain mechanical integrity of the injection well at all times.

2. Periodic Mechanical Integrity Testing [OAC Rule 3745-34-57]. 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 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 years. The Director may require that a casing inspection log be run every five 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 Rules 3745-34-34(D) and 3745-34-57(I)(5).
   f. In accordance with OAC 37-34-34(G), the Director may require additional or alternative tests of the results presented by the permittee under 3745-34-34(E) are not satisfactory to the Director to demonstrate that there is no movement of fluid into or between USDWs resulting from the injection activity.

3. <u>Prior Notice and Report</u>. 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)(b, c and d) above, the permittee shall submit the planned test procedures to the Director for approval at the time of notification. At the discretion of the Director a shorter time period may be allowed. Plans for pressure testing of the long string casing, injection tubing and annular seal shall specify the planned test pressure. 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. The Director may require a specific type of testing, testing parameters, and/or specific technology if 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. All requirements specified in accordance with the preceding sentence will be consistent with the well testing regulatory standards in OAC Rules 3745-34-34 and 3745-34-57, including that the applied methods and standards be generally accepted in the industry. 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.

4. <u>Gauges</u>. 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. <u>Loss of Mechanical Integrity</u>. If the permittee or the Director finds that the well fails to demonstrate mechanical integrity during a test, or fails to maintain mechanical integrity during operation, or that a loss of mechanical integrity as defined by OAC Rule 3745-34-34 is indicated during operation, the permittee shall halt the operation immediately and follow the reporting requirements as directed in Part I (E)(12) of this permit. The permittee shall not resume operation until mechanical integrity is demonstrated and the Director gives approval to recommence injection.

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

I. FINANCIAL RESPONSIBILITY

1. Financial Responsibility. The permittee shall comply with the closure and post-closure financial responsibility requirements of OAC Chapter 3745-34. The permittee estimates that the 2022 cost of closure and post-closure of the four permitted Class I hazardous injection wells on site is $1,363,916. The 2022 financial assurance mechanism is provided in Attachment C of this permit.

   a. The permittee shall maintain written cost estimates, in current dollars, for the closure and post-closure plans as specified in OAC Chapter 3745-34. 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 and 3745-55-43.
   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 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 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 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 plan (Attachment D to 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.

PART II

WELL SPECIFIC CONDITIONS FOR UIC PERMITS

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) Rule and 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 the well 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 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

1. 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 of the permittee's four Class I injection wells is used for testing each year and each well shall be tested at least once every forty-eight (48) 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:

1. The transmissivity of the injection zone;
2. The formation or reservoir pressure; and
3. 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 Mt. Simon Formation in the approximate subsurface interval between 2885 feet and 3159 feet below kelly bushing (KB) for INEOS Well No. 4.

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

   Bottom hole pressure shall be limited so that a maximum of 2163 psi is never exceeded, calculated with a fracture gradient of 0.75 psi/foot applied at a depth of 2885 feet KB. The injection pressure shall be limited so that a maximum pressure of 864 psig (measured at the surface) is not exceeded. The maximum surface injection pressure limit shall be adjusted downward if fluid specific gravity increases above 1.04, in accordance with the calculation set forth in Attachment A 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 injection volume for all permitted Class I injection wells at this facility shall not exceed 30 million gallons.

4. Additional Injection Limitation. No substances other than those listed in Attachment A of this permit shall be injected. 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(s) required for approved well testing and/or monitoring.

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, for the purpose of leak detection. Temporary deviations from this fifty psig positive differential requirement, which are a part of normal well start-up and shut-down operations or an approved well stimulation, are authorized with the following conditions:

a. Deviations may not exceed 15 minutes in duration; and
b. A positive pressure differential is required to be maintained at all times.

This 15 minute maximum time allowance applies only to this permit parameter and does not apply to any other permit parameter that is required to be maintained continuously. All instances of deviation from the fifty psig positive differential pressure are subject to reporting requirements listed in Part II (E) of this permit.

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 reaches 864 psig;
    ii. Bottomhole pressure reached 2163 psi; and
    iii. When injection/annulus pressure differential falls below fifty (50) psi, except during conditions specified above in Part II (C)(5).

    Written plans and specification for a warning and shut-off system that fulfill these requirements were submitted to the Director and approved on March 17, 1995.

b. Unless otherwise approved by the Director, the permittee shall test the automatic warning and shut-off system at least once every twelfth month from the date of the last approved demonstration. This test must involve subjecting the system to simulated failure conditions and shall be witnessed by the Director or his or her representative. The permittee shall notify the Director of their 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 investigate immediately and identify as expeditiously as possible 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 Rule 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 stimulations plan submitted by Ineos and approved by Ohio Environmental Protection Agency was previously approved on June 30, 2021. If a future proposed stimulation substantively differs from the June 30, 2021 approval, Ohio EPA must be notified with a new plan for approval forty-five (45) days prior to conducting the stimulation event. INEOS must notify Ohio EPA 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. As specified in Part II(C)(8), a stimulation report must be submitted to Ohio EPA. Reports on well stimulations shall be submitted in accordance with Part II (E)(3) pf 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 this permit shall be complied with during the well stimulation including maximum injection pressure and 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. <u>Injection Fluid Analysis [OAC Rules 3745-34-38 and 3745-34-57]</u>.
The combined wastestream, comprised of both INEOS and Fort Amanda wastestreams, shall be analyzed no less frequently than quarterly for parameters which include, at a minimum, those listed below. A final list of parameters is included in the approved Waste Analysis Plan.

The total wastestream emanating from the Fort Amanda facility shall be measured weekly for pH. This measurement shall be performed weekly in conjunction with the weekly grab sample of the INEOS wastestream collected for pH, specific gravity, TDS, TSS, acrylonitrile, and acetonitrile. Method and location of pH measurements shall be specified in the WAP.

Metals	Organics	Other
Ammonium sulfate	Acetone	Alkalinity
Arsenic	Acetonitrile	Carbon Oxygen Demand (COD)
Barium	Acrolein	Conductivity
Calcium	Acrylic Acid	pH
Chloride	Acrylonitrile	Specific Gravity
Chromium	Acrylamide	Total Dissolved Solids (TDS)
Cobalt	Benzene	Total Organic Carbon (TOC)
HCN (free)	ED2A*	Total Suspended Solids (TSS)
HCN (total)	Maleonitrile	
Magnesium	Methyl Pyridine	
Nickel	Nicotinonitrile	
Sodium	Propionitrile	
Strontium	Pyridine	
Vanadium		
Zinc		

** Ethylenediamine-N-N-diacetic acid added per 10/28/13 permit modification.*

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) of this permit.

3. <u>Waste Analysis Plan</u>. The permittee has developed a written Waste Analysis Plan which describes the procedures which it will carry out to comply with permit conditions (D)(1) and (D)(2) above and Rule 3745-34-57 of the OAC. The latest revision of this plan was approved by Ohio EPA on June 30, 2005. 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. At a minimum, the plan must specify:

a. The parameters for which each hazardous wastestream will be analyzed and the rationale for the selection of these parameters;
b. The test methods which will be used to test for these parameters; and
c. The sampling method which will be used to obtain a representative sample of the waste to be analyzed.

The combined wastestream sampling location shall be at the sample tap in the pump building. The location for weekly pH measurements of the Fort Amanda wastestream shall be at the sample tap on the discharge of the transfer pump from Fort Amanda to the permittee's deep well system. 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 E) of this permit. This form must be completed and submitted to the Director within thirty (30) days of the effective date of this permit.

The permittee shall assure that the Waste Analysis Plan (WAP) remains accurate and the analyses of any fluid sampled remain representative.

4. <u>Continuous Monitoring and Recording Devices [OAC 3745-34-56(F)]</u>. Continuous monitoring and recording devices shall be maintained and operated to monitor injection pressure, flow rate and volume of the combined wastestream, flow rate and volume of the Fort Amanda wastestream, the pressure in the annulus between the tubing and the long string of casing, and the temperature of the combined wastestream.

   The permittee shall operate and maintain a continuous flow meter placed on the flow line emanating from Fort Amanda Specialties. The meter shall provide a digitized flow rate of the incoming Fort Amanda wastestream that is displayed on the computer screen in the control room. Volume (gallons) contributed by Fort Amanda shall be recorded and records retained by the permittee as required by Part I (E)(9)(a) of the permit to operate.

5. <u>Monitoring Wells</u>. The permittee submitted a ground water monitoring plan for protection of the underground sources of drinking water. The latest revision of this plan was approved by the Director on February 7, 1995. The permittee shall submit an updated ground water monitoring plan for approval by the Director within 60 days of the approval of this permit. The 1995 approved ground water monitoring plan shall remain in effect until the Director approves the updated plan. A copy of the most recently approved 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 most current corrosion monitoring plan submitted by the permittee was approved by Ohio EPA on January 26, 2005. 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. INEOS shall submit a revised plan for approval within ninety (90) days of permit issuance. The corrosion Mass Loss Rate must be displayed on the quarterly reports in Mils Per Year (mpy) for metallic coupons. This unit of measurement for the corrosion must be calculated using the appropriate Mass Loss Rate equation as stated in the latest approved Corrosion Monitoring Plan.

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 is 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 Lima, 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 on-site 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 monthly operating 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 system downtime, the permittee shall provide seismic data from available regional monitoring sources in the quarterly report. A complete analysis and interpretation of the data shall be submitted within thirty (30) days after completion of the quarter.

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

Specific reporting requirements of this permit in no way relieve the permittee of other applicable reporting requirements specified in any action of Ohio EPA or a court of appropriate authority.

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

   a. Results of the quarterly injection fluid analysis of the combined wastestream specified in permit condition Part II (D)(2).
   b. Daily and monthly average values for injection pressure, flow rate and volume, annular pressure, temperature of the combined wastestream, and specific gravity. Daily and monthly average flow rate and daily and monthly volume of the Fort Amanda wastestream.
   c. Daily and monthly maximum and minimum values for injection pressure, flow rate of the combined wastestream, and annulus pressure. Daily and monthly maximum and minimum values for flow rate of the Fort Amanda wastestream.
   d. Daily minimum differential pressure.
   e. The monthly combined average flow rate for all operating wells. These data shall appear once on the monthly report.
   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 wastestream injected daily, monthly, and the cumulative volume of fluid injected for the life of the well. Total monthly and cumulative fluid volume (gallons) contributed by Fort Amanda.
   h. Date, time and volume of annulus fluid addition to or removal from the annulus system.
   i. The amount of the annular fluid in the annulus tank, measured in gallons, recorded daily at a specified time. The monthly operating report shall also list the percentage of the tank volume that the gallons recorded represent.
   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. Weekly determinations of (injectate) pH, including monthly maximum and minimum values, for both the combined and Fort Amanda wastestreams.

n. Determinations of injectate specific gravity 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.

p. A description of any non-operating periods for the seismic monitoring system including date(s), duration, cause, schedule for repair, and anticipated date that the monitoring system was or will be returned to service.

2. Quarterly Reports [OAC 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 waste analysis as stipulated in an approved waste analysis plan required in Part II (D)(2) of this permit, within fifteen (15) days after the end of the quarter.

   d. 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. 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

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. CLASS I HAZARDOUS WASTE MANIFEST

Permittees injecting hazardous wastes which are accompanied by a manifest or delivery document shall comply with the requirements of OAC Rule 3745-65-70 or OAC Rule 3745-54-70, as applicable.

G. CERTIFICATION PURSUANT TO OAC RULE 3745-34-59(E)

The authorized representative of INEOS Nitriles USA, LLC., as designated pursuant to OAC Rule 3745-34-17, has provided the certification required by OAC 3745-34-59(E), provided in Attachment F of this permit. In addition, the Plant Manager at Fort Amanda Specialties has provided certification required by OAC 3745-34-59(E), included in Attachment F of this permit.

H. 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 permittee developed a facility waste minimization and treatment plan which was adopted on June 7, 1994. 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.

ATTACHMENT A

INEOS Nitriles USA LLC
Lima, Ohio
WDW #1

ATTACHMENT A

I. Operation and Monitoring Requirements

OPERATING, MONITORING AND REPORTING REQUIREMENTS
WDW #4

CHARACTERISTIC REQUIREMENTS	LIMITATION		MINIMUM MONITORING REQUIREMENTS	MINIMUM REPORTING REQUIREMENTS
	Maximum	Minimum	Frequency	Frequency
*Maximum Allowable Injection Pressure Not to be exceeded	864 psig		continuous	
*Bottomhole Pressure (max)	2163 psig			
Annulus Pressure	50 psig higher than injection pressure throughout entire tubing		continuous	monthly
Flow Rate (combined wastestream)			continuous	monthly
Flow Rate (Fort Amanda wastestream)			continuous	monthly
**Flow Volume (combined wastestream)			continuous	monthly
Flow Volume (Fort Amanda wastestream)			continuous	monthly
Temperature			continuous	monthly
Sight Glass Level			daily	monthly
Corresponding Annulus Pressure			daily	monthly
Corresponding Waste Temperatures			daily	monthly
Corresponding Injection Pressure			daily	monthly
Corresponding Flow Rate			daily	monthly
Cumulative Volume (combined wastestream)			daily	monthly
Cumulative Volume (Fort Amanda wastestream)			daily	monthly
Specific Gravity			every 4 hours	monthly
pH (combined wastestream)			weekly	monthly
pH (Fort Amanda wastestream)			weekly	monthly
***Chemical Composition of combined wastestream			quarterly	monthly
****MEK concentration in Fort Amanda wastestream			quarterly	monthly

*Injection Pressure: MASIP = 2885 x [0.75 - (0.433 x 1.04)] where:
0.75 = applied fracture gradient in psi/ft
1.04 = fluid specific gravity (maximum)
2885 = depth to the top of the injection interval in feet

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

$$BHP_{max} = (0.75)(2885)$$

**Flow Volume: The combined monthly injection volume for the site must not exceed 30 million gallons.

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

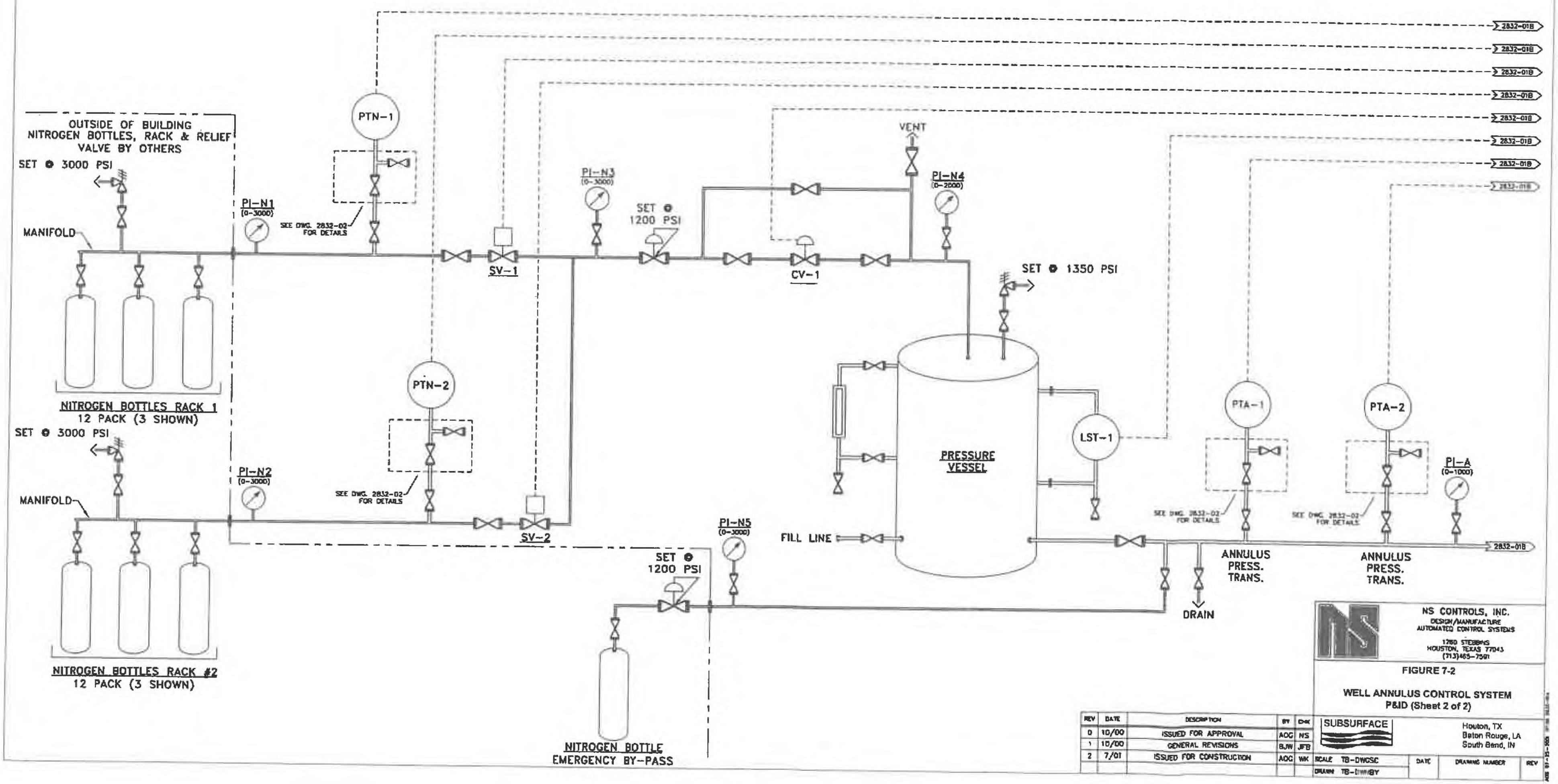
****MEK: Quarterly sampling of the Fort Amanda wastestream shall be conducted in accordance with the Waste Analysis Plan.

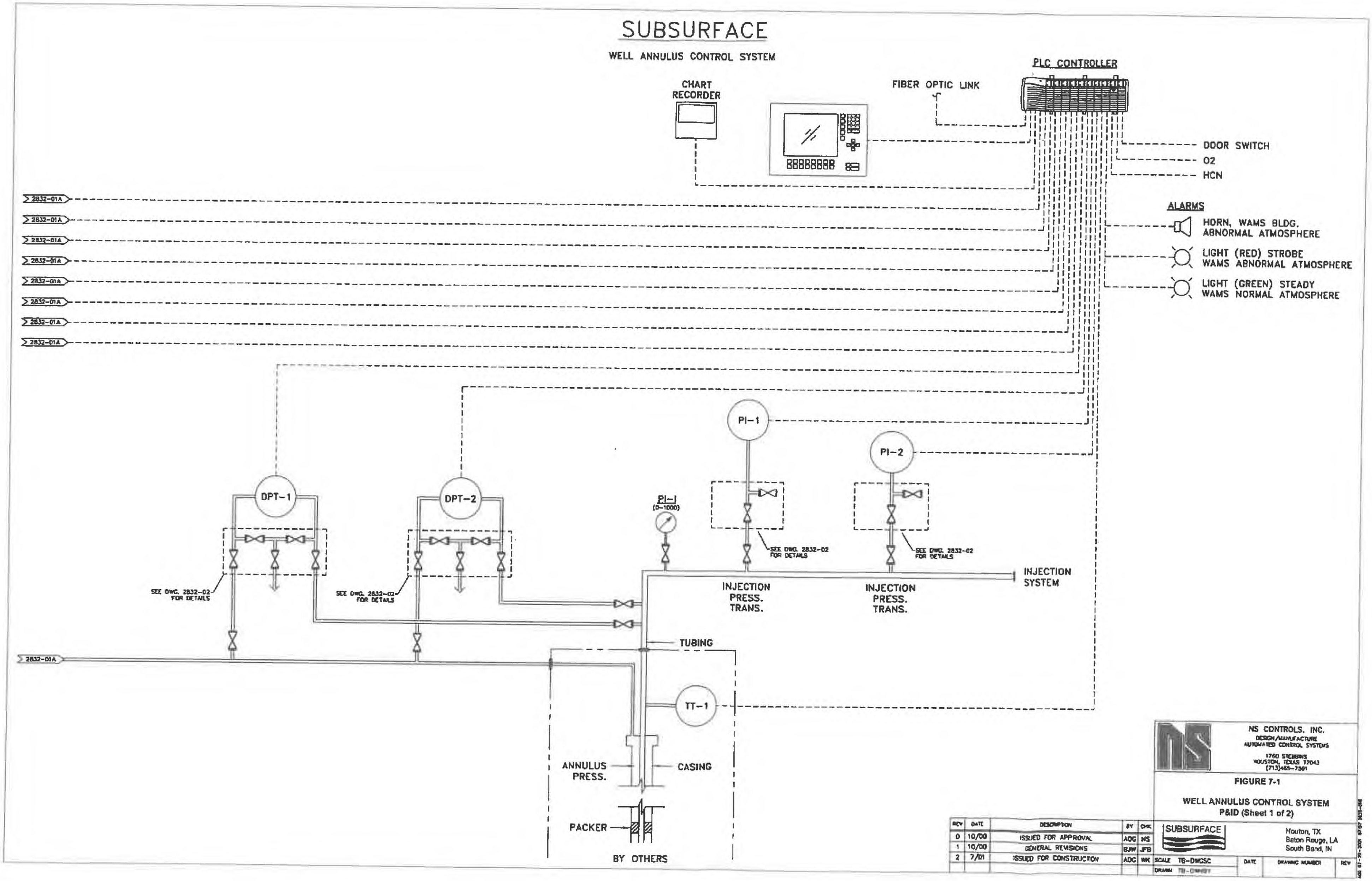
ATTACHMENT A

II. Injection Well Monitoring Systems

SUBSURFACE

WELL ANNULUS CONTROL SYSTEM





NS CONTROLS, INC.
DESIGN/MANUFACTURE
AUTOMATED CONTROL SYSTEMS
1760 STEBBINS
HOUSTON, TEXAS 77043
(713)465-7591

FIGURE 7-1

WELL ANNULUS CONTROL SYSTEM
P&ID (Sheet 1 of 2)

SUBSURFACE
Houton, TX
Baton Rouge, LA
South Bend, IN

REV	DATE	DESCRIPTION	BY	CHK
0	10/00	ISSUED FOR APPROVAL	ADG	NS
1	10/00	GENERAL REVISIONS	BJW	JFB
2	7/01	ISSUED FOR CONSTRUCTION	ADG	WK

SCALE TB-DWGSC | DATE | DRAWING NUMBER | REV
DRAWN TB-DWNBY

INEOS Nitriles USA LLC
Lima, Ohio
WDW #1

ATTACHMENT A

III. Wastes Permitted to be Disposed in INEOS USA LLC Class I Injection Wells

TABLE 1

WASTE STREAMS TO BE MANAGED IN THE UNDERGROUND INJECTION SYSTEM

- Bottom stream from the wastewater stripper in the production of acrylonitrile (K011)
- Bottom stream from the recovery column in the production of (acrylonitrile (K013)
- Batch still bottoms from the production of acetonitrile (K014)
- Kill kettle pump out from the production of acetonitrile
- Bottoms from the brine stripper from the production of acetonitrile
- Bottoms from acetonitrile dryer column from the production of acetonitrile
- Condensed overhead streams from the purification of acetonitrile
- Crude - off spec acetonitrile streams
- Characteristically corrosive wastewaters (D002)
- Wastewater from the catalyst manufacturing unit
- Regeneration wash water from the resin treatment of product acrylonitrile
- Stormwater pond overflow
- Caustic or acid from equipment cleaning
- Off spec products from the manufacture of acrylonitrile (U0091P063)
- Unsaleable co-product acetonitrile from the manufacture of acetonitrile (U003)
- Contaminated groundwater and multi-source leachate (F039)
- Ammonia blowdown

TABLE 1 (Continued)

WASTE STREAMS TO BE MANAGED IN THE UNDERGROUND INJECTION SYSTEM

- Scrubber water
- Slopwater from the acrylonitrile process area
- Contaminated stormwater from the process areas
- Pump seal water from the acrylonitrile process area
- Water from the loading/unloading area sump
- Contaminated groundwater
- Contaminated water from site remediation activities
- Equipment wash water
- Laboratory chemicals
- Wastewaters generated during maintenance activities in the nitrites area
- Wastewater, including wash waters, slopwaters, lab chemicals, *etc.*, from the manufacture of cyanide derivatives at Ft. Amanda Specialties Company

TABLE 2

WASTE CODES TO BE MANAGED IN THE UNDERGROUND INJECTION SYSTEM

K011	-	Bottom stream from the wastewater stripper in the production of acrylonitrile
K013	-	Bottom stream from the recovery column in the production of acrylonitrile
K014	-	Batch still bottoms from the production of acetonitrile
D001	-	Ignitability
D002	-	Characteristically corrosive wastewaters
D003	-	Cyanide
D004	-	Arsenic
D005	-	Barium
D006	-	Cadmium
D007	-	Wastewaters containing more than 5 mg/L chromium
D008	-	Lead
D009	-	Mercury
DOW	-	Selenium
D011	-	Silver
D018	-	Wastewaters containing more than 0.5 mg/L benzene
D018	-	Benzene
D019	-	Carbon Tetrachloride
D035	-	Methyl Ethyl Ketone
D038	-	Wastewaters containing more than 5 mg/L pyridine
D038	-	Pyridine
F039	-	Contaminated groundwater/multi-source leachate
F039	-	Multi-source leachate
P003	-	Acrolein
P005	-	Allyl alcohol
P030	-	Cyanide Salts
P063	-	Hydrogen Cyanide
P069	-	Acetone Cyanohydrin
P098	-	Potassium Cyanide
P101	-	Propionitrile
P106	-	Sodium Cyanide
P120	-	Vanadium Pentoxide
U001	-	Acetaldehyde

TABLE 2 (Continued)

WASTE CODES TO BE MANAGED IN THE UNDERGROUND INJECTION SYSTEM

U002	-	Acetone
U003	-	Acetonitrile
U007	-	Acrylamide
U008	-	Acrylic Acid
U009	-	Acrylonitrile
U019	-	Benzene
U044	-	Chloroform
U053	-	Crotonaldehyde
U056	-	Cyclohexane
U057	-	Cyclohexanone
U080	-	Methylene Chloride
U112	-	Ethyl Acetate
U122	-	Formaldehyde
U123	-	Formic Acid
U124	-	Furan
U125	-	Furfural
U129	-	Lindane
U140	-	Isobutyl Alcohol
U147	-	Maleic Anhydride
U149	-	Malononitrile
U151	-	Mercury
U152	-	Methacrylonitrile
U154	-	Methanol
U159	-	Methylethylketone
U161	-	Methylisobutylketone
U169	-	Nitrobenzene
U188	-	Phenol
U191	-	2-Methyl Pyridine (2-Picoline)
U196	-	Pyridine
U211	-	Carbon tetrachloride
U213	-	Tetrohydrofuran
U219	-	Thiourea
U220	-	Toluene
U239	-	Xylene

TABLE 3

TYPICAL AND MAXIMUM CONCENTRATIONS OF THE MAIN CONTAMINANTS OF THE COMMINGLED INJECTATE TO BE MANAGED IN THE UNDERGROUND INJECTION SYSTEM

Parameter	CAS #	Maximum* Assumed Concentrations (mg/L)	Typical Measured Concentration (mg/L)
Acetamide	60-35-5	2,500	100
Acetaldehyde	75-07-0	500	100
Acetic Acid	64-19-7	1,500	800
Acetone	67-64-1	500	175
Acetone Cyanohydrin	75-86-5	1,500	<10
Acetonitrile	75-05-8	25,000	1,600
Acrolein	107-02-8	500	<25
Acrylamide	79-06-1	1,500	600
Acrylic Acid	79-10-7	15,000	4,000
Acrylonitrile	107-13-1	6,000	500
Allyl Alcohol	107-18-6	500	<10
Benzene	71-43-2	100	<5.0
Crotonaldehyde	41770-30-3	50	<10
Crotonitrile (Allyl Cyanide)	109-75-1	250	50
Formic Acid	64-18-6	1,000	225
Formaldehyde	50-00-0	1,000	40
Formamide	75-12-7	250	100
Fumaronitrile	17656-09-6	1,000	300
HCN (free)	67-56-1	800	365
HCN (total)	74-90-8	5,300	550
Isopropyl Alcohol	67-63-0	300	<25
Maleonitrile (*cis*-2-Butenc Dinitrile)	928-53-0	5,000	300
Methanol	67-56-1	.10,000	60
Methacxylonitrile	126-98-7	100	<2.0
Methylethyl Ketone	78-93-3	250	<25
Methyl Pyridine	108-99-6	250	50
Malononitrile	109-77-3	500	<100
Nicotinonitrile (3-Cyanopyridinc)	100-54-9	1,500	500

TABLE 3 (Continued)

TYPICAL AND MAXIMUM CONCENTRATIONS OF THE MAIN CONTAMINANTS OF THE COMMINGLED INJECTATE TO BE MANAGED IN THE UNDERGROUND INJECTION SYSTEM

Propionitrile	107-12-0	500	110
Pyrazole	288-13-1	1,000	300
Pyridine	110-86-1	500	110
Sodium Cyanide	143-33-9	300	<25
Succinonitrile	110-61-2	1,500	250
Antimony	7440-36-0	25	1.0
Arsenic	7440-38-2	25	0.05
Barium	7440-39-3	25	<0.2
Cadmium	7440-43-9	25	NA
Chromium	7440-47-3	25	0.22
Cobalt	7440-48-4	25	0.5
Lead	7439-92-1	25	<1.0
Nickel	7440-02-0	25	1.0
Mercury	7439-97-6	25	<1.0
Strontium	7440-24-6	25	1.0
Selenium	7782-49-2	25	<1.0
Vanadium	7440-62-2	25	<1.0
Silver	7440-22-4	25	<1.0
Zinc	7440-66-61	25	0.05
Vanadium Pentoxide	1314-62-1	100	<10
Formic Acid	64-18-6	1,000	225
Formamide	75-12-7	250	100
Glycolonitrile	107-16-4	1,000	15
Nitrilotriacetonitrile	7327-60-8	250	15
Hexamethylenetetramine	100-97-0	250	15
IDAN	628-87-5	250	15
DMH	77-71-4	250	15
MEH	5394-36-5	250	15
EDTN	5766-67-6	250	15
PDTN	110057-45-9	250	15
Ethyl Acetate	141-78-6	25	15
Oleic Acid	112-80-1	250	15

Table 2-1 Summary of Injectate Analysis Performed for the Ineos Waste Disposal Wells

	2015 Annual Average	2016 Annual Average	2017 Annual Average	2018 Annual Average	2019 Annual Average	2020 Annual Average	2021 Annual Average
Alkalinity as $CaCO_3$	1,180	1,343	1,001	1,001	1,115	1,113	1,408
Carbon Oxygen Demand (COD)	31,525	35,900	36,150	32,900	28,275	27,475	35,800
Total Organic Carbon (TOC)	10,160	12,270	10,575	11,195	9,715	9,735	12,003
Total Dissolved Solids (TDS)	47,325	35,450	37,200	43,225	30,850	38,200	44,225
Total Suspended Solids (TSS)	33	73	60	86	65	76	85
Specific Gravity	1.03	1.02	1.02	1.03	1.02	1.02	1.03
Total Solids	51,425	40,950	40,150	47,550	34,250	42,625	51,475
Viscosity (cp)	0.736	0.719	0.720	0.752	0.749	0.734	0.751
Conductivity	93,100	76,900	69,575	85,500	62,775	77,700	89,850
Ammonium (NH_4)	11,283	11,850	8,695	10,328	7,465	8,705	10,105
Sulfate (SO_4)	29,825	22,725	22,225	28,800	21,355	27,100	31,300
Ammonium Sulfate $(NH_4)_2SO_4$							
Antimony *	0.250	0.250	0.250	0.028	0.025	0.025	0.025
Arsenic*	0.250	0.250	0.138	0.025	0.025	0.025	0.025
Barium*	0.050	0.050	0.050	0.050	0.050	0.050	0.050
Calcium	14.77	12.15	14.70	17.35	26.40	23.70	15.58
Chloride	929	850	787	736	682	617	667
Chromium*	0.107	0.105	0.106	0.098	0.156	0.107	0.097
Cobalt	0.100	0.119	0.100	0.100	0.168	0.181	0.111
Iron	8.68	7.49	12.08	261.48	152.29	198.72	100.07
Magnesium	6.90	6.27	6.08	6.52	14.54	10.70	8.93
Manganese	2.596	0.180	0.144	1.997	0.347	1.282	0.282
Molybdenum	20	33	26	24	31	19	26
Nickel*	3.75	7.33	5.88	4.93	6.83	4.12	4.87
Sodium	4,710	481	2,502	3,742	2,690	2,670	2,850
Strontium	0.357	0.229	0.256	0.323	1.189	0.438	0.467
Vanadium*	0.050	0.050	0.157	0.058	1.085	1.658	0.378
Zinc	2.590	1.800	0.429	1.394	0.136	0.137	4.141
Acetaldehyde*	14.02	20.80	19.28	16.42	16.23	16.34	9.79
Acetamide	51	86	41	90	138	143	198
Acetic Acid	962	1,347	1,173	1,393	964	1,111	1,403
Acetone*	16	6	19	19	25	25	12
Acetonitrile*	842	1,408	1,465	1,683	2,357	932	2,720
Acrolein*	<0.500	<0.500	<0.500	<0.500	<0.500	<0.500	<0.500
Acrylonitrile*	364	599	303	97	616	128	302
Acrylamide*	619	656	585	587	446	539	604
Allyl Alcohol*	42.20	51.48	45.33	35.25	50.93	28.10	27.18
Benzene*	0.100	0.100	0.100	0.100	0.100	0.100	0.450
Crotonitrile	10.88	36.95	16.23	8.65	84.18	13.14	12.99
Formaldehyde*	2.68	0.86	1.63	1.42	0.74	5.41	0.71
Formic Acid*	71	84	89	75	86	86	86
Fumaronitrile	232	338	252	242	187	205	302
Hydroquinone(HQ)	58.90	46.28	41.30	62.15	29.73	18.58	41.43
Maleonitrile	85	127	112	98	63	89	126
Malononitrile*	10.00	10.00	10.00	10.00	10.00	10.00	10.00
Methacrylonitrile*	<0.500	<0.500	<0.500	<0.500	<0.500	<0.500	<0.500
Methanol*	415	158	313	431	272	303	424
Propionitrile*	50.53	93.30	51.50	96.10	88.53	132.60	215.67
Pyrazole	218.75	194.25	121.98	176.75	106.35	141.00	140.33
Pyrimidine	74.23	105.70		103.00	74.30	75.63	180.50
Pyridine*	49.63	53.50	41.33	50.48	41.35	44.53	71.13
Succinonitrile	1,069.75	1,198.75	917.75	1,120.75	691.50	869.75	1,033.75

ATTACHMENT B

WELL CONSTRUCTION SPECIFICATIONS

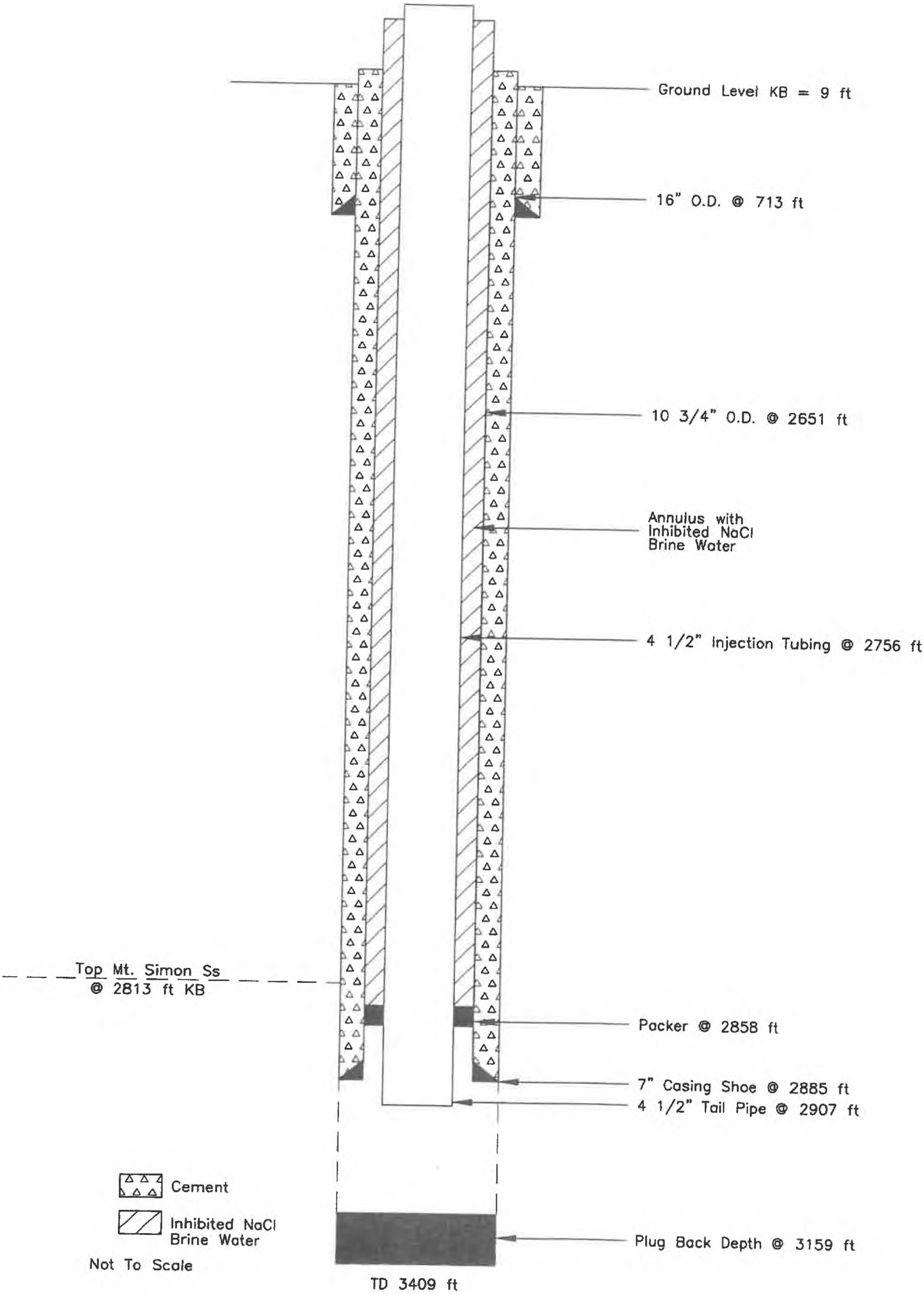


FIGURE 2-7

WELL SCHEMATIC OF INEOS WDW NO.4 AS OF DECEMBER 2021

7.0 WELL CONSTRUCTION

General Comments Regarding Updates for the Renewal Application

The conclusions of this section remain basically unchanged from the 2015 UIC permit renewal application submittal. This section has been updated, however, as appropriate based on published literature, site operating history, test results, and data analysis conducted in regard to the INEOS injection well activities since July 1992.

Section 7 contains versions of various compliance implementation plans required by the existing permits. These are contained in Appendices 7-3, 7-4, 7-5, 7-7 and 7-8. As discussed in Section 1, these plans are periodically re-submitted to OEPA. Consequently, those versions contained herein, which are provided to facilitate stand-alone review, may not be the most current. The most recent versions, submitted under separate cover, should be considered the governing versions.

The four currently permitted INEOS Class I Waste Disposal Wells 1, 2, 3 and 4 (Wells 1, 2, 3 and 4) are constructed with multiple casing strings for protection of USDWs and potential mineral resources (Ohio EPA Permit to Operate Numbers UIC 03-02-003-PTO-I, 03-02-004-PTO-I, 03-02-005-PTO-I, 03-02-006-PTO-I). Well Nos. 1 and 2 are constructed with two casing strings in addition to a carbon steel injection string that is internally coated with corrosion-resistant epoxy. WDW No. 3 is constructed similarly but a full-length casing liner was installed in January 2010. WDW No. 4 is constructed similarly but also includes an intermediate casing string. The surface casing is set below the lowermost USDW (the Sub-Lockport Group) in all wells and cemented to the surface. The protection or long string casing is set at the top of the injection interval and cemented in place. Thus, the USDWs at INEOS are protected by a minimum of two carbon steel and two cement barriers. Waste is emplaced in the injection interval in all wells via carbon steel injection tubing which is internally coated with corrosion-resistant epoxy and surrounded by a pressurized and monitored liquid annulus system, thus providing additional protection for USDWs. Details on the construction and cementing of the INEOS injection wells are provided on Table 7-1 of this application. Wellbore schematics of the four injection wells are provided as Drawings 7-1, 7-2, 7-3 and 7-4.

The wells at INEOS are constructed such that they can be tested annually for mechanical integrity. The following table summarizes the mechanical integrity demonstrations conducted since the last permit application submittal in June 2015. The results of these mechanical integrity tests were documented and submitted to the Ohio EPA in detailed Mechanical Integrity and Well Workover reports submitted to the agency within 60 days of completion of the work. In most cases, Ohio EPA employees witnessed the key aspects of these mechanical integrity demonstrations. In all cases, mechanical integrity was successfully demonstrated. Details of the mechanical integrity demonstrations, well logs run, and well workovers conducted over the history of the four injection wells is summarized in Appendix 9-1.

WELL NAME & NO.	MIT DEMONSTRATIONS
WDW No. 1	September 2015 October 2016 October 2017 October 2018 September 2019 October 2020 October 2021
WDW No. 2	April 2015 April 2016 April 2017 May 2018 April 2019 April 2020 April 2021
WDW No. 3	August 2015 August 2016 September 2017 September 2018 August 2019 August 2020 August 2021
WDW No. 4	June 2015 June 2016 June 2017 June 2018 June 2019 June 2020 June 2021

Subsequent to the July 1992 permit to operate application, INEOS requested a permit modification to change the 5-year MIT casing inspection requirements in the future to times when the injection string is pulled from the injection well. This permit modification was finalized by the Ohio EPA on June 13, 1997. INEOS anticipates that the current permit modification language consistent with OAC 3745-34-57(I)(4) will remain in the renewal of the permits to operate for these four wells.

WDW Nos. 1, 2, 3 and 4 have been worked over several times to either replace the injection string or increase injectivity. No casing leaks have ever occurred in any of the wells. Other than minor tubing or packer leaks, related to normal life expectancy of these materials, the wells have maintained mechanical integrity since the beginning of injection operations attesting to the adequacy of the well design. Through the results of the extensive testing conducted and the multiple layers of protection provided by the design of well construction, INEOS has been successful in demonstrating that injected fluids have not moved into unauthorized zones. Details of the mechanical integrity demonstrations, well logs run, and well workovers conducted over the history of the four site injection wells is summarized in Appendix 9-1.

The annulus monitoring systems were replaced in 2001. The wellhead annulus monitoring systems are designed to comply with the regulations as defined in 40 CFR 146 and in rule 3745-34-56 of the Ohio Administrative Code. This includes a system to track the changes in annulus fluid volume during the operation of the injection wells. A schematic of the annulus monitoring system in the existing INEOS injection wells is illustrated in Figures 7-1 and 7-2 of this application.

The surface injection pressure, surface annulus pressure, and flow rate are monitored and recorded continuously on both the plant Data Collection System (DCS) system and on electronic strip charts. The plant DCS is the compliance monitoring system at the site to satisfy all permit monitoring conditions. Only in the event of a failure of this primary system will the strip charts and/or field pressure gauges be used to satisfy the permit monitoring conditions. Field readings of local wellhead pressure gauges for both the annulus and injection systems are recorded on a 4-hour basis. These readings are compared to the chart recordings and calibrations are performed as indicated.

The monthly averages, maximums, and minimums for injection pressure, flow rate, annular pressure, and injection volumes are reported as required under the existing permits to operate.

The annular fluid in each well is composed of 9 lb/gal NaCl saltwater brine containing corrosion inhibitor and bacterial control chemicals per the manufactures recommendations with the pH adjusted as necessary. The annular pressure will be maintained at a minimum of 50 psi above the injection pressure as measured at the surface during injection operations. The density of the annular fluid (SG=1.08) is greater than the density of the injectate which has an average specific gravity of 1.025 and a maximum of 1.05, thus ensuring that a positive annular pressure is maintained throughout the length of the injection string.

The annulus monitoring systems maintain the minimum differential pressure. Backup systems are in place should the primary systems become unable to maintain the minimum differential pressure. In addition to differential pressure, annulus fluid loss is also monitored.

All casing used in INEOS's wells is standard API tubulars. Surface equipment, surface piping, and key components of the packer are stainless steel. These materials provide for indefinite life of these components. The injection string is carbon steel, internally coated with a corrosion resistant epoxy coating or liners. Through INEOS' experience of over 30 years in handling this wastewater stream, carbon steel has been determined to experience significant pitting and corrosion when exposed to the injectate stream. For this reason, the surface equipment and piping and key components of the packer are stainless steel. These materials provide for indefinite life of these components. The use of threaded stainless steel for the injection string is problematic, and problems maintaining a sealed threaded connection does not justify the use of stainless steel for this application. For this reason, INEOS has chosen to use carbon steel tubulars internally coated with a corrosion resistant epoxy coating or lined pipe.

To protect the lower section of the long string casing located below the packer from corrosion from exposure to the injectate, INEOS installed a tail pipe that hangs below the packer and conducts the injectate past the bottom of the long string casing. A diesel buffer was injected that will float up between the tailpipe and the bottom of the long string casing, isolating this section of the long string casing from the injectate. INEOS has experienced relatively good success with this technique. The following table summarizes the current materials of construction of the four existing Lima injection wells. Based on the current results from the UIC Corrosion Monitoring Plan (Appendix 7-5) and the operating history over the years, all of these materials have been demonstrated to have good operating characteristics and to experience minimal reactions or attack from the fluids injected at the facility. INEOS reserves the right to change these materials of construction in the future based on operating experience and the ongoing results from the site UIC Corrosion Monitoring Plan.

The casing and cementing program for each well at INEOS is summarized in Table 7-1 of this application. As discussed above, the wells are designed to both prevent the movement of fluids into or between USDWs and they are equipped with an annulus monitoring system to detect any potential leaks. The casing and cementing program for WDW No. 4 is presented in Appendix 7-1 which details the cementing and casing program for the surface, intermediate, and long string casings. Portions of these discussions are excerpted as appropriate to address the requirements contained in this section.

All of the INEOS injection wells are designed so that the surface casing is set below the lowermost USDW which occurs at depths ranging from 352 ft to 373 ft in the four wells. Drawings 7-1, 7-2, 7-3 and 7-4 illustrate the casing depths for the four INEOS Class I wells. The setting depth for the surface casing ranges from 432 ft to 713 ft within argillaceous dolomites in the Cincinnati Group, and all surface casings were cemented to the surface.

All of the INEOS injection wells are designed with a 7-in long string casing set below the top of the modeled injection interval which occurs in the lower Eau Claire Formation at the top of the EC1 model unit. Drawings 7-1 through 7-4 contain the casing depths for the four INEOS Class 1 wells. The setting depth for the 7-in long string casing ranges from 2,783 to 2,885 ft within shaley sections of the Mt. Simon Sandstone, and all were cemented to the surface.

INEOS Well No. 1 was completed in July 1968. All depths listed in the description of this well are referenced to rotary Kelly bushing (KB), 8 feet above ground level at an elevation of 872 MSL. The surface casing, long string casing and the injection tubing are described below:

- 10 3/4-inch O.D., 32.75 lb/feet, H-40 casing was set in a 13.5-inch hole at a depth of 432 feet. The outside of the 10 3/4-inch casing was cemented with float shoe and centralizer, using 125 sacks of 50/50 Pozmix with 2% Gel and 600 lb of Gilsonite, did not circulate. Filled 10 3/4 inch by 13 1/2-inch annulus to surface with 102 sacks of regular cement. Cement was circulated to the surface. In 1993, the 10 3/4-inch casing was cut 2.4 feet below the concrete pad and 4.4 feet of new 10 3/4-inch casing was welded to the existing casing. The annulus was filled with common cement.

- 7-inch O.D., 20 lb/ft, J-55, casing was set in a 9-inch hole at 2,783 feet. A D.V. tool was placed in the 7-inch casing at 1,296 feet. Cemented in two stages, through casing shoe with 400 sacks of high-density cement. Circulated out excess cement above D.V. tool. Second Stage of 450 sacks of High-Density Cement was pumped through D.V. tool at 1,296 feet. Cement circulated to surface. In December 1993 the top two joints, 65.75 feet, were removed from the well and replaced with two joints (67.15 feet) plus one 3-foot pup joint of new casing. The new casing was cemented in place with 150 sacks common cement and 2% $CaCl_2$.

- 4 1/2-inch O.D., 11.6 lb/ft, K-55, injection tubing, internally coated with TK-77 was set at 2,757 feet and attached to the Baker Model 80-32 Seal Assembly. The Baker Seal Assembly was set inside a Baker 7-inch Model "A" Retrieva D packer located at 2,759 feet. There are approximately 43.80 feet of 4 1/2 inch 11.6 lb/ft internally plastic-coated tubing attached to the bottom of the Baker 7-inch packer.

Well No. 1 was drilled to a total depth of 3,133 feet. The well was completed in the Mt. Simon Formation with an open hole completion from 2,783 feet to 3,133 feet.

INEOS Well No. 2 was completed in July 1968. All depths listed in the description of this well are referenced to rotary Kelly bushing (KB), 14 feet above ground level at an elevation of 854 MSL. The surface casing, long string casing and the injection tubing are described below:

- 10 3/4-inch O.D., 32.75 lb/ft, H-40 casing was set in a 13 3/4-inch hole at a depth of 504 feet. The outside of the 10 3/4-inch casing was cemented with float shoe and centralizer, using 400 sacks of Class A with 4% Gel, 5% $CaCl_2$ and 12% Gilsonite. Circulated 59 bbls of cement to the surface. In April 1997, the 10 3/4-inch casing was cut 2.0 feet below the concrete pad and 3.0 feet of new 10 3/4-inch casing were welded to the existing casing. The annulus was filled with common cement.

- 7-inch O.D., 20 lb/ft, J-55, casing was set in a 9-inch hole at 2,813 feet. A D.V. tool was placed in the 7-inch casing at 1,370 feet. Cemented in two stages. Cemented through casing shoe with 250 sacks of light weight cement with 18% NaCl, followed by 100 sacks of Type II with 18% NaCl and 1.25% CFR-2. Circulated out 35 bbls excess cement above D.V. tool. Second stage was pumped through D.V. tool at 1,370 feet and consisted of 200 sacks of light weight with 18% NaCl, followed by 50 sacks of light with 18% NaCl and 10 lb/sx Gilsonite. Circulated 18 bbls of cement to surface. In April 1997 the 7-inch casing was cut 1.5 feet below the concrete pad and 4.7 feet of new 7-inch casing was welded to the existing casing. The casing annulus was filled with common cement.

- 4 1/2-inch O.D., 11.6 lb/ft, K-55, injection tubing, internally coated with TK-15 was set at 2,792 feet and attached to the Baker Model 80-32 Seal Assembly. The Baker Seal Assembly is set inside a Baker 7-inch Model "A" Retrieva D packer with the center of the elements located at 2,789 feet. The tail pipe below the packer extends to 2,865 feet.

Well No. 2 was drilled to a total depth of 3,166 feet. The well was completed in the Mt. Simon Formation with an open hole completion from 2,813 feet to 3,143 feet.

INEOS Well No. 3 was completed in March 1972. All depths listed in the description of this well are referenced to rotary Kelly bushing (KB), 8 feet above ground level at an elevation of 856 MSL. The surface casing, long string casing and the injection tubing are described below:

- In 2018, the area around the well was excavated to 20 feet below surface. A new section of 5 ½ inch casing and 10 ¾ inch casing were welded into place. A cement culvert was set around the outside of the 10 ¾-inch casing and cemented into place. Cement was then poured between all casings back to the surface.

- 10 3/4-inch O.D., 32.75 lb/ft, H-40 casing was set in a 13-inch hole at a depth of 505 feet. The outside of the 10 3/4-inch casing was cemented with float shoe and centralizer, using 235 sacks of Pozmix with 2% $CaCl_2$ and 10 lb/sx Gilsonite. Circulated cement to the surface. In July 1994, the 10 3/4-inch casing was cut just below the surface and 5.1 feet of new 10 3/4-inch casing were welded to the existing casing.

- 7-inch O.D., 20 lb/ft, J-55, casing was set in a 9-inch hole at 2,810 feet. A D.V. tool was placed in the 7-inch casing at 1,395 feet. Cemented in two stages. Cemented through casing shoe with 250 sacks of light weight cement with 18% NaCl, followed by 100 sacks of Type II with 18% NaCl and 1.25% CFR-2. Circulated out excess cement above D.V. tool. Second stage, pumped through D.V. tool at 1,395 feet, consisted of 250 sacks of light weight cement with 18% NaCl, followed by 50 sacks of light weight cement with 18% NaCl and 10 lb/sx Gilsonite. Circulated cement to surface. In July 1994 the 7-inch casing was cut just below the surface and 6 feet of new 7-inch casing were welded to the existing casing.

- 5 1/2-inch O.D., 15.5 lb/ft, J-55 liner was set at 2813.47 feet inside the 7-inch casing in January 2010. The liner was cemented from the bottom of the liner up to 956 feet below KB.

- 3 1/2-inch O.D., 9.3 lb/ft, J-55, injection tubing, internally coated with TK-69 is set at 2,793 feet and attached to the Baker Model 42-30 Seal Assembly. The Baker Seal Assembly is set inside a Baker 5 1/2-inch Model FB-1 packer, with the top of the packer located at 2,793 feet. One joint of approximately 26 feet of tail pipe is attached to the bottom of the packer, extending to 2,831 feet.

Well No. 3 was drilled to a total depth of 3,170 feet. The well was completed in the Mt. Simon Formation with an open hole completion from 2,810 feet to 3,140 feet.

INEOS Well No. 4 was completed in 1991. Well No. 4 was drilled during the period from March 11, 1991, through October 4, 1991, as the Lima Stratigraphic Test Well. Extensive testing of the well included:

- A comprehensive logging suite, obtaining over 2,250 feet of 4-inch diameter core,
- Drill stem testing, and
- Interference test to establish hydrogeologic properties of the gross Mt. Simon injection interval.
- 24-inch O.D. conductor casing was driven to 73 feet.
- 16-inch O.D. 65 lb/ft casing was set to a depth of 712.6 feet KB in a 20-inch surface hole. The lowermost USDW in WDW No. 4 occurs at a depth of 373 feet KB; therefore, the surface casing was set significantly below potential USDWs in this well. Cemented on March 25, 1991, with 580 sacks of Standard Howco Cement with 3% $CaCl_2$, 4% Gel, and ¼ lb/sack floccele at 14.33 lb/gal. Circulated 152 sacks to surface.
- 10¾ inch O.D. L-80 and J-55, 51 and 40.5 lb/ft, intermediate string casing was set at 2,650.78 feet KB, in a 14 3/4-inch hole drilled to 2,656 feet KB. The intermediate casing was cemented in two stages with a D.V. tool set at 1,791 feet. The well was cemented on May 29, 1991. Cemented in two stages: the first stage through the shoe with 415 sacks of Standard Howco Cement with 6% Microbond, 2% $CaCl_2$, ¼ lb/sx flocele, 0.5% Halad 344, 0.1% FWCA, at 15.0 ppg. 45 sacks of cement were circulated to surface above the D.V. tool. The second stage was cemented through the D.V. tool with 905 sacks of Standard Howco Cement with 6% Microbond, 2% $CaCl_2$, ¼ lb/sx flocele, 0.5% Halad 344, 0.1% FWCA, at 15.0 ppg. 120 sacks of cement were circulated to the surface.
- 7-inch O.D., 23 lb/ft, N-80, casing was set in a 9.5-inch hole at 2,885 feet. A D.V. tool was placed in the 7-inch casing at 2,043 feet. Cemented in two stages. Cemented through casing shoe with 225 sacks of Class A with 6% Microbond, 2% $CaCl_2$, 0.5% Halad-344, 0.1% FWCA, and ¼ lb/sx flocele at 15.0 ppg. Circulated out

65 sacks excess cement above D.V. tool. Second stage was pumped through D.V. tool at 2,043 feet, cemented with 475 sacks of 50:50 mix standard Howco Class A cement and pozmix, 8% Microbond, 2% $CaCl_2$, 0.75% CFR2, 0.5 D-Air, 2% HC-2, and no gel at 14.8 ppg. 35 sacks of cement were circulated to surface.

- 4 1/2-inch O.D., 11.6 lb/ft, N-80, Injection Tubing, internally coated with TK-15 is set at 2,862 feet and attached to the Baker Model 80-32 Seal Assembly. The Baker Seal Assembly is set inside a Baker 7-inch Model "A" Retrieva D packer with the center of the packer elements at 2,865 feet. The tail pipe extends below the packer to 2,900 feet.

Well No. 4 was drilled to a total depth of 3,409 feet. The well was completed in the Mt. Simon and Middle Run Formations with an open hole completion from 2,885 feet to 3,409 feet. Well No. 4 was plugged back to 3,159 feet. The open hole section of the Mt. Simon is from 2,885 feet to 3,159 feet.

Wells 1, 2 and 4 employ a retrievable Baker general purpose packer to make an isolated annulus between the 7-inch-long string casing and the 4½ inch injection string. A three-piece packing element system is sealed against the 7-inch-long string casing by a dual lock ring system in conjunction with opposing non-transferring slips to maintain positive pack-off. The packer used is a Baker Model "A" "Retrieva-D" casing packer. This packer is set with either a wireline setting tool or by using a tubing work string and can be released from the casing with a wireline retrieving tool or a tubing work string tool. Premature release of the packer from the casing is prevented by the latch retainer which covers the ends of the latch retainer fingers, locking them to the body. The latch retriever is secured in position by four brass shear screws. The specific packer is a Baker 47C Model "A" Retrieva-D packer with a 4½ inch LTC pin down. Sections of 4½ inch LT&C casing are run beneath the packer into the open hole interval to isolate the section of the 7-inch-long string casing beneath the packer from the turbulent injection flow. The packer setting details are included in table below. The location of the packers in the four site injection wells were reviewed and approved by Ohio EPA staff through the review of well workover plans and reports.

A seal assembly is installed on the bottom of the 4½ inch injection string in Wells 1, 2, and 4. This consists of a Baker Model 80-32 locator type seal assembly, 316 stainless steel with a 3½ inch, 8-round box premium seal assembly, three Baker Model 80-32 seal units, 316 stainless steel, and a 2 7/8 inch by 5-foot 316 stainless steel production tube and mule shoe guide. The packer materials are made from 316 stainless steel due to the high velocities and turbulence experienced by the flow through the packer restrictions. The seal assembly rests in the polished seal bore of the packer, fully isolating the annulus. This seal assembly is free to move in the polished seal bore to accommodate thermal expansion and contraction of the 4½ inch injection string, minimizing tensile stresses on the casing. INEOS maintains a full spare packer and seal assembly at the manufacturer's shop which can be received onsite rapidly if required during workovers of the injection wells.

Well 3 has a Baker Model FB-1 packer installed to make an isolated annulus between the 5½ inch liner and the 3½ inch injection tubing. A Baker Model 42-30 "G-22" locator seal assembly is installed on the bottom of the tubing. The seal assembly rests in the seal bore extension of the packer. Metal in the packer that is exposed to the injection stream is stainless steel.

The maximum annulus pressure that the packer is expected to see is 3,000 psig (1,500 psig surface pressure plus 1,500 psig fluid column pressure) which is approximately 38 percent of the rated upper differential pressure capability of these packers. The maximum internal pressure that the packer is expected to experience is 2,150 psig (reflecting the historical 844 psig maximum surface pressure plus 1,306 psig fluid column pressure). This is approximately 36 percent of the rated lower differential pressure capability of these packers. The maximum temperature limitations of the packer element system are 300°F, considerably higher than the maximum anticipated operating temperature of 150°F. A fluid seal is not used in any of the existing INEOS injection wells.

The INEOS contingency plan designed to cope with all shut-ins or well failures is included as Appendix 7-3. In addition, INEOS maintains several monitoring plans in accordance with the requirements set forth in 3745-34-57. These are summarized below.

Waste Analysis Plan

The most recently updated UIC Waste Analysis Plan applicable to the injection wells is included as Appendix 7-4 and meets the requirements of rules 3745-34-57(A) through (F) of the State of Ohio Administrative Code in addition to the permit requirements contained in Section D(3) of the INEOS UIC Permit to Operate the Class I wells. The Ohio EPA approved the current INEOS UIC Corrosion Monitoring Plan in a letter dated September 4, 2018

Corrosion Monitoring Plan

The most recently updated UIC Corrosion Monitoring Plan is included as Appendix 7-5 and is submitted in accordance with rule 3745-34-57(G)(H) of the State of Ohio Administrative Code. The Ohio EPA approved the current INEOS UIC Corrosion Monitoring Plan in a letter dated March 1, 2017.

Mechanical Integrity Demonstrations

Mechanical Integrity Testing is conducted in accordance with rule 3745-34-57(I) of the Ohio Administrative Code. The results of the most recent 2021 mechanical integrity testing on WDW No. 1, WDW No. 2, WDW No. 3, and WDW No. 4 are included in Appendix 7-6. These latest Mechanical Integrity Demonstrations have been reviewed and approved by the Ohio EPA.

Groundwater Monitoring Plan

INEOS originally submitted the groundwater monitoring plan on December 8, 1993. In response to comments received from the Ohio EPA, a revised plan was submitted on May 2, 1994. The Ohio EPA approved the current INEOS UIC Groundwater Monitoring Plan in a letter dated March 17, 1995.

The 2021 UIC Groundwater Monitoring Program status report is included in Appendix 7-7 and includes a description of the program being implemented.

Injection Zone Ambient Monitoring Program

The monitoring program plan at INEOS consists of annual ambient monitoring of the injection zone. The monitoring program plan is included as Appendix 7-7. The results of the most recent injection zone ambient monitoring are included with the most recent mechanical integrity testing on WDW No. 1, WDW No. 2, WDW No. 3, and WDW No. 4 are included in Appendix 7-6. These latest Mechanical Integrity Demonstrations have been reviewed and approved by the Ohio EPA.

Seismic Monitoring Program

Seismic monitoring at INEOS was initiated in 1988 in accordance with permit requirements. The seismic monitoring program is described in Appendix 7-8. The Ohio EPA approved the current INEOS UIC Seismic Monitor in a letter dated January 14, 2015.

Auto Warning and Shutdown Plan

The most recently updated UIC Auto-Warning and Shutdown Plan is included as Appendix 7-3 and is submitted in accordance with rule 3745-34-57(G)(H) of the State of Ohio Administrative Code. The Ohio EPA approved the current INEOS UIC Auto-Warning and Shutdown Plan in a letter dated March 17, 1995. The results of the most recent demonstrations of the automatic shutdown systems are included with the most recent mechanical integrity testing on WDW No. 1, WDW No. 2, WDW No. 3, and WDW No. 4 and are included in Appendix 7-6. These latest Mechanical Integrity Demonstrations have been reviewed and approved by the Ohio EPA.

TABLE 7-1 (Continued)

	INEOS WDW No. 1	INEOS WDW No. 2	INEOS WDW No. 3	INEOS WDW No. 4
Cement	Two Stages	Two Stages	Two Stages	Two Stages
1st Stage	300 sks Pozmix and 100 sks Type II Set for 12 hrs	250 sks Halliburton Light with 18% $CaCl_2$, 100 sks Type II with 18% $CaCl_2$ and 1¼% CFR-2. Circulated 35 bbs to surface.	250 sks Light with 18% $CaCl_2$, 100 sks Type II plus 18% $CaCl_2$ with 1¼% CFR-2.	225 sks Class A with 6% Microbond, 2% $CaCl_2$, 0.5% Halad-344, 0.1% FWCA, ¼ lb/sk Flocele. Circulated to surface with 40% excess.
2nd Stage	Set at 1,305 ft using 450 sks Pozmix. Circulated cement to surface.	200 sks Halliburton Light 18% $CaCl_2$ plus 50 sks Halliburton Light, 18% $CaCl_2$, 10 lb/sk Gilsonite. Circulated 18 bbls to surface.	250 sks Light plus 18% $CaCl_2$ plus 50 sks Light plus 18% $CaCl_2$ with 10 lb/sk Gilsonite. Cement circulated to surface.	475 sks 50% Class A/ 50% Pozmix 8% Microbond, 2% $CaCl_2$ 0.75% CFR-2, 0.5% D-Air 1 2% Hc-2. Circulated to surface with 8.5% excess.
Liner	N/A	N/A	5½-in. O.D., 15.5 lb/ft, J55, R-3@2813 ft	N/A
Tubing	4½-in., 11.60 lb/ft, J-55 Internally Lined with Falcon Ploy Core @ 2810 ft	4½-in., 11.60 lb/ft, N-80 Internally Coated withTK-15 Epoxy Coating @ 2792 ft	3½-in., 9.3 lb/ft, J-55, Internally Coated withTK-69 Epoxy Coating @ 2793 ft	4½-in., 11.60 lb/ft, N-80 Internally Coated withTK-70 Epoxy Coating @ 2858 ft
Packer	Baker Model "A" Retrieva D with seal locator assembly Top @ 2756 ft	Baker Model "A" Retrieva D with seal locator assembly Top @ 2766 ft	RSB Packer with seal locator assembly Top @ 2789.5 ft	Baker Model "A" Retrieva D with seal locator assembly Top @ 2858 ft
Bottom of Tail Pipe	2805 ft	2861 ft	2838 ft	2907 ft
Annulus	Inhibited NaCl brine	Inhibited NaCl brine	Inhibited NaCl brine	Inhibited NaCl brine

TABLE 7-1 (Continued)

	Data for All Wells
Injection Pressure: Average/Maximum	750/825 psig
Injection Zone Lithology	Sandstone, Siltstone, Dolomite
Confining Zone Lithology	Shale and Dolomite
Formation Fluid	
pH	6.9 - 7.3
Specific Gravity	1.075
Temperature	96°F
Injectate	
pH	4.5 - 6.0
Specific Gravity	1.015 - 1.05
Temperature	90° - 105°F
Volume (gpm)	
Average/Well	140
Maximum/Well	240
Instantaneous Maximum (per site)	560

[a] All elevations are provided with respect to KB.
[b] Top of the injection interval is equivalent to the casing shoe of the protection casing.
[c] Proposed casing setting depth after workover on WDW No. 1.
[d] WDW No. 2, WDW No. 3, and WDW No. 4 will be plugged from total depth with cement.
[e] N/A = not applicable.

Table 7-1

Well Design and Construction of the INEOS Injection Wells (Reference State of Ohio 3745-34[c])

	INEOS WDW No. 1	INEOS WDW No. 2	INEOS WDW No. 3	INEOS WDW No. 4
Elevation	872 ft	854 ft	856 ft	872 ft
Total Depth	3133 ft	3172 ft	3165 ft	3409 ft
Type Completion	Open Hole	Open Hole	Open Hole	Open Hole
Top Injection Zone (Top Eau Claire Formation)	2430 ft	2418 ft	2422 ft	2430 ft
Top Mt. Simon Sandstone	2810 ft	2800 ft	2803 ft	2813 ft
Top Injection Interval[a,b]	2783 ft/2830 ft[c]	2813 ft	2810 ft	2885 ft
Open Hole Interval After Plug Back[d]	2830 ft - 3133 ft	2813 ft - 3140 ft	2810 ft - 3140 ft	2885 ft - 3140 ft
Surface Casing: Hole Diameter Size and Grade	12¼-in. 10¾-in. O.D., 32.75 lb/ft, H-40, 8rd, R-3, ST&C @ 432 ft	13¾-in. 10¾-in. O.D., 32.75 lb/ft, H-40, 8rd @ 504 ft	13_-in. 10¾-in. O.D., 32.75 lb/ft, H-40, 8rd @ 505 ft	20 in. 16-in. O.D., 65 lb/ft @ 713 ft
Cement	50 sks Surface Pozmix, 2% $CaCl_2$, 12.5 lb/sk Gilsonite 75 sks Class A, 2% $CaCl_2$ 10 sks Class A, 3% $CaCl_2$ Pumped from surface down borehole, filled to surface	400 sks Class A 4% gel, 5% $CaCl_2$ 12% Gilsonite per sack cement Cemented to surface Circulated 59 bbls of slurry to surface	235 sks Surface Pozmix and 2% $CaCl_2$ with 10 lb/sk Gilsonite Cement circulated to surface	Cemented to surface with 580 sks Class A plus 3% $CaCl_2$ plus 1/4-lb/sk Flocele. Circulated to surface with 35% excess.
Intermediate Casing Hole Diameter Size and Grade	No intermediate casing	No intermediate casing	No intermediate casing	14¾-in. 10¾-in. O.D., 40.5 lb/ft and 51 lb/ft @ 2651 ft
Cement	N/A[d]	N/A	N/A	Cemented in two stages: 1st stage 415 sks cement, (6% Microbond 2% $CaCl_2$ 0.5% Halad-344 ¼ lb/sks Flocele 0.1% FWCA) Circulated to surface with 12% excess. 2nd stage 905 sks STD cement Circulated to surface with 15% excess.
Protection Casing: Hole Diameter Size and Grade	9 in. 7-in O.D., 20 lb/ft, J-55, R-2, ST&C @ 2783 ft	9 in. 7-in O.D., 20 lb/ft, J-55, R-2 @ 2813 ft	9 in. 7-in O.D., 20 lb/ft, J-55, R-2 @ 2810 ft	9½ in. 7-in O.D., 23 lb/ft, N-80, R-3 @ 2885 ft

ATTACHMENT C

I. CLOSURE PLAN
II. POST-CLOSURE PAN
III. CLOSURE AND POST-CLOSURE FINANCIAL ASSURANCE

INEOS Nitriles USA LLC
Lima, Ohio
WDW #1

ATTACHMENT C

I. Closure Plan

APPENDIX 10-1

CLOSURE PLAN

This closure plan is prepared pursuant to Rules 3745-34-09, 3745-34-36 and 3745-34-60 of the Ohio Administrative Code and shall be kept at the facility at all times. INEOS will notify the OEPA at least 60 days before planned closure of the well(s). INEOS will submit any proposed significant revision to the method of closure reflected in the plan for approval by the Agency at this time. Plugging and abandonment procedures involve the removal of the injection tubing and plugging the entire long string casing with cement for protection of the subsurface environment and USDWs. Two cement plugs will be placed by the balance method and the plugs shall be tagged and tested for seal and stability. The open hole section will be filled with a heavy bentonite mud. Two cement plugs are used to minimize fluid column pressure on the formation face during the plugging operation.

1. Notify the OEPA of the intention to close the well(s).

2. Monitor pressure decay in the injection zone for a period of six months to determine if injection activity has conformed with predicted values.

3. Inform the OEPA of closure date 60 days before plugging and abandonment is to commence. Submit plan to plug with any updated changes and obtain permission to proceed to plug.

4. Displace the tubing and wellbore with sufficient fresh water to flush waste out of the tubular goods and near wellbore area (minimum of 3 injection tubing volumes). Remove all flow lines, associated equipment and instrumentation from wellhead and immediate area.

5. Prepare location, move in rig, pump, tanks, pipe racks, and work string.

6. Place heavy well control fluid in one tank. Pump down tubing to kill the well. Release packer and pump heavy fluid down the annulus to overbalance reservoir pressure. Install blow out preventer. Pull tubing and packer. Decontaminate tubing to EPA standards and prepare for final disposal.

7. Rig up wireline service unit and run appropriate logs to assess the integrity of the protection casing and the cement that will remain in the well(s). Run final caliper log and metal thickness log, temperature log, cement bond log on the long string casing and pressure test the long string casing using a retrievable packer assembly and a water filled annulus. Rig down wireline service unit. Evaluate any additional actions as indicated by the MIT tests after review of these tests with the OEPA.

APPENDIX 10-1 (Continued)

8. Mix bentonite drilling mud in tank.

9. Run work string near the bottom of the well and displace mud down tubing, filling open hole to within 100 feet of the bottom of the casing. The required volume of the bentonite plug is listed in Table 10-A.

10. Set cement retainer approximately 100 feet above casing shoe.

11. Displace sufficient cement below retainer to fill up to retainer and fill 100 feet above retainer (cement plug #1). Allow cement to set and pressure test to 2000 psig. The cement will be Halliburton premium grade cement. The required volume of cement plug #1 is listed in Table 10A-1.

12. Tag cement and displace fluid from top of cement plug #1 to surface with cement (cement plug #2). The cement will be premium grade. The required volume of cement plug #2 is listed in Table 10-A.

13. Remove BOP and wellhead equipment. Cut casing off at surface and complete cementing at surface. Release rig and equipment.

14. Weld a steel plate on top of the casing. Inscribe on the plate, in a permanent manner, the following information: (1) operator name; (2) closure date; and (3) UIC permit number. The surface area concrete pad around the wellhead will remain in place.

15. Prepare closure report and final well status drawing and file with OEPA within 60 days. File a plugging affidavit with the Ohio Geological Survey, Division of Oil and Gas and with the OEPA, Division of Groundwater. In accordance with Ohio Administrative Code (OAC) Rule 3745-34-36D(2)(a) and OAC Rule 3745-66-15, INEOS will submit by registered mail to the Director of the OEPA, within 60 days of the final plugging of the injection well, a certification that the closure has been conducted in accordance with the specifications in the approved Closure Plan. The certification will be signed by the owner and by an independent, qualified, registered professional engineer.

ESTIMATED COST TO PLUG AND SECURE INJECTION WELLS (PER WELL)

Post-Shutdown Pressure Modeling	$67,933
Prepare Location	9,022
Rig, Pump, Tanks, Pipe Racks	44,110
Work String, Rental Tools	18,044
Pressure Control Fluid	9,022
Casing Pressure Test Equipment	9,022
Logging (7-in Caliper Log, 7-in. CBL, 7-in. Vertilog, 7-in. Casing Tempature Log)	27,065
Mud	12,629
Cement Retainer	5,413
Cementing and Testing	36,087
Planning, Supervision, Report Preparation	27,065
Frac Tanks	9,022
Fluid Disposal	9,022
Contingencies	56,521
Total Estimated Cost, Per Well	**$340,979**

TABLE 10-A

PLUGGING VOLUMES FOR CLOSURE OF LIMA CHEMICALS INJECTION WELLS

Well ID	Well Total Depth (ft KB)	Well Casing Shoe (ft KB)	Open Hole Diameter (inches)	Long String Casing ID (inches)	Bentonite Plug Volume* (bbls)	Cement Plug #1 Volume** (bbls)	Top of Cement Plug #1 (ft KB)	Cement Plug #2 Volume *** (bbls)	Top of Cement Plug #2 (ft KB)
WDW #1	3133	2783	12.5	6.456*	47.5	28.3	2583	109.5	8
WDW #2	3172	2813	9.0	6.456*	25.5	19.3	2613	110.5	14
WDW #3	3165	2810	9.0	6.456*	25.1	19.3	2610	110.8	8
WDW #4	3159	2885	9.5	6.366*	20.3	20.3	2685	110.6	9

* Bentonite plug fills open hole section to within 100 feet of casing shoe. Volume required represents open hole volume plus 25% excess for formation losses.

** Cement plug #1 is set from 100 feet below the casing shoe to 200 feet above the casing shoe. Volume required represents this volume plus 25% excess for formation losses.

*** Cement plug #2 is set from the top of cement plug #1 to ground surface. Volume required represents the long string casing volume plus 5%.

ESTIMATED COST TO PLUG AND SECURE INJECTION WELLS (PER WELL)

Post-Shutdown Pressure Modeling	$67,933
Prepare Location	9,022
Rig, Pump, Tanks, Pipe Racks	44,110
Work String, Rental Tools	18,044
Pressure Control Fluid	9,022
Casing Pressure Test Equipment	9,022
Logging (7-in Caliper Log, 7-in. CBL, 7-in. Vertilog, 7-in. Casing Tempature Log)	27,065
Mud	12,629
Cement Retainer	5,413
Cementing and Testing	36,087
Planning, Supervision, Report Preparation	27,065
Frac Tanks	9,022
Fluid Disposal	9,022
Contingencies	56,521
Total Estimated Cost, Per Well	**$340,979**

APPENDIX 10-1

CLOSURE PLAN

This closure plan is prepared pursuant to Rules 3745-34-09, 3745-34-36 and 3745-34-60 of the Ohio Administrative Code and shall be kept at the facility at all times. INEOS will notify the OEPA at least 60 days before planned closure of the well(s). INEOS will submit any proposed significant revision to the method of closure reflected in the plan for approval by the Agency at this time. Plugging and abandonment procedures involve the removal of the injection tubing and plugging the entire long string casing with cement for protection of the subsurface environment and USDWs. Two cement plugs will be placed by the balance method and the plugs shall be tagged and tested for seal and stability. The open hole section will be filled with a heavy bentonite mud. Two cement plugs are used to minimize fluid column pressure on the formation face during the plugging operation.

1. Notify the OEPA of the intention to close the well(s).

2. Monitor pressure decay in the injection zone for a period of six months to determine if injection activity has conformed with predicted values.

3. Inform the OEPA of closure date 60 days before plugging and abandonment is to commence. Submit plan to plug with any updated changes and obtain permission to proceed to plug.

4. Displace the tubing and wellbore with sufficient fresh water to flush waste out of the tubular goods and near wellbore area (minimum of 3 injection tubing volumes). Remove all flow lines, associated equipment and instrumentation from wellhead and immediate area.

5. Prepare location, move in rig, pump, tanks, pipe racks, and work string.

6. Place heavy well control fluid in one tank. Pump down tubing to kill the well. Release packer and pump heavy fluid down the annulus to overbalance reservoir pressure. Install blow out preventer. Pull tubing and packer. Decontaminate tubing to EPA standards and prepare for final disposal.

7. Rig up wireline service unit and run appropriate logs to assess the integrity of the protection casing and the cement that will remain in the well(s). Run final caliper log and metal thickness log, temperature log, cement bond log on the long string casing and pressure test the long string casing using a retrievable packer assembly and a water filled annulus. Rig down wireline service unit. Evaluate any additional actions as indicated by the MIT tests after review of these tests with the OEPA.

APPENDIX 10-1 (Continued)

8. Mix bentonite drilling mud in tank.

9. Run work string near the bottom of the well and displace mud down tubing, filling open hole to within 100 feet of the bottom of the casing. The required volume of the bentonite plug is listed in Table 10-A.

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11. Displace sufficient cement below retainer to fill up to retainer and fill 100 feet above retainer (cement plug #1). Allow cement to set and pressure test to 2000 psig. The cement will be Halliburton premium grade cement. The required volume of cement plug #1 is listed in Table 10A-1.

12. Tag cement and displace fluid from top of cement plug #1 to surface with cement (cement plug #2). The cement will be premium grade. The required volume of cement plug #2 is listed in Table 10-A.

13. Remove BOP and wellhead equipment. Cut casing off at surface and complete cementing at surface. Release rig and equipment.

14. Weld a steel plate on top of the casing. Inscribe on the plate, in a permanent manner, the following information: (1) operator name; (2) closure date; and (3) UIC permit number. The surface area concrete pad around the wellhead will remain in place.

15. Prepare closure report and final well status drawing and file with OEPA within 60 days. File a plugging affidavit with the Ohio Geological Survey, Division of Oil and Gas and with the OEPA, Division of Groundwater. In accordance with Ohio Administrative Code (OAC) Rule 3745-34-36D(2)(a) and OAC Rule 3745-66-15, INEOS will submit by registered mail to the Director of the OEPA, within 60 days of the final plugging of the injection well, a certification that the closure has been conducted in accordance with the specifications in the approved Closure Plan. The certification will be signed by the owner and by an independent, qualified, registered professional engineer.

TABLE 10-A

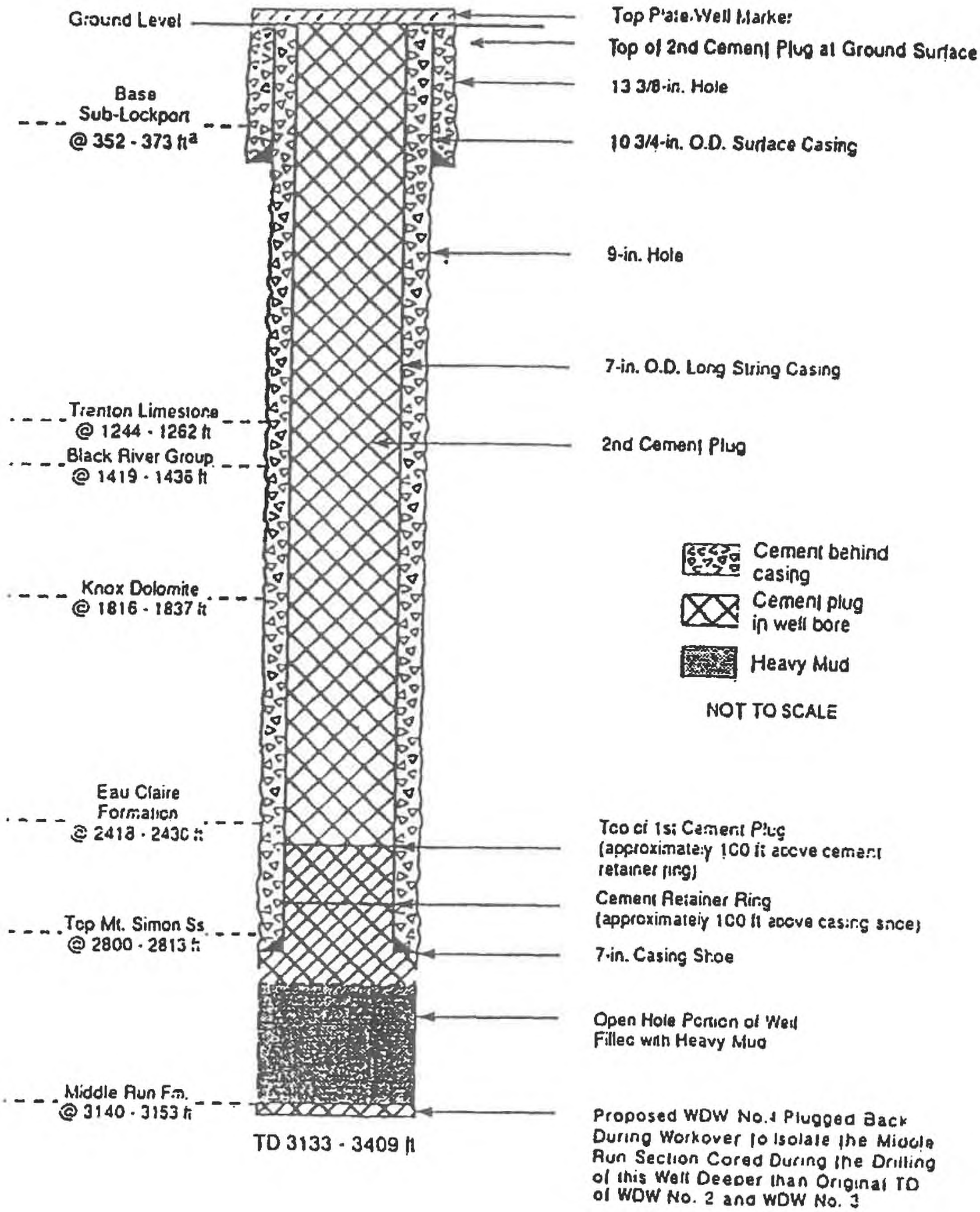
PLUGGING VOLUMES FOR CLOSURE OF LIMA CHEMICALS INJECTION WELLS

Well ID	Well Total Depth (ft KB)	Well Casing Shoe (ft KB)	Open Hole Diameter (inches)	Long String Casing ID (inches)	Bentonite Plug Volume* (bbls)	Cement Plug #1 Volume** (bbls)	Top of Cement Plug #1 (ft KB)	Cement Plug #2 Volume *** (bbls)	Top of Cement Plug #2 (ft KB)
WDW #1	3133	2783	12.5	6.456*	47.5	28.3	2583	109.5	8
WDW #2	3172	2813	9.0	6.456*	25.5	19.3	2613	110.5	14
WDW #3	3165	2810	9.0	6.456*	25.1	19.3	2610	110.8	8
WDW #4	3159	2885	9.5	6.366*	20.3	20.3	2685	110.6	9

* Bentonite plug fills open hole section to within 100 feet of casing shoe. Volume required represents open hole volume plus 25% excess for formation losses.

** Cement plug #1 is set from 100 feet below the casing shoe to 200 feet above the casing shoe. Volume required represents this volume plus 25% excess for formation losses.

*** Cement plug #2 is set from the top of cement plug #1 to ground surface. Volume required represents the long string casing volume plus 5%.



[a] Range of depths encountered in INEOS injection wells.

FIGURE 10-1

GENERALIZED PLUGGING AND ABANDONMENT WELL SCHEMATIC FOR INEOS WASTE DISPOSAL WELLS

INEOS Nitriles USA LLC
Lima, Ohio
WDW #1

ATTACHMENT C

II. Post-Closure Plan

APPENDIX 11-A

POST-CLOSURE PLAN

The INEOS post-closure plan is submitted in accordance with OAC Rule 3745-34-09, 3745-34-36 and 3745-34-61 of the Administrative Code and shall be kept at the facility at all times. The post-closure care period corresponds to the time it takes for the pressure in the injection zone to decrease to a point where it no longer intersects the base of the lowermost USDW. INEOS anticipates that this will be the length of post-closure monitoring period. However, in accordance with Ohio Administrative Code (OAC) Rule 3745-34-61(G), the Director of the Ohio EPA may extend the period of post-closure monitoring upon a finding that the well may endanger a USDW.

A. Reservoir Information

The values for pressure at the top of the injection zone and for the waste plume location at the end of the operational period were predicted from reservoir simulations using the SWIFT/98 groundwater flow model as described in Section 5 of this permit application. It should be noted that the values in Section 5 represent conservative (overestimated) pressurization and migration results designed to meet the requirements of 40 CFR 148 and are not representative of what would be expected given typical injection well operations. The predictive modeling will be updated at closure based on the actual injection history and measured reservoir conditions at the time of closure.

B. Status of Corrective Action for Wells in the Area of Review.

As indicated in Section 6, there are no problem artificial penetrations or confining zone within the 10-mile radius cone-of-influence/area of review. Therefore, no cleanups or corrective actions are anticipated under 3745-34-53 of the Administrative Code.

No maintenance is anticipated following the completion of the closure of the well. OAC 3745-67-23 (dikes), 3745-67-28 (surface impoundments), 3745-67-80 (land treatment), 3745-68-10 (landfills) and 3745-65-91 (groundwater monitoring) are not applicable to closure of deepwells.

INEOS will continue to conduct the groundwater monitoring required by UIC Permits to Operate until the pressure in the injection zone decays to the point that the well's cone of influence no longer intersects the base of the lowermost USDW in accordance with OAC Rule 3745-34-61(F)(2). The requirements for the closure of the above ground facilities associated with the injection wells are addressed in the site's RCRA Part B Permit Closure Plan.

C. Post-Closure Activities

APPENDIX 11-A (Continued)

3. Records Management

Records reflecting the nature, composition and volume of all injection fluids will be retained for at least three years following the well closure. At the end of the retention period, the records shall be delivered to the OEPA.

D. Responsible Official

Site Director
INEOS USA LLC
Post Office Box 628
Lima, Ohio 45804

E. Estimated Cost for Post-Closure Care

Updated Predictive Modeling	$152,528
Legal Filings	41,600
Post Closure Monitoring	41,600
Contingency	25,294
Estimated Post-Closure Costs, Site	$261,023

INEOS Nitriles USA LLC
Lima, Ohio
WDW #1

ATTACHMENT C

III. Closure and post-Closure Financial Assurance

INEOS Olefins & Polymers USA

INEOS USA LLC
d/b/a INEOS Olefins & Polymers USA
Marina View Building
2600 South Shore Boulevard
Suite 500
League City, TX 77573
Tel: (281) 535-6600
Fax: (281) 535-6760

www.ineos-op.com

March 30, 2022

CERTIFIED MAIL NO. 7021 2720 0001 0658 3929
RETURN RECEIPT REQUESTED
Copy via email to shawn.sellers@epa.ohio.gov

Ms. Laurie A. Stevenson
Director, Ohio Environmental Protection Agency
50 West Town St., Suite 700
Columbus, OH 43215

RE: **INEOS Nitriles USA LLC**
2022 Annual Inflation Adjustment
Financial Assurance for Closure and Post-Closure Care for Lima Chemical

Attn: Shawn Sellers, Environmental Response and Revitalization, Financial Assurance

This letter is provided, pursuant to Ohio Administrative Code 3745-55-43(D)(4) and 3745-55-45(D)(4), to provide information regarding Irrevocable Standby Letter of Credit No. NYSB-2039, amended by Barclays Bank PLC, New York, on behalf of INEOS Nitriles USA LLC and supplied under separate cover. The letter of credit is to demonstrate financial assurance for closure and post-closure care for the Lima Chemical Plant and Lima Chemical UIC Wells, P. O. Box 628, Lima, Ohio 45802-0628, Ohio Permit No. 03-02-0450, EPA ID No. OHD042157644. These facilities are owned and operated by INEOS Nitriles USA LLC. The amounts assured by the Letter of Credit are as follows:

Plant Closure:	$4,444,663
Plant Post-Closure:	$ 980,538
Plant Total:	$5,425,201
UIC Well Closure:	$1,049,175
UIC Well Post-Closure:	$ 271,725
UIC Total:	$1,363,916
Total Closure and Post Closure:	$6,789,118

If you have any questions, please do not hesitate to contact me by telephone at 281-248-7032 or by e-mail listed below.

Sincerely,

Susan Zollers

Susan Zollers
Sr. Environmental Engineer, INEOS O&P SHEQ
susan.zollers@ineos.com

cc: Mr. Chuck Lowe, Geologist – UIC Unit, Ohio EPA – DDAGW, Lazarus Government Center
P.O. Box 1049, Columbus, OH 43216-1049

Shannon Nabors, Chief – NWDO Ohio EPA
Attn: Div. of Hazardous Waste Management, 347 N. Dunbridge Road, Bowling Green, Ohio 43402

ATTACHMENT D

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

I. 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 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.

6.0 ARTIFICIAL PENETRATIONS

INEOS has elected to research all artificial penetrations within a nominal radius of 10 miles. This radius extends well beyond the furthest extents of both the 10,000-year projection of lateral plume migration (Section 5.4 and 5.5) and the Cone of Influence (Section 5.6). In preparation of this section, the main source of information regarding all oil and gas wells in Ohio was a computer database compiled by the Ohio Department of Natural Resources, Division of Mineral Resources Management (ODNR DMRM). Staff of this agency provided a subset of this database that listed wells within a 15-mile radius. This larger radius was selected because location information for some wells is limited to listing the township. Townships are generally six-by-six-mile squares. Thus a 15-mile radius was considered adequate to encompass the "nominal" 10-mile radius cited above. Wells in the ODNR DMRM database within 10 miles at the INEOS site are listed in Appendix 6-1. Wells for which Ohio State Plane coordinates are listed in the ODNR DMRM database are plotted on Drawing 6-1. Permit numbers on Drawing 6-1 are listed in Appendix 6-1.

Table 6-1, the list of wells deeper than 1800 feet (sub-1800-foot wells was updated based on a records search through October 2021. Well records for those wells identified in the publicly available records that are greater than 1,800 feet in depth are provided in Appendix 6-2. Wellbore schematics for the sub-1800-foot wells are provided as Figures 6-1 through 6-9. Three Class I non-hazardous injection wells have been installed at the Lima Refining Company, located at 1150 South Metcalf Street, Lima, Ohio, adjacent to the INEOS facility. The three wells were permitted by Ohio EPA for injection into the lower Eau Claire and Mount Simon Sandstone formations under permit numbers UIC 03-02-014-PTO-I (Deep Well 1, or DW-1), UIC 03-02-015-PTO-I (Deep Well 2, or DW-2), and UIC 03-02-016-PTO-I (Deep Well 3, or DW-3). All three wells are in operation and based on the Agency's records indicating the wells have mechanical integrity and meet regulatory conditions for operations, these wells do not require any further evaluation or corrective action under the Ohio EPA regulations as related to INEOS permit renewal. In addition, map PG-2 (Revised 8/2004), which plots wells drilled below the Knox Dolomite published by ODNR, DGS, was utilized (Figure 6-13).

As shown in Table 6-1 and on Figure 6-13, the only wells within the 10-mile AOR that have recorded depths below the base of the Knox Dolomite are the INEOS injection wells, the Hubbard, D-1, Permit No. 60668, and the three Lima Refining Company injection wells DW-1, DW-2, and DW-3 permit numbers UIC 03-02-014-PTO-I, UIC 03-02-015-PTO-I, and UIC 03-02-016-PTO-I, respectively, in Table 6-1.

In the records search performed for the 1991 No Migration Petition, two wells were found permitted as D-1 and D-2, which reportedly had total depths of 2630 feet and 1951 feet, respectively (Table 6-1). These are considered to be "orphan" wells since the permit numbers do not fit the normal ODNR numbering sequence. The D-1 well (2630 feet) does not appear on the PG-2 Map (Figure 6-13) of sub-Knox Dolomite wells.

In an attempt to verify that the wells permitted as D-1 and D-2 were ever drilled, a field investigation was made on August 14, 1991. The D-1 well, logged by Hubbard, is located in Section 18, Auglaize Township, Allen County, and approximately 8 miles southeast of the plant's injection wells.

There is no evidence of this well location anywhere on the farm based on interviews, and the present resident of 40 years does not recall such a well. The tract of land has been in his family for many years and there is no knowledge of a well ever having been drilled on this property.

A field reconnaissance was also made of the well permitted as D-2 (the J.W. Sellers No. 6 well). The record of this well is very limited with no location indicated on the card record. Maps of the Ohio Historical Society were reviewed, and it was determined that the location of the No. 5 well agreed with the current Shawnee township map. For investigative purposes, the No. 6 well location was assumed to be correct on the current map. Assuming this to be correct, the Sellers No. 6 well location is approximately 2.6 miles south of the plant in a small lot subdivision. There is no evidence of a well having been drilled on these properties from the field reconnaissance trip.

Based on the existing records, D-2, with a total depth of 1951 feet does not penetrate the confining zone. The total depth of D-1, 2630 feet, is close to the top of the injection interval. However, the location of this well, approximately 8 miles east-southeast of INEOS, is outside of the cone of influence, and consequently outside the area of review as narrowly defined by conservative non-endangerment criteria. It should be noted that the 10-mile radius was an arbitrary and overly conservative choice for the area of investigation of artificial penetrations.

It should be noted that many of the wells spotted on the map and listed in the ODNR DMRM database do not have total depths assigned to them. This is because many wells were drilled in the late 1800's and early 1900's before accurate records were kept. As discussed in the following section, the oil productive interval in the AOR is the Trenton Limestone at approximately 1250 feet. As the Trenton Limestone was the objective of the early wells that lack records, it is extremely doubtful that any early well penetrated the sub-Knox Dolomite formations (injection zone) as there was no sub-Trenton production then and there has never been sub-Trenton production established in the area of the AOR.

In conclusion, it has been determined through an update of oil and gas records, incorporation of the ODNR DGS Map PG-2, and field reconnaissance, that no documented wells penetrate the injection zone within the cone of influence of the INEOS injection wells do not pose issues for corrective action. If well D-1 exists, this wellbore will not experience pressurization sufficient to drive vertical migration because it is located outside of the cone of influence.

Corrective Action Plan

As indicated above, no corrective action is required for wells with the AOR.

Water Well Search

Water well locations are plotted on Drawings 6-2, 6-3, 6-4, 6-5, and 6-6. Topographic maps (USGS quad Sheets) with water well locations through 1966 were copied at the ODNR, Division of Water and utilized for Drawing 6-2. Revised locations of wells drilled to September 2004, were downloaded from the ODNR, Division of Water database and plotted on the topo map base and shown on Drawing 6-3. Locations of wells drilled from September 2004 through mid-April 2010 were downloaded from the Division of Water database and were plotted on Drawing 6-4. Monitoring well locations at the INEOS facility are also provided.

Mines, Karst Areas, Flood Areas and Other Features

Several quarries and gravel pits are present within the AOR (Drawing 6-2). According to the Ohio Mineral Industries Report, 2002, these extract sand, gravel, limestone, and dolomite for various industrial purposes. These will not be affected by injection operations. No coal mining occurs in western Ohio and mines are not present in the AOR.

The area of the AOR is covered by Pleistocene glacial deposits which overlie Silurian limestone and dolomite. The map of Ohio Karst Areas (Figure 6-14) does not include karsting in the AOR.

The Twin Lake, Lost Creek, Metzger, Lima, and Ferguson Reservoirs are present to the northeast of the INEOS facility (Drawing 6-2 and 6-3).

Appendix 6-3 is a 100-year floodplain map that demonstrates that the INEOS facility is not located in an area subject to flooding hazard.

Hydrocarbon storage caverns are located adjacent to the INEOS facility, to the southeast. None of these is greater than 1800 feet deep. Information regarding these wells is included as appendix 6-4.

Oil and Gas Resources Within the AOR

The Trenton Limestone at approximately 1250 feet is productive of oil and gas within the 10-mile AOR (Drawing 6-1). Trenton Limestone production is part of the giant Lima-Indiana Trend, which includes 60 actual individual fields, and extends for 185 miles from Toledo, Ohio southwestward to Indianapolis, Indiana (Figure 6-15; Wickstrom, et al, 1992).

The Lima-Indiana Trend was extensively drilled in the late 1800's to early 1900's with peak production in 1895 (Figure 6-16). By 1910, the fields were largely depleted (Wickstrom, et al, 1992).

No formations below the Trenton Limestone are productive of oil and gas within the AOR. No oil and gas production has been established from any sub-Knox Dolomite formations in Ohio (Harris and Baranoski, 1996). Therefore, there has been no oil and gas production from the confining or injection zones.

ATTACHMENT E

QUALITY ASSURANCE ACKNOWLEDGMENT

I hereby affirm that all chemical data submitted for injection Well Permit Number UIC 03-02-006-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

INEOS Nitriles USA LLC
Lima, Ohio
WDW #1

ATTACHMENT F

CERTIFICATION PURSUANT TO OAC 3745-34-59(E)

3.0 WASTESTREAM JUSTIFICATION

Section No. 59(E)

(C) The owner or operator will provide a certification that states:

(1) The generator of the hazardous waste has a program to reduce the volume or quantity and toxicity of such waste to the degree determined by the generator to be economically practicable; and

(2) Injection of the waste is that practicable method of disposal currently available to the generator which minimizes the present and future threat to human health and environment.

Summary

Alternative handling and disposal options for process wastewater from the production of acrylonitrile have been extensively studied by INEOS. Options to reduce wastes generated by the process (waste minimization) have been evaluated as well as options for elimination of deepwell disposal that rely on above ground treatment and disposal techniques. The results of this investigation show that while alternatives to deepwell injection may exist, these alternatives are less protective of human health and the environment and are not readily capable of being put into practice due to technical limitations. Furthermore, waste minimization was found to be the best approach, as currently practiced at the Lima Chemical plant, when practiced in conjunction with deepwell injection. Since approximately 2.5 pounds of water is generated for each pound of acrylonitrile produced, water will always need to be disposed of from the process even with efficient waste minimization.

The viable surface treatment options for elimination of deepwell injection involve incineration of the entire wastewater stream or incineration of polymers formed in the production of acrylonitrile after separation from the wastewater. In addition, all of the treatment options considered result in significant air emissions, surface water pollution and generation of industrial sludge which must be either landfilled or incinerated, all of which may result in exposures to the public. In comparison, deepwell injection does not result in these environmental negatives and exposure of pollution to the public. Therefore, it is concluded that deepwell injection of wastewater at the Lima Chemical plant is the practicable method currently available which minimizes the present and future threat to human health and the environment.

INEOS hereby requests that this section be inserted in the permits to operate in accordance with OAC Rule 3745-34-59(E).

Background

All of the acrylonitrile manufactured in the United States is produced using the Sohio ammoxidation method. This involves the reaction of air, ammonia and propylene in a fluidized bed catalytic reactor. Wastewater is generated in the process due to the stoichiometry of the reaction (approximately 2.5 pounds of water is made for each pound of acrylonitrile) and the use of sulfuric acid in the quench step to remove excess ammonia from reactor effluent gases. Currently all producers of acrylonitrile in the U.S. use deepwell injection for wastewater disposal because no practicable option exists and all of the production sites are located where the local geology is well suited for underground injection.

Since the Lima site first started operation of the acrylonitrile unit thirty years ago, numerous alternatives for wastewater handling and disposal have been evaluated. Deepwell injection was first practiced in 1968 and eliminated the environmental emissions associated with the previous operations, which was discharge of dilute process wastewater to the Ottawa River which created water quality problems, and the incineration of the contaminated process wastewater which resulted in tremendous NOx and SOx emissions. Alternatives that are technically available are full incineration of the wastewater and use of process modifications to yield biotreatable water for surface discharge and incineration of the organic polymers. These will be described in the next section along with the other handling and disposal alternatives that have been studied over the years and have been found not to be technically available for implementation.

Deepwell Alternatives

INEOS had a research program that has evaluated and studied alternatives to deepwell injection for disposal of acrylonitrile production wastewater. Information on alternatives has been gathered over the years from a number of sources. These include contact with other acrylonitrile producers, the National Technical Information Services (NTIS) of the U.S. Department of Commerce, contact with universities and private research foundations, equipment vendors, and various internal searches of literature and research databases. This has yielded a comprehensive list of technologies that could be applicable to treatment and disposal of acrylonitrile wastewater. The technologies identified fall into the following categories:

- process changes which alter the nature and treatability of the wastes
- incineration
- biological treatment methods
- physical/chemical treatment methods

- combinations of the above

The next step was to identify the technologies within these categories that are available and demonstrated for treating acrylonitrile production wastewater. This yielded the following options:

- liquid incineration with tail gas desulfurization
- process changes with surface treatment of the wastes - biological treatment of water; incineration of organic polymers; and, separation of ammonium sulfate salt.

All of the other technologies identified were considered not viable for various reasons, such as not being demonstrated on acrylonitrile production wastewaters or treatment still required deepwell injection of residual wastewaters. A brief description of the remaining two options which are considered technically viable is given below.

Incineration

Incineration is a proven technology for treating a variety of organic bearing wastes, especially liquid or water-based wastes that flow freely. However, when incinerating acrylonitrile production wastewater, the sulfate salt content (4-5% ammonium sulfate) and high nitrogen content require desulfurization of the incinerator tail gas and use of low-NOx technology to minimize SOx and NOx emissions. Although this technology appears available, there are no operating units which have demonstrated the low-SOx and NOx technology on acrylonitrile production wastewater. Furthermore, since the wastewater contains only 1% organics and a high sulfate level, a tremendous amount of fuel will be needed to fully combust the wastewater and the desulfurization step will generate tremendous quantities of sludge (solid waste), not to mention the sizable increase in total NOx emissions that would be generated.

The permitting of an incineration option has been reviewed and it is anticipated that obtaining a hazardous waste incineration permit will take more than seven years and thousands of man-hours of time. Clearly, the availability of this alternative to deepwell injection is highly questionable given the current regulatory and political environment in the state.

Based on the above discussion, it is concluded that incineration or any alternative that relies on incineration as a component of that alternative is not a viable or practicable method available to eliminate deepwell injection.

Process Changes With Surface Treatment of Wastes

INEOS has identified process changes that could be made to the acrylonitrile process that would minimize and alter the waste streams that are generated. These process changes would accomplish three things - (1) concentration of the organic polymers in one stream for incineration; (2) concentration of the ammonium sulfate salt in another stream which could then be crystallized; and, (3) production of a wastewater stream with limited organic concentration which could be biologically treated for surface water discharge. Although all of these process changes have not been implemented at any acrylonitrile plant, each of the various changes appear technically feasible and could be practiced simultaneously for elimination of underground injection of acrylonitrile wastewater.

The implementation of these process changes as an alternative to deepwell injection is not considered a practicable option at this time for three reasons. First, as discussed in the last section, addition of new incineration capacity is required for this option and is not a practicable method currently available. Second, the ammonium sulfate salt from the process changes would have to be landfilled as hazardous waste since the salt is derived from a hazardous wastewater. This approach would be a cross media transfer since it merely replaces underground injection of these salts with landfilling which is not considered as environmentally protective. Lastly, the "clean" wastewater that would be biologically treated would have to be discharged to the Ottawa River which is a water quality limited stream. Introduction of a new discharge would be critically reviewed and the effluent from treatment would have to meet water quality standards. Treatment of this water to water quality standard is not proven technology and is not a demonstrated alternative.

In conclusion, the process changes that could be implemented to eliminate underground injection of acrylonitrile production wastewater are not considered available practicable approaches.

Fort Amanda Specialties Deepwell Alternatives

The Fort Amanda Specialties waste streams are very similar to the acrylonitrile process wastewater, i.e., they contain ammonia, sulfate, cyanide and nitriles. Due to their similarity, the same alternatives for waste handling and disposal apply, as well as limitations to implementation.

Conclusion

Based on the discussion above, no practicable methods were identified that are available to eliminate underground injection of acrylonitrile production wastewater from the Lima Chemical plant. INEOS hereby certifies, as required by Ohio Administrative Code (OAC) 3745-34-59(E), that no practicable alternatives to deepwell disposal exist for the Lima Chemical plant. INEOS is committed, however, to continue investigating options to deepwell injection and options that minimize the wastes generated from the acrylonitrile process.

Waste Minimization Certification

In accordance with requirement Part II(H) of the above-referenced permits to operate and Ohio Revised Code Section 6111.045, INEOS has prepared and forwarded to the Ohio EPA the latest revision and update of the facility waste minimization plan in 2021.