OHIO ENVIRONMENTAL PROTECTION AGENCY

DIVISION OF DRINKING AND GROUND WATERS,

UNDERGROUND INJECTION CONTROL PERMIT TO OPERATE: CLASS I HAZARDOUS WELL

Ohio Permit No.: UIC 03-02-004-PTO-I
US EPA ID No.: OHD 042157644

Date of Issuance: January 27, 2011
Effective Date: January 27, 2011

Date of Expiration: January 27, 2016

1-27-11

Name of Applicant: INEOS USA LLC
Waste Disposal Well No. 2

Mailing Address: P.O. Box 628
Lima, Ohio 45802-0628

Facility Location: 1900 Fort Amanda Road
Lima, Ohio 45804

County: Allen **Township:** Shawnee

Section, Quarter Section: Section 11
Latitude/Longitude: 40°47'55"N/84°08'09"W

Injection Interval: Eau Claire and Mt. Simon from 2800 to 3210 feet (KB)
Containment Interval: Eau Claire from 2418 to 2800 feet (KB)

Injection Zone: Eau Claire, Mt. Simon, and Middle Run from 2418 to 3210 feet (KB)
Confining Zone: Knox from 2090 to 2418 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, the applicant (Permittee) 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 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 Ohio Administrative Code (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, F, and G.

This permit shall become effective on JAN 27 2011 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.

Scott J. Nally, Director
Ohio Environmental Protection Agency

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ATTACHMENTS

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 the federal Resource Conservation and Recovery Act.

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. Transfer of Permits. This permit may be transferred to a new owner or operator only if it is modified or revoked and reissued pursuant to OAC Rule 3745-34-22 (A), 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. Duty to Comply. 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 6109 or 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. Penalties for Violations of Permit Conditions. Any person who violates a

permit requirement is subject to injunctive relief, civil penalties, fines, and/or other enforcement action under ORC Chapter 6111, 6109 or 3734. Any person who knowingly or recklessly violates permit conditions may be subject to criminal prosecution.

3. 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.

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.

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

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

   a. Enter permittee's premises where a regulated facility or activity is located or conducted, or where records are kept under the conditions of this permit;
   b. Have access to and copy, at reasonable times, any records that are kept under the conditions of this permit;
   c. Inspect at reasonable times any facilities, equipment (including monitoring and control equipment), practices, or operations regulated or required under this permit; and
   d. Sample or monitor at reasonable times for the purposes of assuring permit compliance or as otherwise authorized by ORC chapter 6111 and OAC Chapter 3745-34, any substances or parameters at any location.

9. Records.

a. The permittee shall retain copies of records of all monitoring information, including all calibration and maintenance records and all original recordings for continuous monitoring instrumentation and copies of all reports required by this permit for a period of at least 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 form 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 Rule 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. Records of monitoring information shall include:

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

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

a. Monitoring the nature of injected fluids shall comply with the applicable analytical methods cited and described in Table I of 40 CFR 136.3 or in Appendix III of 40 CFR Part 261 or (in certain circumstances) by other methods that have been approved by the Administrator of U.S. EPA, or by the Director.

b. The monitoring information shall include conditions of quality assurance for each type of measurement required for reporting by the operator. Reference to established, published criteria shall be made wherever possible.

c. Sampling and analysis shall comply with the specifications of the Waste Analysis Plan required in Part II (D) (3) of this permit and OAC Rule 3745-34-57.

11. <u>Signatory Requirements.</u> 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. <u>Reporting Requirements.</u>

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.

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.

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. <u>Closure Plan.</u> 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 A 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 Rule 3745-34-60 (C). The report shall be certified as accurate by the permittee and by the person who performed the closure operation (if other then the owner or operator). Such report shall consist of either:

   a. A statement that the well was closed in accordance with Attachment A of this permit; or
   b. Where actual closure differed from Attachment A of this permit, a written statement specifying the differences between Attachment A 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. Financial Responsibility for Closure. The owner or operator shall comply with closure financial assurance requirements of OAC Rules 3745-34-36 (D) and 3745-34-62. The obligation to maintain financial responsibility for closure survives the termination of this permit or cessation of injection.

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

1. Post-Closure Plan. A plan for post-closure activities has been submitted and is included in Attachment A 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. An assurance of financial responsibility as required by OAC Rule 3745-34-62.

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

3. Duration of Post-Closure Period. 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 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 2010 financial assurance documentation has been submitted and is included in Attachment A. 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 Rule 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 Rule 3745-34-57 (I) (1) at least once every twelfth month beginning with the date of the last 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 Rule 3745-34-57 (I) (2) at least once every twelfth month beginning with the date of the last approved demonstration;
   c. An approved temperature, noise or other approved log shall be run in accordance with OAC Rule 3745-34-57 (I) (3) at least once every 36 months from the date of the last approved 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 Rule 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).

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

5. Loss of Mechanical Integrity. If the permittee or the Director 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. Mechanical Integrity Testing on Request From Director. 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 2010 cost of closure and post-closure of the four permitted Class I hazardous injection wells on site is $1,107,336. The 2010 financial assurance mechanism is provided in Attachment A 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 Rules 3745-34-09 (C) (8) and 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 E 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 Rules 3745-34-37 (B) 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 C 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 Rule 3745-34-54 (D)]. Injection shall take place only through approved tubing with an approved packer 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 C 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. Data on the injection and confining zones are contained in Attachment B of this permit. The permittee's determination of the following information concerning the injection interval also appears in Attachment B.
   a. Formation fluid pressure;
   b. Formation fracture pressure; and
   c. Physical and chemical characteristics of the formation.

2. In accordance with OAC Rule 3745-34-57 (J), the permittee shall monitor the pressure buildup in the injection zone at least every twelfth month beginning with the date of the completion of the last approved monitoring event. The permittee shall schedule pressure buildup testing such that one of the permittee's four Class I injection wells is tested each year and each well shall be tested at least once every forty-eight (48) months. This shall include, at a minimum, a shut down of the well for a time sufficient to conduct a valid observation of the pressure fall-off curve. A plan for such monitoring shall be submitted for the Director's review and approval at least thirty (30) days prior to initiating monitoring or testing. The results of this test shall be used to calculate the following:
   a. The transmissivity of the injection zone;
   b. The formation or reservoir pressure; and
   c. The skin effect.

   The results of this test and the permittee's interpretation of the results shall be submitted to the Ohio EPA in accordance with OAC Rule 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 Sandstone in the approximate subsurface interval between 2800 feet and 3210 feet below kelly bushing (KB) for INEOS Well No. 2.

2. Injection Pressure Limitation [OAC Rule 3745-34-38(A) and 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 2100 psi is never exceeded, calculated with a fracture gradient of 0.75 psi/foot applied at a depth of 2800 feet KB. The injection pressure shall be limited so that a maximum pressure of 839 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 D of this permit. Downward adjustments in injection pressure shall be made based on injectate specific gravity measurements made and recorded at least once every four (4) hours.

3. Injection Volume Limitation. The combined monthly injection volume for all

permitted Class I injection wells at this facility shall not exceed 24 million gallons.

4. Additional Injection Limitation. No substances other than those listed in Attachment D 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 non-hazardous fluids recovered from monitor wells and other non-hazardous fluid required for approved well testing and/or monitoring.

5. Annulus Fluids and Pressure [OAC Rule 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 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 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 839 psig;
      ii. Bottomhole pressure reached 2100 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. 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.

D. MONITORING

1. Monitoring Requirements [OAC Rules 3745-34-38 (B) and 3745-34-57 (A) - (F)]. Samples and measurements taken for the purpose of monitoring shall be protective of human health, safety and the environment and 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)	Maleonitrile	Total Suspended Solids (TSS)
HCN (total)	Methyl Pyridine	
Magnesium	Nicotinonitrile	
Nickel	Propionitrile	
Sodium	Pyridine	
Strontium		
Vanadium		
Zinc		

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 he or she 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 F) 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 Rule 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 Specialities. 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. 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.

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)

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, and temperature of the combined wastestream. 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. The monthly combined average flow rate for all operating wells. These data shall appear once on the monthly report.
   e. 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.
   f. 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.
   g. Date, time and volume of annulus fluid addition to or removal from the annulus system.
   h. Annulus sight glass level readings noted daily at a specified time.
   i. 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.
   j. A listing of the duration and cause of any non-operating period for the well during the month.
   k. Any procedures conducted at the injection well other than routine operational procedures.
   l. Weekly determinations of (injectate) pH, including monthly maximum and minimum values, for both the combined and Fort Amanda wastestreams.
   m. Determinations of injectate specific gravity every four (4) hours.
   n. 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.

o. 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. <u>Quarterly Report [OAC Rule 3745-34-58]</u>. 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. <u>Reports on Well Tests and Workovers</u>. 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 D 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, whichever is applicable.

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

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

INEOS USA LLC
Lima, Ohio
WDW #2

ATTACHMENT A

I. Closure Plan
II. Post-Closure Plan
III. Closure and Post-Closure Financial Assurance

ATTACHMENT A

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	$21,974
Prepare Location	7,325
Rig, Pump, Tanks, Pipe Racks	36,624
Work String, Rental Tools	14,650
Pressure Control Fluid	7,325
Casing Pressure Test Equipment	7,325
Logging (7-in Caliper Log, 7-in. CBL, 7-in. Vertilog, 7-in. Casing Tempature Log)	21,974
Mud	10,254
Cement Retainer	4,395
Cementing and Testing	29,298
Planning, Supervision, Report Preparation	21,974
Frac Tanks	7,325
Fluid Disposal	7,325
Contingencies	23,914
Total Estimated Cost, Per Well	**$221,682.00**

TABLE 10-A

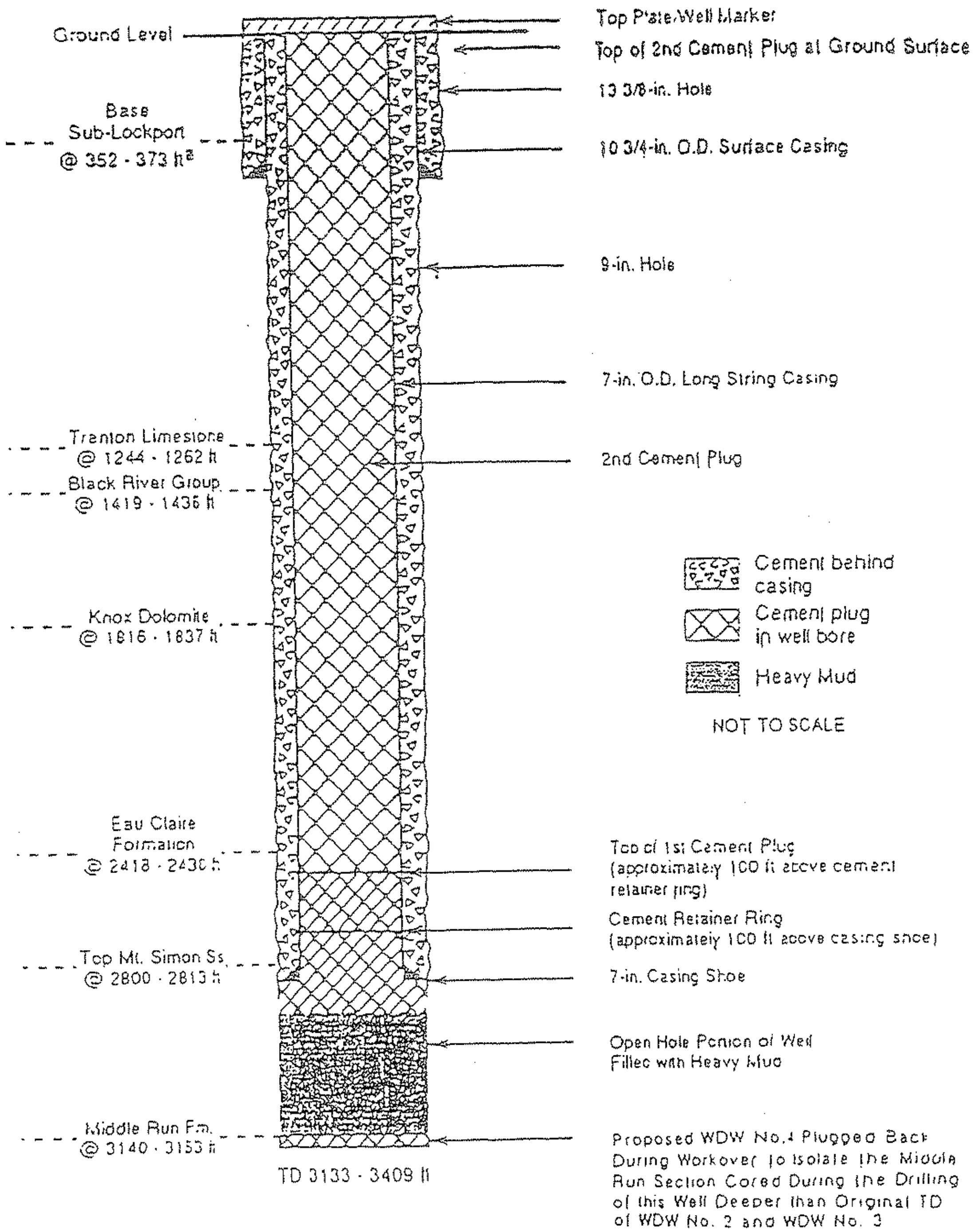
PLUGGING VOLUMES FOR CLOSURE OF LIMA CHEMICALS INJECTION WELLS

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

FIGURE 10-1

GENERALIZED PLUGGING AND ABANDONMENT WELL SCHEMATIC

ATTACHMENT A

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)

Upon closure, a survey plat will be submitted to the local zoning authority, to the USEPA, Region V, to the OEPA Division of Water, and to the State Department of Public Health. The following activities will be completed at the time of closure of the INEOS injection wells.

1. Survey Plat – The survey plat will include the following information:

   (a) The surface and subsurface locations of the wellbore(s) and the stratigraphic location of the injection zone.

   (b) Plat to be certified by a professional land surveyor.

   (c) Include notice restricting disturbance of affected areas. Surface use of the property will be unrestricted except at the monument. Subsurface disturbance is not permitted in the immediate vicinity of the borehole.

2. Notification of the Deed

   (a) The fact that the land was used to manage hazardous waste.

   (b) The type, location and quantity of waste disposed of by each injection well at the facility. The depth of the injection zone for each injection well at the facility will also be recorded on the deed in addition to the period over which injection occurred. The permitted injection zones for each of the site injection wells is as follows (depths below Kelly Bushing Datum):

WDW No. 1	2340-3220 ft KB
WDW No. 2	2418-2800 ft KB
WDW No. 3	2422-3213 ft KB
WDW No. 4	2430-3223 ft KB

   The predictive modeling will be updated based on the actual injection history and measured reservoir conditions at the time of closure and recorded.

   (c) The names of the organizations including the local zoning authority and the OEPA, Division of Water, with which the plat was filed as well as the address of the OEPA, Division of Water.

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	$128,915
Legal Filings	35,158
Post Closure Monitoring	35,158
Contingency	21,377
Estimated Post-Closure Costs, Site	$220,608

INEOS USA LLC
Lima, Ohio
WDW #2

ATTACHMENT A

III. Closure and Post-Closure Financial Assurance

BARCLAYS

200 Park Avenue
New York NY 10166
USA

Tel +1 (212) 412 4000

Director of the Ohio Environmental Protection Agency
Lazarus Government Center
122 South Front Street
Columbus, Ohio 43215

COPY

Re: Letter of Credit No. NYSB-2039

Dear Sir or Madam:

This letter amends our Irrevocable Standby Letter of Credit No. NYSB-2039 effective April 1, 2006 issued in your favor at the request and for the account of INEOS USA LLC.

Effective April 1, 2010, the amount is hereby decreased by US$1,678,529.00 to a new aggregate amount of US$5,480,120.00 (Five Million Four Hundred Eighty Thousand One Hundred Twenty 00/100 U.S. Dollars).

This amendment letter in no way changes any of the terms of the Letter of Credit, which remains in full force and effect.

If you have any questions about this letter amendment, please contact Dawn Townsend, Telephone (201) 499-2081, Fax (212) 412-5011.

Please indicate your acceptance/rejection of this amendment by signing and checking appropriate response and returning the copy to us at our above address.

Sincerely,

BARCLAYS BANK PLC, NEW YORK

DAWN TOWNSEND
AUTHORIZED SIGNATORY

(Date) April 1, 2010

This credit is subject to the most recent edition of the Uniform Customs and Practice for Documentary Credits, published and copyrighted by the International Chamber of Commerce.

Amended terms ____Accepted ____Rejected
Director of the Ohio Environmental Protection Agency

____
AUTHORIZED SIGNATURE

JPMorganChase

JPMorgan Chase Bank, N.A.
C/O JPMorgan Treasury Services
10420 Highland Manor Drive, 4TH Floor
Tampa, Florida 33610, U.S.A.
ATTN: Standby Letter of Credit Dept.

Date: June 2, 2010

To:
JPMorgan Trust Company, N.A.
Attn: Institutional Trust Services
Leonard Gnat 312.267.5114
227 West Monroe, 26th Floor
Chicago, IL 60606
(the "Beneficiary")

Re: P-624435

In respect to our Standby Letter of Credit reference P-624435 issued in favor of the above referenced beneficiary, this letter shall serve as confirmation of the current expiration date of March 30, 2011.

Regards,

Luba Stewart
Operations Risk/Control Analyst
Global Trade Services
JPMorgan Chase Bank, N.A.

JPMorgan

JPMorgan Chase Bank, N.A.
c/o JPMorgan Treasury Services
Global Trade Services
10420 Highland Manor Drive
Tampa, FL 33610
Tel.: 866-632-5101

MAR 31, 2005
OUR L/C NO.: P-624435

TO:
JPMORGAN TRUST COMPANY, N.A.
ATTN: INSTITUTIONAL TRUST SERVICES
(LEONARD GNAT 312.267.5114)
227 WEST MONROE, 26TH FLOOR
CHICAGO, IL 60606

APPLICANT:
O&D USA LLC,
LIMA CHEMICAL -- UIC WELL,
200 E. RANDOLPH DRIVE,
CHICAGO, ILLINOIS 60601

WE ENCLOSE HEREWITH (AS A PERMANENT PART OF THIS LETTER OF CREDIT) AN IRREVOCABLE STANDBY LETTER OF CREDIT OPENED IN YOUR FAVOR SUBJECT TO UCP500

TRANSACTION REFERENCE NUMBER:	P-624435
DATE AND PLACE OF EXPIRY:	MARCH 30, 2006 AT OUR COUNTER
DOCUMENTARY CREDIT AMOUNT:	USD8,000,000.00
AUTO EXTENSION:	YES
EXTENSION PERIOD:	12 MONTH(S)
NOTIFICATION PERIOD:	120 DAY(S)

PLEASE REVIEW THE DETAILS OF THIS ENCLOSURE AND THE ATTACHED LETTER OF CREDIT IMMEDIATELY AND CONTACT OUR CUSTOMER SERVICE AREA AT 1-866-632-5101 IF YOU HAVE ANY QUESTIONS.

AUTHORIZED SIGNATURE
HENRY AVELINO
ASSISTANT VICE PRESIDENT

JPMorgan

JPMorgan Chase Bank, N.A.
c/o JPMorgan Treasury Services
Global Trade Services
10420 Highland Manor Drive
Tampa, FL 33610
Tel.: 866-632-5101

MAR 31, 2005
OUR L/C NO.: P-624435

IRREVOCABLE STANDBY LETTER OF CREDIT NO. P-624435

NAME AND ADDRESS OF ISSUING INSTITUTION:
JPMORGAN CHASE BANK, N.A.
C/O JPMORGAN TREASURY SERVICES
ATTN: STANDBY LETTER OF CREDIT DEPT.
10420 HIGHLAND MANOR DRIVE, 4TH FLOOR
TAMPA, FL 33610

DIRECTOR OF THE OHIO ENVIRONMENTAL PROTECTION AGENCY
LAZARUS GOVERNMENT CENTER
122 SOUTH FRONT STREET
COLUMBUS, OHIO 43215

DEAR SIR OR MADAM:

WE HEREBY ESTABLISH OUR IRREVOCABLE STANDBY LETTER OF CREDIT NO. P-624435 IN THE FAVOR OF JPMORGAN TRUST COMPANY, NATIONAL ASSOCIATION, AS TRUSTEE UNDER THE STANDBY TRUST AGREEMENT OF MARCH 30, 2005 BY AND BETWEEN O&D USA LLC AND JPMORGAN TRUST COMPANY, AT THE REQUEST AND FOR THE ACCOUNT OF O&D USA LLC, LIMA CHEMICAL -- UIC WELL, 200 E. RANDOLPH DRIVE, CHICAGO, ILLINOIS 60601, FOR THIRD-PARTY LIABILITY AWARDS OR SETTLEMENTS UP TO ONE MILLION AND NO/100 U.S. DOLLARS $1,000,000.00 PER OCCURRENCE AND THE ANNUAL AGGREGATE AMOUNT OF TWO MILLION AND NO/100 U.S. DOLLARS $2,000,000.00, FOR SUDDEN ACCIDENTAL OCCURRENCES AND/OR FOR THIRD-PARTY LIABILITY AWARDS OR SETTLEMENTS UP TO THE AMOUNT OF THREE MILLION AND NO/100 U.S. DOLLARS $3,000,000.00 PER OCCURRENCE AND THE ANNUAL AGGREGATE AMOUNT OF SIX MILLION AND NO/100 U.S. DOLLARS $6,000,000.00, FOR NONSUDDEN ACCIDENTAL OCCURRENCES AVAILABLE UPON PRESENTATION OF A SIGHT DRAFT, BEARING REFERENCE TO THIS LETTER OF CREDIT NO. P-624435.

THIS LETTER OF CREDIT IS EFFECTIVE AS OF MARCH 31, 2005 AND SHALL EXPIRE ON MARCH 30, 2006, BUT SUCH EXPIRATION DATE SHALL BE AUTOMATICALLY EXTENDED FOR A PERIOD OF ONE YEAR ON MARCH 30, 2006 AND ON EACH SUCCESSIVE EXPIRATION DATE, UNLESS, AT LEAST ONE HUNDRED TWENTY DAYS BEFORE THE CURRENT EXPIRATION DATE, WE NOTIFY YOU, THE DIRECTOR, AND O&D USA LLC BY CERTIFIED MAIL THAT WE HAVE DECIDED NOT TO EXTEND THIS LETTER OF CREDIT

JPMorgan

JPMorgan Chase Bank, N.A.
c/o JPMorgan Treasury Services
Global Trade Services
10420 Highland Manor Drive
Tampa, FL 33610
Tel.: 866-632-5101

MAR 31, 2005
OUR L/C NO.: P-624435

BEYOND THE CURRENT EXPIRATION DATE.

WHENEVER THIS LETTER OF CREDIT IS DRAWN ON, UNDER AND IN COMPLIANCE WITH THE TERMS OF THIS CREDIT, WE SHALL DULY HONOR SUCH DRAFT UPON PRESENTATION TO US.

WE CERTIFY THAT THE WORDING OF THIS LETTER OF CREDIT IS IDENTICAL TO THE WORDING SPECIFIED IN PARAGRAPH (K) OF RULE 3745-55-51 OF THE ADMINISTRATIVE CODE AS SUCH REGULATIONS WERE CONSTITUTED ON THE DATE SHOWN IMMEDIATELY BELOW.

JPMORGAN CHASE BANK, N.A.

BY: ______________________
(SIGNATURE)
(TITLE) HENRY AVELINO
ASSISTANT VICE PRESIDENT
DATE: MARCH 31, 2005

THIS CREDIT IS SUBJECT TO THE UNIFORM CUSTOMS AND PRACTICE FOR DOCUMENTARY CREDITS (1993 REVISION), PUBLISHED AND COPYRIGHTED BY THE INTERNATIONAL CHAMBER OF COMMERCE, PUBLICATION NO. 500.

____
AUTHORIZED SIGNATURE
HENRY AVELINO
ASSISTANT VICE PRESIDENT

INEOS USA LLC
Lima, Ohio
WDW #2

ATTACHMENT B

GEOTECHNICAL INFORMATION

I. Stratigraphy and Injection Interval Description
II. Fracture Pressure
III. Core Analysis (Open Hole Strata Only)

ATTACHMENT B

I. Stratigraphic and Injection Interval Description

4.0 GEOLOGY

WDW Nos. 1, 2, 3 and 4 are located in Sections 2 and 11 of Shawnee Township in Allen County, Ohio (Figure 4-1). The following sections provide both local and regional geologic information pertaining to the four injection wells at the INEOS facility.

4.1 Regional Geology

The following sections discuss the regional geologic setting in the vicinity of the INEOS facility in order to demonstrate the continuity and physical properties of critical geologic units.

4.1.1 Regional Geologic History

The INEOS facility is located on the Indiana Ohio Platform, which is a positive area between the Michigan, Appalachian and Illinois Basins (Wickstrom, et al, 1992; Figure 4-1). Structural relief on the Indiana Ohio Platform is generally the result of differential subsidence of the surrounding basins as opposed to tectonic uplift (Wickstrom, et al, 1992).

During the Precambrian (Keweenawan), a period of extension prevailed in the Mid Continent of North America which led to the formation of the Mid Continental Rift System, and associated East Continent Rift Basin, with the peak of rifting, associated volcanic activity and deposition of sedimentary rocks occurring at this time (Baranoski, 2002; Drahovzal, et al, 1992). A more detailed discussion of Precambrian rifting and sedimentation (Middle Run Formation) is included in the sections on Regional Stratigraphy and Structure.

The beginning of the compressional phase of the Grenvillian Orogeny marks the termination of Keweenawan rifting (East Continent Rift Basin). Rocks of the Grenville Province were thrust north-northwestward onto the older craton with accompanying regional metamorphism and additional plutonism which accounts for the increase of crustal thickness along the Grenville Front (Grenville Tectonic Zone) (Hoehn and Hinze, 1992). Movement along the north-south trending Bowling Green Fault Zone and associated Outlet Fault zones initiated during the Grenville Orogeny (Figures 4-2 and 4-3). Paleozoic reactivation along the Bowling Green Fault is discussed in Section 4.1.3 – Regional Structure. Santos (2002) analyzed detailed zircon grains from the Precambrian Middle Run Formation and determined its maximum age is 1.048 Ga (billion years) ± 22 Ma (million years).

During the Late Precambrian and into the Cambrian, the North American plate began to separate from northern Europe east of the Grenville Mountains. The ancient proto -Atlantic Iapetus Sea opened and by the Late Cambrian the stable margin of the sea became the site of subsidence and the accumulation of terrigeneous clastics. The Cambrian Sea moved across Ohio from east to west as the passive margin subsided. The Cambrian section therefore represents an overall transgressive depositional sequence (Harris and Baranoski, 1996). The basal sandstone, named the Mt. Simon, is a quartz-rich, occasionally arkosic, fine to coarse-grained sandstone. This was deposited unconformably upon the Precambrian (Janssens, 1973), and is interpreted to be a barrier bar sequence which migrated across a basal lagoonal estuarine sequence (Saeed, 2002).

The Eau Claire Formation (Cambrian) conformably overlies the Mt. Simon Sandstone with a gradational contact. Lithologically, the Eau Claire is a blend of very fine to fine grained, glauconitic, quartz sandstone, siltstone, dolomite and shale (Janssens, 1973). Glauconitic sandstone with increased carbonates towards the top of the section indicate increasingly marine conditions during deposition of the Eau Claire.

When sea floor spreading slowed during tectonically quiescent periods, carbonate deposits of the Knox Group occurred on the shelf (Hansen, 1997 and Milici, 1996). In northwestern Ohio, the Knox Group (Cambro-Ordovician) is referred to by Janssens (1973) as the undifferentiated Knox Dolomite where it consists of white to light gray dolomite and dolomitic sandstone with glauconite present at the top of the section (Wickstrom, et al, 1992).

The transition from deposition on a passive margin to deposition on a convergent margin caused the Knox Dolomite to be truncated by a major regional unconformity (Wickstrom, et al, 1992, Read, 1980). The continent was uplifted and karst topography and associated drainage patterns probably formed on the exposed surface (Dolly and Bush, 1972; Mussman and Read, 1986; from Wickstrom, et al, 1992).

Following erosion of the Knox surface, the land began to subside and a shallow sea covered the area, resulting in a brief period of intercalated clastic and carbonate sedimentation, represented by the Wells Creek Formation (Wickstrom, et al, 1992). Continued encroachment of the sea from east to west caused the deposition of the Ordovician Black River Group (micritic to finely crystalline limestone) in environments ranging from subtidal to intertidal (Wickstrom, et al, 1992).

Subsequent to the deposition of the Black River Group, the epeiric sea deepened and became more normal marine in composition. Bentonites at the top of the Black River Group are evidence that the Taconic Orogeny was increasing in intensity to the east (Wickstrom, et al, 1992). The deepening of the sea resulted in the deposition of the basal, subtidal and open-shelf facies of the Ordovician Trenton Limestone. As a result of the subsidence of the proto-Appalachian Basin and the early stages of the Taconic Orogeny, the deposition of the basal Trenton facies ended which is marked by a change in depositional strike from north-south to northeast-southwest. This caused a shallowing of the sea to the northwest and the deposition of the thick carbonates of the platform facies of the Trenton (Figure 4-4). Southeast of the platform, in deeper water, the Point Pleasant (interbedded shale and limestone) was deposited (Wickstrom, et al, 1992).

The end of Trenton deposition was probably the result of a more intense phase of the Taconic Orogeny (Hudson Valley Phase) (Titus, 1989; from Wickstrom, et al, 1992). This was marked by rapid subsidence and/or rise in sea level. In northwest Ohio, the sea moved westward and in effect drowned the Trenton carbonate platform and deposited the Cincinnati Group (shales and limestones) (Wickstrom, et al, 1992). At this time, the Bowling Green Fault Zone was probably reactivated.

The Ordovician-Silurian is postulated to be unconformable in adjacent portions of Indiana, based upon faunal evidence. However, Wickstrom, et al., (1992) finds no physical evidence for this in northwestern Ohio and therefore the nature of the contact is questionable.

Throughout the Silurian, the Taconic Mountains continued to erode during a time of tectonic stability. Thin-bedded shales and limestones of the Lower Silurian demonstrate that northwestern Ohio, while continuing to subside, was located far from the provenance for terrigeneous clastics. Deposition of the Lockport Group and the undifferentiated dolomites of the Salina Group further exemplify the quiescence of the period. Northwestern Ohio was sub-aerially exposed during the Upper Silurian and Devonian Periods and erosion removed the top of the Salina Group. While the entire area of Ohio was probably covered by Mississippian through Lower Permian sediments, at one time, subaerial exposure and associated erosion during the Mesozoic and Cenozoic removed these formations (Bownocker, 1920).

Pleistocene glaciation resulted in the deposition of Wisconsian-aged end moraines, ground moraines and associated outwash plains disconformably upon the post-Silurian erosional surface.

4.1.2 Regional Stratigraphy

The stratigraphic nomenclature utilized in this report is shown on the generalized stratigraphic column (Figure 4-5). Regional cross-sections A-A' and B-B' (Drawings 4-1 and 4-2), are included to show regional continuity and characteristics of the Paleozoic formations.

Precambrian Basement Complex

The Precambrian unconformity surface in Ohio is divided by the Grenville Front which separates metamorphic rocks of the Grenville Province from the older Granite-Rhyolite Province and East Continent Rift Basin sedimentary and volcanic rocks in western Ohio (Baranoski, et al, 2002) (Figure 4-2). The Grenville Province is younger than the East Continent Rift Basin rocks. Theories of Precambrian rifting proposed by Lucius and Von Frese, 1988, and other workers were substantiated with the discovery of Precambrian aged sedimentary rocks in the stratigraphic test drilled by the Ohio Geological Survey in Warren County in 1988, and the stratigraphic test (WDW No. 4) drilled by INEOS in 1991. This led to the re-examination of cuttings from wells in Ohio and it was discovered that Precambrian samples previously described as granitic were actually sedimentary rocks. This revealed that Precambrian sedimentary rocks lie unconformably below the Cambrian section and led to the naming of the Middle Run Formation (Shrake, et al, 1990, 1991, 1992; Drahovzal et al, 1992). Drahovzal et al, (1992) estimates upwards of 20,000 feet of sedimentary and volcanic rocks could be present in the East Continent Rift Basin (Figure 4-6).

The Middle Run Formation in the Warren County test is a well indurated, fine to medium grained sandstone that is predominantly silica cemented. The approximate areal extent of the sandstone was determined to be 30 miles wide by 99 miles long extending across western Ohio (Shrake, etal, 1991). The INEOS stratigraphic test well penetrated 256 feet of the Middle Run Formation before reaching a total depth of 3409 feet. The upper portion of the Middle Run lies within the injection interval.

Mt. Simon Sandstone (Cambrian)

The Mt. Simon is a widespread, very fine to coarse grained, partly conglomeratic sandstone that lies unconformably upon the Precambrian in western Ohio. A basal conglomerate overlies the Precambrian erosional surface (Janssens, 1973). In a recent MS Thesis from Bowling Green State University, Saeed (2002) describes the Mt. Simon in the ODNR Warren County well as a generally coarsening upward sequence of sandstone, siltstone and minor clay stone. Tidal rhythmites, flaser, lenticular and wavy bedding, mud-drapes, intraclasts and significant bioturbation structures attest to a shallow marine tidally-influenced depositional setting. The coarsening upward sequence is interpreted as a transgressive barrier sequence which migrated above a basal lagoonal estuarine succession (Saeed, 2002) (Figure 4-8).

The Mt. Simon Sandstone lacks index fossils and its precise age is uncertain (Saeed 2002). Trilobites in the Eau Claire Formation (above the Mt. Simon) are late Middle Cambrian to early late Cambrian in age which implies the Mt. Simon is roughly Middle Cambrian (Babock, 1994).

Historically, the Mt. Simon has been distinguished from the overlying Eau Claire Formation by the absence of glauconite (Janssens, 1973). However, some glauconite may be present at the top of the Mt. Simon indicating increasingly marine conditions. Glauconite was noted in the top of the Mt. Simon at the INEOS site. The Mt. Simon Sandstone ranges in thickness regionally from 140 feet to 350 feet (Janssens, 1973) (Figure 4-7). The Mt. Simon is 340 feet thick at the INEOS facility.

The contact and correlation of the Eau Claire-Mt. Simon Sandstone is further discussed in the section on Local Geology. However, it should be noted that the contact displayed on the regional cross-sections is the preferred pick of the ODNR (Rea and Wickstrom, et al, 1991). However, Saeed (2002) picks the top of the Mt. Simon at the top of the lower gamma ray response at the top of the more massive sand sequence (Figure 4-9).

Eau Claire Formation (Cambrian)

The Eau Claire Formation conformably overlies the Mt. Simon Sandstone and consists of very fine to fine grained, glauconitic quartz sandstone, siltstone, dolomite and shale (Janssens, 1973). It is more sandy at the base with carbonate content increasing in the upper part of the formation. Approximately 34 miles east of the study area there is a facies change where the Eau Claire is subdivided into the Kerbel, Rome and Conasauga Formations (Figure 4-10).

The Eau Claire ranges in thickness from less than 300 feet in the northeast to more than 500 feet in the southwest. The Eau Claire is 382 feet thick at the INEOS site and comprises part of the injection and arrestment intervals.

Knox Dolomite (Cambo-Ordovician)
The Knox Dolomite (undifferentiated) in northwestern Ohio is composed of white to light gray crystalline dolomite containing glauconitic siltstone and minor interbedded silty dolomite near the base of the formation (Janssens, 1973). Glauconite is present near the top of the formation (Wickstrom, et al 1992). The base of the Knox is transitional with the Eau Claire Formation. The Knox Dolomite ranges in thickness from approximately 200 feet in the northeast to approximately 700 feet in the southwest (Figure 4-11). The Knox Dolomite is 590 feet thick at the INEOS site and the lower half is the confining zone for injected fluids.

Wells Creek Formation (Ordovician)
Lying unconformably upon the Knox Dolomite, the Wells Creek Formation is composed of distinctive green, waxy, dolomitic and pyritic shale with some argillaceous carbonates, brown, gray and black shales, and minor amounts of sandstone and siltstone (Wickstrom). The thickness of the Wells Creek is related to the Knox Dolomite paleotopography, i.e., thin sections of Wells Creek correspond to thick sequences of Knox Dolomite (Wickstrom, et al, 1992). The maximum thickness of the Wells Creek is 30 feet. The Wells Creek is 18 feet thick at the INEOS site.

Black River Group (Ordovician)
The Black River Group conformably overlies the Wells Creek Formation except where relief on the post-Knox erosional surface was enough to preclude deposition of the Wells Creek, in which case it lies upon the Knox unconformity. Lithologically, the Black River group consists of tan, light-brown or gray micritic to finely crystalline limestone with some fossiliferous zones. Bentonites are abundant at the top of the formation (Wickstrom, et al, 1992). Regionally, the thickness of the Black River Group ranges from 300 feet in the west to 480 feet in the east (Figure 4-12). The Black River Group is 391 feet thick at the INEOS site.

Trenton Limestone (Ordovician)
The contact of the Trenton Limestone and Black River Group is conformable and is determined regionally on the basis of a prominent bentonite marker. In general, the Trenton Limestone is a fossiliferous limestone with a dark-gray to light-brown matrix. Thin shale beds are common. The Trenton Limestone in northwest Ohio consists of platform, platform margin and open shelf facies (Wickstrom, et al, 1992) (Figure 4-4). The INEOS site is within the platform facies. The top of the Trenton was an important oil producer during the early 1900's.

The Trenton Limestone ranges in thickness from 200 – 300 feet to the northwest and thins abruptly to less than 100 feet to the southeast (Figure 4-13). Southeast of the Trenton platform the Point Pleasant interbedded shales and limestone were deposited (Figure 4-14). The Trenton Limestone is 174 feet thick at the INEOS facility.

Cincinnati Group – Undifferentiated (Ordovician)
The contact of the Cincinnati Group with the underlying Trenton Limestone is sharp and easily distinguishable on geophysical logs. The Cincinnati Group grades upward from light to dark gray

calcareous shales and silty shales to light-gray to green calcareous shales interbedded with fine to medium crystalline fossiliferous limestone and dolomites (Wickstrom, et al, 1992). The Cincinnati Group ranges from 700 feet to the west to approximately 950 feet to the east (Figure 4-15). The Cincinnati Group is 888 feet thick at the INEOS site.

Lowermost Undifferentiated Silurian Rocks

The contact of the lowermost undifferentiated Silurian rocks with the underlying Cincinnati Group is thought to be unconformable in Indiana based on faunal evidence. However, no physical evidence is present in northwestern Ohio (Wickstrom, et al, 1992). The lowermost undifferentiated Silurian rocks consist of thin bedded gray calcareous shales and white crystalline limestones. In north-central Ohio, the lowermost undifferentiated Silurian rocks can be divided into the Brassfield Formation (argillaceous limestone), the Cabot Head Formation (limestone) and the Dayton and Rochester formations (shale). Through a series of facies changes and pinchouts, these formations do not correlate to the west. (As discussed in the Hydrology section, the base of the lowermost undifferentiated Silurian rocks is defined as the base of the lowermost USDW.) The lowermost undifferentiated Silurian rocks are 58 feet thick at the INEOS facility.

Lockport Group (Silurian)

The Lockport Group, also referred to as the Lockport Dolomite, is subdivided regionally into the Gasport, Goat Island and the Guelph Dolomites. These formations are present throughout the region but the contacts between them are transitional, making correlation between them tenuous and therefore are not differentiated in this study. The Lockport in Ohio and adjacent areas is known for containing reefs, massive accumulations of skeletal framework and debris from an abundance of reef building organisms (Hansen, 1998). The Lockport Group is 100 feet thick at the INEOS site.

Pleistocene Glacial Deposits

During the Mesozoic and Cenozoic, the region was subaerially exposed resulting in moderate relief topography and incised drainage. The Lockport Group is the main source of drinking water in northwestern Ohio and the base is considered to be the base of the 3000 mg/L USDW. As discussed in the section on Geologic History, post-Silurian rocks were removed by erosion. The Pleistocene in the study area consists of Wisconsinan glacial deposits. These lie disconformably upon the post-Silurian erosional surface and consist of end moraines, ground moraines and outwash plains and range in combined thickness from 30 to 300 feet (Figure 4-16). The Fort Wayne, Wabash and St. Johns moraines cross the study area along east-west lines and are the most prominent remnant glacial landforms in the area (Figure 4-17).

4.1.3 Regional Structure

This section is a discussion of the Precambrian structural elements of the region and the relation to the overlying Paleozoic section, in which the Cambrian-Mt. Simon and Eau Claire Formations comprise the injection zone, and the lower half of the Knox Dolomite comprises the confining zone at the INEOS site.

The regional structure on the Precambrian unconformity and the relation to Paleozoic structure is interpreted and discussed based on regional studies encompassing magnetic gravity, seismic and well data (geophysical logs and cuttings).

The Grenville Front (Grenville Tectonic Zone) and the East Continent Rift Basin (Fort Wayne Rift) dominate the Precambrian structure of northwestern Ohio (Figure 4-2).

The position of the Grenville Front is well defined by the residual aeromagnetic map of the state of Ohio (Wickstrom, et al, 1992) (Figure 4-18). The Grenville Front is the result of the compressional phase of the Grenville Orogeny, when rocks of the Grenville Province were thrust (north-northwestward) onto the older craton (Hoehn and Hinze, 1992).

Located approximately 30 miles east of the INEOS facility, the Bowling Green Fault Zone and the associated outlet fault zone coincide with the Grenville Front (Wickstrom, et al, 1992) (Figure 4-3). The Bowling Green Fault is reverse in nature, upthrown to the east and extends at least 45 miles from Hancock to Lucas County. Due to deviations of its trace, variations of offset and several associated faults, the fault zone is considered to be a complex wrench system (Wickstrom, et al, 1992). It is interpreted to have had three primary episodes of movement: Precambrian, Ordovician, and Silurian. Ordovician movement and displacement of rocks is evident on a seismic profile (Figure 4-19). An episode of faulting occurred concurrent with or slightly after Trenton deposition, probably a byproduct of the Hudson Valley Phase of the Taconic Orogeny (Titus, 1989; Wickstrom, et al, 1992). Structural contour maps of the Knox, Trenton and Cincinnati Groups exhibit displacement along the fault zones (Figures 4-20, 4-21 and 4-22). Silurian movement is exemplified by exposures of Silurian bedrock at the France Stone Co. Waterville Quarry in Wood County. At this outcrop, fault gouge is apparent (Wickstrom, et al, 1992). Recurrent movement of the Bowling Green Fault zone is confirmed by Onasch (1995). Onasch has documented not only several periods of Paleozoic movement but possibly Cretaceous and younger activity.

The second feature important to the Precambrian structure of northwestern Ohio is the East Continent Rift Basin and associated Fort Wayne Rift Zone (Figure 4-2). In recent years, much attention has been focused on this area, especially after the discovery of Precambrian sedimentary rocks below the Cambrian Mt. Simon Sandstone, in the Warren County stratigraphic test conducted by the Ohio Geological Survey (Shrake, et al, 1990) and by the stratigraphic test well (WDW No. 4) drilled by INEOS in 1991.

Many workers had speculated on the presence of Precambrian rifts in western Ohio, using magnetic and gravity data (Baranoski, 2002). The discovery of Precambrian sedimentary rocks (Middle Run Formation) was additional proof of Precambrian rifting and the existence of the East Continent Rift Basin and the associated Fort Wayne Rift Zone (Figure 4-2).

The East Continent Rift Basin (Fort Wayne Rift Zone) is postulated to be slightly older than the Grenville Province, but post-dates the Central Granite-Rhyolite Province (Drahovzal et al, 1992; Hoehn and Hinze, 1992).

The structure contour map of the Precambrian published by the Ohio Department of Natural Resources, Division of Geological Survey (Baranoski, 2002) utilized available well control and seismic data (Figure 4-23; entire map Appendix 4-1). As depicted on the map, a series of fault blocks have been mapped along the Cocorp (OH-1) seismic line run through Shelby, Logan and Union counties. This line is approximately 18 miles south of the INEOS site. This series of fault blocks is coincident with the Fort Wayne Rift Zone and coincides with the aeromagnetic anamolies mapped by Hildenbrand and Kucks (Figure 4-18) in 1984.

Paleozoic structure maps compiled by Janssens (1973) and Wickstrom et al (1992) do not indicate any evidence of Paleozoic involvement or reactivation in this area of faulting (Figures 4-20 through 4-25). In addition, and as will be discussed in more detail in the section on Local Structure, no evidence of Paleozoic movement is evident on seismic lines run near the INEOS facility (Brune, 1991; Baranoski, 2002; Paramo, 2002; Wolfe 1993).

Several unpublished studies which include Heidorn (M.S. Thesis, 1979) and Stone and Webster (1976), postulated the existence of a number of faults in northwestern Ohio which previously were unrecognized. These have been named the Anna, Auglaize, Logan-Hardin and Union Faults (Figure 4-26).

There is some correlation of a portion of the Anna, Logan-Hardin and Union Faults to both the faults mapped on the Cocorp OH-1 line and anomalies on the aeromagnetic map. However, the speculative Auglaize Fault does not seem to correlate with the seismic line or the aeromagnetic map. The Auglaize Fault trend is depicted on the Precambrian structure map of Baranoski 2002 as inferred with "displacement questionable." In addition, as Wickstrom, et al (1992) states, there is no direct evidence of Paleozoic movement along these trends and their positions are highly speculative.

The closest (approximately 8 miles) proposed fault to the INEOS site is the Auglaize Fault that has been studied by several workers. The studies will be summarized below.

Stone and Webster (1976) reported that the Auglaize Fault trends northeast-southwest, is upthrown to the southeast and has displacement of 50 feet on top of the Trenton Limestone (Janssens, 1991); Appendix 4-2; Figure 4-27). However, as stated by Janssens, only selected Trenton wells were utilized to confirm the fault trace and if all Trenton data is incorporated, the fault cannot be mapped and only regional dip is present.

Heidorn (1979) is a M.S. Thesis from Wright State University that theorizes that a fault (Auglaize) influenced the development of the buried bedrock valley, a tributary of the Teays Valley System, which bisects Auglaize County. To support this, a gravity survey was made to gather bedrock information and a Trenton structure map was constructed. As in the case of the Stone and Webster report, only selected Trenton wells were incorporated into the thesis and if all available data were utilized, only regional dip is present (Janssens, 1991) (Appendix 4-2). In addition, it is Janssens' opinion that a gravity study "is a proper one to explore for such features as salt domes and ore bodies but not to search for such subtle density – contrast features such as Precambrian basement or overlying Paleozoic sedimentary rocks." It is also important to note that Heidorn's version of the fault is mapped to the west of Stone and Webster's Auglaize Fault and the sense of throw is reversed, i.e., upthrown to the northwest instead of to the southeast. This further exemplifies the highly speculative nature of the Auglaize Fault.

Wickstrom (1990, 1992) proposed that the Auglaize and Logan-Hardin Faults were controlling factors for the development and position of the Trenton carbonate platform and that they had possible Paleozoic reactivation. However, structure maps of the Knox Dolomite and Trenton Limestone show only regional dip to the northwest (Figures 4-20 and 4-21).

In response to the possibility of Trenton age and Paleozoic faulting in general, Rike (1989) performed a detailed subsurface structural analysis (utilizing extensive well control) of the Trenton Limestone for a distance of 8 miles surrounding the INEOS site (a summary by S.A. Lang of the Rike, 1989 report is included as Appendix 4-3). Although some small scale closures are mapped, no faults were detected in this study (Drawing 4-3).

Regionally, as far as Paleozoic section is concerned, there is definite proof that there was reactivation along the Bowling Green Fault Zone, which is approximately thirty miles from the INEOS site (Figures 4-20, 4-21 and 4-22). There is also evidence of Paleozoic reactivation along the Fort Wayne Rift Zone which is approximately 14 miles south of the INEOS site (Baranoski, 2002). Baranoski (2002) utilized the COCORP OH-1 seismic line as part of his study (Figure 4-23; Appendix 4-1). This is in contrast to the work of Janssens (1973), which utilized limited well control and did not reveal Paleozoic faulting along the area later designated as the Fort Wayne Rift.

The aeromagnetic map (Figure 4-18) of Hildenbrand and Kucks (1984) which is utilized in Wickstrom et al (1992) displays significant magnetic anomalies which align and coincide with the Fort Wayne Rift (14 miles South) and Bowling Green Fault Zones (31 miles East). No anomalies of this intensity or linear nature occur in the immediate vicinity of the INEOS site.

In the region adjacent to the INEOS facility, Precambrian and Paleozoic structure to the top with the Eau Claire exhibits regional dip to the northwest, changing to a more northerly regional dip on progressively younger formations (Figures 4-20 through 4-25; Janssens, 1973; Wickstrom, et al, 1992). In addition, the rate of dip decreases upward in the section. This coincides with Wickstrom's (1992) description of the Indiana Ohio platform structural relief as resulting from differential subsidence of the surrounding basins as opposed to tectonic uplift.

In conclusion, it appears that the closest documented Precambrian faulting with Paleozoic reactivation is located approximately fourteen miles to the south of the INEOS site in the Fort Wayne Rift Zone. Paleozoic reactivation also occurred along the Bowling Green Fault Zone, approximately thirty miles to the east of the INEOS site. The highly speculative Auglaize Fault, approximately 8 miles southeast of the site has questionable Precambrian displacement and highly unlikely Paleozoic movement (Baranoski, 2002). Further discussions on local structure and interpretation of seismic lines run at the INEOS site are provided in Section 4.2.1 and 4.2.1.1. These lines were very useful in delineating structure at the INEOS site, considering the paucity of sub-Trenton data (well control).

Seismic Activity

Earthquake epicenters within the INEOS region are tabulated in Appendix 4-4, based on information through May 1, 2010, from the Advanced National Seismic System. The region searched for earthquakes is 78° W to 90° W longitude and 36° N to 45° N latitude. A map showing earthquakes in this region is included in Appendix 4-4. Also included in Appendix 4-4 and as Figure 4-28 is a map of earthquakes local to the INEOS site. Figure 4-28 shows earthquakes that have been recorded from 1775 through May 1, 2010. The University of Michigan monitored the Anna Seismogenic Region, where the INEOS facility is located, from 1976 to 1992. . Significant historical earthquakes through 1992 in the general vicinity of the INEOS site, reported in literature and recorded by the University of Michigan are listed in Table 4-1. In addition, INEOS maintains a seismic monitoring instrument on site that has been operational since March 1991. Seismic records are obtained with a Mark Products downhole triaxial geophone and transducers and a Kinemetrics recorder. The operation of these instruments is summarized in quarterly reports. A recent seismic monitoring quarterly report is included in Appendix 7-8. During the period 1999 through early 2005, no local events recorded by the instruments displayed characteristics associated with either natural or induced seismicity. any events are attributed to high levels of activity and background noise associated with INEOS facility operations, such as passing trucks (Geoscience Services, 1991).

Two local earthquakes occurred near Lima in 2006: the May 12, 2006, earthquake with magnitude 2.8 and the August 15, 2006, earthquake with magnitude 2.5. Both events were located approximately 2 miles east of the INEOS facility. A series of 85 local microearthquakes was recorded by the INEOS seismic monitoring system beginning on March 25, 2005, and ending on March 28, 2008. The following description of the magnitudes and locations of the microearthquakes was excerpted from Weston Geophysical (2006):

> Analyses of recorded seismograms including measurement of peak vibration amplitudes and time separation between P and S wave arrivals produced the following estimated magnitudes and focal distances from the BPC seismic monitor. Magnitudes range from -1.5 to +0.5. Four events are located closer to the monitor in a distance range from about 1.5 to 2.5 km. Remaining events are more distant in the range of about 4.0 to 5.0 km. All events are too small to have been detected by regional seismograph stations, which typically operate with a magnitude detection threshold of M=2.0, or larger. Therefore, accurate locations for these events cannot be determined using just the single station records obtained at BPC [the INEOS seismic station].

INEOS has not recorded any seismic activity related to injection operations.

The historical data indicate the majority of seismic activity has occurred near Anna, Ohio where the first well-documented earthquake in Ohio was recorded in 1875. It was estimated to be a

Modified Mercalli Intensity VI; intense enough to cause damage to poorly constructed buildings. Appendix 4-5 describes the Modified Mercalli Intensity Scale.

The small- to medium-sized earthquakes of the Anna Seismogenic Region shown on Figure 4-29 coincide with the Precambrian faults of the Fort Wayne Rift Zone delineated by the COCORP (OH-1) seismic line and depicted on the Precambrian structure map compiled by the ODNR, Division of Geological Survey (Baranoski, 2002; Figure 4-23). The depths of the small events northeast of Anna are between three and six miles based on P-wave arrival time. In general, the seismicity of the Anna Seismogenic Region is consistently deeper than three miles for the events in which data are available. These depths are consistent with the concept of deep-seated Precambrian faulting and are considerably deeper than the injection zone at the INEOS facility.

4.2 Local Geology

The following sections present the geologic information available in the vicinity of the INEOS injection well facility.

4.2.1 Local Structure

Seismic reflection data were collected by INEOS during the period from 1988 to 1991. Details of the seismic reflection survey and a summary of the results are summarized in this section. The original report (Brune, 1991) is included as Appendix 4-6. Cross-sections A-A' and B-B' show the continuity of the injection zone and shallower horizons (Drawings 4-1 and 4-2).

Due to the lack of well control deeper than the Trenton Limestone, only very local structure contour maps of the Top of Mt. Simon, Eau Claire and Knox Dolomite could be generated (Figures 4-33, 4-34 and 4-35). Rike (1989) performed a detailed structural analysis of the Trenton Limestone utilizing abundant well control. This map is included as Drawing 4-3. A summary by S.A. Lang of Rike's report is included as Appendix 4-3.

4.2.1.1 Seismic Reflection Survey

A seismic reflection survey was conducted by INEOS from 1988 to 1991 in order to meet the permit requirements in Ohio EPA Part II(D)(5) for the permitted deep wells that require "adequate seismic lines and profiles... to provide information on the deep structure of the area" (Brune, 1991). A detailed description of the seismic program and evaluation is provided in Appendix 4-6.

The following summary is based on Brune (1991):

Approximately 70 miles of seismic data, all of which were 30 or 50 fold, were acquired on 13 lines. A synthetic seismogram was generated from a sonic log from the INEOS injection wells (Figure 4-30). All of the acquisition work and most of the processing was performed by geophysical contracting companies. Tables 4-2, 4-3 and 4-4 summarize the chronology, acquisition and processing parameters. For quality control during the 1989 and 1990 program, a third party technical representative was present during acquisition.

The seismic investigation of 1988 and 1989 focused on the area southeast of the INEOS facility in order to investigate the presence of the postulated Auglaize and Teay Tributary or related faults and most importantly, evidence of Paleozoic reactivation. The 1990 seismic program consisted of east-west and north-south lines that boxed in the INEOS site and provided the points for the 1988 and 1989 data (Figure 4-31). Three seismic reflectors were recognized and utilized in the study: the Trenton, Eau Claire and the Mt. Simon. The synthetic seismogram was correlated to the seismic lines as shown in Figure 4-30. The best reflector correlates to a tight zone near the top of the Eau Claire Formation and could be traced throughout the area. Precise picks of the base of the Mt. Simon (Top of Precambrian unconformity), events within the Precambrian and the top of the Knox Dolomite were not possible.

Interpretation of the Precambrian structure indicated that there is evidence of Precambrian structure consisting of possible faults or fracture planes. In most cases, these lack evidence of vertical throw. Brune (1991), Chapter 6, p. 2, para. 4 states "There is evidence of some faulting in the pre-Mt. Simon, and there is probable evidence of many possible fracture/fault planes seen by horizontal seismic event terminations and dim spots. However, there is a significant concern that such events can be confused with various noise sources and/or out-of-the-plane seismic events." Also see p.3, chapter 5, Horizontal Noise and Fault Planes.

The Eau Claire reflector was constant throughout the area and showed no evidence of faulting. Statistical scatter of the Eau Claire reflector was enough to obscure the known regional dip (northwest) which made contouring the data pointless. However, it can be determined that the Eau Claire Formation is essentially flat. The Trenton Limestone reflector was consistent throughout the area and also showed no evidence of the faulting. However, the depth resolution of the seismic data is much less than subsurface mapping based on well control. Therefore, rather than a Top of Trenton seismic map, an isochron map of the Top of Trenton to the Top of Eau Claire (dolomitic shale/fine grained sandstone near the top of the Eau Claire) was compiled. It was found that the isotime interval was constant. This is an excellent indication that the Precambrian had no control over the deposition of the overlying Paleozoic and thus reactivation of deep-seated Precambrian features during the Paleozoic did not occur. The Mt. Simon reflector had even more statistical scatter than the Trenton or Eau Claire and any isopach mapping involving the Mt. Simon was not useful to the study.

The seismic lines acquired and evaluated by INEOS were also analyzed and incorporated into a Precambrian structure map compiled by the ODNR, Division of Geological Survey (Baranoski, 2002). No faults with definite Precambrian movement or Paleozoic reactivation were mapped on these lines (Figure 4-23; Appendix 4-1).

In a MS Thesis performed at Ohio State University, Paramo (2002) reprocessed and evaluated the INEOS lines. Paramo notes evidence of Precambrian faulting which he interprets as extensional due to the formation of the East Continent Rift Basin and concludes the "Cambrian and Ordovician strata are flat beneath the seismic lines (p.112 para. 2)." He also states that Cambrian-Ordovician sediments are near constant thickness throughout the study area (p. 73, para. 2). This agrees with the isochron work of Brune (1991). Paramo's model for the subsurface geology of Allen County is provided as Figure 4-32. His model does not include any evidence for Paleozoic reactivation.

Wolfe (1993) also analyzed the INEOS seismic lines and identified Precambrian faulting. As does Brune (1991), Paramo (2002), his report does not give evidence for Paleozoic reactivation on the INEOS lines (Figure 32-A).

In conclusion, studies of the seismic lines at the INEOS facility have indicated that:

1. Evidence of Precambrian structural features exist, such as fault or fracture planes (Brune, 1991; Paramo, 2002; Wolfe, 1993). However, these had little to no vertical throw and some possibly are noise related (Brune, 1991).
2. The Precambrian faults/fracture planes do not seem to correlate from line to line (Brune 1991) and the Precambrian structure map of Baranoski (2002) which utilized these lines does not display faults in the area in question.
3. The Trenton, Eau Claire and Knox Dolomite reflectors showed no evidence of Paleozoic faulting (reactivation of the deep-seated features) (Paramo, 2002; Brune 1991; Wolfe, 1993).
4. Although Paleozoic sedimentation was influenced by recurrent fault movement and Precambrian paleotopography along the COCORP OH-1 seismic line 14 miles south of the INEOS facility (Baranoski, 2002) and regionally in other areas, isochron mapping of seismic lines at the INEOS facility on the Top of Trenton to Top of Eau Claire showed uniform thickness of the stratigraphic units, thus indicating that local Precambrian structure or paleotopography had little influence on Paleozoic sedimentation. This is strong evidence that in contrast to the Bowling Green Fault Zone and the Fort Wayne Rift, the deep-seated Precambrian features did not undergo Paleozoic reactivation. As stated previously, this is supported by the work of Paramo (2002), Brune (1991) and Wolfe (1993).

4.2.1.2 Local Structure Maps and Cross-Sections

Cross-sections A-A' and B-B' (Drawings 4-1 and 4-2) traverse east-west and north-south through the INEOS injection wells. The section from the Lockport Dolomite to the Mt. Simon Sandstone and Precambrian is displayed and shows lateral continuity of the formations, and lack of faulting.

Although lack of well control in the immediate vicinity of the INEOS facility prevents detailed structure contour mapping on the top of the Mt. Simon Sandstone, Eau Claire Formation and Knox Dolomite, structure contour maps of these three horizons are included as Figures 4-33, 4-34 and 4-35.

The structure maps of the Top of the Mt. Simon Sandstone and Eau Claire Formation show dip of approximately 25 – 30 feet/mile to the northwest. This coincides well with the work of Shearow (1987), and seismic work of Brune (1991), and the documented regional structure.

The top of the Knox Dolomite map shows dip of approximately 100 feet/mile to the southwest. The southwest dip coincides with work of Wickstrom, et al (1992) where a trough on top of the Knox appears to exist beneath the INEOS facility (Figure 4-20). The steeper dip on top of the Knox Dolomite, is probably reflective of paleotopography (due to karsting) as the Knox thins from WDWs No. 1 and 3 (northeast) to WDWs No. 2 and 4 (southwest) (Drawings 4-1, 4-2 and 4-4; see also section on Regional Stratigraphy).

As discussed in the section on Regional Structure, Rike (1991) performed a detailed structural analysis of the Trenton Limestone within an 8-mile radius of the INEOS facility. A summary by S.A. Lang of this report is provided in Appendix 4-3. The Top of the Trenton Map is displayed as Drawing 4-3. As shown on the map, several small closures are mapped on top of the Trenton. As stated previously, the Trenton Limestone at the INEOS site is interpreted by Wickstrom et al (1992), to lie within the platform margin facies. Several of the closures align southwest to northeast, coincident with the trend of the platform margin. Since no evidence of deeper closed anticlinal features has been presented by Brune (1991), Baranoski (2002), Paramo (2002) or Wolfe (1993) in seismic interpretation in the area of the INEOS site, it is likely that these closures are the result of depositional topography on top of the Trenton Limestone, which is consistent with a platform margin setting (see Geologic History and Regional Stratigraphy discussions). No evidence of faulting is indicated on the structure map. This coincides with the seismic analysis performed by Brune (1991), Paramo (2002), Baranoski (2002) and Wolfe (1993).

In conclusion, structure mapping from well control and seismic data of the Mt. Simon, Eau Claire, Knox and Trenton Formations indicates that the Paleozoic section has not been faulted in the vicinity of the INEOS facility and therefore the injection zone is not structurally compromised.

4.2.2 Wellsite Lithology

4.2.2.1 Properties of the Injection Zone

The injection zone at the INEOS site is comprised of the Mt. Simon Sandstone and Eau Claire Formation, and in some wells the Precambrian Middle Run Formation. The INEOS injection zone was subdivided into a number of different intervals in order to conservatively over estimate the gross injection zone behavior. These intervals are defined below. The injection zone and these intervals as applied to the INEOS injection wells are illustrated in Figures 4-36 and 4-37, and Drawings 4-4 and 4-5.

Permitted Injection Interval

The portion of the injection zone into which the wastewater is directly placed. At INEOS Lima, this corresponds to the openhole portion of the injection wells.

Effective Injection Interval
The portion of the injection zone that directly receives the injected wastewater from any of the INEOS Lima wells at a radial distance from a wellbore. This contains the modeled injection interval. The dimensions of the effective injection interval are greater than the permitted injection interval because of the potential for vertical fluid flow in the relatively low-permeability strata immediately overlying and/or underlying the permitted injection interval.

Passive Injection Interval
The passive injection interval was defined by INEOS in order to conceptualize a conservative predictive model. This interval consists of the strata above the modeled injection interval underlying the arrestment strata (containment interval). This interval does not directly influence the injection interval reservoir behavior during the injection activities due to its low permeability and porosity (reservoir) properties. However, since the DSTs conducted in WDW No. 4 indicate the potential for injectate in this passive injection interval, it has been included in the effective injection interval.

Modeled Injection Interval
The portion of the effective injection interval that directly receives the injected wastewater and possesses the reservoir properties that govern the injection pressure. The modeled injection interval and the passive injection interval form the effective injection interval.

Arrestment Strata
The strata above the effective injection interval that impedes vertical fluid movement from the effective injection interval. All modeled vertical transport of injected wastewater components will be contained within the arrestment strata (containment interval) for a minimum of 10,000 years. Figure 4-36 summarizes information for this interval.

The discussion of the local wellsite lithology of the three formations representing the injection zone (Middle Run, Mt. Simon, Eau Claire) focuses on results obtained from coring the stratigraphic test well (WDW No. 4), cuttings and geophysical log data obtained on all four injection wells. A lithologic composite log graphically displaying the core descriptions is included as Appendix 4-7.

The measured and subsea depths along with formation thickness comprising the injection zone (and all penetrated formations) is provided in Table 4-5.

Middle Run Formation (Precambrian)
As illustrated in Figures 4-36 and 4-37 and Drawings 4-4 and 4-5, the lowermost portion of the injection interval lies within the uppermost part of the Middle Run Formation. The top of the Precambrian was not penetrated in WDW No. 1. The largest amount of Middle Run drilled was in the stratigraphic test well (WDW No. 4). This section will be discussed below.

A total of 255.5 feet of the Middle Run was cored in WDW No. 4. The total thickness of the Middle Run is unknown as the formation was not completely penetrated.

The contact between the Middle Run and the overlying Mt. Simon is characterized by an abrupt lithologic change from a conglomeratic sandstone in the Mt. Simon to a fine grained argillaceous sandstone with no visible intergranular porosity at the top of the Middle Run. The overall Middle Run section in the WDW No. 4 consists of interbedded sandstone and siltstone ranging in thickness from 30 to 60 feet.

The sandstone is generally a medium to dark reddish brown, argillaceous, well-sorted, fine grained quartzose feldspathic sand (see Photo C-1, Appendix 4-8). The sandstone is occasionally cross-bedded.

Bedding strike is strongly oriented east-west with less than 30 degree dip, generally to the south. Natural and induced fractures are prevalent throughout the core. In general, the siltstone units contain a greater overall percentage of the open, partially open and mineralized closed natural fractures than do the sandstone layers.

Mt. Simon Sandstone

The Mt. Simon Sandstone averages 340 feet in thickness at the INEOS facility and comprises the main portion of the injection interval. Lack of well control prevents a local isopach map. A regional isopach is provided (Figure 4-7; Janssens, 1973). Due to the gradational nature of the contact with the overlying Eau Claire Formation, the top of the Mt. Simon was correlated by representatives from ODNR and INEOS based upon a review of log and core data (Rea and Wickstrom, et al, 1991). All of the cross-sections provided reflect the preferred correlation of the ODNR that differs from Janssens (1973). Figure 4-9 displays the correlation of Saeed, 2002. Despite the differing opinions on the Mt. Simon thickness, the regional isopach is useful for displaying the overall lateral extent of the Mt. Simon.

The Mt. Simon regionally lies unconformably upon the Middle Run. This is evident by the abrupt change from the poorly sorted, heterogenous, angular, well cemented rocks of the Middle Run and the lighter, homogenous, less cemented partially friable basal sandstone of the Mt. Simon (Saeed, 2002). The paucity of tidally influenced and biogenic features in the Middle Run and as opposed to the Mt. Simon, is also evidence for the unconformity (Saeed, 2002). Additional evidence for the unconformity is noted by Wolfe (1993). He notes the absence of the Middle Run in some regional seismic sections which suggests a long period of erosion prior to Mt. Simon deposition. In some seismic lines evidence of a low angle unconformity exists.

The Mt. Simon at the site can be divided into two lithologic packages related to depositional environment based on core descriptions (WDW No. 4). The lower portion of the Mt. Simon (2970' – 3153') represents a fluvial-deltaic environment with increasing marine influence towards the top of the sequence. The upper portion (2813' – 2970') represents a transitional marine sequence characterized by the presence of glauconite. Saeed's interpretation is provided as Figure 4-8.

For the purpose of modeling, the Mt. Simon Sandstone was subdivided into three layers (Drawing 4-4, and Figure 4-37).

The MS_1 layer in WDW No. 4 extends from 2970 feet to the Middle Run contact at 3153.5 feet. The top of the MS_1 layer approximates Saeed's (2002) Mt. Simon top. This interval is distinguished by 1 to 6 inch thick interbedded dark red, white gray and tan sandstone (Photo C-2, Appendix 4-8). Hematite staining is present in dark red layers, which are very fine to very coarse to pebbly and occasionally conglomeratic, indicating non-marine deposition. The white, gray and tan layers are typically medium-to-coarse grained sandstones which are angular and friable with good to excellent porosity. This layer is extensively cross-bedded.

The MS_2 layer in WDW No. 4 (2840' – 2970') contains interbedded white-gray, reddish-brown and tan sandstones and siltstones (see Photo C-3, Appendix 4-8). This layer is characterized by abundant discontinuous clay compaction layers and laminations. Bioturbated, glauconitic, very fine to medium grained feldspathic and quartzose sandstones are present along with some interbedded shales. This layer represents a transitional, increasingly marine environment of deposition.

The MS_3 layer (2800' – 2840') consists of predominantly clay-rich sandstone with interbedded siltstone and is gradational with the overlying Eau Claire. As discussed previously, the ODNR pick for the contact is 2813 feet in WDW No. 4. The sandstone is typically white to tan and light to rust brown, very fine to fine grained, well-sorted and subangular to sub-rounded (see Photo C-4, Appendix 4-8). As in MS_2, the sandstone is feldspathic and quartzose. Near the contact with the Eau Claire, glaconite comprises up to 80% of the matrix, indicating marine conditions. This layer is very argillaceous. This is the primary control of effective net porosity as effective net porosity increases with decreasing clay content.

The Mt. Simon Sandstone core contains few natural fractures. Two types observed are partially open and closed natural fractures. These are present only in the MS_1 Layer.

Eau Claire Formation

The Eau Claire averages in 382 feet thickness at the INEOS site. Lack of well control prevents a local isopach map. A regional isopach is provided as Figure 4-10. As discussed previously, the contact between the Mt. Simon and Eau Claire is open to interpretation. Thus the Eau Claire thickness utilized in the permit is different from Janssens (1973). However, the regional isopach is useful for displaying the overall lateral extent of the Eau Claire.

As discussed in the Regional Stratigraphy section, the Eau Claire represents deposition in a transgressive marine sequence. The basal portion (gradational with Mt. Simon) is characterized by glauconitic sandstones, which grade to dolomitic sandstones and dolomites in the middle to dolomite and mudstones near the top of the formation. The upper contact is also gradational with the overlying Knox Dolomite. The contact was picked by representatives from ODNR and INEOS (Rea and Wickstrom, et al, 1991).

For modeling purposes the Eau Claire was subdivided into six layers based on core and geophysical logs (Drawings 4-4, 4-5, Figure 4-37).

EC_1 is 25 feet thick in WDW No. 4 and consists of interbedded white, gray and light brown sandstone and medium gray siltstone. Sandstones are very fine to medium grained, sub-rounded to sub-angular and are feldspathic and quartzose. Numerous clay-rich laminations occur (see Photo C-5, Appendix 4-8). The base of this layer is glauconitic. Effective net porosity is controlled by silt and clay content.

EC_2 is approximately 95 feet to 100 feet thick and is comprised of dolomite glauconitic sandstone, argillaceous sandstone, siltstone and dolomite. The sandstone is light to dark gray or tan, very fine grained and is sub-angular to angular. The sandstones are predominantly feldspathic with some quartz and glauonite present. Clay laminations are common (Photo C-6, Appendix 4-8). In addition to clay content, the amount of quartz overgrowths control porosity and permeability. Crystalline dolomites occur as thin medium gray to brown stringers.

EC_3 consists of dolomitic, glauconitic sandstones approximately 60 feet in thickness. The sandstone is medium gray brown, very fine to medium grained, sub-rounded to sub-angular and well cemented with dolomite and quartz overgrowths (Photo C-7, Appendix 4-8). Equal amounts of quartz, feldspar and glauconitic grains are present. Some secondary leached porosity is present and as well was intergranular primary porosity.

EC_4 is approximately 70 feet in thickness and is composed of argillaceous dolomite limestone and silty shale. The dolomite is dark gray, medium crystalline, silty and glauconitic in part and has low porosity (Photo C-8, Appendix 4-8). Dolomitized, skeletal grainstone is also present. Argillaceous siltstone layers with no visible pore space are interbedded within this layer.

EC_5 contains a net shale thickness of 58 feet with thin interbeds of silty dolomitic limestone. This layer has a distinctive seismic signature and was the mapped reflector. The shale is dark gray to black and is largely comprised of illite. The limestone is medium to dark brown, medium to coarsely crystalline, partially dolomitized and composed of fine skelatal fragments, peloids, glauconite grains and terrigenous silt. This layer has very low effective net porosity and permeability.

EC_6 is a crystalline dolomite interbedded with highly bioturbated zones of argillaceous siltstone and argillaceous glauconitic and dolomitic sandstone (Photo C-10, Appendix 4-8).

The dolomite is dark gray, medium crystalline, arenaceous and glauconitic in parts with very low porosity. The sandstones are dark gray to brown, very fine to fine grained, angular to sub-angular and cemented with dolomite.

The Eau Claire lacks natural macro-fractures below 2591 feet in WDW No. 4. Some closed and mineralized closed fractures were found in EC_4, EC_5 and EC_6.

A detailed discussion of porosity and permeability within the three formations comprising the injection zone will be provided in the ensuing section.

TABLE 4-5

COMPARISON OF MEASURED AND SUBSEA DEPTHS
INEOS WDW NOS. 1, 2, 3, AND 4 (STRATIGRAPHIC TEST WELL)

	INEOS WDW No. 1 (ft)	INEOS WDW No. 2 (ft)	INEOS WDW No. 3 (ft)	INEOS WDW No. 4 (Stratigraphic Test Well) (ft)
KB	872	854	856	872
Salina Group (undifferentiated)	32[a] +840[b] 178[c]	NA[d]	NA	61 +811 151
Lockport Group	210 +662 98	200 +654 97	204 +652 100	212 +660 104
Sub-Lockport Group	308 +564 61	297 +557 55	304 +552 58	316 +556 57
Cincinnati Group (undifferentiated)	369 +503 883	352 +502 892	362 +494 889	373 +499 889
Trenton	1252 -380 172	1244 -390 175	1251 -394 175	1262 -390 174
Black River Group	1426 -554 383	1419 -565 401	1426 -570 380	1436 -564 401
Wells Creek Formation	1809 -937 12	1820 -966 30	1806 -950 10	1837 -965 18
Knox Dolomite	1821 -949 609	1850 -996 568	1816 -960 606	1855 -983 575
Eau Claire Formation	2430 -1558 380	2418 -1564 382	2422 -1571 382	2430 -1558 383
Mt. Simon Sandstone	2810 -1938	2800 -1946 344	2803 -1947 337	2813 -1941 340
Precambrian (Middle Run Formation)	DNP[e]	3144 -2290	3140 -2284	3153 -2281
Total Depth	3133	3172	3165	3409

[a] Measured depth to top of unit with respect to KB.
[b] Subsea depth to top of unit.
[c] Thickness of unit.
[d] NA = not available.
[e] DNP = did not penetrate.

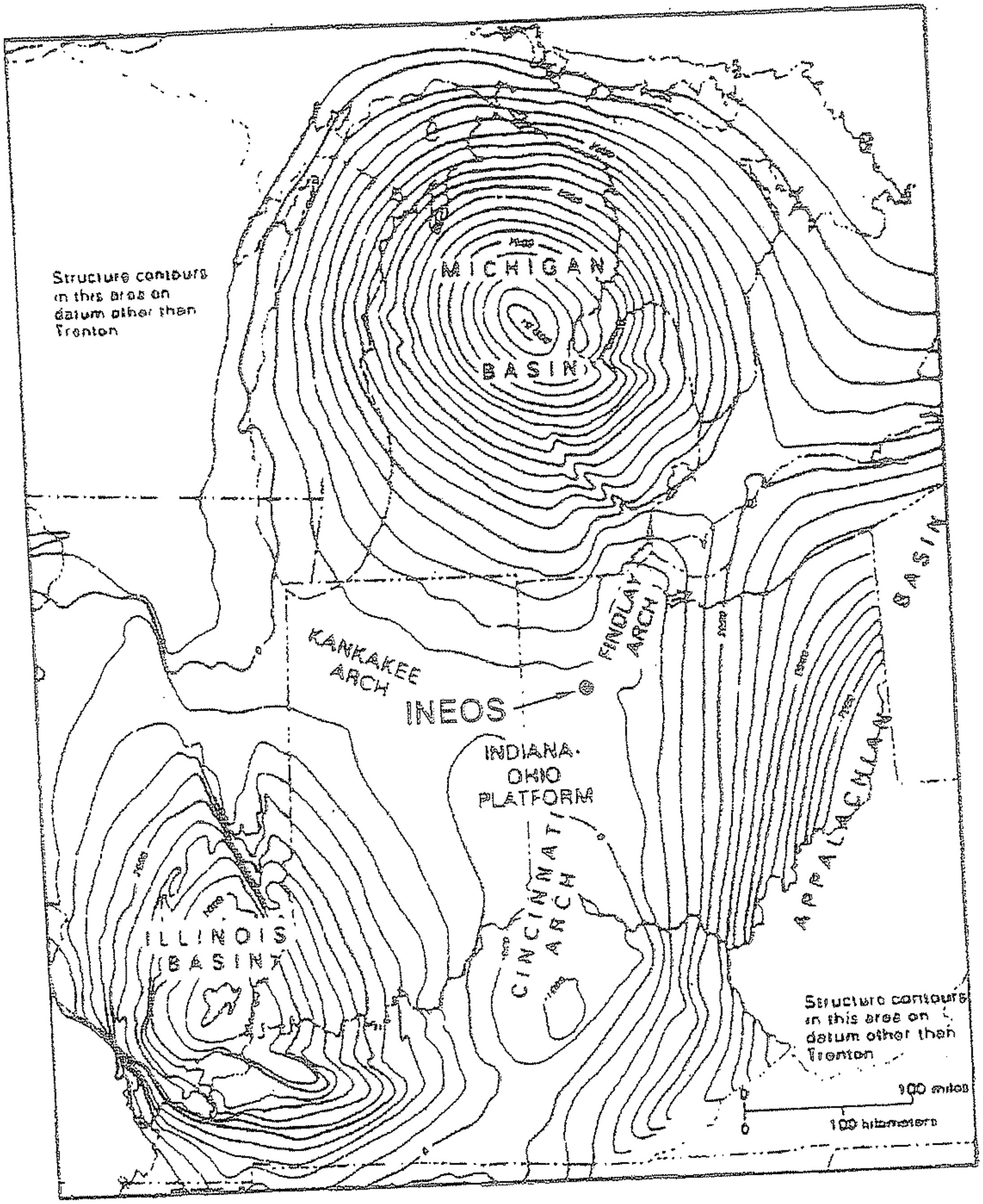
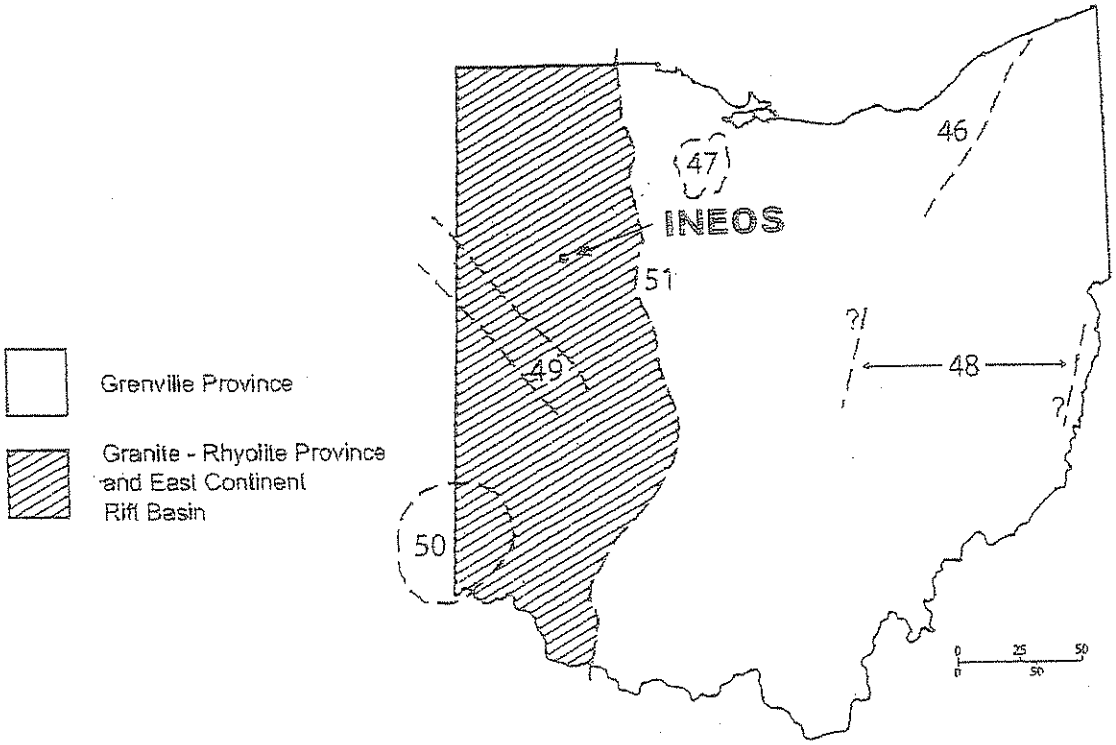


FIGURE 4-1

GENERALIZED, REGIONAL STRUCTURE CONTOUR MAP
DRAWN ON TOP OF THE TRENTON LIMESTONE
(Modified from Cohee; 1962 Paramo, 2002)



Map showing Granite - Rhyolite Province, East Continent Rift Basin, Grenville Province, and major Precambrian structural features defined by geopotential and seismic reflection data.

46	Akron Magnetic Boundary
47	Seneca Anomaly
48	Coshocton Zone
49	Fort Wayne Rift
50	Southwestern Ohio Anomaly
51	Grenville Front Tectonic Zone

FIGURE 4-2

REGIONAL PRECAMBRIAN GEOLOGY
ODNR, ODGS MAP PG-23
(Baranoski, 2002)

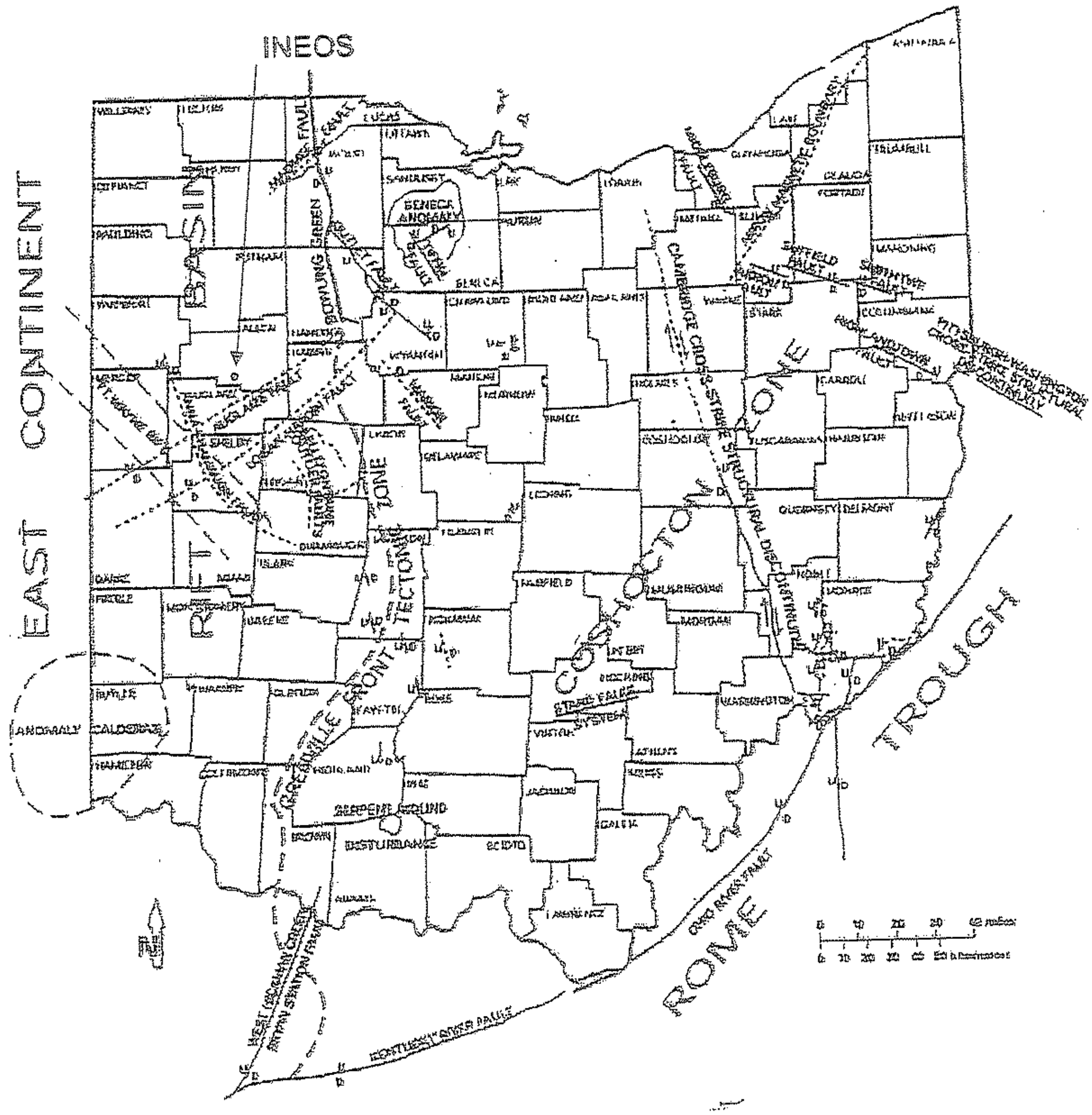


FIGURE 4-3

BASEMENT STRUCTURES IN OHIO
(Modified from Division of Geology Survey Digital Chart & Map Series No. 7, 1991)

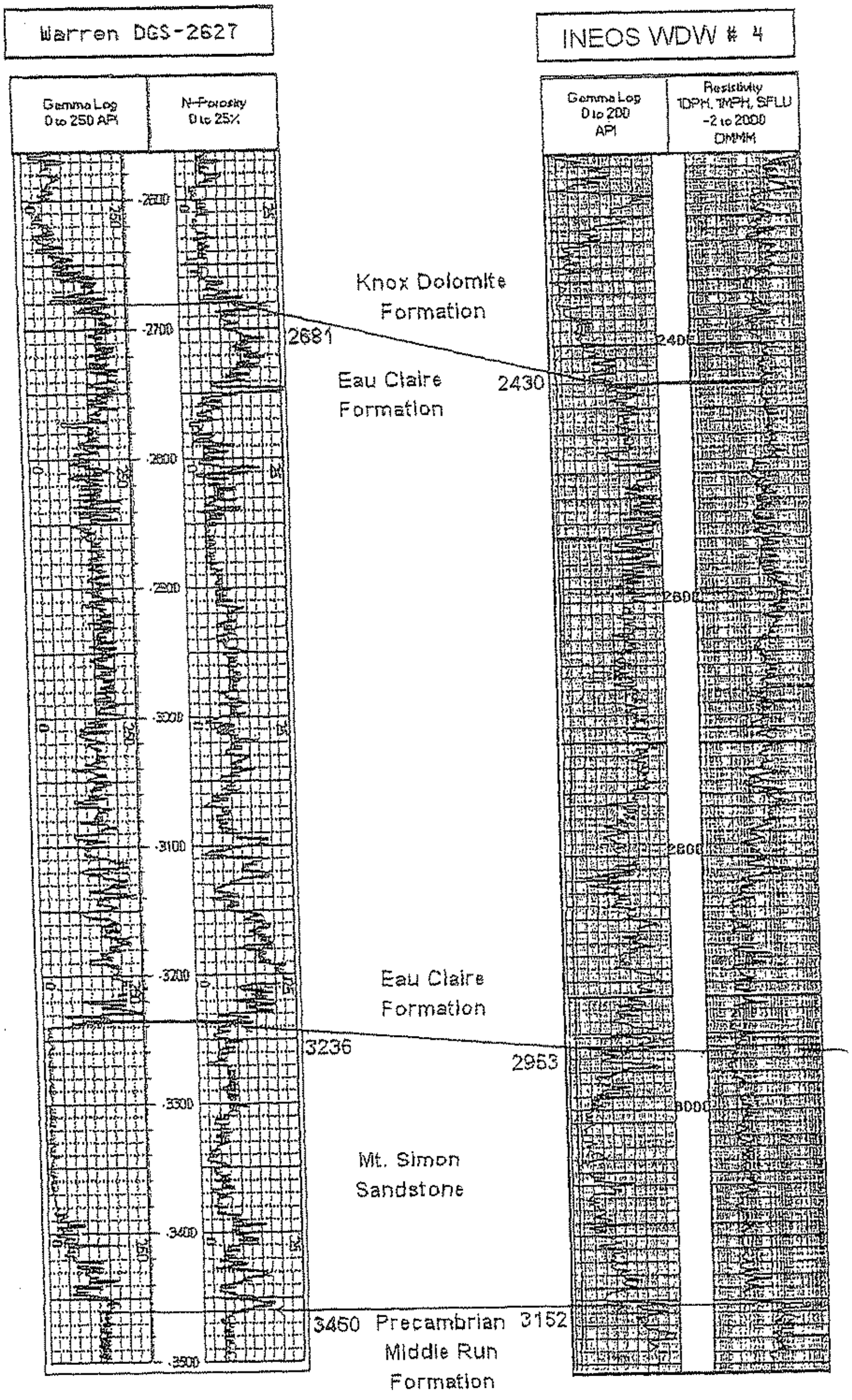


FIGURE 4-9

MT. SIMON SANDSTONE CORRELATION
(Modified from Saeed, 2002)

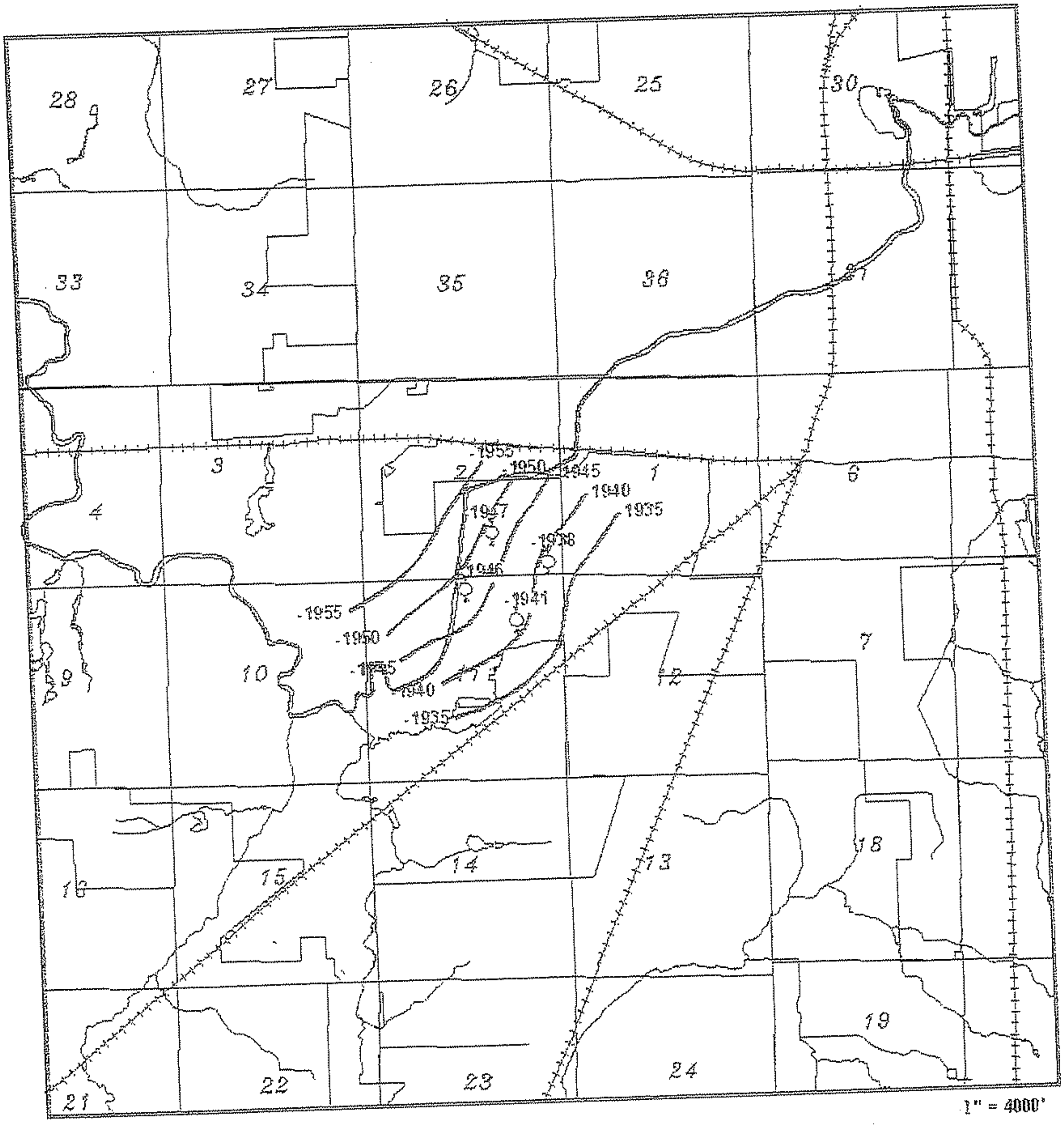


FIGURE 4-33

LOCAL STRUCTURE MAP - TOP OF MT. SIMON SANDSTONE

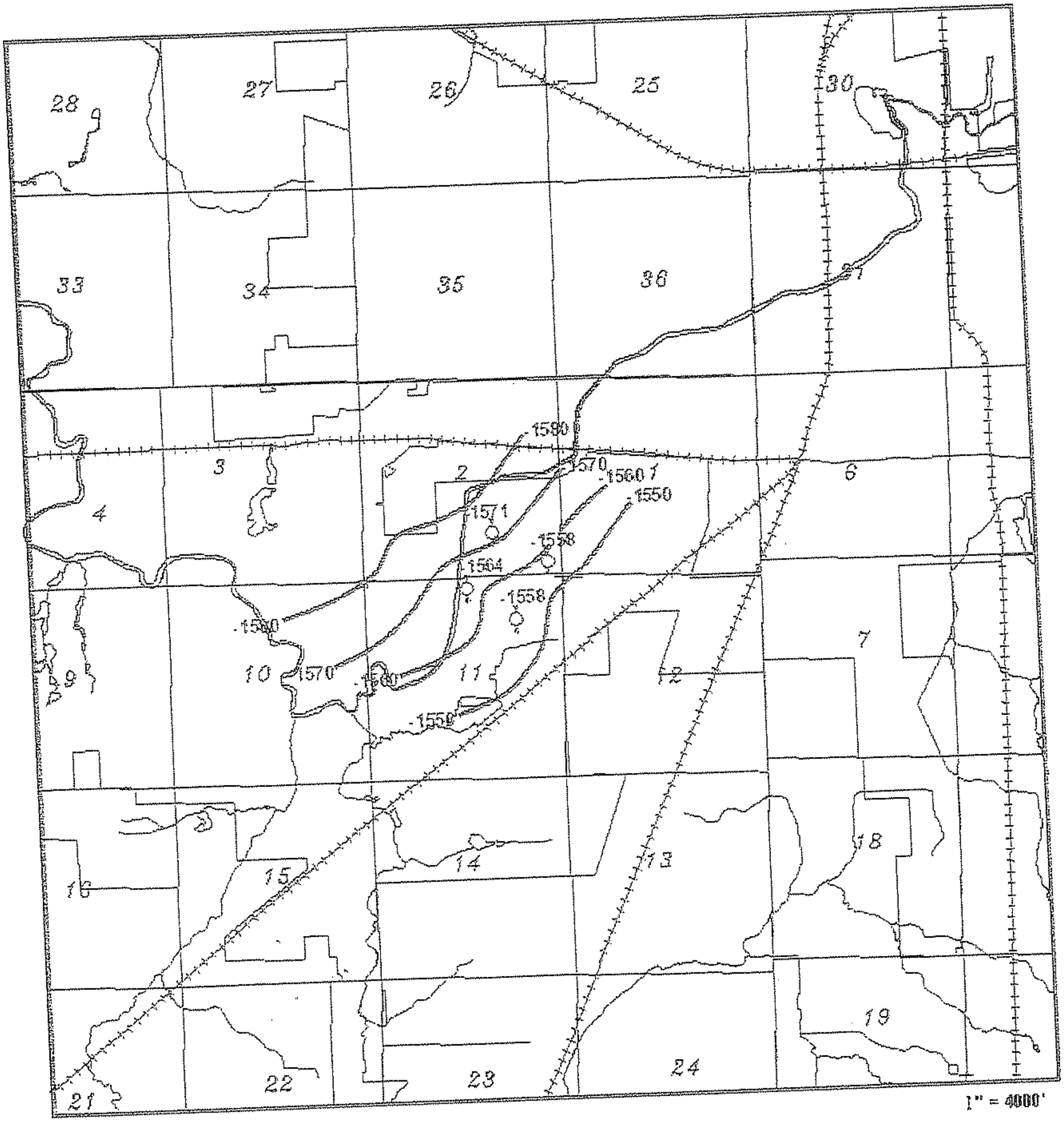


FIGURE 4-34

LOCAL STRUCTURE MAP - TOP OF EAU CLAIRE FORMATION

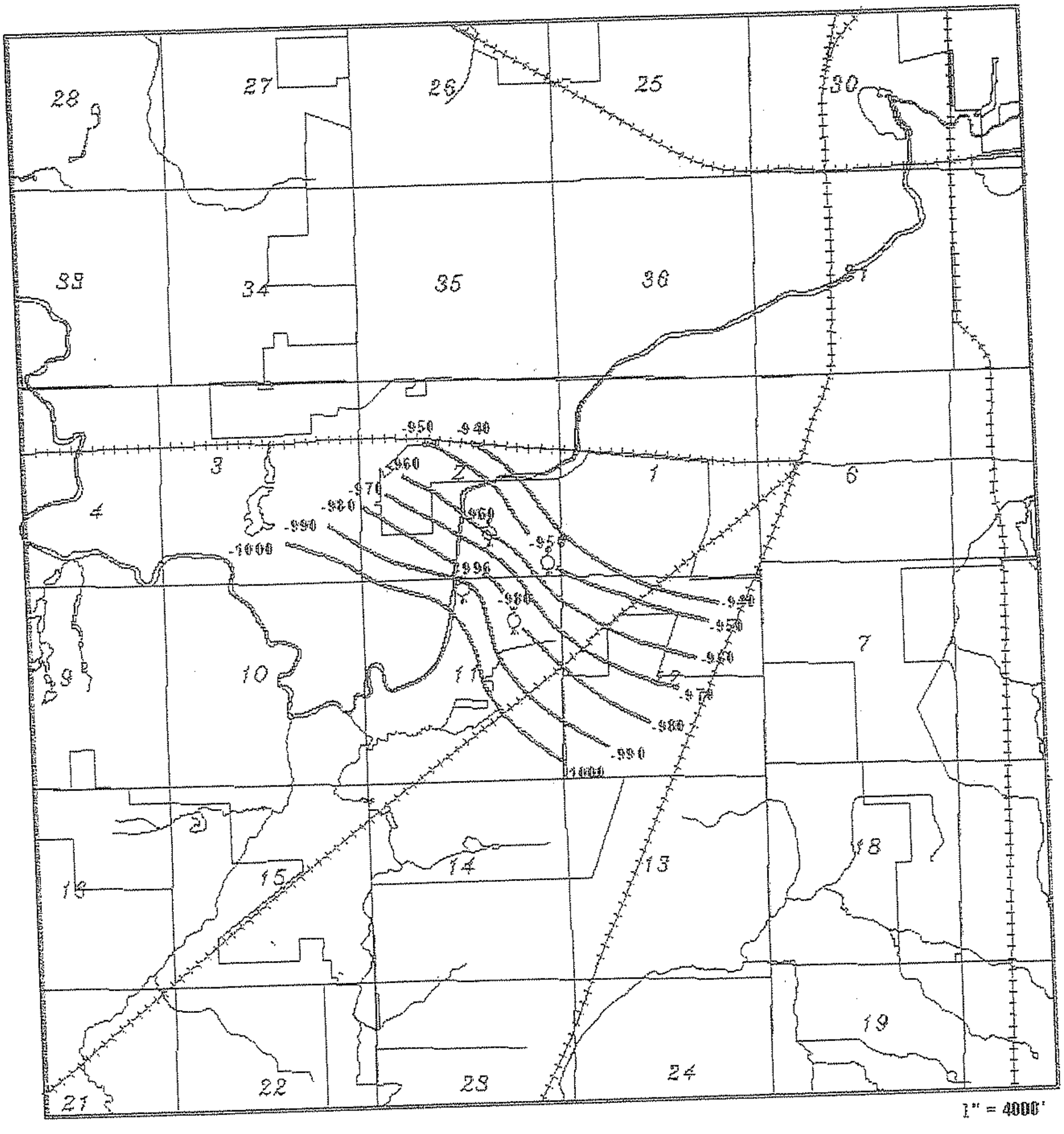


FIGURE 4-35

LOCAL STRUCTURE MAP - TOP OF KNOX DOLOMITE

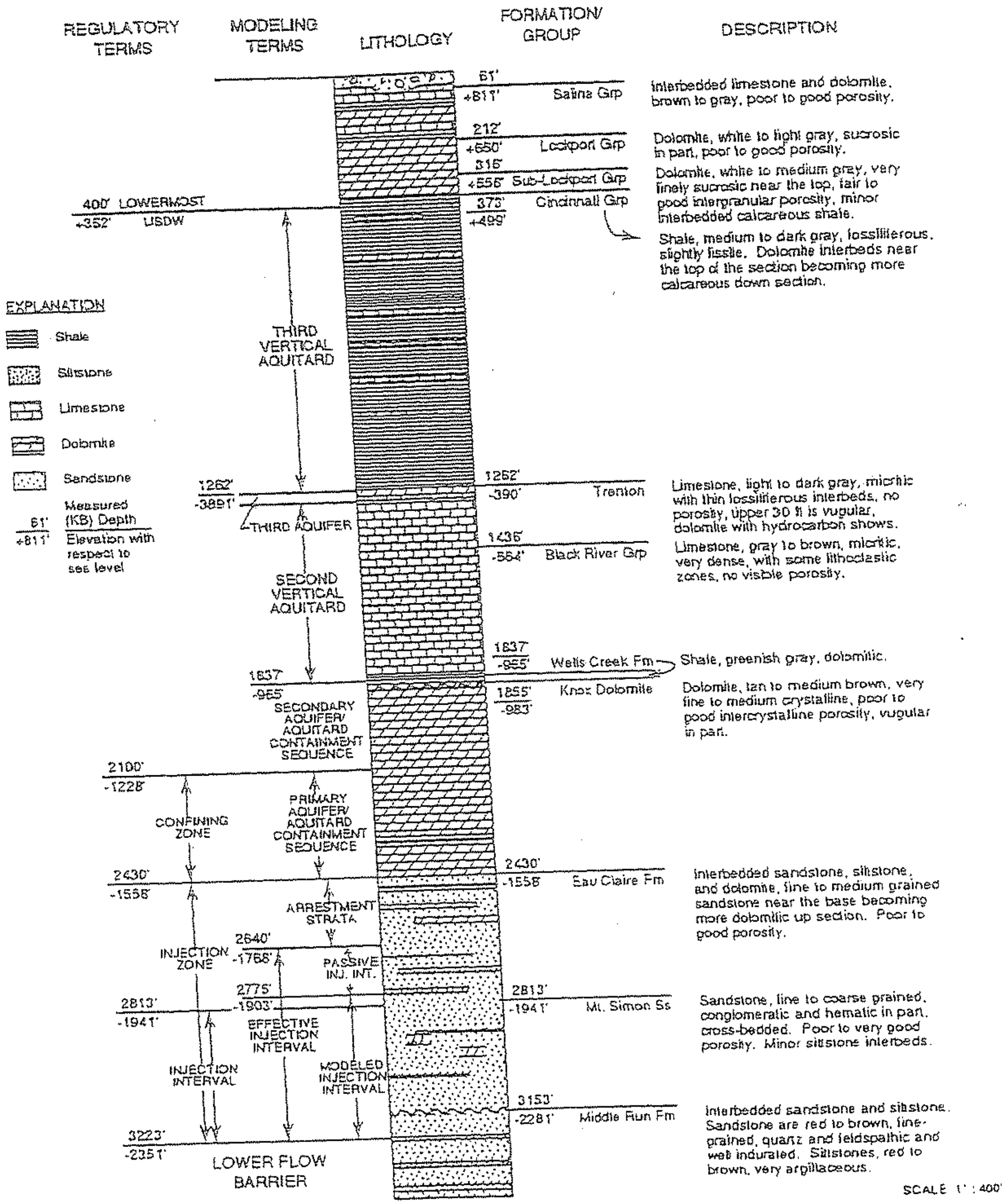


FIGURE 4-36

GENERALIZED STRATIGRAPHIC COLUMN
(Lima Stratigraphic Test Well)

ATTACHMENT B

II. Fracture Pressure

8.0 FORMATION TESTING PROGRAM

General Comments Regarding Updates for the Renewal Application

The conclusions of this section remain basically unchanged from the October 2004 UIC permit renewal submittal. This section has been updated, as appropriate, based on published literature, site operating history, test results, and data analysis conducted in regards to the INEOS injection well activities between September, 2004 and April, 2010.

INEOS ran an extensive suite of logs on WDW No. 4 to establish accurate baseline data to compare future measurements. The complete list of open and cased hole logs conducted on WDW No. 4 are summarized in Table 8-1. Table 8-2 summarizes the geophysical open hole logs run in WDW No. 4 and the function of the log. Table 8-3 presents the cased hole logs run on WDW No. 4 and Table 8-4 through 8-7 is a summary of key logs available for WDW No. 1, WDW No. 2, and WDW No. 3, and WDW No. 4.

The deviation surveys conducted during drilling of WDW No. 4 are summarized below:

DATE	DEPTH (ft)	DEVIATION DEG.
3/13/91	208	¾
3/13/91	400	½
3/19/91	711	1 ¼
3/29/91	1,200	1 ¼
4/12/91	1,577	½
4/24/91	2,173	½
5/5/91	2,676	¼
7/18/91	3,409	½

These deviation surveys confirm that the hole drilled for WDW No. 4 is very nearly vertical as would be expected from a hole which was fully cored. The deviation survey measurements were confirmed by the downhole core orientation tools run during the deeper coring activities.

The surface casing logs run on WDW No. 4 are summarized below:

Original Core Hole (8½ in.) Depth: 710 ft KB

Final Enlarged Hole (20 in.) Depth: 720 ft KB

Surface Casing: 16 in. 65.0 lb/ft H-40 Range 3 STC

Open Hole Logs (3/15-3/16/91) - Schlumberger

Compensated Neutron/Litho - Density/GR

Dual Induction/SFL/GR

Natural Gamma Ray Spectrometry

Array Sonic/STC/GR

Sonic Waveforms/GR

Cased Hole Logs (5/4/91) - Schlumberger

Cement Bond Log/VDL

Temperature Log

The cased hole logs are described in Appendix 8-6 of this application and have been submitted to the OEPA in past correspondence.

The geophysical logs run on the intermediate and long string casing in WDW No. 4 are summarized below. These logs have been submitted to the OEPA in past correspondence.

Intermediate String Casing Logs

Original Core Hole (8½ in.) Depth: 2676 ft KB

Final Enlarged Hole (14-3/4 in.) Depth: 2676 ft KB

Intermediate String Casing: 58 joints 10-3/4-in. 51 lb/ft L-80 Range 3 ST&C

6 joints 10-3/4-in. 40.5 lb/ft J-55 Range 3 ST&C

Open Hole Logs (5/4-5/5/91) – Schlumberger

Compensated Neutron/Litho - Density/GR

Dual Laterolog/MSFL/GR

Phasor Induction/GR

Natural Gamma Ray/Spectrometry

Array Sonic/STC/GR

Variable Density Log

Formation Micro-Scanner

Fracture Identification Log

Open Hole Logs (5/11/91) - Atlas
CBIL/GR (Circumference Borehole Image Log)
Cased Hole Logs (6/2/91) - Atlas
Cement Bond Log/VDL

Cased Hole Logs (6/19/91 - 6/20/91) - Schlumberger
Cement Bond Log/VDL
Cement Evaluation Log
Temperature Log

Cased Hole Logs (7/17/91 - 7/18/91) - Schlumberger
Cement Bond Log/VDL (Under Pressure)
Cement Evaluation Tool (Under Pressure)
Cement Scan Log (Under Pressure)

Long String Casing Logs
Original Core Hole (8½ in.) Depth: 3220 ft KB
Final Enlarged Hole (9½ in.) Depth: 3160 ft KB
Long String Casing: 7 in. 23 lb/ft N-80 Range 3 LTC

Open Hole Logs (6/19-6/20/91) - Schlumberger
Compensated Neutron/Litho - Density/GR
Dual Laterolog/MSFL/GR
Phasor Induction/GR
Natural Gamma Ray Spectrometry
Array Sonic/STC/GR
Variable Density Log

Open Hole Logs (6/29/91) - Atlas
CBIL/GR (Circumference Borehole Image Log)
Cased Hole Logs (7/23 - 7/24/91) - Schlumberger
Cement Bond Log/VDL
Cement Evaluation Tool
Cement Scan Log

Cased Hole Logs (9/26 - 10/3/91) - Computalog
Flow Spinner Log
Production Temperature Log

INEOS conducted the initial mechanical integrity testing for WDW No. 4 from September 15 through October 26, 1992. The guidelines used initially by INEOS for mechanical integrity testing are summarized in Appendix 8-1 of this application. The data and results from this testing are included in Appendix 8-5. The data and results contained in Appendix 8-5 demonstrated that there was no fluid channeling behind the casing and that the injected fluid was entering the injection interval as designed. That data demonstrated the initial mechanical integrity for WDW No. 4. Mechanical Integrity demonstrations have been conducted on WDW No. 4 each year following that initial demonstration, starting in 1994 when that injection well was commissioned as an injection well.

The Lima Stratigraphic Test Well (WDW No. 4) was cored extensively to obtain site-specific data for the INEOS site. Over 2,250 ft of 4-in. core was obtained and submitted to a variety of testing including air permeability and porosity, liquid permeability and porosity, and electrical property tests.

Formation fluid sampling was conducted by drill stem testing 16 zones in the Lima Stratigraphic Test Well. Data from 11 of the DSTs were of sufficient quality to be analyzed to determine reservoir properties. BP Exploration (BPX) also analyzed DSTs. The BPX analyses are considered to be more representative since they incorporated the full test history in each analysis, including the swab runs and the volume of fluid produced.

Formation fluid samples from the DSTs were analyzed for index organics (acrylic acid, acrylamide, acetonitrile, and nicotinonitrile) and index inorganics (ammonia-N, calcium, sodium, chloride, magnesium, sodium, and sulfate); and conductivity, specific gravity, total dissolved solids (TDS), pH and alkalinity were measured.

From the data reported during the drilling of WDW No. 1 in 1968, the most reliable measurements indicate a value of 1,050 psia at 2,783 ft KB is a reasonable estimate for the original Mt. Simon Sandstone bottom hole pressure (BHP) (0.38 psi/ft surface gradient). The original surface gradient at the Lima Stratigraphic Test Well (WDW No. 4) during the drilling in 1991 was 0.46 psi/ft, representing a net pressure increase of approximately 230 psi at this location due to injection activities.

Fluid temperature, pH, conductivity, and pressure data were collected during the DST testing discussed above. The static fluid level of the injection zone can be calculated from the pressure data collected from the DSTs. The pressure data are more accurate than static fluid level measurements. Two formation fluid samples were taken which were believed to represent native Mt. Simon connate water; one on February 25, 1968 and one from DST No. 9 from the Lima Stratigraphic Test Well (WDW No. 4). The analysis of the February 25, 1968 sample is suspect due to several contradictions in the parameters, and it is believed that this was a contaminated sample. Due to the absence of any quantifiable organic analytical parameters, the sample collected during DST No. 9 is believed to be an uncontaminated Mt. Simon connate water sample. The data from these two analyses are presented in Table 8-8. The specific gravity of fluid taken from DST No. 9 is plotted with respect to other Mt. Simon formation fluid analyses in Figure 8-1.

Under Rule 3745-34-56(A) of the State of Ohio Administrative Code for Class I hazardous waste injection wells it is stated that:

> *Except during stimulation, the owner or operator of a Class I injection well shall assure that injection pressure at the wellhead does not exceed a maximum which shall be calculated so as to ensure that the pressure in the injection zone during injection does not initiate new fractures or propagate existing fractures in the injection zone. The owner or operator shall operate a Class I injection well such that the injection pressure does not initiate fractures or propagate existing fractures in the confining zone, or cause the movement of injection or formation fluids into a USDW.*

A variety of tests were conducted in the Lima Stratigraphic Test Well to help in determining the fracture characteristics of the injection and confining zone. The stress profile has been determined from micro-frac stress tests in the Injection and Confining Zones and from an analysis of uniaxial strain core tests. Other data have come from an analysis of geophysical logs and from tensile fracturing of the wellbore. Other information on fracture pressure has come from an analysis of fracture treatments in WDW No. 1 and 2 and of various step rate tests in these wells and WDW No. 3. Analysis of these data was used to define a safe maximum operating pressure for these injection wells. This analysis determined that the previously (pre-1992 permits to operate) permitted maximum operating pressure of 844 psig meets the requirements of Rule 3745-34-56(A) of the Ohio Administrative Code. An analysis of the historic injectivity performance of the existing injection wells at pressures at and above this value of WHP, confirm that at this pressure fractures are neither initiated or propagated. Indeed this analysis indicates that the injection performance of these wells at these pressures is dominated by formation plugging. This information was presented in Appendices 5-1, 8-2 and 8-4 of this document. USEPA determined that the data demonstrated that historic injection pressures have not initiated nor propagated fractures in the injection zone. The USEPA made a final decision to grant INEOS an exemption from the land disposal restrictions of the Hazardous and Solid Waste Amendments of 1984 (HSWA) regarding the injection of hazardous wastes on May 7, 1992 (Federal Register Vol. 57, No. 105, page 23094). This decision determined that INEOS had demonstrated to a reasonable degree of certainty that there will be no migration of hazardous constituents from the injection zone for as long as the waste remains hazardous.

Fracture initiation data have come from breakdown pressures from the micro-frac tests in the Lima Stratigraphic Test Well (WDW No. 4), and from fracture treatments in WDWs No. 1 and 2. These data are summarized in Table 8-9. Injection at surface pressures less than 990 psi will ensure that new fractures are not initiated in the injection interval.

Extension pressures are more difficult to deduce from the micro-frac tests performed in WDW No. 4 since these were performed in high permeability zones by injection into a restricted, packed off interval. As a result, pressure data which may appear to indicate fracture extension may actually be a result of flow through a fracture around the packers and into the wellbore. The pressure rise in the upper and lower guard intervals of the packer assembly indicate that this is the case. The apparent fracture extension pressures from these tests do, however, indicate lower bounds for these values which may be used to verify the propagation pressures obtained from other sources.

Data on fracture extension pressures in the Mt. Simon can be estimated from the results of the mini-frac tests performed on WDW No.1 and No. 2 prior to the hydraulic fracture stimulations performed in 1988. The results from these tests will be estimates, since these mini-fracs were performed with gelled fluid rather than water, and since wellbore extension pressures will vary with the size of the fracture and the degree of fracture plugging. Since friction pressure drop will increase with fracture length, and since fracture tip plugging by entrained solids will increase propagation pressures, the wellbore pressures estimated from these mini-fracs are likely to be lower bounds.

The pressure-flow rate history during the mini-frac on WDW No. 1 is shown in Figure 8-2. Continued pumping at rates above 9 bpm requires a WHP of greater than 1015 psi. For a depth of 2800 feet and a fluid specific gravity of 0.442 psi/ft, this corresponds to a BHP of 2250 psi, or 2220 psi if a friction pressure drop of 30 psi is assumed. This corresponds to a pressure gradient of 0.793 psi/ft. Data for the mini-frac in WDW No. 2 are shown in Figure 8-3. Here a WHP of about 1050 psi is required for pumping 30 bpm. At these flow rates the pipe friction pressure drop will be about 200 psi (Halliburton Services Data). Allowing for this, and the hydrostatic head of 1235 psi, gives a BHP of 2085 psi at 2800 feet, or 0.745 psi/ft.

These data together with lower bound micro-frac data are summarized in Table 8-10. It is apparent that the lower bound extension pressure corresponds to 0.745 psi/ft., or a BHP of 2085 psi at 2800 feet. For a 0.442 psi/ft. fluid column and a 30 psi pressure drop (Table 8-13) this corresponds to a WHP of 880 psi. A more reasonable estimate is probably the average value from the mini-fracs of 0.769 psi/ft. This corresponds to a BHP of 2155 psi at 2800 feet, or a WHP of 950 psi.

These data are confirmed by information on the injection history of WDW No. 1, No. 2 and No. 3 and by modeling of the injection response. It is apparent that despite injection into these wells at surface pressures up to and above the current maximum permitted wellhead pressure of 844 psi, no fracture extension has occurred, as discussed in more detail later in this section. This is true even after the hydraulic fracture stimulations of these wells in mid-1988. These fracture stimulations gave either no, or a minor increase in injectivity, and any increase was quickly negated by formation plugging. Modeling of injection into a 300 ft fracture at 204 gpm indicates that the pressure buildup due to injection at the prescribed rates is insufficient to maintain a 300 ft fracture length, and fracture shrinkage actually can occur.

Closure pressures have been determined from data from WDW No. 4. Relevant data from this well are given in Table 8-11. Relevant data from this well are given in Table 8-12, including information from the minifrac treatments in WDWs No. 1 and No. 2. From this data, a conservative estimate of the in-situ stress gradient in the injection interval of 0.69 psi/ft can be made, corresponding to an equivalent WHP of 695 psi at 2,800 ft or 770 psi at 3,105 ft.

The various data for closure, propagation, and breakdown are summarized in Figure 8-4, and Table 8-14 together with gradients for these parameters based on average data for the microfracture and minifrac tests. Based upon these data, and the requirement that new fractures should not be initiated nor existing fractures propagated, a maximum permissible WHP of 844 psi was established. The BHP line for this WHP, calculated for a minimum fluid pressure gradient of 0.438 psi/ft, an average fluid pressure gradient of 0.444 psi/ft and a maximum fluid pressure gradient of 0.455 psi/ft., and neglecting friction, are also included in Figure 8-4.

Table 8-14 gives the BHP's for a maximum WHP of 844 psi over the expected range of injectate specific gravity of 1.010 - 10.50. The BHP is calculated without any allowance for friction at depths corresponding to the approximate depths to the bottoms of the casing in

WDW No. 1, WDW No. 2, WDW No. 3 and WDW No. 4 and is compared to the estimated minimum values of closure, propagation, and initiation pressures at those depths. These values indicate that the proposed maximum permitted operating pressure meets the requirements of Rule 3745-34-56(A) of the Ohio Administrative Code, since it is based on site specific data and is:

- at least 302 psi and probably 332 psi below the WHP which would be estimated (conservatively) to initiate new fractures;
- at least 37 psi and probably 67 psi below the WHP which would be estimated (conservatively) to propagate existing fractures.

Table 8-14 also shows the calculated BHP range, neglecting friction, for a depth of 2640 feet, corresponding to the top of the passive injection interval as defined in the No-Migration Petition. The BHP's at this depth are significantly overestimated since fluid at this level will have experienced a significant pressure drop in flowing through any permeable pathway. Nevertheless, even this highly conservative estimate of BHP only exceeds the estimated minimum propagation pressure by 15 psi for the case with maximum injectate specific gravity. If friction is accounted for even this highly overestimated pressure at 2640 feet will not exceed the minimum estimated propagation pressure.

An additional safety margin is provided in the way INEOS operates the injection activities to ensure that the maximum permitted wellhead pressure is not exceeded. The current system operating parameters are as follows:

High Injection Pressure Alarm: 800 psi
Injection Pump Shutdown: 810 psi

These operating requirements provide an additional margin of safety between 17 and 30 psi under the permitted maximum wellhead pressure. These control and alarm set points are not intended to be incorporated as permit conditions and INEOS requests the flexibility to adjust these control and alarm set points as required, based on the facility's operating experience, to ensure reliable equipment operations.

The permitted maximum WHP exceeds the estimated closure pressure by 70 psi at 3,150 to 158 psi at 2,800 feet. Data from the borehole televiewer log run in WDW No. 2 in 1988 immediately after the fracture treatment indicated that there were no vertical fractures above 2,903 feet. Vertical fractures are seen from the bottom of the logged interval (3,062 feet) up to 2,903 feet. At this depth the proposed WHP exceeds the conservative closure pressure by 132 psi.

INEOS acknowledges that closure pressure may be a reasonably conservative pressure for new operation with little experience or data to base operating pressure on. However, given the 26 years of experience in operating this field, including data on the behavior of planned stimulations, the high quality of data from the Lima Stratigraphic Test Well, and the demonstration of containment presented in the No Migration Demonstration submittal, INEOS believes that for this site such a limitation is unwarranted to assure that a fracture is not initiated or propagated in the injection zone. An abundance of data has been presented at the Lima site, the most important of which is the demonstration of containment over the 20 plus years of operating experience at this site.

This experience can be analyzed in terms of the daily injectivity index and the cumulative injection performance of WDW No. 1, WDW No. 2, and WDW No. 3. Neither of these analyses indicates any increase in performance which could be related to fracture propagation even after the hydraulic fracture treatments in mid 1988. On the contrary, the records indicate a reduction of performance attributable to formation damage, at injection pressure levels at and above the current maximum operating pressure. The injection history for INEOS Lima injection wells is contained in Appendix 2A-3. The tabulation of the data used in the Hall plots is contained in Appendix 8-3.

Figures 8-5 through 8-7 show the injectivity index for the three injection wells. This index is calculated as the average injection rate divided by the average WHP. It is controlled by the permeability x thickness (kh) product of the formation, and the skin. Any increase in kh, or reduction in skin, which would occur if fractures were being propagated, would be seen as an increase in injectivity. WDW No. 1 (Figure 8-5) shows a gradual decrease in the index from October 1988 to April, 1991. At this time, the well was cleaned up using a chemical treatment leading to an immediate increase in injectivity index. Since that time the index has decreased to close to the historic values. WDW No. 2 (Figure 8-6) shows an essentially constant index as does WDW No. 3 (Figure 8-7) up to mid 1991. Since that time, however, WDW No. 3 shows a reducing injectivity. Note that these decreases in injectivity are occurring at wellhead pressures up to and above 800 psi.

These historic injection data can also be analyzed using the series of steady state analysis technique devised by Hall (1963). The analysis is based on the steady flow relationship:

This analysis tool is routinely employed by oil field water-flood operations as the primary control tool to determine that an active operating injection well is not propagating a fracture. This method is preferred for water-flood control, where close control to avoid fracturing is critical, because it is viewed as the best indication of fracture propagation. A propagating fracture will lead to an increasing negative skin. For example, an infinitely conductive fracture growing from a length of 7.5 feet to 150 feet over one year (0.39 feet/day) will lead to a skin change from -3 to -6. The effect of this on a Hall plot is shown in Figure 8-8. Conversely, a positive increase in skin due to formation damage will show as an increase in slope.

Figures 8-9 through 8-11 show the Hall plots for the three injection wells for data from 1968 through June, 1992. The Hall plot trends for all wells (Figures 8-9 to 8-11) show early constant slopes, then a general increase in slope due to formation damage. Clean up of WDW No.1 in 1974, 1981, and 1991 and of WDW No.2 and No.3 in 1987 and 1990 shows some improvement in injectivity, but this improvement is soon lost to additional formation damage. The intentional hydraulic fracturing stimulations in all wells in 1988 has an insignificant effect on injectivity. Similar trends are seen in the injectivity index plots in Figures 8-5 to 8-7. There are no indications in any of these plots of the increasingly negative skin which would be associated with fracture propagation. It should also be noted that the injectivity of all of these wells indicates a lower kh and a more positive skin than found in the Lima Stratigraphic Test Well. This is characteristic of injection wells dominated by formation damage not by propagation of fractures.

Additional support for the lack of fracture propagation at historic injection pressures comes from the various transient fall-off and step rate tests performed on the site injection wells in 1988 and 1991. The analysis of the transient pressure falloff tests in WDW No. 4 have consistently shown a skin on the order of -4, which is attributed to the pressure sensitive permeability of the main injection horizon. Note that this result comes from the falloff portion of the testing during which any injection induced fractures will close and not be reflected in the analysis.

The step rate test for this well (Figure 8-12) show a curve which has been analyzed as being a result of a pressure sensitive permeability in the predominant injection zone (2,970 - 3,020 feet). This conclusion was reached for a variety of reasons. Of note here are that the pressures in the step rate test were well below the measured closure stress. The negative skin in this well is therefore a direct expression of the nature of the injection horizon and is not related to any propagation of fractures during the injection into this well. The step rate test for WDW No. 2 and 3 show a very similar form to that for the stratigraphic test well, with similar final slopes at higher pressures (indicating similar kh), although the curves are displaced upwards due to the effects of a reduced permeability zone around the wellbore.

The phenomena of pressure sensitive permeability permits the continued injection through this damaged wellbore radius. This phenomena is distinguishable from the propagation of fractures and has been demonstrated at Lima through both fundamental core testing and well transient testing. A conclusion from this observation is that there are no indications of fractures in the results for WDW No. 2 and 3, even though these wells were hydraulically fractured in 1988. WDW No. 1 shows quite dissimilar behavior, primarily because injection here is predominately into a different zone. However, there are again no indications of fractures in these tests. These points are discussed in more detail in Appendix 8-2.

Update on Lima Site Well Performance and Operating Pressure Issues

Table 5-3 summarizes the results of all of the historic pressure falloff tests conducted with the Lima injection wells since the No-Migration Demonstration. The overall review of the table of well test summaries indicates that the native in-situ formation permeability within the limited wellbore region investigated by these tests is on the order of 35 md. This value for average Mt. Simon permeability is consistent with the core data obtained from the Lima Stratigraphic Test Well Project, considering the extent of pluggage experienced in that region from the historic injection activities. When considering the effects of the historic injectivity on the near wellbore regions, the results of the analysis of this extensive data indicates a wellbore region formation permeability thickness product of 12,500 md-ft (35 md permeability). This value is reflected in the outer ring permeabilities from the WDW No. 4 tests and the calculated permeabilities from the historic injection wells following formation clean-up programs. The results from the analyses of the historic site injection well tests reflect the level of near wellbore pluggage and resultant loss of permeability near wellbore for the existing three injection wells and the counter-balancing effects of the formation clean-up programs. The latest results indicate that INEOS has been successful in keeping the site injection wells close to their base capabilities through the ongoing clean-up programs based on a review of the calculated inner ring permeabilities. The comparisons of these tests confirm the general observation, though, that the Lima injection wells are experiencing progressive formation pluggage which is apparently continuing over time.

Two other important observations can be made from this data. The first regards the performance of plant injection well WDW No. 1. By 1990, this historic injection well had a capability of approximately 75 gpm at a wellhead pressure of greater than 800 psig. Following a series of chemical clean-up activities to remove the pluggage in the near wellbore region, the capacity of this injection well has steadily increased. Currently, the capacity of this injection well is approximately 135 gpm at 700 psig wellhead pressure, more than was previously thought possible based on the injection step rate tests conducted in 1989. With the improvements to the filters but less frequent clean-up treatments the effective capacity of these injection wells has not decreased significantly over the past five year period.

The other data submitted to the Ohio EPA during the period following the previous submittal of the UIC permits to operate application was the conducting and detailed evaluation of a significant number of temperature logs run on all four INEOS injection wells. The method by which INEOS conducts these temperature logs provides a good opportunity to investigate for fracture flow and vertical migration of injected fluids. The evaluations of all of these temperature logs show no indication of vertical migration of fluids from the injection zones. INEOS engaged Dr. Richard M. McKinley, a private consultant, to interpret the subject logging program. Dr. McKinley is a consultant specializing in the technology associated with production logging operations and interpretations. He retired as a Research Advisor from Exxon Production Research Company at the end of 1993 after more than 30 years in the oil and gas industry which was devoted to formation evaluation in general and to production logging in particular.

Dr. McKinley's undergraduate and graduate work was interspersed with periods of employment with the former Humble Oil and Refining Company. He obtained a BS in Chemical Engineering from the University of Alabama in 1955 and a Ph.D. in Chemical Engineering from Purdue University in 1961. From that time through 1964 he was on the staff of the Mechanical Engineering Department at Purdue University. He then returned as a permanent staff member of Exxon's production logging department. When Esso ceased all logging operations of its own in the early 1970's, Dr. McKinley organized the company training course on production log interpretation. This course remains one of the highest rated schools in the company's training program. Dr. McKinley also authored the company manual on production logging.

With Dr. McKinley potentially retiring, INEOS has not contracted Subsurface Technologies to provide the analysis of the testing conducted on the individual wells. The first report completed by Subsurface was compared to that reported by Dr. McKinley and was found to be very similar in the described conclusions.

The conclusion from these analyses is that none of the injection wells show any indication that fractures are being initiated or propogated during several years of injection at well head pressures up to and exceeding the proposed maximum permitted operating pressures. On the contrary, these wells show all indications of being un-fractured injectors with progressive formation plugging and damage, despite the fact that all of the wells were stimulated with propped hydraulic fractures in 1988.

Based on the large amount of data gathered and analyzed at the INEOS Lima site, a permitted maximum wellhead pressure of 844 psi will provide the required assurance that the injection pressure will not initiate or propagate fractures in the injection zone. The calculation supporting a permitted maximum wellhead pressure of 844 psi is contained in Table 8-14. In addition, due to the nature of the arrestment and confining units at the site and the presence of multiple bleed-off zones between the maximum vertical extent of injected migration and the lowermost USDW, protection of human health and the environment has been clearly assured at the INEOS site.

Appendix 8-2 contains the January 29, 1992 letter to USEPA which provided a summary of the relevant data which demonstrates that a maximum permitted wellhead pressure of 844 psig will not initiate nor propagate fractures in the injection zone. Appendix 8-3 contains the input data for the Hall plots. Appendix 8-4 contains the supplemental submissions to USEPA demonstrating that the historic operating pressures at 844 psig and higher had not initiated nor propagated fractures in the injection zone.

In summary, INEOS performed a detailed analysis of the maximum permitted wellhead injection pressure as part of the No Migration Demonstration process (see Appendix 5-1) approved by the USEPA in 1992 and reviewed and approved as part of the last Ohio EPA permit application process. No additional data has been developed during the last 10 years of plant operations and data collection that changes any of the analysis presented in the No Migration Demonstration nor the last permit application. In fact, the continued site specific data has confirmed those analysis. Therefore, INEOS requests no change to the maximum permit allowable wellhead injection pressures as listed below:

WDW No. 1	834 psig [1]
WDW No. 2	839 psig [1]
WDW No. 3	840 psig [1]
WDW #4	843 psig [1]

[1]Based on an injectate specific gravity of 1.040 or less. These maximum wellhead injection pressures are adjusted downward as the injectate specific gravity increases above 1.040.

An extensive analysis has been made of core from the Lima Stratigraphic Test Well (WDW No. 4). These include permeability and porosity determinations (Section 4.2.2.2), fracture logging and mechanical (deformation and strength) tests. The mineralogy of the injection and confining zones have been determined and are discussed in Section 4.2.2.1.

These fluid characteristics have been determined on samples taken in the DSTs run in the Lima Stratigraphic Test Well (WDW No. 4). Samples from DSTs 7, 8, 9, 10, 11 and 13 have given the fluid characteristics from the injection interval (Section 5). The sample from DST 9 is believed to represent Mt. Simon connate water. Samples from DSTs 14 and 15 have given data on the formation fluids from the lower Eau Claire (passive effective injection interval). Samples from DSTs 4, 5 and 6 have given data on the fluids from the confining zone and overlying strata (Section 5).

A series of sixteen DSTs were run on the Lima Stratigraphic Test Well (WDW No. 4) from April to July, 1991. These tests have been used to define the permeability-thickness product, initial reservoir pressure and porosity of the injection and confining zones, and of the overlying strata. These tests are summarized in Section 5.

Thirteen injection/fall-off tests were run in the Lima Stratigraphic Test Well (WDW No. 4) in May and June, 1991. The results of these tests were difficult to interpret due to packer by-pass, and little reliance is placed on these data. These tests are discussed further in Section 6.

From September to November, 1991 a series of step rate injection tests were conducted in the Lima Stratigraphic Test Well (WDW No. 4) open hole interval (2885 to 3409 ft KB). The results from these tests helped to confirm the injection characteristics of the injection zone. In particular they confirmed that most injection occurs in the high permeability zone around 3000 ft, that this zone exhibits strong pressure sensitivity of permeability, and that fracture propagation does not occur at the injection pressures used.

To quantify the magnitude of the observed pressure sensitive permeability, each step of the September through November, 1991 injection tests have been analyzed to determine an estimated permeability using the BP reservoir model/well test analysis PIE program.

For consistency, all steps were analyzed using a homogeneous reservoir model. The results of the analyses are summarized in Table 8-15.

These data show a general downward trend in skin values and increase in permeability as the test sequence progresses indicating injection interval clean-up. Thus the first 4 bpm test showed an estimated permeability of 27 md, the second 4 bpm test had an estimated permeability of 46 md, the third 4 bpm test 52 md, and the fourth 4 bpm test had an estimated permeability of 58 md. The bulk of this formation clean-up by injection appears to have occurred by the second step of the October test sequence.

The results for each flow rate were also analyzed using the equilibrium flow equation and the pressures at the end of each injection step. While not strictly applicable because of the superimposed effects of the earlier flow rates, this analysis will give permeabilities indicative of the change in permeability with pressure. This analysis is presented in the following table.

$$\overline{K} = \frac{141.2q\mu}{\Delta\, pH}\ln(r_o / r_w) = \frac{(141.2)(Q)(1440)(0.99)(7.5)}{(\Delta P)(250)} = 6039\frac{Q}{\Delta P}$$

Both sets of values are graphed in Figure 8-13 (Estimated Permeability Versus Injection Rate). Figure 8-14 is a graph of permeability versus bottom hole pressure. From these figures, an estimate of the magnitude of the pressure sensitive permeability is obtained. The most meaningful estimate is obtained from the graph of permeability versus bottom hole pressure. In this plot a distinction was made between the estimates from the first 4 rate steps and the estimates from the last seven rate steps. This distinction clearly shows the impact of the progressive well clean-up with the continued injection of clean, filtered 3% NaCl brine. A similar trend is observed with both the estimates from the steady state equation and from the reservoir model. Using the last seven steps, an estimate of the magnitude of the pressure sensitive permeability was obtained from the slope of the lines. Similar slopes were obtained from both data sets. The estimate of the magnitude of the pressure sensitive permeability is 14 mD/100 psi.

In August 1991 a pulse (interference) test was run, with WDW No. 2 used as the pulsing well, and WDW No. 1 and 4 as observation wells. The results of this test were used to define the global injection interval transmissivity, storativity and diffusivity, and formed the basis for calibration of the flow model.

INEOS USA LLC
Lima, Ohio
WDW #2

ATTACHMENT B

III. Core Analysis (Open Hole Strata Only)

6.0 INJECTION AND CONFINING ZONE GEOHYDROLOGIC PROPERTIES

This section describes the geohydrologic testing program. The primary purpose of this section is to present the geohydrologic data that have been collected within the injection interval, the arrestment strata, and confining zone. These data will be used as input to the waste transport modeling as discussed in Section 8.

This section is divided into five major subsections. Subsection 6.1 is an introductory section that briefly defines the scope of the testing program. Subsections 6.2, 6.3 and 6.4 describe the core testing, spinner surveys, and well testing programs, respectively. Subsection 6.5 concludes this section with a summary of the data results in terms of the injection interval, arrestment strata, and the confining zone.

6.1 Introduction

A variety of tests were performed by BPCI to determine the geohydrologic properties of the injection interval, the arrestment strata, and the confining zone. The testing program included physical property tests on core, spinner surveys, and hydrologic testing of the wells. As part of this program, over 250 core samples from the stratigraphic test well were tested to determine the permeability, porosity, tortuosity, grain density, and formation/cementation factors of the formations. A continuous spinner survey was run in WDW No. 1, WDW No. 2, WDW No. 3, and the stratigraphic test well. Sixteen drill stem tests and 13 injection/falloff tests were performed in the stratigraphic test well. Within WDW No. 1, a step-rate injection/falloff test was conducted. In addition, a pulse test was run using WDW No. 2 as the injector and using WDW No. 1 and the stratigraphic test well as the responder wells. In addition, an injection/falloff test was run in the stratigraphic test well completion interval. The following subsections describe the details of this testing program.

6.2 Core Testing

The core tests conducted included air permeability and porosity tests, liquid permeability and porosity tests, and electrical property tests. The testing objectives, test procedure, and data results for the testing program are described in detail below.

6.2.1 Gas Permeability and Porosity Testing of Whole Cores and Plugs

Gas permeability and porosity tests were conducted on cores and plugs from the confining, arrestment, and injection zones to determine the variability in the relative magnitudes of the permeability and porosity values throughout the section. Over 130 horizontal plugs were tested to provide a statistically representative sample of the permeability and porosity values of each zone. Whole core samples were tested to determine vertical and horizontal permeability values for the tight zones, and the vertical and horizontal permeability anisotropy of the potential thief zones.

Sample locations were selected at the well site by the site geologist. Locations were selected according to how accurately they represented the observed rock type. The testing locations are listed in Table 6-1, which, because of its length, is located at the end of Section 6.

6.2.1.1. Test Description of Permeability Testing

A universal permeameter system was utilized to measure the permeability and pore volume of the test samples at overburden stress conditions. The system consists of a pressure vessel and pressure generation unit that delivers the required hydrostatic confining pressure. The pore pressure manifold maintains pore pressure and delivers steady-state or pulse-fluid flow to the sample under test. A fully automated personal computer-based system provides data acquisition and control. Nitrogen gas is the flow media for permeability measurements and helium is used for pore volume measurements. Data are recorded by the computer and the calculated values and raw data are stored on the fixed disk.

The pulse decay technique was used to test the samples that were in the nano-Darcy to microDarcy range; the steady-state method was used for samples above 0.3 mD (Hseih, et al., 1980). To initiate the tests, all samples were installed into an impermeable sleeve and sealed with the end caps connected to the pore pressure tubing. The sample assembly was loaded into the pressure vessel. An initial confining pressure of 500 psi was applied to the sample to check for system leaks. The pore pressure was then applied and the confining pressure slowly increased to the pressure required to provide a net effective stress equal to the overburden stress. The designated overburden stress was calculated from the stress gradient of 0.65 psi/ft provided by BPCI.

Permeability values were determined using a modified Brace technique with updated storage coefficients if the pulse decay method was used on the sample (Brace, et al., 1968). When steady-state measurements were made, a Klinkenberg correction for gas slippage was used. All the radial permeability values were corrected for the non-linear flow path across the core cylinder.

6.2.1.2 Test Description of Porosity Testing

Porosity measurements were made using Boyle's Law Double Cell Method as described in standard testing procedure API RP 40 (American Petroleum Institute, 1960). In this method, the grain volume of the sample is measured in a porosimeter which is an apparatus consisting of two connected chambers. The core sample is placed in one chamber and the gas pressure is adjusted to the required value. The gas in the second chamber is adjusted to some different known pressure. The pressure is equalized and measured. From these data and Boyle's Law (PV=C), the volume occupied by the grains is calculated. In addition, the bulk volume of the sample is measured using calipers. The porosity is then calculated by subtracting the grain volume from the bulk volume.

Both ambient and overburden porosity measurements were made. The overburden porosity measurements were run by attaching the porosimeter manifold to the pore pressure ports in place on the permeameter manifold. The overburden porosity was then measured using modification B to the Boyle's law double cell method as described in API RF 40 (API, 1960). The ambient porosity measurements were made by placing the sample in a matrix cup and following the standard API RF 40 procedure. When both ambient and overburden pressure tests were run on the same core sample, the ambient tests were completed before the overburden tests were performed.

Additional detail concerning the sample preparation, calibration, and testing procedures are described in the RUI test report (Appendix F-1, Volume 10) and the BPCI Work Plan and Quality Assurance Document.

6.2.1.3 Test Results

A complete list of the data results from the plug permeability and porosity tests are listed by descending depth in Table 6-2, which is located at the end of this section due to its length. Physical characteristics of the plug that may have affected the results are noted with the reported value and described at the bottom of the table. Porosity values less than 0.1 percent are reported as 0.1 percent with the "<" (less than) symbol to the right. Steady-state derived data is reported in integer format. Pulse-decay derived data is reported in decimal format with 3-digit precision and trailing zeros are only a format artifact.

Permeability and porosity were measured at ambient conditions for some plugs to compare with data from WDW No. 1. A summary of this comparison is shown in Table 6-3. These data are noted with the letters Am or the word Ambient to the right of the reported value in Table 6-2, the summary of the plug permeability and porosity measurements from the stratigraphic test well.

Table 6-3. Comparison of Ambient Permeability and Porosity Measurements

	Gas Porosity (percent)		Gas Permeability (mD)	
	Stratigraphic Test Well	WDW No. 1	Stratigraphic Test Well	WDW No. 1
2849-2850	16.4	20	3.29	4.1
2910-2911	N/A	4.6	0.06	<0.1
2959-2960	12.3	19.8	348	120
2989-2990	13.4	12.5	30	45
3009-3010	16.8	12.6	412	75
3070-3072	18.0	10.5	25	26
3090-3091	13.6	22.2	154	865

Table 6-4 compares the core measurements (permeability and porosity) from 1968 from the Lima WDW No. 1 well measured at ambient conditions, with the core measurements from the stratigraphic test well which were measured at overburden conditions. Depth corrections were made to the WDW No. 1 data for stratigraphic comparison of beds with the data from the stratigraphic test well. This comparison illustrates a combination of slight differences in the correlation of the lithologic streaks and the difference between ambient and overburden measurements. A detailed review of the cores from Lima WDW No. 1 and the stratigraphic test well were made by the site geologist. All features were found to be correlatable between these two sets of cores within ±15 ft. Therefore, it is believed that Table 6-4 can be used to provide a good indication of the effect of overburden versus ambient measurements for those various beds.

Table 6-5 shows a direct comparison of permeability and porosity measurements from selected cores from the Lima stratigraphic test well measured at both ambient and overburden conditions. This data is plotted for permeability measurements in Figure 6-1 and porosities in Figure 6-2. The results show that the impact of ambient versus overburden measurements is directly dependent upon the petrographic nature of the sample being measured.

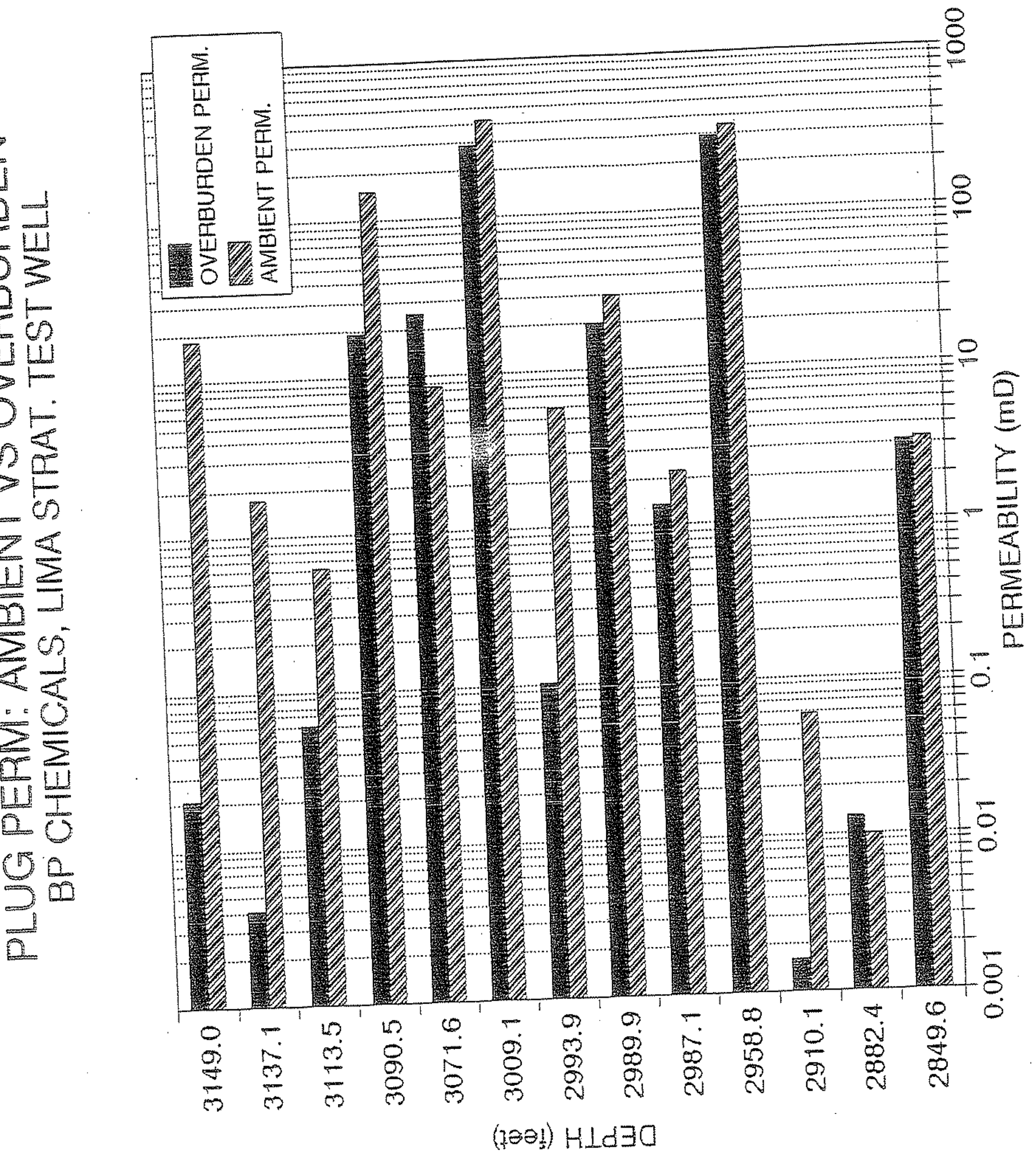


Figure 6-1. Summary of air permeability test results from plugs.

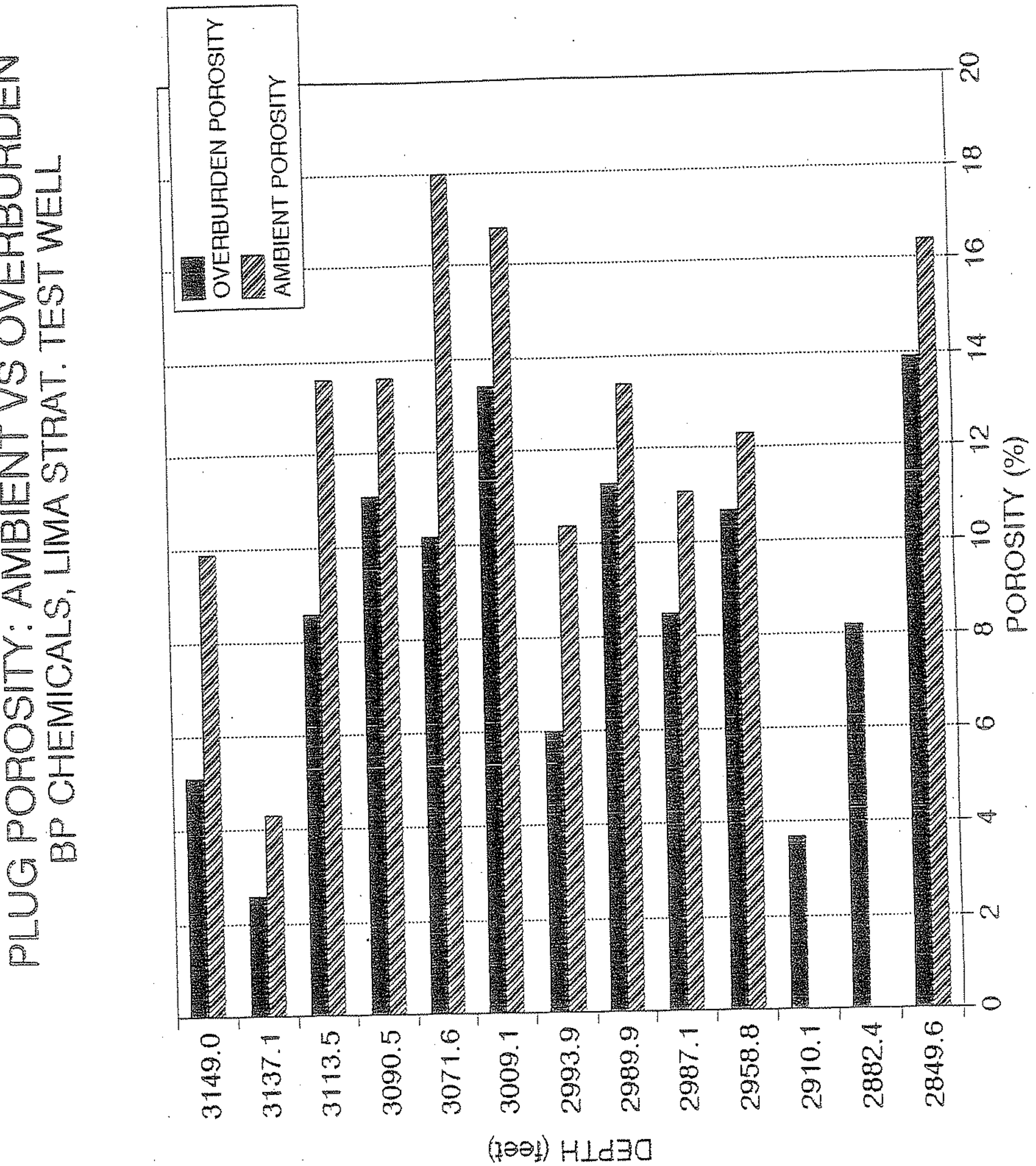


Figure 6-2. Plug porosity: ambient versus overburden.

Table 6-4. Comparison of Gas Permeability and Porosity Results from the Stratigraphic Test Well and WDW No. 1

	Gas Porosity		Gas Permeability	
	Overburden Porosity Stratigraphic Test Well (%)	Ambient Porosity WDW No. 1 (%)	Overburden Permeability Stratigraphic Test Well (mD)	Ambient Permeability WDW No. 1 (mD)
2795-2796	6.2	12.1	0.0623	1.7
2801-2802	3.0	3.1	0.001	<0.1
2803-2804	4.2	13.6	0.00138	1.3
2809-2810	7.1	9.6	0.007	<0.1
2814-2815	15.6	15.6	0.004	112
2820-2821	12.9	20.1	164	161
2823-2824	2.8	17.6	0.000521	165
2828-2829	14.1	10.9	520	2
2832-2833	20.1	21.5	12	157
2838-2839	15.8	17.2	N/A	61
2845-2846	20.8	14.5	162	183
2849-2850	13.9	20	3.13	4.1
2861-2862	19.9	22.5	57	64
2885-2888	2.6	19.5	0.009	42
2889-2890	16.5	10.2	169	<0.1
2885-2901	13.7	20	3.5	65
2903-2905	18.2	16.7	44	11
2910-2911	3.7	4.6	0.002	<0.1
2919-2920	13.7	19.6	64	28
2925-2926	16.7	19.6	31.3	240
2930-2931	15.3	19.1	62	71
2934-2935	20.8	11.4	171	<0.1
2943-2945	14.2	21.3	130	21
2950-2951	16.1	16.1	47	19
2959-2960	10.7	19.8	293	120
2965-2967	20.3	19.6	97	277
2970-2971	15.0	16.1	149	45
2974-2975	12.1	15.9	695	114
2979-2980	11.2	14.2	54	9.7
2985-2987	8.5	18.2	N/A	102
2989-2990	11.3	12.5	20	45
2993-2995	6.0	11.0	0.102	26
3000-3002	10.6	13.5	98	3.2
3005-3006	8.1	15.9	26	27
3009-3010	13.4	12.6	285	75
3013-3015	15.9	18.7	230	565
3020-3022	12.3	14.4	178	102
3025-3026	12.4	17.4	168	89
3029-3030	5.6	13	30	15
3049-3050	5.5	14.7	5.01	40
3053-3055	8.4	15.4	85	4.4
3070-3072	10.2	10.5	8.54	26
3085-3088	14.6	17.8	139	670
3090-3091	13.1	22.2	110	865
3098-3100	13.3	17.6	83	93
3105-3106	14.1	19.7	17	46
3110-3111	12.1	19	115	82
3113-3115	8.6	17.5	0.0614	142
3115-3117	16.3	17.5	392	142
3123-3125	16.4	13.3	419	1.8

Table 6-5. Overburden Versus Ambient Permeability and Porosity

	Porosity (%)			Permeability (mD)		
	Ambient	Over	Percent Change	Ambient	Over	Percent Change
2849.6	16.4	13.9	15	3.29	3.13	5
2882.4	N/A	8.2	N/A	0.00985	0.0129	24
2910.1	N/A	3.7	N/A	0.0592	0.00161	97
2958.8	12.3	10.7	13	348	293	16
2987.1	11.1	8.5	23	2.21	1.35	39
2989.9	13.4	11.3	16	30	20	33
2993.9	10.4	6	42	5.83	0.102	98
3009.1	16.8	13.4	20	412	285	31
3071.6	18	10.2	43	25	8.54	66
3090.5	13.6	11.1	18	154	19	88
3113.5	13.6	8.6	37	0.626	0.0614	90
3137.1	4.3	2.6	40	1.72	0.00404	100
3149.0	9.9	5.1	48	18.3	0.0209	100

Figure 6-3 shows a comparison of log calculated porosities from the open hole log suite run in the stratigraphic test well versus the core measured porosities (at overburden) from the Lima stratigraphic test well. The correlation between the measured values and log derived values is good, and provides a continuous record of the porosity trend that can be used to calculate a reservoir capacity for the effective injection interval.

A summary of the gas permeability measurements (measured at overburden conditions) by model layer is presented in Figure 6-4. The permeabilities shown in Figure 6-4 are geometric means due to the large range of permeability values measured in some of the model layers. This averaging does not fully reflect the higher and lower permeability streaks that are found in some of these model layers. A summary of the gas porosity measurements (measured at overburden conditions) are shown by model layer in Figure 6-5.

Whole core samples from potential tight zones were tested for permeability in two directions, axial (vertical) and radial (horizontal). These data are listed by descending depth order in Table 6-6. The same symbol convention described for plug test data applies to these data. Some samples had prohibitively long pore pressure equilibration times allowing only an upper limit of the permeability value to be determined under the prescribed test parameters. Using this upper limit for these tight zone permeabilities results in conservative permeability values for the arrestment strata (greater vertical transport than actual).

Whole core samples from potential thief zones were tested for permeability in the axial (vertical) direction and radially (horizontally) in four separate directions. These data are listed in Table 6-7. The same symbol convention as described for whole core bi-directional test data applies to this data set. The radial measurements were made in 45 degree sections spanning the direction noted in the table. The radial direction numbers noted on the table are degrees clockwise from true north.

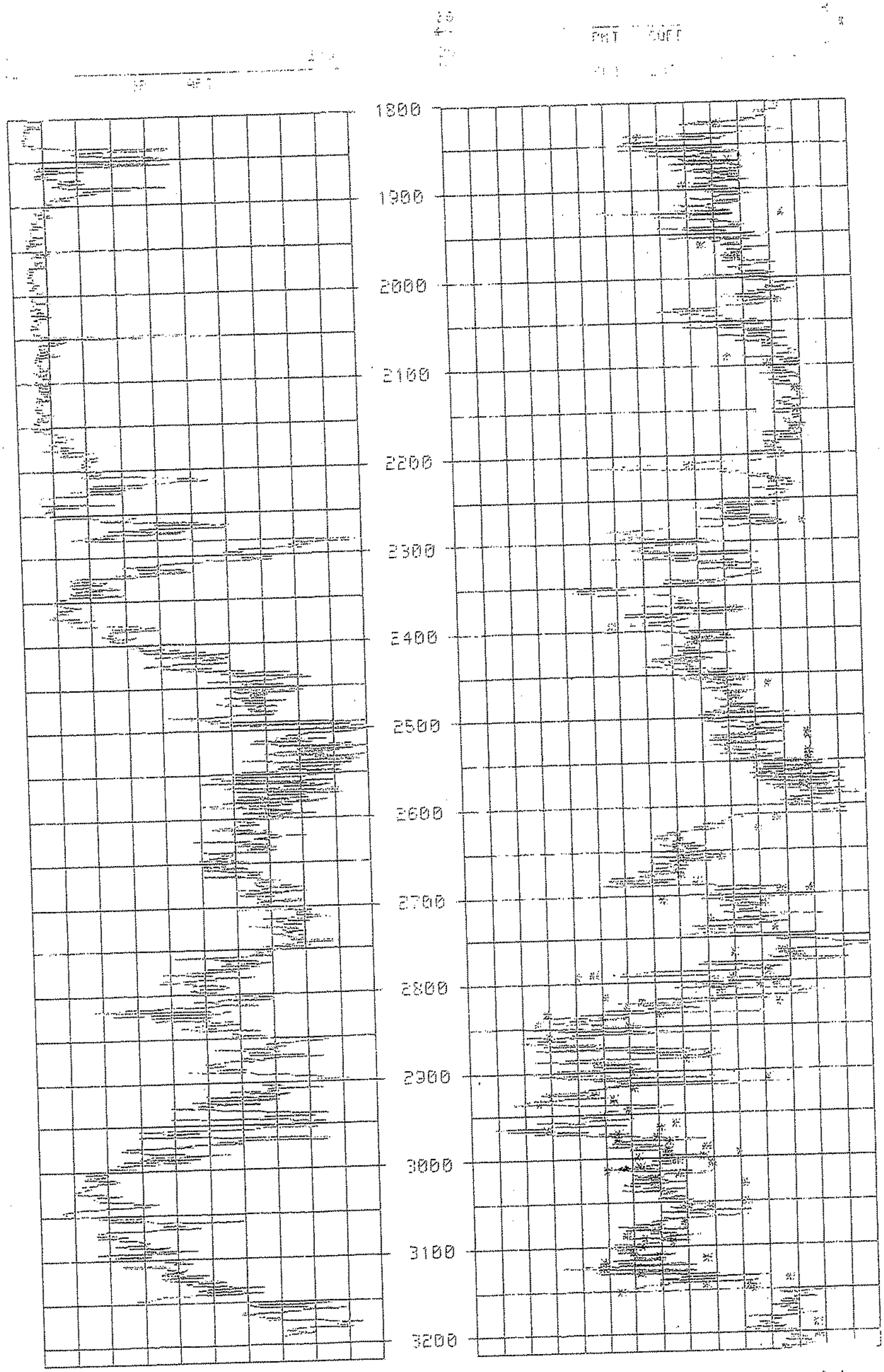
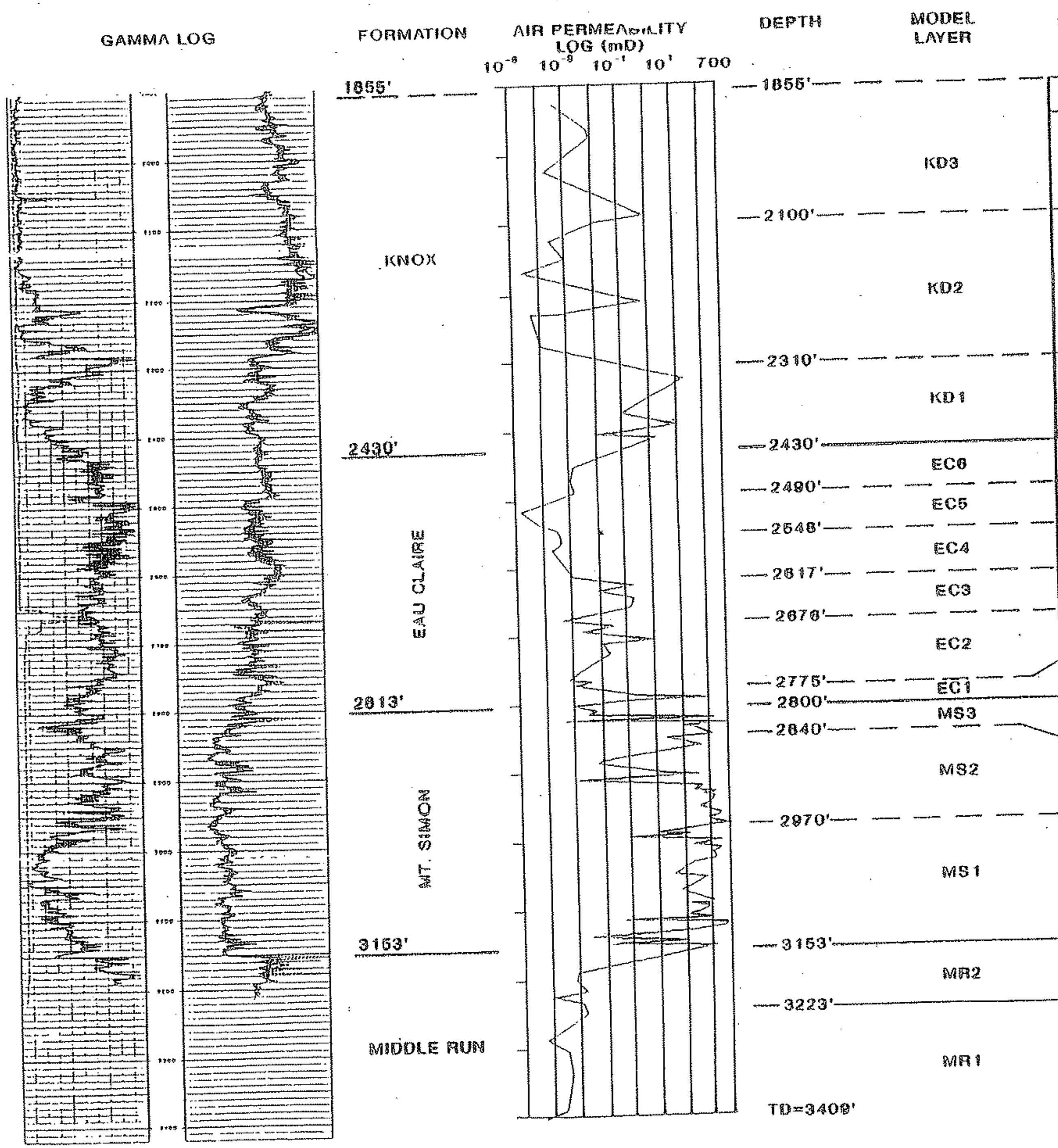


Figure 6-3 Comparison of log-calculated porosity measurements to lab-measured porosities.



GAS PERMEABILITY PLUG DATA (mD)

MODEL LAYER	MAX	MIN	MEAN
KD3	1.43	0.00023	0.009
KD2	0.748	0.00003	0.0006
KD1	24.1	0.011	0.753
EC6	0.0040	0.00121	.0021
EC5	0.00176	0.000017	0.0002
EC4	0.00131	0.000227	0.0005
EC3	0.24	0.011	.084
EC2	1.390	0.000473	0.0087
EC1	160	0.0623	4.293
MS3	520	0.000521	0.4148
MS2	293	0.00161	14.994
MS1	695	0.00404	21.74
MR2	0.00214	0.00010	0.00067
MR1	0.00213	0.000053	0.00032

Figure 6-4. Summary of gas permeability test results from plugs.

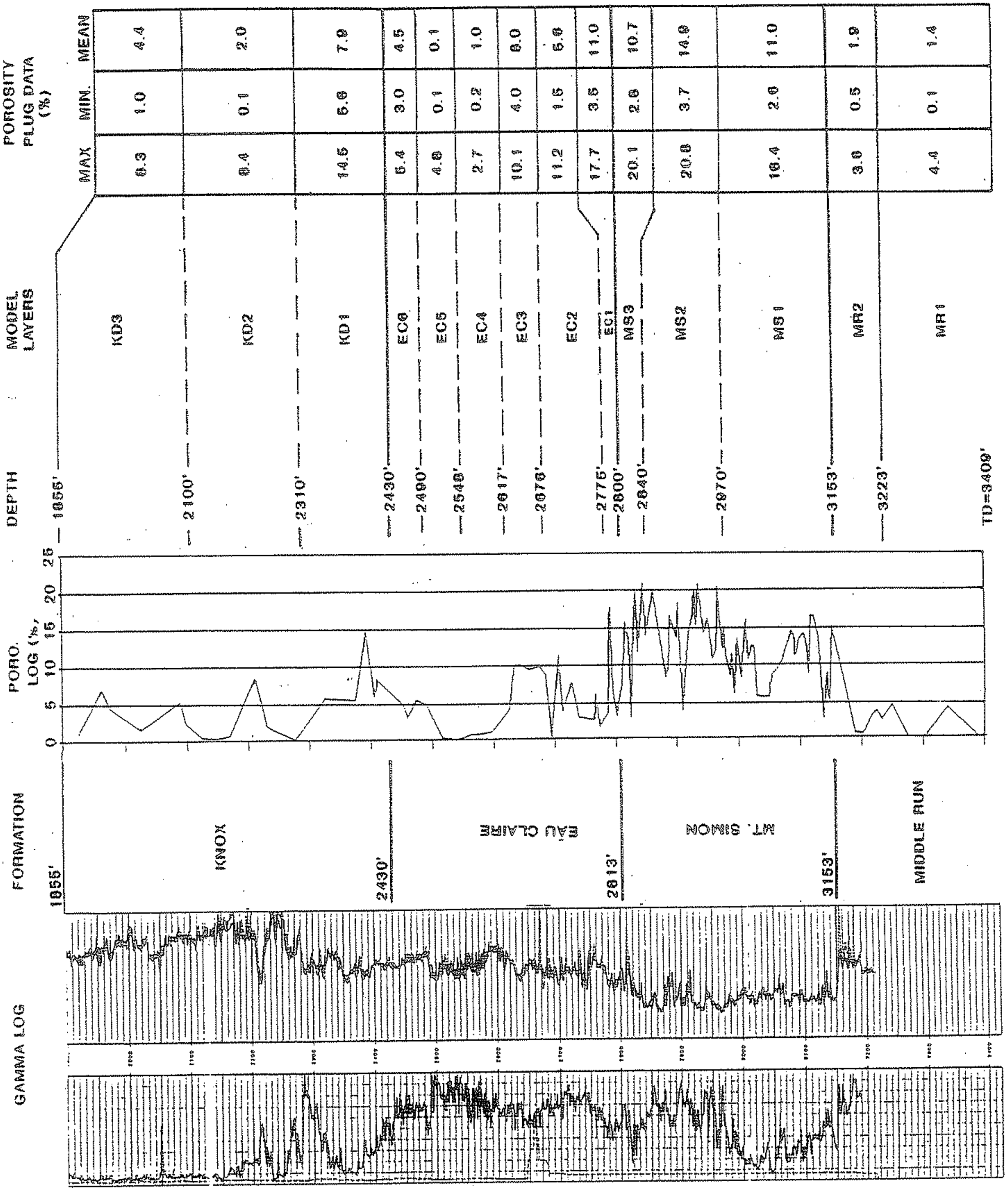


Figure 6-5. Summary of air porosity test results from plugs.

Table 6-6. Whole Core Permeability Data from Tight Zones in Lima Stratigraphic Test Well

Sample Depth (ft)	Direction	Permeability (mD)
1204.8	Axial	0.000068
	Radial	0.000110
1357.6	Axial	0.000008
	Radial	0.000422
1460.3	Axial	<0.000237
	Radial	<0.000139
2096.7	Axial	<0.004980
	Radial	<0.001330
2293.4	Axial	0.004740
	Radial	0.007970
2500.9	Axial	0.000234
	Radial	*0.007090
2502.5	Axial	*0.003860
	Radial	*0.003160
2554.5	Axial	0.000011
	Radial	*0.000782
2604.5	Axial	<0.000808
	Radial	<0.000484
2672.5	Axial	<0.002720
	Radial	<0.001640
2689.9	Axial	0.040600
	Radial	<0.002150
2695.8	Axial	0.062500
	Radial	0.043000
2732.0	Axial	<0.004820
	Radial	0.193000
2746.7	Axial	0.001490
	Radial	0.131000
2814.0	Axial	0.249000
	Radial	0.007910
3154.4	Axial	0.029700
	Radial	NA

< Sample permeability is less than reported value
* Bedding plane partings, stress/dehydration cracks

Note: Precision equals 3 significant digits, trailing zeros are a format artifact.

Table 6-7. Whole Core Directional Permeability Data from Potential Thief Zones in Lima Stratigraphic Test Well

Sample Depth (ft)	Direction	Permeability (mD)
1915.7	Axial	0.520000
	Radial 0	1.270000
	Radial 45	2.220000
	Radial 90	4.130000
	Radial 135	3.920000
2230.0	Axial	0.030200
	Radial 0	0.021100
	Radial 45	0.010200
	Radial 90	0.002680
	Radial 135	0.000688
2351.2	Axial	502
	Radial 0	372
	Radial 45	295
	Radial 90	277
	Radial 135	147
2642.9	Axial	<0.003350
	Radial 0	0.030300
	Radial 45	0.031200
	Radial 90	0.027300
	Radial 135	0.028850
2680.7	Axial	<0.005530
	Radial 0	0.027600
	Radial 45	0.024600
	Radial 90	0.022000
	Radial 135	0.022000
2790.0	Axial	0.000677
	Radial 0	101
	Radial 45	144
	Radial 90	187
	Radial 135	127
2854.1	Axial	0.040900
	Radial 0	38
	Radial 45	36
	Radial 90	36
	Radial 135	35

Table 6-7. Whole Core Directional Permeability Data from Potential Thief Zones in Lima Stratigraphic Test Well (continued)

Sample Depth (ft)	Direction	Permeability (mD)
2905.7	Axial	99
	Radial 0	190
	Radial 45	216
	Radial 90	183
	Radial 135	266
2944.3	Axial	3.62
	Radial 0	83
	Radial 45	81
	Radial 90	82
	Radial 135	81
3033.2	Axial	29
	Radial 0	50
	Radial 45	86
	Radial 90	110
	Radial 135	78
3055.6	Axial	0.072800
	Radial 0	4.13
	Radial 45	2.63
	Radial 90	3.20
	Radial 135	2.97
3146.0	Axial	0.057300
	Radial 0	154
	Radial 45	131
	Radial 90	132
	Radial 135	119

< Sample Permeability is less than reported value

Note: Precision equals 3 significant digits, trailing zeros are a format artifact.

6.2.2 Liquid Permeability Testing of Core Plugs

Fourteen uniaxial strain tests were conducted on selected core plugs from zones within the injection interval. Seven tests were run on vertically oriented specimens and seven tests were run on horizontally-oriented specimens from the same depth locations. A detailed description of the uniaxial strain testing procedures has been included in the appendix for the geomechanical section (Appendix G, Volume 11). The following paragraphs describe the continuous permeability determinations that were made throughout the deviatoric loading cycle of each uniaxial strain test.

6.2.2.1 Test Description

Measurements were made of liquid permeability as a function of effective stress on a number of samples cut from the whole core in both a vertical and horizontal direction. These tests were conducted in conjunction with the uniaxial strain tests to give an indication of the pressure sensitivity of the permeability of these cores, described in Section 7.

The tests were conducted on 2-in.-diameter by 4-in. (nominal) and 1-in.-diameter by 2-in. (nominal) core plugs, which were vacuum-saturated for 48 hours with 3 percent KCl brine prior to testing. The specimens were then placed between two endcaps with 120-mesh screens on top and bottom; and a heat-shrink Teflon jacketing was placed over the specimen and secured to the endcaps with wire ties. The specimen was then inserted in a 20,000 psi triaxial test vessel.

A nominal (100 to 200 psi) confining pressure was applied to the specimen to seat it in the pressure vessel, to close the jacketing gaps, and to prevent jacket rupture during the initial flow. Approximately 50 ml of 3 percent KCl brine was passed through the test specimen prior to applying deviatoric loading to ensure that the lines and samples were fully saturated. For the low permeability samples, the 50 ml of 3 percent KCl was not passed through when the sample displayed a differential pressure >150 psi at a flow rate <0.5 ml/min.

During each test, flow was established through the sample at a constant flow rate supplied by a Milton Roy constant flow metering pump, provided by British Petroleum Exploration. Flow rates were selected so as to maintain the differential pressure of <200 psi across the sample during the deviatoric loading cycle. Pressure drop across the sample was monitored continuously using a strain gaged differential pressure transducer. Data were recorded using a computer-based data acquisition system. The uniaxial strain deviatoric loading proceeded by applying an axial load at an axial strain rate of $<1 \times 10^{-5}$ in/in/sec for all Formations, with the exception of the Cincinnatian and Black River horizons, which were loaded at an axial strain rate of $<1 \times 10^{-6}$ in/in/sec. The confining pressure was increased in order to maintain a constant radial strain during the axial loading.

The flow pump and pressure transducer were calibrated prior to testing using standard SAIC QA procedures (Section 12, Appendix G-4, Volume 11). In addition, prior to testing, a system pressure drop was measured while the loading platens, 120-mesh screens, and all pore flow tubing used in the permeability system were in place. A pressure drop calibration was performed at various flow rates with no back pressure induced on the system.

Liquid permeability (k) was determined as:

$$k = \frac{q \mu L}{\Delta p A} \qquad (6\text{-}1)$$

where:

k	=	Permeability (darcies)
q	=	Flow Rate (cc/sec)
L	=	Specimen Length (cm)
μ	=	Fluid Viscosity (cp) (Assumed = 1.0)
A	=	Cross Sectional Flow Area (cm^3)
Δp	=	Pressure Differential (atm)

6.2.2.2 Test Results

Table 6-8 presents the permeability data results at an overburden stress level of 2,000 psi. Plotted results of each test may be found in the appendix for the geomechanical section (Appendix G-), which includes curves representing the radial strain (in/in) permeability (milliDarcy) and axial strain (in/in) vs. total axial stress (psi).

Table 6-8. Liquid Permeability Test Results from Plugs at In Situ Conditions*

Depth (ft KB)	Formation	Vertical Permeability (mD)	Horizontal Permeability (mD)
2657	Eau Claire	0.33	1.3
2789	Eau Claire	135	58
2838	Mt. Simon	11.7	150
2889	Mt. Simon	33	117
2998	Mt. Simon	34	0.35
3071	Mt. Simon	190	43
3145	Mt. Simon	240	0.65

* Permeability at the 2,000 psi overburden stress level

6.2.3 Electrical Testing of Core Plugs

Nine sample plugs were submitted for electrical testing to determine the formation factors, cementation factors, and tortuosity values, as presented in Table 6-9. All samples were selected from the confining and injection zones. Porosity and permeability measurements were also made on each sample and the selected depths are shown on Table 6-10.

Table 6-2

PLUG PERMEABILITY AND POROSITY

Company: **BP Chemicals**
Well: **Lima Stratigraphic Test**
Location: **Lima, Ohio**

	OVERBURDEN			
Sample Depth (ft)	Grain Density (g/cc)	Porosity (%)		Permeability (mD)
1925.9	2.73	1.0		0.000476
1961.9	2.85	7.0	*	0.008840
1975.1	2.81	4.5		0.011000
2025.1	3.08	1.5	*	0.000229
2088.8	2.87	5.3	*	1.200000
2098.2	2.82	2.4		0.018200
2125.1	2.84	0.4		0.000296
2150.1	2.84	0.3		0.001060
2169.5	2.83	0.6		0.000027
2211.5	2.76	8.4		0.748000
2228.9	2.76	2.3		0.000512
2229.7	2.83	2.0	*	0.000052
2276.6	2.83	0.1	<	0.000126
2326.3	2.87	5.6		24.1
2375.9	2.84	5.4		0.115000
2392.8	2.80	14.5	*	14.3
2405.6	2.74	5.9		0.011000
2409.9	2.75	7.2		0.192000 UX
2410.0	2.71	8.2		2.18
2439.9	2.59	8.7	#	0.002800
2453.2	2.63	4.8		0.001800
2460.6	2.76	3.0		0.004000 UX
2474.6	2.62	5.4		0.001210
2490.1	2.67	4.8		0.001760
2516.8	2.72	0.2		0.000017
2520.9	2.76	0.1	<	0.000243 UX
2537.6	2.72	0.1		0.000083
2544.5	2.66	0.1	<	0.000333
2552.8	2.82	0.2		0.000421

PLUG PERMEABILITY AND POROSITY

Company: **BP Chemicals**
Well: **Lima Stratigraphic Test**
Location: **Lima, Ohio**

		OVERBURDEN		
Sample Depth (ft)	Grain Density (g/cc)	Porosity (%)	Permeability (mD)	
2564.9	2.65	0.7	0.000528	
2575.1	2.63	0.6	0.000227	
2596.9	2.68	1.0	0.000615	
2614.0	2.94	2.7	0.001310	
2625.5	2.72	4.0	0.226000	
2634.1	2.68	9.8	0.010600	
2645.1	2.64	10.1	0.245000	
2657.9	2.76	6.8	0.037500	UX
2658.1	2.72	9.4	0.191000	
2676.1	2.73	9.8	0.000473	
2685.0	2.62	8.6	0.042800	
2694.4	2.65	0.3 <	0.002660	V
2694.6	2.65	2.5	0.004550	H
2706.1	2.67	11.2	1.390000	
2711.5	2.65	3.7	0.014200	
2727.4	2.64	7.7	0.029900	
2737.9	2.66	2.9	0.007910	
2763.9	2.74	2.5	0.000812	
2766.5	2.72	6.0	0.005470	
2772.9	2.71	1.5	0.001310	
2787.5	2.71	3.5	0.262000	
2789.9	2.62	16.6	160	UX
2791.1	2.61	17.7	130	
2795.1	2.66	6.2	0.062300	
2801.1	2.71	3.0	0.001090	
2803.2	2.66	4.2	0.001380	
2809.1	2.70	7.1	0.007430	
2814.9	2.64	15.6	0.004010	
2820.4	2.62	12.9	164	

PLUG PERMEABILITY AND POROSITY

Company: **BP Chemicals**
Well: **Lima Stratigraphic Test**
Location: **Lima, Ohio**

Sample Depth (ft)	Grain Density (g/cc)	OVERBURDEN Porosity (%)	Permeability (mD)	
2823.4	2.71	2.8	0.000521	
2828.1	2.61	14.1	520	
2832.8	2.64	20.1	12	
2836.2	2.61	11.7	41	
2838.9	2.61	15.8	152	UX
2845.5	2.63	20.8	162	
2849.6	2.66	13.9	3.130000	
2849.6		16.4 Am	3.290000	Ambient
2861.1	2.59	19.9	57	
2882.4	2.70	8.2	0.012900	
2882.4			0.009850	Ambient
2887.1	2.64	9.6	0.008710	
2889.4	2.61	16.5	169	UX
2901.1	2.59	13.7	3.540000	
2903.1	2.59	18.2	44	
2910.1	2.64	3.7	0.001610	
2910.1			0.059200	Ambient
2919.1	2.62	13.7	64	
2925.9	2.61	16.7	31.3	
2928.0	2.60	19.9	190	
2931.6	2.61	15.3	62	
2934.9	2.59	20.8	171	
2943.5	2.65	14.2	130	
2950.4	2.60	16.1	47	
2958.8	2.64	10.7	293	
2958.8		12.3 Am	348	Ambient
2963.8	2.64	11.8	228	
2966.6	2.58	20.3	97	
2971.1	2.61	15.0	149	

PLUG PERMEABILITY AND POROSITY

Company: **BP Chemicals**
Well: **Lima Stratigraphic Test**
Location: **Lima, Ohio**

Sample Depth (ft)	Grain Density (g/cc)	OVERBURDEN Porosity (%)		Permeability (mD)	
2974.8	2.65	12.1		695	
2976.9	2.64	15.0		121	
2976.9		17.6	Am	148	
2979.4	2.64	11.2		54	
2987.1	2.65	8.5		1.350000	
2987.1		11.1	Am	2.210000	Ambient
2989.9	2.64	11.3		20	
2989.9		13.4	Am	30	Ambient
2993.9	2.65	6.0		0.102000	
2993.9		10.4	Am	5.830000	Ambient
2997.2	2.65	8.7		0.802000	UX
2998.2	2.64	13.5		302	
3001.9	2.64	10.6		98	
3005.5	2.64	8.1		26	
3009.1	2.64	13.4		285	
3009.1		16.8	Am	412	Ambient
3013.1	2.64	15.9		230	
3016.3	2.64	10.5		120	
3021.9	2.64	12.3		178	
3026.1	2.64	12.4		168	
3029.1	2.64	5.6		30	
3048.8	2.64	5.5		5.01	
3053.2	2.64	8.4		85	
3071.6	2.65	10.2		8.54	
3071.6		18.0	Am	25	Ambient
3087.3	2.63	14.6		139	
3090.2	2.65	13.1		110	
3090.5	2.64	11.1		19	
3090.5		13.6	Am	154	Ambient

PLUG PERMEABILITY AND POROSITY

Company: **BP Chemicals**
Well: **Lima Stratigraphic Test**
Location: **Lima, Ohio**

		OVERBURDEN			
Sample Depth (ft)	Grain Density (g/cc)	Porosity (%)		Permeability (mD)	
3094.4	2.62	11.1		86	
3098.9	2.62	13.3		83	
3105.9	2.62	14.1		17	
3110.5	2.68	12.1		115	
3113.5	2.64	8.6		0.061400	
3113.5		13.6	Am	0.626000	Ambient
3116.9	2.64	16.3		392	
3123.4	2.63	16.4		419	
3130.2	2.63	13.5		19	
3137.1	2.67	2.6		0.004040	
3137.1		4.3	Am	1.72	Ambient
3143.2	2.64	8.7		13	
3144.8	2.65	5.5		0.336000	UX
3149.0	2.65	5.1		0.020900	
		9.9	Am	18.3	Ambient
3151.7	2.63	15.1		164	
3189.1	2.58	0.6		0.001030	
3202.7	2.63	0.5		0.000869	
3217.2	2.62	3.0		0.002140	
3225.1	2.68	3.6		0.000104	
3233.7	2.61	2.3		0.001350	
3250.1	2.68	4.4		0.002130	
3275.6	2.68	0.1	<	0.000210	
3288.1	2.66	0.1	<	0.000063	
3302.7	2.62	0.1	<	0.000365	
3340.9	2.73	4.0		0.000536	
3390.3	2.63	0.1	<	0.000312	
3404.3	2.65	0.1	<	0.000053	

PLUG PERMEABILITY AND POROSITY

Company: **BP Chemicals**
Well: **Lima Stratigraphic Test**
Location: **Lima, Ohio**

		OVERBURDEN	
Sample Depth (ft)	Grain Density (g/cc)	Porosity (%)	Permeability (mD)

* Vugs
# Chipped plug
< Porosity is less than reported number
@ Porosity and Permeability from whole core sample
UX Uniaxial liquid permeability samples
WW Sohio hole #1 samples, permit 68

Note: Precision is to 3 significant digits, trailing zeros are a format artifact.

INEOS USA LLC
Lima, Ohio
WDW #2

ATTACHMENT C

WELL CONSTRUCTION SPECIFICATIONS

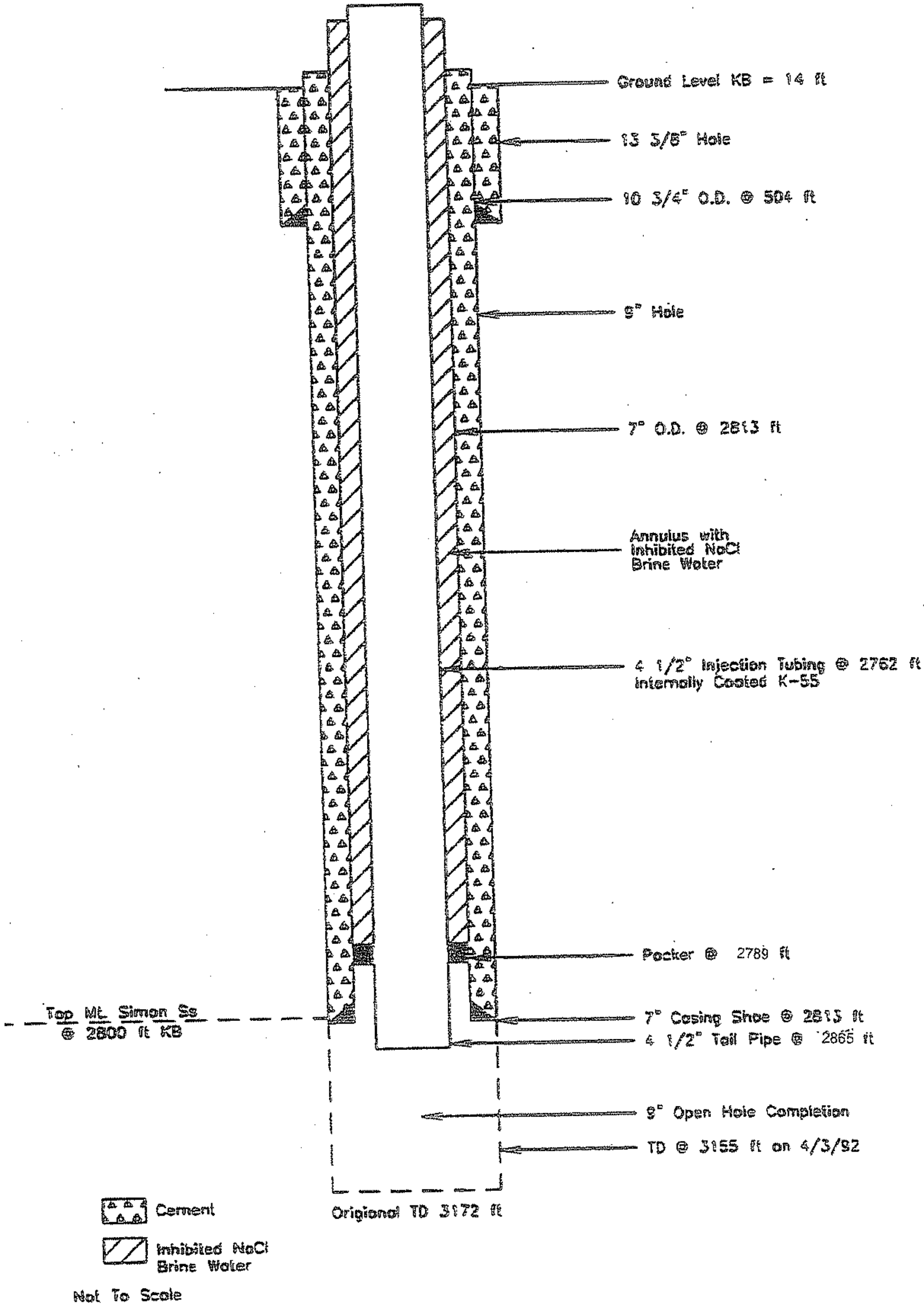


FIGURE 2-5

WELL SCHEMATIC OF INEOS WDW NO. 2 AS OF APRIL 2010

7.0 WELL CONSTRUCTION

General Comments Regarding Updates for the Renewal Application

The conclusions of this section remain basically unchanged from the July 1992 UIC permit application submittal. This section has been updated, however, as appropriate based on published literature, site operating history, test results, and data analysis conducted in regards 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 (WDW Nos.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). WDW Nos. 1 and 2 are constructed with two casing strings in addition to a carbon steel injection string which is internally coated with a corrosion resistant epoxy coating. WDW No. 3 is similarly constructed, 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 a corrosion resistant epoxy coating 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. Packer and seal assembly schematics of the four wells are provided as Drawings 7-5, 7-6, 7-7 and 7-8.

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 permit application submittal in September 1998. 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	October 1998 October 1999 October 2000 October 2001 October 2002 October 2003 October 2004	October 2005 October 2006 October 2007 October 2008 October 2009
WDW No. 2	April 1999 April 2000 May 2001 May 2002 April 2003 July 2003 (During Workover[1]) April 2004	April 2005 April 2006 April 2007 May 2008 April 2009
WDW No. 3	July 1999 August 2000 August 2001 August 2002 August 2003 October 2003 August 2004	August 2005 August 2006 August 2007 August 2008 August 2009
WDW No. 4	June 1999 June 2000 June 2001 June 2002 June 2003 June 2004	June 2005 June 2006 June 2007 June 2008 June 2009

1 On July 1, 2003, INEOS verbally notified the Ohio EPA regarding the loss of differential pressure in WDW No. 2 which had occurred on July 1, 2003. This was determined to be a leak in the injection string. INEOS ceased injection in WDW No. 2 prior to loss of differential pressure. INEOS was able to successfully shut-in the well until an emergency well workover was conducted. Ohio EPA provided field approval to resume injection after INEOS successfully demonstrated mechanical integrity on July 16, 2003.

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 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. These charts are verified daily and filed for reference and reporting purposes. 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 salt water brine containing approximately 5 gal of corrosion inhibitor per 300 gal of brine and a bactericide and with the pH adjusted to 10 with NaOH. 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 specific gravity of the annular fluid (approximately 1.08) is greater than the specific gravity of the injectate, which has an average specific gravity of 1.025 and a maximum of 1.05, thus insuring that a positive annular pressure is maintained throughout the length of the injection string.

The annulus monitoring systems maintain a 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 casings used in the INEOS wells are standard API tubulars. Through INEOS's experience of over 40 years in handling this waste water 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 do 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.

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 tailpipe. 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.

	WDW #1	WDW #2	WDW #3	WDW #4
Surface Piping	304 L SS	304 L SS	304 L SS	304 L SS
Wellhead Valves	316 SS	316 SS	316 SS	316 SS
Injection Tubing	N-80 Coated with TK-15	N-80 Coated with TK-15	J-55 Coated with TK-69	N-80 Coated with TK-15
Downhole Landing Nipple	410 SS	410 SS	410 SS	410 SS
Crossover Sub	304 SS	304 SS	304 SS	304 SS
Seal Assembly	316 SS	316 SS	316 SS	316 SS
Seal Assembly Elastomers	**V-Ryte (Viton)**	**V-Ryte (Viton)**	**V-Ryte (Viton)**	**V-Ryte (Viton)**
Packer	41-40 Steel	41-40 Steel	41-40 Steel	41-40 Steel
Packer Elastomer	Nitrile	Nitrile	Nitrile	Nitrile

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.

In WDW No. 4, 16-inch surface casing was set to a depth of 712.6 ft KB in a 20-inch surface hole. The lowermost USDW in WDW No. 4 occurs at a depth of 373 ft KB; therefore, the surface casing was set significantly below potential USDWs in this well.

The casing was cemented in the 20-inch hole from 700 ft to the surface employing a designed 50% excess cement. The cement used was as follows:

Standard Howco Cement with 3% $CaCl_2$ 4% gel, and 1/4 lb/sack floccele.

The slurry properties were as follows:

Slurry Weight: 14.33 lb/gal
Slurry Yield: 1.55 ft^3/sack
Water
Requirement: 5.2 gal/sack

The cement volume calculations were as follows:

24-in. conductor casing run to 62 ft, I.D. = 23.25 in.
20-in. I.D. hole to 721 ft
Hole Volume = (62 ft)(2.948 ft^2) + (659 ft)(2.182 ft^2) = 1,620 ft^3
Casing Volume = (712.6 ft)(1.396 ft^2) = 995 ft^3
Required Cement Volume = 1620 - 995 = 625 ft^3
Required Cement Volume = 625 ft^3/(1.55 ft^3/sack) = 403 sacks of cement.

The well was cemented on March 25, 1991, with 580 sacks of Standard Howco Cement with 3% $CaCl_2$, 4% Gel, and ¼ lb/sack floccele. The laboratory cement test report is included as Attachment 2 in Appendix 7-1 of this application. The stepwise cementing summary for the surface casing is included in Appendix 7-1. The reported cement slurry density was 14.1 lb/gal with a yield of 1.56 ft^3/sack. The cement developed a compressive strength of 1,940 psi in 10 days.

Excess cement (152 sacks) was circulated to surface versus the calculated 177 sacks (86% of calculated). Approximately 35% excess cement was actually employed.

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 EC_1 model unit. Drawings 7-1 through 7-4 contain the casing depths for the four INEOS Class I wells. The setting depth for the 7-in long string casing ranges from 2,813 to 2,885 ft within shaly sections of the Mt. Simon Sandstone, and all were cemented to the surface.

Intermediate and long string casings were run in WDW No. 4. Details on the cementing and casing program are included in Appendix 7-1 and summarized below.

An intermediate casing string was run in WDW No. 4 and cemented prior to drilling into the anticipated waste water plume. The 10 ¾-inch intermediate string casing was set at 2650.78 ft KB, in a 14 ¾-inch hole drilled to 2656 ft KB. This zone corresponds to the arrestment strata within the injection zone. The intermediate casing was cemented in two stages to minimize the fluid column weight on the formation during testing. A Davis-Lynch 10 ¾-inch 8-round integral casing packer type 100-1075-1275 and a 10 ¾-inch 8-round M&F stage cement collar type 778-MC were used for staging. The casing was cemented as follows:

Stage 1: Standard Howco Cement with 2% $CaCl_2$, 6% microbond, ¼ lb/sack floccele, 0.5% Halad 344, 1/10 of 1% FWCA.

Stage 2: Standard Howco Cement with 2% $CaCl_2$, 6% microbond, ¼ lb/sack floccele, 0.5% Halad 344, 1/10 of 1% FWCA.

The slurry properties of the cement were as follows:

Slurry Weight:	15.0 lb/gal
Slurry Yield:	1.36 ft^3/sack
Water Requirement:	6.20 gal/sack

The cement volume calculations were as follows:

262.30 ft J-55, 40.5 lb/ft casing 10¾ in.
2358.78 ft L-80, 51.0 lb/ft casing 10 ¾ in.
21.70 ft cement packer, float collar and shoe
16-in. casing set at 712.60 ft KB
Cement Packer Set at 1791.0 ft KB
Hole Volume = (712.60 ft)(1.268 ft^2) + (1943.40 ft)(1.187 ft^2) = 3,210 ft^3
Stage 1 Hole Volume = (865 ft)(1.187 ft^2) = 1027 ft^3
Stage 1 Casing Volume = (860.00 ft)(0.630 ft^2) = 542 ft^3
Stage 1 Required Cement Volume = 1027 - 542 = 485 ft^3
Stage 1 Required Cement = 485 ft^3/(1.36 ft^3/sack) = 357 sacks
Stage 2 Hole Volume = (712.60 ft)(1.268 ft^2)+(1078.4 ft)(1.187 ft^2) = 2183 ft^3
Stage 2 Casing Volume = (1791.00 ft)(0.630 ft^2) = 1128 ft^3

The well was cemented on May 29, 1991. The first stage was cemented at a designed 20 percent excess with 415 sacks of Standard Howco Cement with the additives noted above. The second stage was cemented with 905 sacks of Standard Howco Cement with the additives noted above at a designed 20% excess. The BP Research Cement Slurry Evaluation Report is included as Attachment 4 in Appendix 7-1 of this application. A similar evaluation was prepared by Halliburton. The reported cement slurry density was 15.0 lb/gal, with a yield of 1.36 ft^3/sack. The cement developed a compressive strength of 1,638 psi in 24 hours.

For Stage 1, 45 sacks of excess cement were circulated to the surface versus the calculated 58 sacks (78% of calculated). Approximately 12% excess cement was actually employed. For Stage 2, 120 sacks of excess cement were circulated to surface versus the calculated 129 sacks (93% of calculated). Approximately 15% excess cement was actually employed.

The 7-inch long string casing string was set as the final isolation of the open hole injection interval and cemented. This casing was set at 2885.35 ft KB, significantly inside the modeled injection interval for the Lima Site.

The casing was cemented in the 9 ½-inch hole in two stages to minimize the fluid column weight on the formation during cementing. A Davis-Lynch 7-inch integral packer, type 100-700-825 and stage cement collar, type 778-MC, were employed. The cement used was as follows:

Stage 1: Standard Howco Class A cement with 2% $CaCl_2$, 6% Microbond, 0.25 lb/sack floccele, 0.5% Halad 344, 1/10 of 1% FWCA.

Stage 2: 50:50 Mix Standard Howco Class A cement plus Zanesville Fly Ash, 8% Microbond, 2% $CaCl_2$, 0.75% CFR2, 0.5 D-Air, 2% HC-2, no gel.

The slurry properties of the cement were as follows:

	Stage 1	Stage 2
Slurry Weight:	15.0 lb/gal	14.8 lb/gal
Slurry Yield:	1.36 ft^3/sack	1.22 ft^3/sack
Water Requirement:	6.20 gal/sack	4.85 gal/sack

The cement volume calculations were as follows:

2,650.78 ft 10¾-in. casing	
262.30 ft J-55, 40.5 lb/ft 10¾ in: I.D. = 10.050 in.	145 ft^3
2388.48 ft L-80, 51.0 lb/ft 10¾ in: I.D. = 9.850 in.	1,264 ft^3
9½-in. hole from 2650.78 to 2,891 ft	119 ft^3

Total open hole volume = 1,528 ft^3
7-in. casing from 0 to 2885.35 ft O.D. volume = 771 ft^3
Total cement volume = 1,528 - 771 = 757 ft^3
Cement packer set at 2,050 ft KB; stage collar set at 2,043 ft KB
Stage 1 hole volume = 119 + 145 + 183 = 447 ft^3
Stage 1 casing volume = 225 ft^3
Stage 1 required cement = (225 ft^3)/(1.36 ft^3/sack) = 163 sacks
Stage 2 hole volume = 1.085 ft^3
Stage 2 casing volume = 546 ft^3
Stage 2 required cement = (535 ft^3)/(1.22 ft^3/sack) = 438 sacks

The 7-inch casing was cemented on July 20, 1991. The first stage was cemented with 225 sacks of Standard Howco Class A cement with the additives noted above. This volume was a designed 40% excess. The second stage was cemented with 475 sacks of 50:50 Pozmix, with the additives noted above. This volume was a designed 10% excess since the second stage cement job was all inside the 10 ¾-inch casing. The BP Research Center cement evaluation reports for both stages are included as Attachment 6 in Appendix 7-1 of this application. Similar evaluations were prepared by Halliburton. The first stage cement developed a compressive strength of 1,536 psi after 24 hours. The second stage developed a compressive strength of 1,551 psi after 72 hours.

For Stage 1, approximately 65 sacks of excess cement were circulated to the surface with the displacement versus the calculated 62 sacks (105% of calculated). Approximately 40% excess cement was actually employed. For Stage 2, approximately 35 sacks of excess cement were circulated to the surface with the displacement versus the calculated 37 sacks (95% of calculated). Approximately 8.5% excess cement was actually employed.

The long string casings in WDW Nos. 1, 2, and 3 were cemented in two stages. The intermediate and long string casings in WDW No. 4 were both cemented in two stages.

WDW No. 4

The technical specifications for the casing strings employed in WDW No. 4 are summarized in the table below. The surface casing was new, inspected at the mill and prior to shipment. It was certified to conform to API specification 5CT Gr H40. The bottom six joints of the intermediate casing were J-55, 40.5 lb/ft ST&C R-3 casing and six were new, inspected at the mill and prior to shipment. This casing was certified to conform to API specifications 5CT Gr J55. The remaining 58 joints of the intermediate casing were L-80, 51 lb/ft ST&C R-3 used casing that was inspected to ensure that it met published tolerances for the grade and weight of casing. The 7-inch long string casing was new, inspected at the mill and third party inspected prior to shipment. The long string casing was certified to conform to API specifications 5CT Gr N80.

Casing Diameter (in.)	Casing Grade	Wt Per Ft w/Coupling (lb/ft)	Inside Diameter (in.)	Drift Diameter (in.)	O.D. of Coupling (in.)	Collapse Resistance (psi)	Internal Yield (psi)	Body Yield (Klbs)	Joint Strength (Klbs)
16	H-40	65.0	15.25	15.06	17.0	670	1,640	736	439
10¾	L-80	51.0	9.850	9.694	11.750	3,220	5,860	1,165	804
10¾	J-55	40.5	10.050	9.894	11.750	1,580	3,130	629	420
7	N-80	23.0	6.366	6.241	7.656	3,830	6,340	532	442
4½	N-80	11.6	4.00	3.785	5.000	6,350	7,780	267	223

The total weight of the surface casing was approximately 45,650 lbs, approximately 10 percent of the 439,000 lbs joint yield strength. The maximum internal pressure that this casing is expected to be exposed to is the cement column weight (15.6 lb/gal) of approximately 585 psi at the casing shoe. This value is approximately 35% of the rated internal yield strength.

The total weight of the intermediate casing was approximately 135,150 lbs, approximately 17 percent of the 804,000 lbs joint yield strength. The maximum internal pressure that this casing is expected to be exposed to is the cement column weight (15 lb/gal) of approximately 2,066 psi at the casing shoe. This value is approximately 66% of the rated internal yield strength of the J-55 casing.

The total weight of the long string casing was approximately 66,500 lbs, approximately 15% of the 442,000 lbs joint yield strength. The maximum external pressure that this casing would be expected to be exposed to is the full column cement weight (15 lb/gal) of approximately 2,250 psi at the casing shoe. This value is approximately 59% of the rated collapse resistance for this N-80 casing. The maximum anticipated operating pressure for the annulus is 3,000 psi, approximately 48% of the rated internal yield strength for the N-80 casing.

The total weight of the 4 ½-inch injection string is approximately 33,500 lbs, approximately 15% of the 223,000 lbs joint yield strength. The maximum external pressure that this casing is expected to be exposed to is the maximum anticipated operating pressure for the annulus system of 3,000 psi which is approximately 47% of the rated collapse resistance for this casing. The maximum internal pressure that this casing is expected to be exposed to is the maximum permitted wellhead pressure (WHP) of 825 psig (BHP = 2,131 psig) which is approximately 28% of the rated internal yield strength for this N-80 casing.

WDW No. 1, WDW No. 2, WDW No. 3

The technical specifications for the casing strings employed in WDW No. 1 and WDW No. 2 are summarized in the table below. The maximum stresses expected for these casing strings versus the design ratings are summarized in Table 7-2. The 10-3/4-inch and 7-inch casing strings in WDW No. 3 are also described in the table below. Stresses and design ratings for the liner and the injection tubing that were installed in Well No. 3 in January 2010 are provided in Table 7-2. These tables illustrate that the casing strings in the INEOS injection wells are conservatively overrated with respect to the maximum burst and collapse pressures at the maximum tensile stress which may be experienced during the construction, operation, and closure of the well(s).

Casing Diameter (in.)	Casing Grade	Wt Per Ft w/Coupling (lb/ft)	Inside Diameter (in.)	Drift Diameter (in.)	O.D. of Coupling (in.)	Collapse Resistance (psi)	Internal Yield (psi)	Body Yield (Klbs)	Joint Strength (Klbs)
10¾	H-40	32.75	10.192	10.036	11.750	880	1,820	367	205
7	J-55	20.0	6.456	6.331	7.656	2,270	3,740	316	234
4½	N-80	11.6	4.000	3.875	5.000	6,350	7,780	267	223

Standard Class A cement with appropriate additives to maximize the quality of the cement job were used in the various casing cement programs. INEOS experience with the waste stream indicates no reactions between the waste and the standard cement. The waste stream is a highly buffered ammonium sulfate brine stream with a neutral to slightly acidic pH. No reactions are predicted between the waste stream and the cements. This is confirmed by the latest INEOS MIT results that demonstrate the absence of significant vertical flow at the well casing shoes in WDW No. 1, WDW No. 2, and WDW No. 3 over 35 years of continuous operation in the current service.

The four INEOS injection wells employ general purpose packers to make an isolated annulus between the long string casing and the injection string. A three-piece packing element system is sealed against the long string casing by a dual lock ring system in conjunction with opposing non-transferring slips to maintain positive pack-off. The packer used in Well Nos. 1, 2 and 4 is a Baker

Model "A" "Retrieva-D" casing packer. This packer is set with either a wireline setting tool or by using a casing workstring, and can be released from the casing with a wireline retrieving 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 4 ½-inch LTC pin down. The technical specifications for this packer can be found in Appendix 7-2 that includes pages from the Baker technical manual. Sections of 4 ½-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.

	Bottom of Casing (ft KB)	Top of Packer (ft KB)	Bottom of Packer (ft KB)	Bottom of Tailpipe (ft KB)
WDW No. 1	2783	2757	2765	2808
WDW No. 2	2813	2784	2792	2864
WDW No. 3	2813	2793	2805	2831
WDW No. 4	2885	2862	2869	2914

A seal assembly is installed on the bottom of the 4 ½-inch injection string. 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 ½ 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 4 ½-inch injection string, minimizing tensile stresses on the casing. Details of the packer and seal assemblies are contained on Drawings 7-5 through 7-8. 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.

In the January 2010 workover of WDW No. 3, a full-length 5 ½-inch liner was installed and cemented. A new string of 3 ½-inch injection tubing, internally coated with TK-69, and new Baker Model "FB-1" packer were installed. Details of the new casing, tubing, and packer are provided in Tables 7-1 and 7-2, and shown on Drawing 7-1.

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 is 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.

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 17, 1995.

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 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 most recent 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 is included with reports of the most recent mechanical integrity testing on WDW No. 1, WDW No. 2, WDW No. 3, and WDW No. 4 that 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 Monitoring Plan in a letter dated March 17, 1995.

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 in the reports of the most recent mechanical integrity testing on WDW No. 1, WDW No. 2, WDW No. 3, and WDW No. 4 that are included in Appendix 7-6. These latest Mechanical Integrity Demonstrations have been reviewed and approved by the Ohio EPA.

WDW 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 was conducted that included a comprehensive logging suite, obtaining over 2,250 ft of 4-inch diameter core, drill stem testing, and performing an interference test to establish hydrogeologic properties of the gross Mt. Simon injection interval. Details on the casing program are provided in Table 7-1 and well material specifications are described in this chapter.

Table 7-1

Well Design and Construction of the INEOS Injection Wells

	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

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 1½% 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	5-in. O.D., 18 lb/ft, R-3 flush joint carbon steel liner @ 2820 ft	N/A	5 ½-in. O.D., 15.5 lb/ft, J-55, R-3 @ 2813 ft.	N/A
Tubing	4½-in., 11.60 lb/ft, N-80 Internally Coated withTK-15 Epoxy Coating @ 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-15 Epoxy Coating @ 2862 ft
Packer	Baker Model "A" Retrieva D with seal locator assembly Top @ 2757 ft	Baker Model "A" Retrieva D with seal locator assembly Top @ 2790 ft	Baker Model "FB-1" packer with seal locator assembly Top @ 2793 ft	Baker Model "A" Retrieva D with seal locator assembly Top @ 2862 ft
Bottom of Tail Pipe	2840 ft	2829 ft	2831 ft	2900 ft
Annulus	Inhibited NaCl brine with pH adjusted to 10	Inhibited NaCl brine with pH adjusted to 10	Inhibited NaCl brine with pH adjusted to 10	Inhibited NaCl brine with pH adjusted to 10

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 7-2

CASING RATINGS VERSUS MAXIMUM STRESSES

Casing	Maximum External Pressure (psi)	Rated Collapse Resistance (psi)	Maximum % of Rating (%)	Maximum Internal Pressure (psi)	Rated Internal Yield (psi)	Maximum % of Rating (%)	String Weight (Klb)	Rated Joint Strength (KLB)	Maximum % of Rating (%)
WDW Nos. 1 and 2									
10 ¾", 32.75 lb/ft, H-40	175 [a]	880	20	400 [b]	1,820	22	16.5	205	8
7", 20.0 lb/ft, J-55	975 [a]	2,270	43	2,890	3,740	77	56.4	234	24
4 ½", 11.6 lb/ft, N-80 [c]	2,890	6,350	46	2,140	7,780	27	32.7	223	15
WDW No. 3									
10 ¾", 32.75 lb/ft, H-40	175	880	20	400 [b]	1,820	22	16.5	205	8
7", 20.0 lb/ft, J-55	975	2,270	43	2,890	3,740	77	56.4	234	24
5 ½", 15.5 lb/ft, J-55	2,281 [e]	4,040	57	3,000	4,810	62	43.1	217	20
3 ½", 9.3 lb/ft, J-55 [d]	3,000	7,400	41	2,150	6,980	31	25.9	109	24
WDW No. 4									
16" 65.0 lb/ft, H-40	275 [a]	670	41	585 [b]	1,640	35	45.7	439	10
10 ¾" 51.0 lb/ft, L-80	920 [a]	3,220	29	2,066 [e]	5,860	35	135.2	804	17
10 ¾" 40.5 lb/ft, J-55	920 [a]	1,580	59	2,066 [e]	3,130	66	135.2	420	32
7" 23.0 lb/ft, N-80	2,250 [e]	3,830	59	3,000	6,340	48	66.5	442	15
4 ½" 11.6 lb/ft, N-80 [c]	3,000	6,350	47	2,150	7,780	28	33.5	223	15

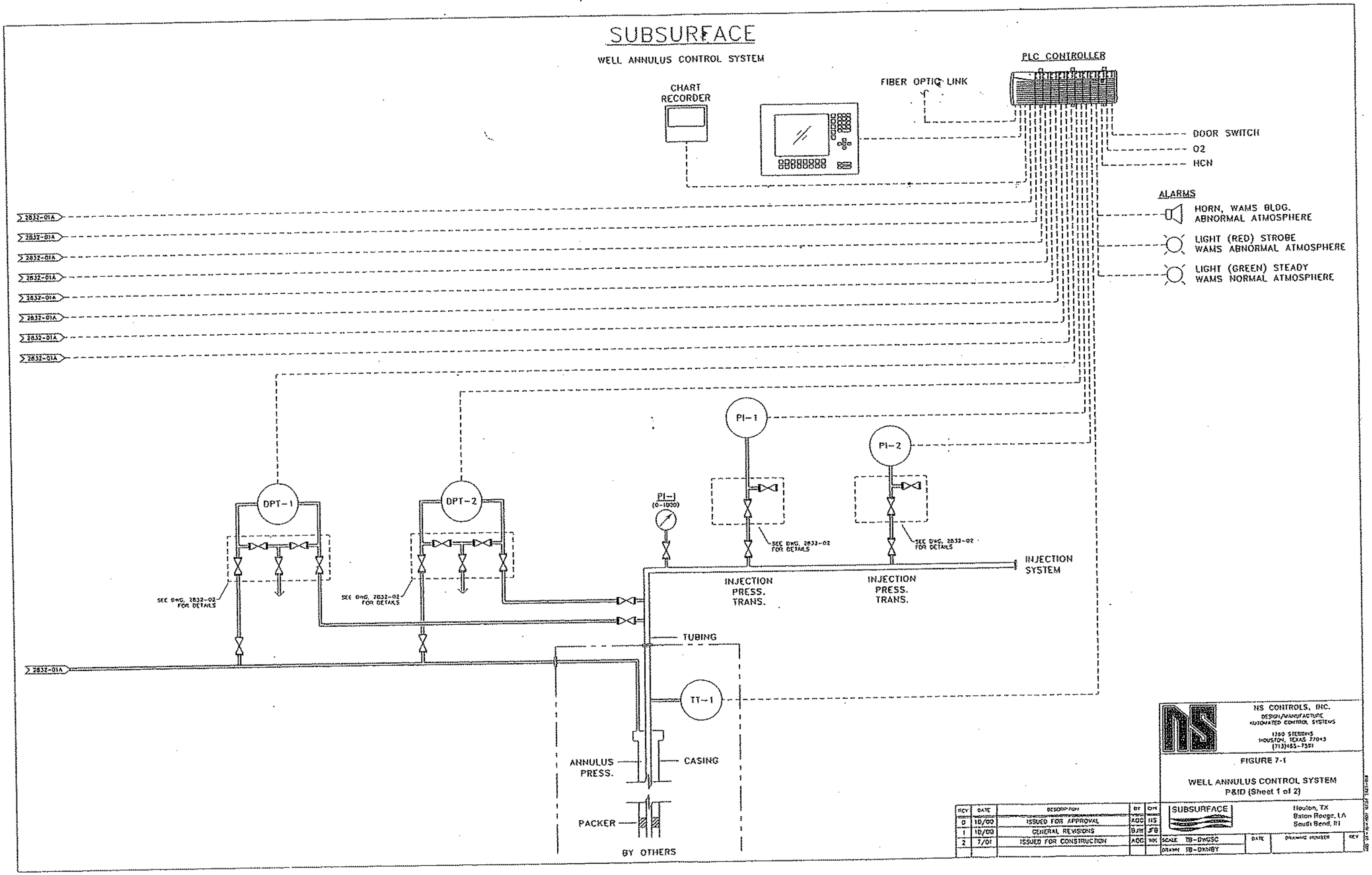
[a] Differential between cement column and fresh water column (0.35 psi/ft = 0.78 psi/ft – 0.43 psi/ft).

[b] Full cement column (15.6 lb/gal x 0.052 psi/ft / lb/gal = 0.811 psi/ft).

[c] Internally coated with TK-15 thick film coating.

[d] Internally coated with TK-69.

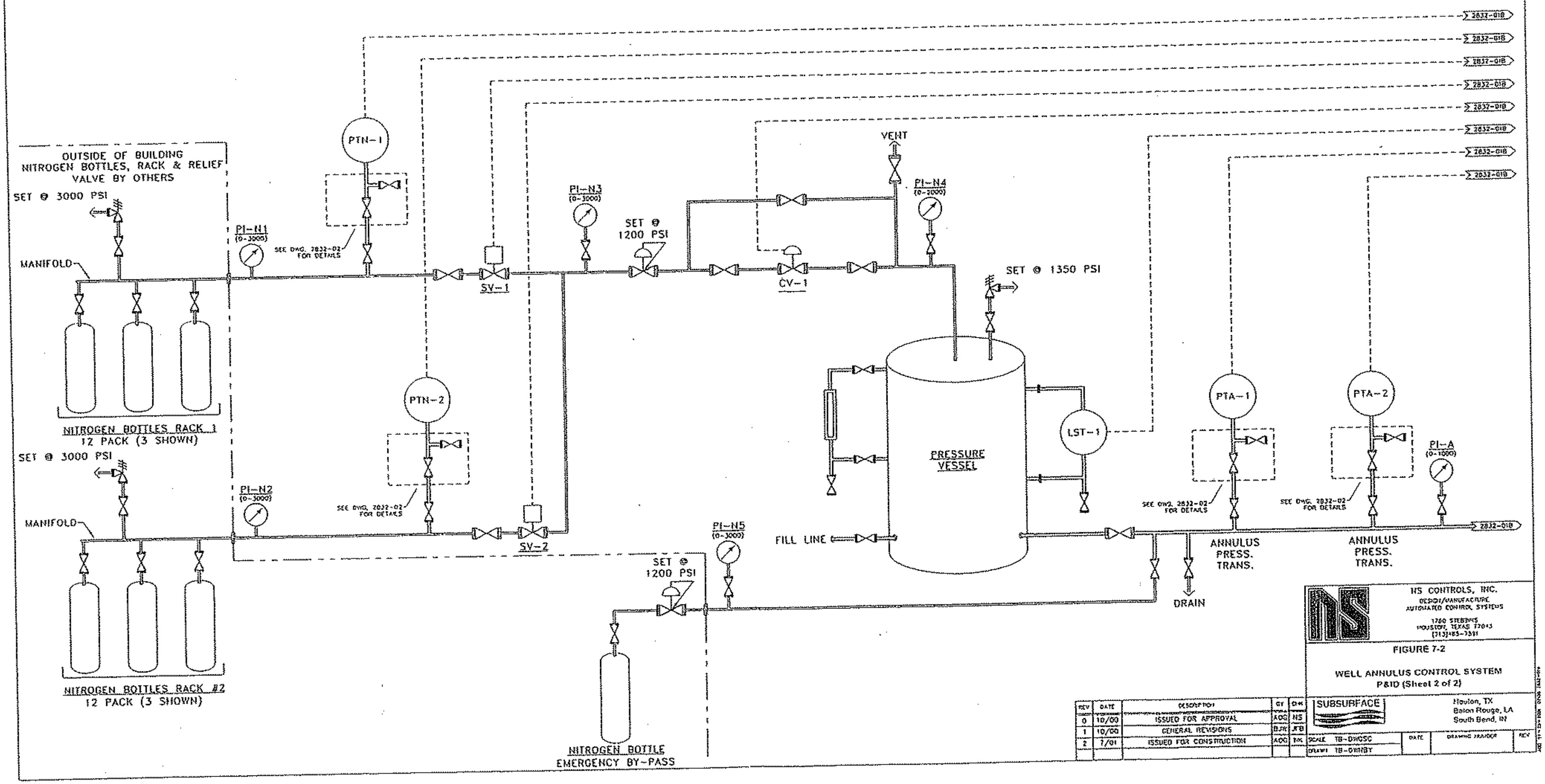
[e] Full cement column (15 lb/gal x 0.052 psi/ft / lb/gal = 0.78 psi/ft.)



REV	DATE	DESCRIPTION	BY	CHK
0	10/00	ISSUED FOR APPROVAL	ADC	NS
1	10/00	GENERAL REVISIONS	BJR	JFB
2	7/01	ISSUED FOR CONSTRUCTION	ADC	RK

SUBSURFACE

WELL ANNULUS CONTROL SYSTEM



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

INEOS USA LLC
Lima, Ohio
WDW #2

ATTACHMENT D

I. OPERATION AND MONITORING REQUIREMENTS
II. INJECTION WELL MONITORING SYSTEM
III. WASTES PERMITTED TO BE DISPOSED IN INEOS USA LLC CLASS I INJECTION WELLS

ATTACHMENT D

I. Operation and Reporting Requirements

OPERATING, MONITORING AND REPORTING REQUIREMENTS
WDW #2

CHARACTERISTIC REQUIREMENTS	LIMITATION		MINIMUM MONITORING REQUIREMENTS	MINIMUM REPORTING REQUIREMENTS
	Maximum	Minimum	Frequency	Frequency
*Maximum Allowable Injection Pressure Not to be exceeded	839 psig		continuous	
*Bottomhole Pressure (max)	2100 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 [Injected Fluid] combined wastestream			quarterly	monthly
****MEK concentration in Fort Amanda wastestream			quarterly	monthly

*Injection Pressure: MASIP = 2800 x [0.75 - (0.433 x 1.04)] where:
0.75 = applied fracture gradient in psi/ft
1.04 = fluid specific gravity (maximum)
2800 = 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:

$$BHP_{max} = (0.75)\ (2800)$$

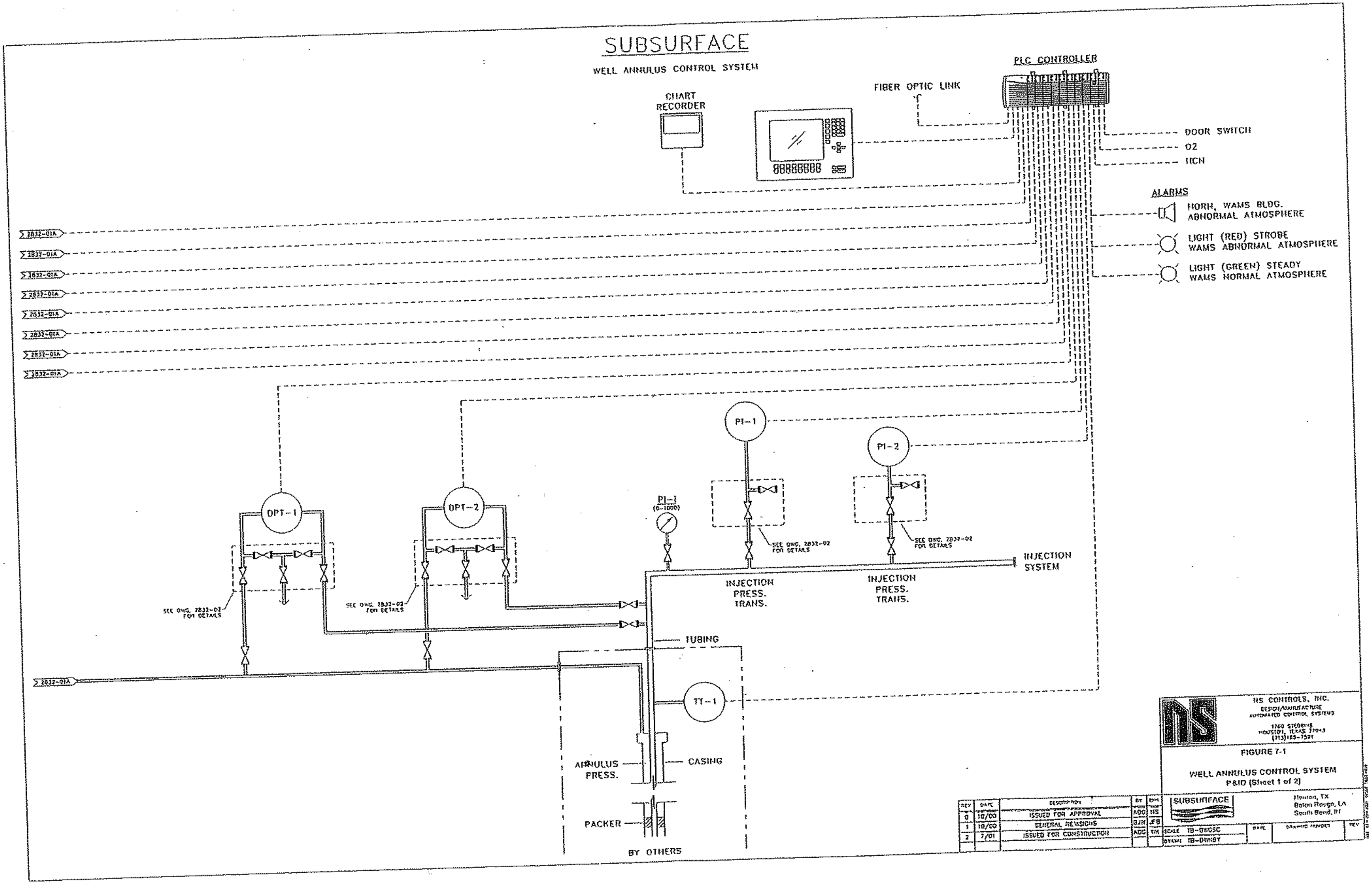
**Flow Volume: The combined monthly injection volume for the site must not exceed 24 million gallons.

*** 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

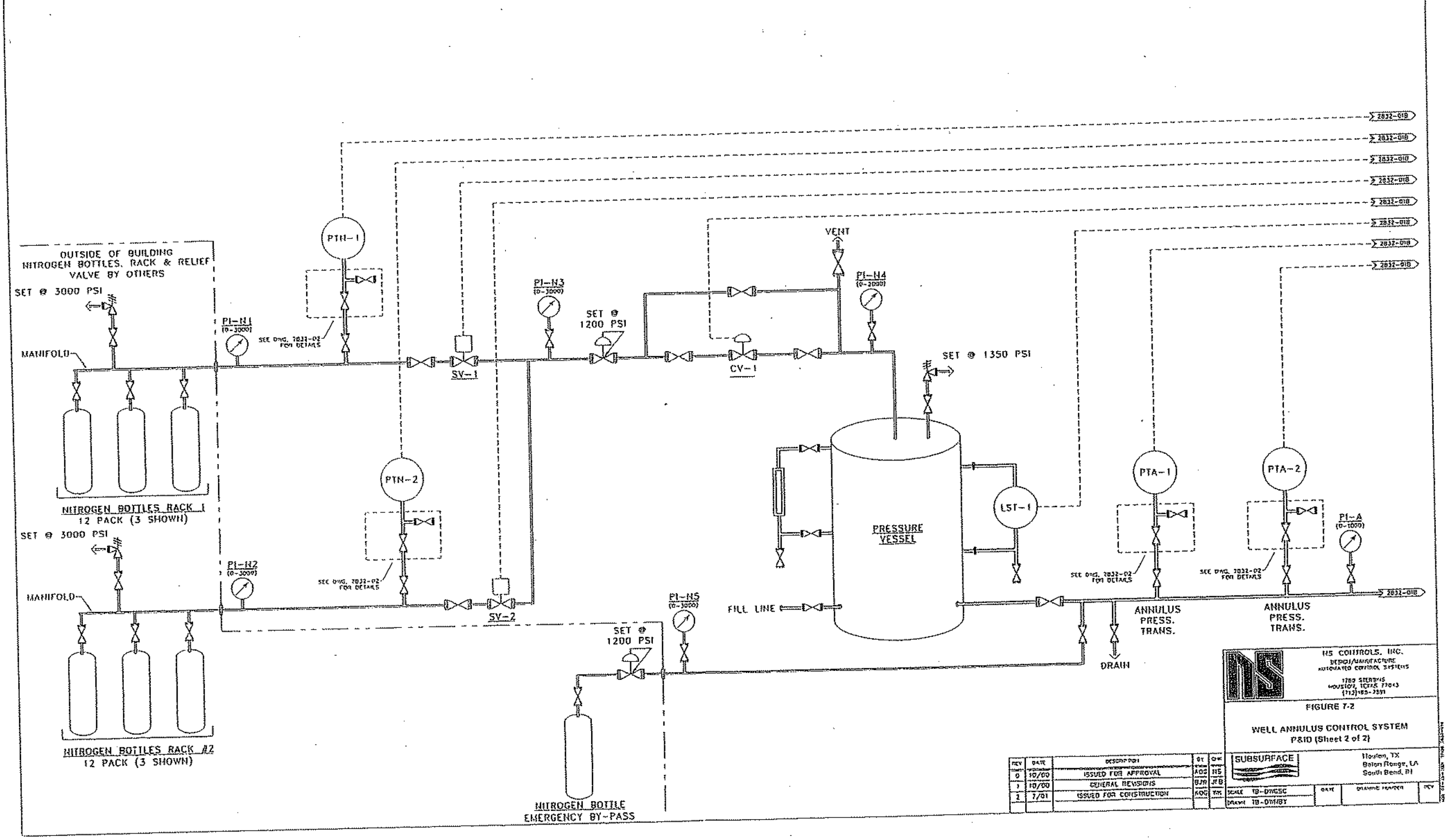
ATTACHMENT D

II. Injection Well Monitoring System


SUBSURFACE
WELL ANNULUS CONTROL SYSTEM
CHART RECORDER
FIBER OPTIC LINK
PLC CONTROLLER
DOOR SWITCH
O2
HCN
ALARMS
HORN, WAMS BLDG. ABNORMAL ATMOSPHERE
LIGHT (RED) STROBE WAMS ABNORMAL ATMOSPHERE
LIGHT (GREEN) STEADY WAMS NORMAL ATMOSPHERE
2832-01A
DPT-1
DPT-2
PI-1
PI-1 (0-1000)
PI-2
SEE DWG. 2832-02 FOR DETAILS
INJECTION SYSTEM
INJECTION PRESS. TRANS.
TUBING
TT-1
ANNULUS PRESS.
CASING
PACKER
BY OTHERS
NS CONTROLS, INC.
DESIGN/MANUFACTURE AUTOMATED CONTROL SYSTEMS
FIGURE 7-1
WELL ANNULUS CONTROL SYSTEM
P&ID (Sheet 1 of 2)
SUBSURFACE
Houston, TX
Baton Rouge, LA
South Bend, IN
REV
DATE
DESCRIPTION
BY
CHK
0 10/00 ISSUED FOR APPROVAL
1 10/00 GENERAL REVISIONS
2 7/01 ISSUED FOR CONSTRUCTION
SCALE
DATE
DRAWING NUMBER

SUBSURFACE

WELL ANNULUS CONTROL SYSTEM



ATTACHMENT D

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

Table 2B-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 drying column from the production of acetonitrile;
- Condensed overhead streams from the production of acetonitrile;
- Crude-Offspec 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;
- Offspec products from the manufacture of acrylonitrile (U009/P063);
- Unsaleable co-product acetonitrile from the manufacture of acetonitrile (U003);
- Contaminated groundwater and multi-source leachate (F039);
- Ammonia blowdown;
- Scrubber water;
- Slopwater from the acrylonitrile process area;
- Contaminated Stormwater from the process area;
- Pump seal water from the acrylonitrile process area;
- Water from the loading / unloading area sump;
- Contaminated groundwater;
- Contaminated water from site remediation activities;
- Equipment washwater;
- Laboratory chemicals;
- Wastewaters generated during maintenance activities in the nitriles area;
- Wastewater from the manufacture of cyanide derivatives at Fort Amanda Specialties including washwaters, slopwaters, lab chemicals, etc.

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	-	Cyanides
D004	-	Arsenic
D005	-	Barium
D006	-	Cadmium
D007	-	Wastewaters containing more than 5 mg/l chromium;
D008	-	Lead
D009	-	Mercury
D010	-	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
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

De Minimus Laboratory/Process Waste

		CAS #
Cyclohexanone	U057	108-94-1
Acetaldehyde	U001	75-07-0
Allyl alcohol	P005	107-18-6
Carbon tetrachloride	U211	56-23-5
Chloroform	U044	67-66-3
Crotonoaldehyde	U053	4170-30-3
Ethyl acetate	U112	141-78-6
Formic acid	U123	64-18-6
Furfural	U125	98-01-1
Furan	U124	110-00-9
Isobutyl alcohol	U140	78-83-1
Mercury	U151	7139-97-6
Methacrylonitrile	U152	126-98-7
Methyl ethyl kerone	U159	78-93-3
Methylene chloride	U080	75-09-2
Methyl isobutyl kerone	U161	108-10-1
Nitrobenzenc	U169	78-93-3
Phenol	U188	108-95-2
Potassium cyanide	P098	151-50-0
Sodium cyanide	P106	143-33-9
Tetrahydrofuran	U123	109-99-9
Thiourea	U219	62-56-6
Toluene	U220	108-88-3
Xylene	U239	1330-20-7
Characteristic Wastes	D001-D011	

Table 2B-3

Typical and Maximum Concentrations of the Main Contaminants of the Comingled 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[1]	64-18-6	5,000[1]	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	928-53-0	5,000	300
Methanol	67-56-1	10,000	60
Methyacrylonitrile	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-Cyanopyridine)	100-54-9	1,500	500
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	100	0.05

Parameter	CAS #	Maximum Assumed Concentrations* (mg/l)	Typical Measured Concentration (mg/l)
Vanadium Pentoxide	1314-62-1	100	<10
Glycolonitrile	107-16-4	1,000	15
Nitrilotriacetonitrile (or acid)	7327-60-8	250	15
Hexamethylenetetramine (or acid)	100-97-0	250	15
IDAN (or acid)	628-87-5	250	15
DMH	77-71-4	250	15
MEH	5394-36-5	250	15
EDTN (or acid)	5766-67-6	250	15
PDTN (or acid)	11057-45-9	250	15
Ethyl Acetate	141-78-6	25	15
Oleic Acid	112-80-1	250	15
Oleoylsarconsinate	110-25-8	250	15
Diethylenetriaminepentaacetic acid	85959-68-8	250	15
1,4-Butanediol 110-63-4		3,500	<50
1,3-Butanediol 107-88-0		250	<50
1,3-Propanediol 504-63-2		500	<50
1,2-Propanediol 57-55-6		15	<50
Butyrolactone 96-48-0		1,250	<50
Tetrahydrofuran -109-99-9		1,250	<50
Ethanol - 64- 17-5		500	<50
Propanol 71-23-8		500	<50
Butanol 71- 36-3		1,000	<50
Butanetriol ?		1,000	<50
Succinic Acid - 110-15-6		200	<50

* Assumed Monthly maximum average concentration

Table 2B-5
Maximum Injection, Health-Based Limit, and Relative Concentration for Major Constituents in the Injectate
(Revised 12/01/94 Based on Worst-Case Addition of Hampshire Wastewater Streams)

Constituent	CAS Number	EPA Hazardous Waste Code	Maximum Injection Concentration[1] (mg/L)	Health-Based Limit Concentration[2] (mg/L)	Source for HBL	Detection Limit (mg/L)	Reference Molecule	SW-846 Test Method[3]	Concentration Reduction Factor
Acetaldehyde	75-07-0	U001	500			0.005	Acrolein	8240	1.0×10^{-9}
Acetamide[4]	60-35-5	—	2500			0.2		BF Method	8.0×10^{-9}
Acetic Acid[4]	64-19-7	—	1500			1.0		BF Method	6.7×10^{-5}
Acetone	67-64-1	U002	500	0.1	RfD				2.0×10^{-4}
Acetone Cyanohydrin	75-86-5	P069	1500			0.1	Propionitrile	8240	6.7×10^{-9}
Acetonitrile	75-05-8	U003	25,000	0.2	RfD				8.0×10^{-6}
Acrolein	107-02-8	P003	500			0.005		8240	1.0×10^{-4}
Acrylamide	79-06-1	U007	1500	9.0×10^{-6}	RSD				6.0×10^{-9} (5)
Acrylic Acid	79-10-7	U008	15000	0.08	RfD				5.3×10^{-6}
Acrylonitrile	107-13-1	U009	6000	7.0×10^{-5}	RSD				1.2×10^{-9}
Allyl Alcohol	107-18-6	P005	500	0.005	RfD				1.0×10^{-5}
Antimony	7440-36-0	F039	25	0.006	MCL				2.4×10^{-4}
Arsenic	7440-38-2	D004	25	0.05	MCL				2.0×10^{-3}
Barium	7440-39-3	D005	25	2.0	MCL				8.0×10^{-2}

Table 2B-5 (continued)
Maximum Injection, Health-Based Limit, and Relative Concentration for Major Constituents in the Injectate
(Revised 12/01/94 Based on Worst-Case Addition of Hampshire Wastewater Streams)

Constituent	CAS Number	EPA Hazardous Waste Code	Maximum Injection Concentration[2] (mg/L)	Health-Based Limit Concentration[2] (mg/L)	Source for HBL	Detection Limit (mg/L)	Reference Molecule	SW-846 Test Method[7]	Concentration Reduction Factor
Benzene	71-43-2	D018, U019	100	0.005	MCL				5.0×10^{-5}
Cadmium	7440-43-9	D006	25	0.005	MCL				2.0×10^{-4}
Carbon Tetrachloride[6]	56-23-5	U211	25	0.005	MCL				2.0×10^{-4}
Chloroform[6]	67-66-3	U044	25	0.1	MCL				4.0×10^{-3}
Chromium	7440-47-3	D007	25	0.1	MCL				4.0×10^{-3}
Cobalt[6]	7440-48-4	—	25			0.003			1.2×10^{-4}
Crotonaldehyde[6]	4170-30-3	U053	50			0.005	Acrolein	8240	1.0×10^{-4}
Crotonitrile[6]	109-75-1	—	250			0.2		BP Method	8.0×10^{-4}
Cyanide Salts	N/A	P030	2000			0.02		9010	1.0×10^{-5}
Cyclohexane[6]	110-82-7	U056	25	0.005					2.0×10^{-4}
Cyclohexanone[6]	108-94-1	U057	25	5.0	RfD				2.0×10^{-1}
Dimethylhydantoin (DMH)[6][7]	77-71-4	—	250			1.0		BP Method	4.0×10^{-3}
Ethyl Acetate[6]	141-78-6	U112	25	0.9	RfD				3.6×10^{-2}
Ethylenediamine Tetracetonitrile (EDTN)[6][7]	5766-67-6	—	250			1.0		BP Method	4.0×10^{-3}

Table 2B-5 (continued)
Maximum Injection, Health-Based Limit, and Relative Concentration for Major Constituents in the Injectate
(Revised 12/01/94 Based on Worst-Case Addition of Hampshire Wastewater Streams)

Constituent	CAS Number	EPA Hazardous Waste Code	Maximum Injection Concentration[2] (mg/L)	Health-Based Limit Concentration[3] (mg/L)	Source for HBL	Detection Limit (mg/L)	Reference Molecule	SW-846 Test Method[5]	Concentration Reduction Factor
Formaldehyde	50-00-0	U122	1000	0.2	RfD				2.0 x 10^{-4}
Formamide[4]	75-12-7	—	250	0.2	(8)				8.0 x 10^{-4}
Formic Acid	64-18-6	U123	5000			0.009		8250	1.8 x10^{-6}
Fumaronitrile[4]	17656-09-6	—	1000			0.2		BP Method	2.0 x 10^{-4}
Furan[2]	110-00-9	U124	25	0.001	RfD				4.0 x 10^{-5}
Furfural[3]	98-01-1	U125	25	0.003	RfD				1.2 x 10^{-4}
Glycolonitrile[4]	107-16-4	—	1000			0.2		BP Method	2.0 x 10^{-4}
Hydrogen Cyanide, Free	67-56-1	—	800	0.02	(9)				2.5 x 10^{-5}
Hydrogen Cyanide, Total[4]	74-90-8	P063	5300	0.02	RSD				3.8 x 10^{-6}
Iminodiacetonitrile (IDAN)[4][7]	628-87-5	—	250			1.0		BP Method	4.0 x 10^{-3}
Isobutyl Alcohol[4]	78-83-1	U140	50	0.3	RfD				6.0 x 10^{-3}
Isopropyl Alcohol[4]	67-63-0	—	300	0.3	(10)				1.0 x 10^{-3}
Lead[4]	7439-92-1	D008	25			0.001		7421	4.0 x 10^{-5}
Maleic Anhydride[4]	108-31-6	U147	25	0.1	RfD				4.0 x 10^{-3}

Table 2B-5 (continued)

Maximum Injection, Health-Based Limit, and Relative Concentration for Major Constituents in the Injectate
(Revised 12/01/94 Based on Worst-Case Addition of Hampshire Wastewater Streams)

Constituent	CAS Number	EPA Hazardous Waste Code	Maximum Injection Concentration[1] (mg/L)	Health-Based Limit Concentration[2] (mg/L)	Source for HBL	Detection Limit (mg/L)	Reference Molecule	SW-846 Test Method[3]	Concentration Reduction Factor
Maleonitrile[9]	928-53-0	—	5000			0.2		BP Method	4.0×10^{-5}
Malononitrile	109-77-3	U149	500			0.005		8240	1.0×10^{-5}
Mercury[6]	7439-97-6	U151,D009	25	0.002	MCL				8.0×10^{-5}
Methanol	67-56-1	U154, F003	10,000	0.5	RfD				5.0×10^{-5}
Methylacrylonitrile	126-98-7	U152	100	1.0×10^{-4}	RfD				1.0×10^{-4}
Methylene Chloride[5]	75-09-2	U080	25	0.005	MCL				2.0×10^{-4}
Methyl Ethyl Ketone	78-93-3	U159, D035, F005	250	0.6	RfD				2.4×10^{-3}
Methylethylhydantoin (MEH)[8][7]	5394-36-5	—	250			1.0		BP Method	4.0×10^{-3}
Methyl Isobutyl Ketone[9]	108-10-1	U161	25			0.005		8015	2.0×10^{-4}
Methyl Pyridine[11]	108-99-6	U191	250			0.005		8240	2.0×10^{-3}
Nickel	7440-02-0	F006	25	0.1	MCL				4.0×10^{-3}
Nicotinonitrile[9]	100-54-9	—	1500	0.1	(12)				6.7×10^{-5}
Nitrilotriacetonitrile(NTAN)[8][7]	7327-60-8	—	250			1.0		BP Method	4.0×10^{-3}
Nitrobenzene[9]	98-95-3	U169	25	5.0×10^{-4}	RfD				2.0×10^{-5}

Table 2B-5 (continued)
Maximum Injection, Health-Based Limit, and Relative Concentration for Major Constituents in the Injectate
(Revised 12/01/94 Based on Worst-Case Addition of Hampshire Wastewater Streams)

Constituent	CAS Number	EPA Hazardous Waste Code	Maximum Injection Concentration[1] (mg/L)	Health-Based Limit Concentration[2] (mg/L)	Source for HBL	Detection Limits (mg/L)	Reference Molecule	SW-846 Test Method[3]	Concentration Reduction Factor
Oleic Acid[4][7]	112-80-1	—	250			1.0		BP Method	4.0×10^{-3}
Oleoylsarcosinate[4][7]	110-25-8	—	250			1.0		BP Method	4.0×10^{-3}
Phenol[3]	108-95-2	U188	25	0.6	RfD				2.4×10^{-3}
Potassium Cynnide[3]	151-50-8	P098	25	0.05	RfD				2.0×10^{-3}
Propionitrile	107-12-0	P101	500			0.1		8240	2.0×10^{-6}
Propylenediamine Tetracetonitrile (PDTN)[4][7]	110057-45-9	—	250			1.0		BP Method	4.0×10^{-3}
Pyrazole[4]	288-13-1	—	1000			0.04		BP Method	4.0×10^{-3}
Pyridine	110-86-1	D038, U196	500	0.001	RfD				2.0×10^{-4}
Selenium	7782-49-2	D010	25	0.05	MCL				2.0×10^{-3}
Silver	7440-22-4	D011	25	0.005	RfD				2.0×10^{-4}
Sodium Cynnide[4]	143-33-9	P106	300	0.04	RfD				1.3×10^{-1}
Stroutium[4]	7440-24-6	—	25			0.005			2.0×10^{-1}
Succinonitrile[4][7]	110-61-2	—	1500	0.1	(12)				6.7×10^{-3}

Table 2B-5 (continued)
Maximum Injection, Health-Based Limit, and Relative Concentration for Major Constituents in the Injectate
(Revised 12/01/94 Based on Worst-Case Addition of Hampshire Wastewater Streams)

Constituent	CAS Number	EPA Hazardous Waste Code	Maximum Injection Concentration[1] (mg/L)	Health-Based Limit Concentration[2] (mg/L)	Source for HBL	Detection Limit (mg/L)[3]	Reference Molecule	SW-846 Test Method[3]	Concentration Reduction Factor
Tetrahydrofuran[4]	109-99-9	U213	25			0.005	4-methyl-2-pentanone	8015	2.0×10^{-4}
Thiourea[6]	62-56-6	U219	25	5.0×10^{-4}	RfD				2.0×10^{-5}
Toluene[6]	108-88-3	U220	25	1.0	MCL				4.0×10^{-3}
Vanadium	7440-62-2	—	25			0.004		7911	1.6×10^{-5}
Vanadium Pentoxide[6]	1314-62-1	P120	100	0.009	RfD				9.0×10^{-5}
Xylene[6]	1330-20-7	U239	25	1.0	MCL				4.0×10^{-3}
Zinc	7440-66-6	—	25	0.3					1.2×10^{-2}

(1) Monthly maximum average concentration for each constituent in the injectate stream.
(2) Source: U.S. EPA Region 6 Land Ban Health Based Guideline, July 6, 1994.
(3) SW-486 test method used to determine the detection limit of the injectate constituent or reference molecule.
(4) Not included in the U.S. EPA Region 6 Land Ban Health Based Guideline, July 6, 1994.
(5) The maximum magnitude of difference between the initial concentration of a constituent and its health-based limit is a reduction of 170,000,000 times for acrylamide.
(6) *de minimus* waste.
(7) Included for information only.
(8) A health-based limit is not established; the limit set for formaldehyde was used as representative.
(9) A health-based limit is not established; the limit set for hydrogen cyanide was used as representative.
(10) A health-based limit is not established; the limit set for isobutyl alcohol was used as representative.
(11) Combination of 2-picoline (109-06-8), 3-picoline (108-99-6), and 4-picoline (108-89-4).
(12) A health-based limit is not established; the detection limit set for propionitrile was used as representative.

(Cont'd)

Constituent	1991 Original				1992 Update				1994 Update			
	Maximum Injectate Conc. (ppm)	Health-Based Limit Conc. (ppm)	Lateral Diffusion Distance[1] (ft)	Total Lateral Distance to HBL Conc.[2] (ft)	Maximum Injectate Conc. (ppm)	Health-Based Limit Conc. (ppm)	Lateral Diffusion Distance[1] (ft)	Total Lateral Distance to HBL Conc.[2] (ft)	Maximum Injectate Conc. (ppm)	Health-Based Limit Conc. (ppm)	Lateral Diffusion Distance[1] (ft)	Total Lateral Distance to HBL Conc.[2] (ft)
Acetaldehyde[3]					500	0.2	4,105	21,295	500	0.005	7250	24,440
Acetamide[3]					1,000	0.2	4,820	22,010	2,500	0.2	5,650	22,840
Acetic Acid[3]									1,500	1.0	3,525	20,715
Acetone	50	4.0	–	15,180	500	4.0	–	17,395	500	0.1	4,820	22,010
Acetone Cyanohydrin[3]									1,500	0.1	5,805	22,995
Acetonitrile	15,000	0.2	7,050	24,240	15,000	0.2	7,045	24,235	25,000	0.2	7,400	24,590
Acrolein	500	0.5	3,010	20,200	500	0.005	7,250	24,440	500	0.005	7,250	24,440
Acrylamide	1,500	9.0×10^{-4}	11,390	28,580	1,500	9.0×10^{-4}	11,390	28,580	1,500	9.0×10^{-4}	11,390	28,580
Acrylic Acid[3]					15,000	1.0	5,805	22,995	15,000	0.08	7,675	24,865
Acrylonitrile	6,000	6.5×10^{-5}	11,115	28,305	6,000	6.0×10^{-5}	11,150	28,340	6,000	7.0×10^{-5}	11,075	28,265
Allyl Alcohol[3]									500	0.005	7,250	24,440
Antimony[3]					25	0.01	4,105	21,295	25	0.006	4,640	21,830
Arsenic	0.11	5.0×10^{-3}	–	12,000	25	0.05	1,975	19,165	25	0.05	1,975	19,165
Barium	0.018	0.005	–	13,200	25	0.005	4,820	22,010	25	2.0	–	15,180
Benzene	10	0.005	3,860	21,050	100	0.005	6,040	23,230	100	0.005	6,040	23,230
Cadmium[3]									25	0.005	4,820	22,010
Carbon Tetrachloride[3]									25	0.005	4,820	22,010
Chloroform[3]									25	0.1	595	17,785

Constituent	1991 Original				1992 Update				1994 Update			
	Maximum Injectate Conc. (ppm)	Health-Based Limit Conc. (ppm)	Lateral Diffusion Distance[1] (ft)	Total Lateral Distance to HBL Conc.[2] (ft)	Maximum Injectate Conc. (ppm)	Health-Based Limit Conc. (ppm)	Lateral Diffusion Distance[2] (ft)	Total Lateral Distance to HBL Conc.[2] (ft)	Maximum Injectate Conc. (ppm)	Health-Based Limit Conc. (ppm)	Lateral Diffusion Distance[2] (ft)	Total Lateral Distance to HBL Conc.[2] (ft)
Chromium	0.5	0.005	—	17,190	25	0.005	4,820	22,010	25	0.1	595	17,785
Cobalt	1	0.003	1,235	18,425	25	0.003	5,295	22,485	25	0.003	5,295	22,485
Crotonaldehyde[2]									50	0.005	5,455	22,645
Crotonitrile[2]					250	0.2	3,295	20,485	250	0.2	3,295	20,485
Cyanide Salts[2]									2,000	0.02	7,250	24,450
Cyclohexane[2]									25	0.005	4,820	22,010
Cyclohexanone[2]									25	5.0	—	13,980
Dimethylhydantoin (DMH)[2]									250	1.0	595	17,785
Ethyl Acetate[2]									25	0.9	—	16,435
Ethylenediamine Tetraacetonitrile (EDTN)[2]									250	1.0	595	17,785
Formaldehyde[2]					50	0.005	5,460	22,650	1,000	0.2	4,820	22,010
Formamide[2]									250	0.2	3,295	20,485
Formic Acid[2]									1,000	0.009	7,320	24,510
Fumaronitrile[2]					1,000	0.2	4,820	22,010	1,000	0.2	4,820	22,010
Furan[2]									25	0.001	6,220	23,410
Furfural[2]									25	0.003	5,295	22,485
Glycolonitrile[2]									1,000	0.2	4,820	22,010

Constituent	1991 Original				1992 Update				1994 Update			
	Maximum Injectate Conc. (ppm)	Health-Based Limit Conc. (ppm)	Lateral Diffusion Distance[1] (ft)	Total Lateral Distance to HBL Conc.[2] (ft)	Maximum Injectate Conc. (ppm)	Health-Based Limit Conc. (ppm)	Lateral Diffusion Distance[1] (ft)	Total Lateral Distance to HBL Conc.[2] (ft)	Maximum Injectate Conc. (ppm)	Health-Based Limit Conc. (ppm)	Lateral Diffusion Distance[1] (ft)	Total Lateral Distance to HBL Conc.[2] (ft)
Hydrogen Cynaide, free	800	0.7	3,185	20,375	800	0.7	3,185	20,375	800	0.02	6,580	23,770
Hydrogen Cynaide, total	8,000	0.7	5,575	22,765	8,000	0.7	5,575	22,765	5,300	0.02	7,900	25,090
Iminodiacetonitrile (IDAN)[4]									250	1.0	595	17,785
Isobutyl Alcohol[3]									50	0.3	–	17,640
Isopropyl Alcohol[3]									300	0.3	3,005	20,195
Lead[3]									25	0.001	6,220	23,410
Maleic Anhydride[3]									25	0.1	595	17,785
Maleonitrile	500	0.04	5,650	22,840	5,000	0.2	6,220	23,410	5,000	0.2	6,220	23,410
Malononitrile[3]					500	0.0042	7,370	24,560	500	0.005	7,250	24,440
Mercury[3]									25	0.002	5,650	22,840
Methanol[3]					1,000	20.0	–	16,890	10,000	0.5	6,040	23,230
Methylacrylonitrile[3]					100	0.004	6,220	23,410	100	1.0×10^{-4}	8,720	25,910
Methylene Chloride[3]									25	0.005	4,820	22,010
Methylethylhydantoin (MEH)[4]									250	1.0	595	17,785
Methyl Ethyl Ketone[3]									250	0.6	1,655	18,845
Methly Isobutyl Ketone[3]									25	0.005	4,820	22,010
Methyl Pyridine	10	0.04	595	17,785	250	0.04	5,030	22,220	250	0.005	6,750	23,940
Nickel	2	0.01	–	17,760	25	0.01	4,110	21,300	25	0.1	595	17,785

Constituent	1991 Original				1992 Update				1994 Update			
	Maximum Injectate Conc. (ppm)	Health-Based Limit Conc. (ppm)	Lateral Diffusion Distance[1] (ft)	Total Lateral Distance to HBL Conc.[2] (ft)	Maximum Injectate Conc. (ppm)	Health-Based Limit Conc. (ppm)	Lateral Diffusion Distance[1] (ft)	Total Lateral Distance to HBL Conc.[2] (ft)	Maximum Injectate Conc. (ppm)	Health-Based Limit Conc. (ppm)	Lateral Diffusion Distance[1] (ft)	Total Lateral Distance to HBL Conc.[2] (ft)
Nicotinonitrile[3]					1,500	0.2	5,200	22,390	1,500	0.1	5,805	22,995
Nitrilotriacetonitrile (NTAN)[4]									250	1.0	595	17,785
Nitrobenzene[3]									25	5.0×10^{-4}	6,750	23,940
Oleic Acid[4]									250	1.0	595	17,785
Oleoylsarcosinate[4]									250	1.0	595	17,785
Phenol[3]									25	0.6	–	16,775
Potassium Cyanide[3]									25	0.05	1,975	19,165
Propionitrile	200	0.05	4,600	21,790	500	0.005	7,250	24,440	500	0.1	4,820	22,010
Propylenediamine Tetraacetonitrile (PDTN)[4]									250	1.0	595	17,785
Pyrrole[3]					1,000	0.04	6,220	23,410	1,000	0.04	6,220	23,410
Pyridine	200	0.04	4,820	22,010	500	0.04	5,650	22,840	500	0.001	8,305	25,495
Selenium[3]									25	0.05	1,975	19,165
Silver[3]									25	0.005	4,820	22,010
Sodium Cyanide[3]									300	0.04	5,195	22,385
Strontium	0.7	0.005	–	17,520	25	0.005	4,820	22,010	25	0.005	4,820	22,010
Succinonitrile[3]					1,500	0.2	5,200	22,390	1,500	0.1	5,805	22,995
Tetrahydrofuran[3]									25	0.005	4,820	22,010

Constituent	1991 Original				1992 Update				1994 Update			
	Maximum Injectate Conc. (ppm)	Health-Based Limit Conc. (ppm)	Lateral Diffusion Distance[1] (ft)	Total Lateral Distance to HBL Conc.[2] (ft)	Maximum Injectate Conc. (ppm)	Health-Based Limit Conc. (ppm)	Lateral Diffusion Distance[1] (ft)	Total Lateral Distance to HBL Conc.[2] (ft)	Maximum Injectate Conc. (ppm)	Health-Based Limit Conc. (ppm)	Lateral Diffusion Distance[1] (ft)	Total Lateral Distance to HBL Conc.[2] (ft)
Thiourea[3]									25	5.0×10^{-5}	8,305	25,495
Toluene[5]									25	1.0	—	16,320
Vanadium	0.05	0.002	595	17,785	25	0.002	5,650	22,840	25	0.004	5,030	22,220
Vanadium Pentoxide[4]									100	0.009	5,545	22,735
Xylene[5]									25	1.0	—	16,320
Zinc	0.056	0.004	—	15,360	25	0.004	5,030	22,220	25	0.3	—	17,130

[1] Incremental diffusion distance from the 0.01 relative concentration contour to the health-based limit concentration.
[2] Taken as the modeled distance to the 0.01 contour times 1.2 plus the lateral diffusion distance. Section 8.6.1.1 of the petition document explains why the model distance was multiplied by a factor of 1.2.
[3] New compound since 1992.
[4] Included for information only.
[5] New compound since 1993.

Constituent	1991 Original Modeling				1992 Update				1994 Update			
	Maximum Injectate Conc. (ppm)	Health-Based Limit Conc. (ppm)	Vertical Diffusion Distance (ft)	Depth to HBL Conc. (ft)	Maximum Injectate Conc. (ppm)	Health-Based Limit Conc. (ppm)	Vertical Diffusion Distance (ft)	Depth to HBL Conc. (ft)	Maximum Injectate Conc. (ppm)	Health-Based Limit Conc. (ppm)	Vertical Diffusion Distance (ft)	Depth to HBL Conc. (ft)
Acetaldehyde[1]					500	0.2	124.5	2515.5	500	0.005	155.3	2484.7
Acetamide[1]					1,000	0.2	117.2	2522.8	2,500	0.2	124.4	2515.6
Acetic Acid[2]									1,500	1.0	108.1	2531.9
Acetone	50	4.0	54.5	2585.5	500	4.0	82.5	2557.5	500	0.1	115.7	2524.3
Acetone Cyanohydrin[2]									1,500	0.1	112.9	2527.1
Acetonitrile	15,000	0.2	162.2	2477.8	15,000	0.2	162.1	2477.9	25,000	0.2	166.3	2473.7
Acrolein	500	0.5	107.6	2532.4	500	0.005	144.4	2495.6	500	0.005	144.4	2495.6
Acrylamide[4]	1,500	9.0×10^{-6}	176.4	2463.6	1,500	9.0×10^{-6}	175.5	2464.5	1,500	9.0×10^{-6}	175.5	2464.5
Acrylic Acid[1]					15,000	1.0	126.3	2513.7	15,000	0.08	139.2	2500.8
Acrylonitrile	6,000	6.5×10^{-5}	183.3	2456.7	6,000	6.0×10^{-5}	183.7	2456.3	6,000	7.0×10^{-5}	182.7	2457.3
Allyl Alcohol[2]									500	0.005	139.3	2500.7
Antimony[1]					25	0.1	92.9	2547.1	25	0.006	96.4	2543.6
Arsenic[3]	0.11	0.05	16.9	2623.1	25	0.05	69.8	2570.2	25	0.05	85.0	2555.0
Barium	0.018	0.005	29.0	2611.0	25	0.005	99.0	2541.0	25	2.0	46.6	2593.4
Benzene	10	0.005	101.7	2538.3	100	0.005	118.4	2521.6	100	0.005	118.4	2521.6
Cadmium[2]									25	0.005	91.0	2549.0
Carbon Tetrachloride[2]									25	0.005	103.9	2536.1
Chloroform[2]									25	0.1	85.2	2554.8
Chromium	0.5	0.005	57.2	2582.8	25	0.005	82.8	2557.2	25	0.1	64.1	2575.9

Constituent	1991 Original Modeling				1992 Update				1994 Update			
	Maximum Injectate Conc. (ppm)	Health-Based Limit Conc. (ppm)	Vertical Diffusion Distance (ft)	Depth to HBL Conc. (ft)	Maximum Injectate Conc. (ppm)	Health-Based Limit Conc. (ppm)	Vertical Diffusion Distance (ft)	Depth to HBL Conc. (ft)	Maximum Injectate Conc. (ppm)	Health-Based Limit Conc. (ppm)	Vertical Diffusion Distance (ft)	Depth to HBL Conc. (ft)
Cobalt	1	0.003	71.8	2568.2	25	0.003	92.9	2547.1	25	0.003	92.9	2547.1
Crotonaldehyde[2]									50	0.005	116.9	2523.1
Crotonitrile[1]					250	0.2	100.7	2539.3	250	0.2	100.7	2539.3
Cyanide Salts[2]									2,000	0.02	181.9	2458.1
Cyclohexane[2]									25	0.005	102.5	2537.5
Cyclohexanone[2]									25	5.0	35.3	2604.7
Dimethylhydantoin (DMH)[2]									250	1.0	74.0	2566.0
Ethyl Acetate[2]									25	0.9	60.1	2579.9
Ethylenediamine Tetraacetonitrile (EDTN)[2]									250	1.0	61.2	2578.8
Formaldehyde[2]					50	0.005	162.2	2477.8	1,000	0.2	154.2	2485.8
Formamide[2]									250	0.2	119.0	2521.0
Formic Acid[1]									1,000	0.009	157.1	2482.9
Fumaronitrile[1]					1,000	0.2	108.5	2531.5	1,000	0.2	108.5	2531.5
Furan[1]									25	0.001	132.2	2507.8
Furfural[1]									25	0.003	113.9	2526.1
Glycolonitrile[2]									1,000	0.2	123.0	2517.0
Hydrogen Cyanide, free	800	0.7	132.3	2507.7	800	0.7	132.2	2507.8	800	0.02	167.5	2472.5
Hydrogen Cyanide, total	8,000	0.7	155.9	2484.1	8,000	0.7	155.9	2484.1	5,300	0.02	183.7	2456.3

Constituent	1991 Original Modeling				1992 Update				1994 Update			
	Maximum Injectate Conc. (ppm)	Health-Based Limit Conc. (ppm)	Vertical Diffusion Distance (ft)	Depth to HBL Conc. (ft)	Maximum Injectate Conc. (ppm)	Health-Based Limit Conc. (ppm)	Vertical Diffusion Distance (ft)	Depth to HBL Conc. (ft)	Maximum Injectate Conc. (ppm)	Health-Based Limit Conc. (ppm)	Vertical Diffusion Distance (ft)	Depth to HBL Conc. (ft)
Iminodiacetonitrile (IDAN)[2]									250	1.0	78.2	2561.8
Isobutyl Alcohol[2]									50	0.3	78.7	2561.3
Isopropyl Alcohol[2]									300	0.3	101.1	2538.9
Lead[2]									25	0.001	115.4	2524.6
Maleic Anhydride[2]									25	0.1	90.0	2550.0
Maleonitrile[2]	500	0.04	120.7	2519.3	5,000	0.2	125.6	2514.4	5,000	0.2	117.2	2522.8
Malononitrile[1]					500	0.0042	136.3	2503.7	500	0.005	135.1	2504.9
Mercury[2]									25	0.002	143.7	2496.5
Methanol[1]					1,000	20.0	85.0	2555.0	10,000	0.5	148.2	2491.8
Methylacrylonitrile[1]					100	0.004	121.6	2518.4	100	1.0×10^{-4}	144.8	2495.2
Methylene Chloride[2]									25	0.005	119.2	2520.8
Methylethylhydantoin (MEH)[2]									250	1.0	71.1	2568.9
Methyl Ethyl Ketone[2]									250	0.6	89.0	2551.0
Methly Isobutyl Ketone[2]									25	0.005	97.4	2542.6
Methyl Pyridine	10	0.04	79.8	2560.2	250	0.04	104.8	2535.2	250	0.005	118.5	2421.5
Nickel	2	0.01	66.9	2573.1	25	0.01	84.3	2555.7	25	0.1	68.5	2571.5
Nicotinonitrile[1]					1,500	0.2	104.9	2535.1	1,500	0.1	109.5	2530.5
Nitrilotriacetonitrile (NTAN)[2]									250	1.0	70.9	2569.1
Nitrobenzene[1]									25	5.0×10^{-4}	115.8	2524.2

Constituent	1991 Original Modeling				1992 Update				1994 Update			
	Maximum Injectate Conc. (ppm)	Health-Based Limit Conc. (ppm)	Vertical Diffusion Distance (ft)	Depth to HBL Conc. (ft)	Maximum Injectate Conc. (ppm)	Health-Based Limit Conc. (ppm)	Vertical Diffusion Distance (ft)	Depth to HBL Conc. (ft)	Maximum Injectate Conc. (ppm)	Health-Based Limit Conc. (ppm)	Vertical Diffusion Distance (ft)	Depth to HBL Conc. (ft)
Oleic Acid(2)									250	1.0	54.8	2585.2
Oleoylsarcosinate(2)									250	1.0	52.1	2587.9
Phenol(2)									25	0.6	64.7	2575.3
Potassium Cyanide(2)									25	0.05	125.0	2515.0
Propionitrile	200	0.05	114.0	2526.0	500	0.005	137.5	2502.5	500	0.1	115.7	2524.3
Propylenediamine Tetraacetonitrile (PDTN)(2)									250	1.0	59.9	2580.1
Pyrrole(2)					1,000	0.04	127.8	2512.2	1,000	0.04	127.8	2512.2
Pyridine	200	0.04	93.7	2546.3	500	0.04	99.4	2540.6	500	0.001	119.8	2520.2
Selenium(2)									25	0.05	86.9	2553.1
Silver(2)									25	0.005	138.5	2501.5
Sodium Cyanide(2)									300	0.04	127.5	2512.5
Strontium	0.7	0.005	69.2	2570.9	25	0.005	95.8	2544.2	25	0.005	95.8	2544.2
Succinonitrile(2)					1,500	0.2	109.1	2530.9	1,500	0.1	113.8	2526.2
Tetrahydrofuran(2)									25	0.005	113.2	2526.8
Thiourea(2)									25	5.0×10^{-5}	146.0	2494.0
Toluene(2)									25	1.0	56.6	2583.4
Vanadium	0.5	0.002	63.9	2576.1	25	0.002	87.6	2552.4	25	0.004	83.8	2556.2
Vanadium Pentoxide(2)									100	0.009	175.0	2465.0

Constituent	1991 Original Modeling				1992 Update				1994 Update			
	Maximum Injectate Conc. (ppm)	Health-Based Limit Conc. (ppm)	Vertical Diffusion Distance (ft)	Depth to HBL Conc. (ft)	Maximum Injectate Conc. (ppm)	Health-Based Limit Conc. (ppm)	Vertical Diffusion Distance (ft)	Depth to HBL Conc. (ft)	Maximum Injectate Conc. (ppm)	Health-Based Limit Conc. (ppm)	Vertical Diffusion Distance (ft)	Depth to HBL Conc. (ft)
Xylene[(7)]									25	1.0	52.3	2587.7
Zinc	0.056	0.004	44.2	2595.8	25	0.004	92.2	2547.8	25	0.3	61.4	2578.6

(1) New compound since 1992.
(2) Include for information only.
(7) New compound since 1993.
(4) The difference between the 1992 migration distance and the 1993 and 1994 migration distances is due to an update in the free-water diffusivity.
(5) The difference between the 1993 and 1994 migration distances is due to an update in the free-water diffusivity.

INEOS USA LLC
Lima, Ohio
WDW #2

ATTACHMENT E

CORRECTIVE ACTION PLAN

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 and the Cone of Influence (Section 5.0). In the 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 6-mile-by-6-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 to April 2010. Well records are provided in Appendix 6-2. Wellbore schematics for the sub-1800 foot wells are provided as Figures 6-1 through 6-9. No wells penetrated 1800 feet since the last records search (1998). In addition, map PG-2 (Revised 8/2004), which plots wells drilled below the Knox Dolomite published by the ODNR, DGS, was utilized (Figure 6-10).

As shown in Table 6-1 and on Figure 6-10, the only wells within the 10-mile AOR that have recorded depths below the base of the Knox Dolomite are the INEOS injection wells and the Hubbard, D-1, Permit No. 60668 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). Records for these wells are considered to be sufficiently incomplete, that further research was warranted. The state of records and other information is discussed below:

- The permit numbers for these wells do not fit the normal ODNR numbering sequence, suggesting that their status as existing wells is provisional.
- The D-1 well (2630 feet) does not appear on the PG-2 Map (Figure 6-10) 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 (as of 1991) Shawnee township map. For investigative purposes, the No. 6 well location was assumed to be correct on the current map as of 1991. 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 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 over-conservative choice for the area of investigation of artificial penetrations.

It should be noted that many of the wells spotted on the maps on-file with the state, 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 wells documented to have penetrated 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 within the AOR.

Water Well Search

Water well locations are plotted on Drawings 6-2, 6-3, and 6-4. 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 on Drawing 2-1.

Mines, Karst Areas, Flood Areas and Other Features

Several quarries and gravel pits are present within the AOR (Drawings 6-2 and 6-3). 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 6-11) 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 (Drawings 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 6-12; 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 6-13). 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 commercial oil and gas production has been established from any sub-Knox Dolomite formations in Ohio (Harris and Baranoski, 1996). Therefore, there has been no commercial oil and gas production from the confining or injection zones.

ATTACHMENT F

QUALITY ASSURANCE ACKNOWLEDGMENT

ATTACHMENT F

QUALITY ASSURANCE ACKNOWLEDGMENT

I hereby affirm that all chemical data submitted for Injection Well Permit No. ____*____ 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, analytical records or 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

*
03-02-003-PTO-I
03-02-004-PTO-I
03-02-005-PTO-I
03-02-006-PTO-I

For ______________________________ Name of Company

INEOS USA LLC
Lima, Ohio
WDW #2

ATTACHMENT G

CERTIFICATION PURSUANT TO OAC RULE 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 2008.